May 14, 2025

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Post Office Box 30221
Lansing, MI 48909

Re: MPSC Case No. U-21806 – In the matter of the application of Consumers Energy Company for authority to increase its rates for the distribution of natural gas and for other relief.

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned case, please find the **Redacted Rebuttal Testimony and Exhibits of Consumers Energy Company's Witnesses**. This is a paperless filing and is therefore being filed only in PDF. Also included are an updated Company Exhibit List, Table of Disputed Issues, and a Proof of Service showing electronic service upon the parties.

Confidential materials of Company witnesses Stacy H. Baker, Neal P. Dreisig, Quentin A. Guinn, and James P. Pnacek are being filed under seal with the Michigan Public Service Commission.

Sincerely,

Digitally signed by Anne M. Uitvlugt
Date: 2025.05.14 14:23:30 -04'00'

Anne M. Uitvlugt
Phone: 517-788-2112
Email: anne.uitvlugt@cmsenergy.com

cc: Parties to Attachment 1 to the Proof of Service

Line No.	Exhibit #	Schedule #	Witness	Witness Exhibit #	Description
	(a)	(b)	(c)	(d)	(e)
	Historical Year Section				
1	A-1	A-1	Rayl, Heather L.	HLR-1	Revenue Deficiency (Sufficiency) for the Historical Year Ended December 31, 2023
2	A-1	A-2	Rayl, Heather L.	HLR-2	Financial Metrics - Gas Results Only
3	A-2	B-1	Rayl, Heather L.	HLR-3	Rate Base for the Historical Year Ended December 31, 2023
4	A-2	B-2	Rayl, Heather L.	HLR-4	Total Utility Plant for the Historical Year Ended December 31, 2023
5	A-2	B-3	Rayl, Heather L.	HLR-5	Depreciation Reserve and Other Deductions for the Historical Year Ended December 31, 2023
6	A-2	B-4	Rayl, Heather L.	HLR-6	Working Capital for the Historical Year Ended December 31, 2023
7	A-2	B-5	Rayl, Heather L.	HLR-7	13-Month Average Balance Sheet for the Historical Year Ended December 31, 2023
8	A-2	B-6	Rayl, Heather L.	HLR-8	Point-in-Time Balance Sheet for the Historical Year Ended December 31, 2023
9	A-3	C-1	Rayl, Heather L.	HLR-9	Adjusted Net Operating Income for the Historical Year Ended December 31, 2023
10	A-3	C-2	Rayl, Heather L.	HLR-10	Revenue Conversion Factor for the Historical Year Ended December 31, 2023
11	A-3	C-3	Rayl, Heather L.	HLR-11	Operating Revenue for the Historical Year Ended December 31, 2023
12	A-3	C-4	Rayl, Heather L.	HLR-12	Cost of Gas Sold for the Historical Year Ended December 31, 2023
13	A-3	C-5	Rayl, Heather L.	HLR-13	Operation and Maintenance Expenses for the Historical Year Ended December 31, 2023
14	A-3	C-5.1	Rayl, Heather L.	HLR-14	Operation and Maintenance Expenses by Witness for the Historical Year Ended December 31, 2023
15	A-3	C-6	Rayl, Heather L.	HLR-15	Depreciation and Amortization Expenses for the Historical Year Ended December 31, 2023
16	A-3	C-7	Rayl, Heather L.	HLR-16	General Taxes for the Historical Year Ended December 31, 2023
17	A-3	C-8	Rayl, Heather L.	HLR-17	Federal Income Taxes for the Historical Year Ended December 31, 2023
18	A-3	C-9	Rayl, Heather L.	HLR-18	State Income Taxes for the Historical Year Ended December 31, 2023
19	A-3	C-10	Rayl, Heather L.	HLR-19	Other (or Local) Taxes for the Historical Year Ended December 31, 2023
20	A-3	C-11	Rayl, Heather L.	HLR-20	Allowance for Funds Used During Construction for the Historical Year Ended December 31, 2023
21	A-3	C-12	Rayl, Heather L.	HLR-21	Income Tax Effect of Interest for the Historical Year Ended December 31, 2023
22	A-3	C-13	Rayl, Heather L.	HLR-22	Interest Synchronization Adjustment for the Historical Year Ended December 31, 2023
23	A-4	D-1	Rayl, Heather L.	HLR-23	Capital Structure and Rate of Return Summary for the Historical Year Ended December 31, 2023
24	A-4	D-2	Rayl, Heather L.	HLR-24	Cost of Long-Term Debt (Excluding Securitization) for the Historical Year Ended December 31, 2023
25	A-4	D-3	Rayl, Heather L.	HLR-25	Cost of Short-Term Debt for the Historical Year Ended December 31, 2023
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27	A-4	D-5	Rayl, Heather L.	HLR-27	Cost of Common Shareholder's Equity for the Historical Year Ended December 31, 2023
28	A-5	E-1	Ahmed, Mustafa	MA-1	Annual Service Area Deliveries by Major Customer Classes and System Output 5-Year Historical
29	A-5	E-1a	Ahmed, Mustafa	MA-2	Summary of 2023 Historical Year Revenues
30	A-5	E-2	Ahmed, Mustafa	MA-3	2023 Historical Year Consumption and Customer Counts
31	A-5	E-3	Ahmed, Mustafa	MA-4	2023 Historical Year Operating Revenues
32	A-6	-	-	-	Exhibit Number Intentionally Left Blank
33	A-7	-	-	-	Exhibit Number Intentionally Left Blank
34	A-8	-	-	-	Exhibit Number Intentionally Left Blank

35	A-6	-	-	-	Exhibit Number Intentionally Left Blank
36	A-7	-	-	-	Exhibit Number Intentionally Left Blank
37	A-8	-	-	-	Exhibit Number Intentionally Left Blank
38	A-9	-	-	-	Exhibit Number Intentionally Left Blank
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Test Year Section

40	A-11	A-1	Rayl, Heather L.	HLR-28	Revenue Deficiency (Sufficiency) for the Projected 12-Month Period Ending October 31, 2026
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43	A-12	B-1	Rayl, Heather L.	HLR-31	Rate Base for the Projected 12-Month Period Ending October 31, 2026
44	A-12	B-2	Rayl, Heather L.	HLR-32	Total Utility Plant for the Projected 12-Month Period Ending October 31, 2026
45	A-12	B-3	Rayl, Heather L.	HLR-33	Depreciation Reserve and Other Deductions for the Projected 12-Month Period Ending October 31, 2026
46	A-12	B-4	Rayl, Heather L.	HLR-34	Working Capital for the Projected 12-Month Period Ending October 31, 2026
47	A-12	B-5	Rayl, Heather L.	HLR-35	Capital Expenditures Summary for the Projected 12-Month Period Ending October 31, 2026
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49	A-12	B-5.2	Ballinger, Corey E.	CEB-1	Summary of Actual & Projected Capital Expenditures Fleet Services
50	A-12	B-5.3	Byrom, Jessica R.	JRB-1	Actual and Projected Capital Expenditures - Customer Experience & Operations
51	A-12	B-5.4	Foster, Matthew J.	MJF-12	Gas Projected Corporate Services Capital Expense for the Years 2023, 2024, 2025; and the 12 Months Ending October 31, 2026
52	A-12	B-5.5	Griffin, Michael P.	MPG-2	Summary of Actual and Projected Capital Expenditures Transmission & Distribution Plant - Summary of Actual & Projected Gas Capital Expenditures - **REVISED**
53	A-12	B-5.6	Guinn, Quentin A.	QAG-1	Summary of Actual & Projected Capital Expenditures
54	A-12	B-5.7	Joyce, Timothy K.	TKJ-5	Projected Capital Expenditures Gas Compression and Gas Storage Summary of Actual & Projected Gas Capital Expenditures
55	A-12	B-5.8	Pascarello, Kristine A.	KAP-3	Projected Capital Expenditures, Distribution Plant – Material Condition and Gas Operations Other, Summary of Actual & Projected Gas and Common Capital Expenditures
56	A-12	B-5.9	Warriner, Lincoln D.	LDW-1	Projected Capital Expenditures, Distribution Plant, Summary of Actual & Projected Gas and Common Capital Expenditures
57	A-13	C-1	Rayl, Heather L.	HLR-36	Adjusted Net Operating Income for the Projected 12-Month Period Ending October 31, 2026
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59	A-13	C-2	Rayl, Heather L.	HLR-38	Calculation of the Revenue Conversion Factor for the Projected 12-Month Period Ending October 31, 2026
60	A-13	C-3	Rayl, Heather L.	HLR-39	Operating Revenues for the Projected 12-Month Period Ending October 31, 2026
61	A-13	C-4	Rayl, Heather L.	HLR-40	Cost of Gas Sold for the Projected 12-Month Period Ending October 31, 2026
62	A-13	C-5	Rayl, Heather L.	HLR-41	Operation and Maintenance Expenses for the Projected 12-Month Period Ending October 31, 2026
63	A-13	C-5.1	Rayl, Heather L.	HLR-42	Summary of Inflation and Merit Increases Included in Operation and Maintenance Expenses for the Projected 12-Month Period Ending October 31, 2026
64	A-13	C-6	Rayl, Heather L.	HLR-43	Depreciation and Amortization Expenses for the Projected 12-Month Period Ending October 31, 2026
65	A-13	C-7	Rayl, Heather L.	HLR-44	General Taxes for the Projected 12-Month Period Ending October 31, 2026
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69	A-13	C-11	Rayl, Heather L.	HLR-48	Allowance for Funds Used During Construction for the Projected 12-Month Period Ending October 31, 2026

70	A-13	C-12	Rayl, Heather L.	HLR-49	Income Tax Effect of Interest for the Projected 12-Month Period Ending October 31, 2026
71	A-13	C-13	Rayl, Heather L.	HLR-50	Interest Synchronization Adjustment for the Projected 12-Month Period Ending October 31, 2026
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79	A-14	D-6	Bleckman, Marc R.	MRB-7	Short-Term Debt Utilization
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89	A-15	E-10	Ahmed, Mustafa	MA-14	Transition from 2023 Historic Actuals to 12 Months Ending October 2026 Test-Year Revenues, Deliveries, and Customers
90	A-16	F-1	Geller, Samuel M.	SMG-1	Gas Cost-of-Service Study – Version 1 - Projected 12 Month Period: November 2025 – October 2026
91	A-16	F-1.1	Geller, Samuel M.	SMG-2	Gas Cost-of-Service Study – Version 2 - Projected 12 Month Period: November 2025 – October 2026
92	A-16	F-2	Smith, S. Austin	SAS-1	Summary of Present and Proposed Revenue by Rate Schedule
93	A-16	F-2.1	Smith, S. Austin	SAS-2	Summary of Present and Proposed Rates by Rate Schedule
94	A-16	F-2.2	Smith, S. Austin	SAS-3	Calculation of Rate Design Targets
95	A-16	F-3	Smith, S. Austin	SAS-4	Present and Proposed Revenue Detail
96	A-16	F-4	Smith, S. Austin	SAS-5	Comparison of Present and Proposed Monthly Bills
97	A-16	F-5	Harrington, Kirkland D.	KDH-2	Proposed Tariff Sheets (MPSC No.3 Redlined Version)
98	A-17		Baker, Stacy H.	SHB-1	Summary of Actual and Projected Information Technology Operations O&M Expense for the Years 2023, 2024, 2025, and Test Year 12 Months Ending October 31, 2026
99	A-18		Baker, Stacy H.	SHB-2	Historical and Projected 13-Month Average of IT Cloud Computing Prepaid Balance for the historical years 2023 - 13-month balance ending December 31, 2024, and for the projected years 2025 – 13-month balance ending October 31, 2026
100	A-19		Baker, Stacy H.	SHB-3	Summary of Actual and Projected Information Technology Investments O&M Expense for the Years 2023, 2024, 2025, and Test Year 12 Months Ending October 31, 2026
101	A-20		Baker, Stacy H.	SHB-5	Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses for the Years 2023, 2024, 2025, and 2026 - Confidential
102	A-21		Baker, Stacy H.	SHB-6	Business Case Executive Summaries for Historical, Bridge Period, and Test Year Projects - Confidential
103	A-22		Baker, Stacy H.	SHB-7	Asset Refresh Programs Projected Gas and Common Capital Expenditures, For the Projected Year 2025 and Test Year Ending October 31, 2026, and For the Historical and Projected Years 2023 and 2024
104	A-23		Baker, Stacy H.	SHB-8	Application Currency Programs Projected Gas and Common Capital and O&M Expenditures for the Years 2025, 2026, and Test Year 12 Months Ending October 31, 2026 - Confidential
105	A-24		Baker, Stacy H.	SHB-9	Projected Versus Actual Enhancement Capital Expenditures and O&M Expense Summary and Analysis
106	A-25		Baker, Stacy H.	SHB-10	Enhancement Worklist Detail for Years 2016 through March 15, 2024
107	A-26		Baker, Stacy H.	SHB-11	Projected 13-Month Average of IT S4/HANA Cloud Implementation Costs for the projected years 2025 – 13-month balance ending October 31, 2026 - Confidential
108	A-27		Ballinger, Corey E.	CEB-2	Fleet Responsibility Costs
109	A-28		Ballinger, Corey E.	CEB-3	Detailed List of Projected Gas Capital Expenditures Fleet Services for the Years 2023, 2024, 2025 and test year 12 months ending October 31, 2026

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116	A-35	Bleckman, Marc R.	MRB-13	Cumulative Annual Interest Savings
117	A-36	Bleckman, Marc R.	MRB-14	S&P Global August 7, 2024 Report – RRA State Regulatory Evaluations – Energy
118	A-37	Byrom, Jessica R.	JRB-2	Summary of Actual & Projected O&M Expenses – Customer Experience, Customer Operations: Customer Interactions
119	A-38	Byrom, Jessica R.	JRB-3	Summary of Actual & Projected O&M Expenses – Third-party ASP - Confidential
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122	A-41	Conrad, Amy M.	AMC-3	Summary of Actual and Projected – Annual Incentive O&M Expenses
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126	A-45	Foster, Matthew J.	MJF-3	Gas Uncollectible Accounts Expense for the Years 2023, 2024, 2025; and the 12 Months Ending October 31, 2026
127	A-46	Foster, Matthew J.	MJF-4	Gas Injuries and Damages Expense for the Years 2019 through the 12 Months Ending October 31, 2026
128	A-47	Foster, Matthew J.	MJF-5	Manufactured Gas Plant Amortization Schedule and Direct Project Management Costs 2005 through the 12 Months Ending October 31, 2026
129	A-48	Foster, Matthew J.	MJF-6	Organization Chart, Affiliate Group of Companies Doing Business with Consumers Energy Company – 2023; and Purpose of Business, Affiliate Group of Companies Doing Business with Consumers Energy Company – 2023
130	A-49	Foster, Matthew J.	MJF-7	Summary of Costs Billed to Affiliated Companies for the Year Ended December 31, 2023; and Summary of Payments Made to Affiliated Companies for the Year Ended December 31, 2023
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137	A-56	Geller, Samuel M.	SMG-5	Gas Cost-of-Service Study – ABATE Witness Jonathan Ly's Direct Testimony Pages 11-12 (Average & Excess) Case U-21490
138	A-57	Geller, Samuel M.	SMG-6	Detailed Analysis of FERC Account 378
139	A-58	Griffin, Michael P.	MPG-1	Summary of Actual & Projected Regulatory Compliance O&M Expenses
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141	A-60	Griffin, Michael P.	MPG-4	Actual & Projected Gas Transmission Capital Expenditures – Regulatory Compliance Program
142	A-61	Griffin, Michael P.	MPG-5	Actual & Projected Gas Transmission and Distribution Capital Expenditures - Capacity/Deliverability Program
143	A-62	Griffin, Michael P.	MPG-6	Actual & Projected Gas Capital Expenditures - Transmission & Distribution Plant - TED-I Program Detail - **REVISED**
144	A-63	Griffin, Michael P.	MPG-7	Projected Capital Expenditures - Transmission & Distribution Plant, Summary of Actual & Projected Gas Capital Expenditures
145	A-64	Grob, Kendra K.	KKG-1	Summary of Actual and Projected Benefits O&M Expenses for the Year 2023 and Test Year Twelve Months Ending October 31, 2026
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157	A-76	Joyce, Timothy K.	TKJ-6	Storage Well Rehabilitation Program Detail
158	A-77	Joyce, Timothy K.	TKJ-7	Storage Fields Month End Summary
159	A-78	-	-	Exhibit Number Intentionally Left Blank
160	A-79	Myers, Heidi J.	HJM-1	SAP S/4HANA Implementation Project – Revenue Deficiency Impact of O&M Deferral - Confidential
161	A-80	Pascarello, Kristine A.	KAP-1	Summary of Actual & Projected O&M Expenses, Gas Engineering and Supply
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164	A-83	Pascarello, Kristine A.	KAP-5	Actual & Projected Gas & Common Capital Expenditures - Gas Operations Other Program
165	A-84	Pascarello, Kristine A.	KAP-6	Detailed Summary of Actual and Projected Capital Expenses – Enhanced Infrastructure Replacement Program
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178	A-97	Meschke, Ashley E.	AEM-3	2024 Customer Benefits: Reliability
179	A-98	Meschke, Ashley E.	AEM-4	2024 Customer Benefits: Culture Index – Reduced Employee
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183	A-102	Warriner, Lincoln D.	LDW-3	Actual & Projected Gas Capital Expenditures - Asset Relocation Program
184	A-103	Warriner, Lincoln D.	LDW-4	Actual & Projected Gas Capital Expenditures - Regulatory Compliance Program
185	A-104	Warriner, Lincoln D.	LDW-5	Actual & Projected Gas Capital Expenditures – Capacity/ Deliverability Program
186	A-105	Warriner, Lincoln D.	LDW-6	Projected Capital Expenditures – Transmission & Distribution Plant, Summary of Actual & Projected Gas Capital Expenditures
187	A-106	Bleckman, Marc R.	MRB-15	UBS May 10, 2023 Report
188	A-107	Bleckman, Marc R.	MRB-16	S&P February 14, 2024 Report
189	A-108	Smith, S. Austin	SAS-6	Development of Rates for Transportation ATL Services
190	A-109	Baker, Stacy H.	SHB-12	Audit Response No. U21806-SA-CE-409
191	A-110	Baker, Stacy H.	SHB-13	Discovery Response No. U21806-AG-CE-0615
192	A-111	Baker, Stacy H.	SHB-14	Discovery Response No. U21806-AG-CE-0616-Revised

193	A-112		Baker, Stacy H.	SHB-15	Audit Response No. U21806-SA-CE-176
194	A-113		Baker, Stacy H.	SHB-16	Discovery Response Nos. U21806-CUB-CE-0121 through 0126 and U21806-AG-CE-0613, 0614, and 0847
195	A-114		Bleckman, Marc R.	MRB-17	S&P January 14, 2025 Report
196	A-115		Bleckman, Marc R.	MRB-18	MPSC Staff's Answer to Consumers Energy's Second Discovery Request
197	A-116		Bleckman, Marc R.	MRB-19	S&P August 20, 2024 Credit Report
198	A-117		Bleckman, Marc R.	MRB-20	Moody's May 31, 2024 Credit Report
199	A-118		Bleckman, Marc R.	MRB-21	Attorney General's Answer to Consumers Energy's Third Discovery Request
200	A-119		Bonner, Luther A.	LAB-1	Footage Allowance & Excess Service Charge Trends 2003-2025
201	A-120		Bonner, Luther A.	LAB-2	Excess Service Cost Formula
202	A-121		Bonner, Luther A.	LAB-3	CE Gas Consumption Jan2020-Jan2025
203	A-122		Bonner, Luther A.	LAB-4	Customer Gas Service Retirement Trend
204	A-123		Bonner, Luther A.	LAB-5	MPSC-MNS CAP Conversion Update Sep 2022
205	A-124		Bonner, Luther A.	LAB-6	Average Vintage Year Gas Retirements
206	A-125		Bonner, Luther A.	LAB-7	Customer Gas Alteration Trend
207	A-126		Bonner, Luther A.	LAB-8	MPSC CAP Pricing Update March 2023
208	A-127		Bulkley, Ann E.	AEB-2	Cost of Common Shareholder's Equity
209	A-128		Bulkley, Ann E.	AEB-3	Jurisdictions Using ECAPM
210	A-129		Byrom, Jessica R.	JRB-4	LMI Mindset Map
211	A-130		Conrad, Amy M.	AMC-4	Audit Response U21806-SA-CE-028_Conrad_ATT_1
212	A-131		Dreisig, Neal P.	NPD-2	Discovery Response Nos. U21806-MNSC-CE-0039, 0066-CONF, 0573, and 0771
213	A-132	-	-	-	Exhibit Number Intentionally Left Blank
214	A-133	-	-	-	Exhibit Number Intentionally Left Blank
215	A-134		Foster, Matthew J.	MJF-13	Gas General Activities Labor Expense
216	A-135		Griffin, Michael P.	MPG-8	Workpapers, WP-MPG-13, WP-MPG-15, WP-MPG-17 and WP-MPG-19
217	A-136		Griffin, Michael P.	MPG-9	Response to Discovery Request U-21806-CECo-AG_DR2
218	A-137		Griffin, Michael P.	MPG-10	Response to Discovery Request U-21806-CUB-CE-0248
219	A-138		Pascarello, Kristine A.	KAP-8	Discovery Response U21806-AG-CE-0431, Attachment 1
220	A-139		Pascarello, Kristine A.	KAP-9	Discovery Response U21806-AG-CE-0426
221	A-140		Pascarello, Kristine A.	KAP-10	Audit Response U21806-SA-CE-0388
222	A-141		Pascarello, Kristine A.	KAP-11	Discovery Response U21806-MNSC-CE-0075, Attachment 2
223	A-142		Pascarello, Kristine A.	KAP-12	EIRP Project List Detail
224	A-143		Pnacek, James P.	JPP-5	Staking Bid Analysis - Confidential
225	A-144		Pnacek, James P.	JPP-6	Staking Bidder List and Summary - Confidential
226	A-145		Pnacek, James P.	JPP-7	EIRP OM&C Headcount Analysis
227	A-146		Rayl, Heather L.	HLR-52	Adjusted Revenue Deficiency for the Projected 12-Month Period Ending October 31, 2026
228	A-147		Rayl, Heather L.	HLR-53	Adjusted Rate Base for the Projected 12-Month Period Ending October 31, 2026
229	A-148		Rayl, Heather L.	HLR-54	Adjusted Utility Plant for the Projected 12-Month Period Ending October 31, 2026
230	A-149		Rayl, Heather L.	HLR-55	Capital Spending Reconciliation for the Projected 12-Month Period Ending October 31, 2026
231	A-150		Rayl, Heather L.	HLR-56	Adjusted Working Capital for the Projected 12-Month Period Ending October 31, 2026
232	A-151		Rayl, Heather L.	HLR-57	Adjusted Net Operating Income for the Projected 12-Month Period Ending October 31, 2026
233	A-152		Rayl, Heather L.	HLR-58	Reconciliation of Adjusted Net Operating Income for the Projected 12-Month Period Ending October 31, 2026
234	A-153		Rayl, Heather L.	HLR-59	Adjusted Operations & Maintenance Expenses for the Projected 12-Month Period Ending October 31, 2026
235	A-154		Rayl, Heather L.	HLR-60	Income Tax Effect of Interest for the Projected 12-Month Period Ending October 31, 2026
236	A-155		Rayl, Heather L.	HLR-61	Interest Synchronization Adjustment for the Projected 12-Month Period Ending October 31, 2026
237	A-156		Smith, S. Austin	SAS-9	Discovery Response No. U21806-CE-MNSC-0005
238	A-157		Snyder, Brian M.	BMS-1	Response to Discovery Requests U21806-MNSC-CE-80, and U-21806-MNSC-CE-218 through 285
239	A-158		Baker, Stacy H.	SHB-17	Discovery Response No. U21806-AG-CE-0852, Attachment 2

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

REDACTED

REBUTTAL TESTIMONY

OF

STACY H. BAKER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Q. Please state your name and business address.

A. My name is Stacy H. Baker, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Stacy H. Baker who provided direct testimony in this proceeding on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the testimony and exhibits submitted by the Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff"), Attorney General witness Sebastian Coppola, and Citizens Utility Board of Michigan ("CUB") witness Joshua W. Denzler in this case concerning the Information Technology ("IT") Department's Operations and Maintenance ("O&M") expenses and capital expenditures. Specifically, I will respond to:

- Staff witness Emma Zichi's proposed adjustments to IT Investments O&M and capital expenditures to correct errors discovered through audit and discovery;
- Staff witness Zichi's proposed adjustments to IT capital expenditures for Asset Refresh Program ("ARP")-Field Device Asset Management ("FDAM") and ARP-Workstation Asset Management ("WAM");
- Staff witness Zichi's proposed recommendations for the SAP S/4HANA Implementation project; and
- Staff witness Brittney Klocke's proposed adjustments to IT capital expenditures and IT Investments O&M expenses for the Product Family Enhancements-Customer-Capital and Click to Chat projects.

I will also respond to Attorney General witness Coppola's proposed adjustments to IT capital expenditures and IT Investments O&M expenses.

I will also respond to CUB witness Denzler's proposed adjustments to IT capital expenditures and IT Investments O&M expenses.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes.

Exhibit A-109 (SHB-12)	Audit Response No. U21806-SA-CE-409;
Exhibit A-110 (SHB-13)	Discovery Response No. U21806-AG-CE-0615;
Exhibit A-111 (SHB-14)	Discovery Response No. U21806-AG-CE-0616-Revised;
Exhibit A-112 (SHB-15)	Audit Response No. U21806-SA-CE-176;
Exhibit A-113 (SHB-16)	Discovery Response Nos. U21806-CUB-CE-0121 through 0126 and U21806-AG-CE-0613, 0614, and 0847; and
Exhibit A-158 (SHB-17)	Discovery Response No. U21806-AG-CE-0852, Attachment 2.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

MPSC STAFF

Q. What project is Staff witness Zichi proposing adjustments for in this case?

A. On page 3, line 8, through page 4, line 3, of her direct testimony, Staff witness Zichi is proposing an adjustment for the Application Currency-Corporate-Capital project.

Q. What amount is Staff witness Zichi proposing to adjust for the Application Currency-Corporate-Capital project?

A. Based on Staff witness Zichi's Exhibit S-19.0, line 1, she is proposing an adjustment of $15,010 for the projected bridge period, $18,013 for the projected test year of capital expenditures, and $1,991 for the projected test year O&M for the Application Currency-Corporate-Capital project.

Q. Do you agree with Staff witness Zichi's proposed adjustment to the Application Currency-Corporate-Capital project?

A. Yes. The Company agrees with the basis of the proposed adjustment as explained in its response to Staff Discovery request U21806-ST-CE-0004 CONF (Exhibit S-19.2, page 2) that the 2025 and 2026 capital hardware/storage upgrade costs in each year were overstated by $15,010 for the bridge year, $18,013 for the projected test year, and $1,991 for the projected test year O&M. As a result, the capital expenditures for the projected bridge period and projected test year should be adjusted by $15,010 and $18,013, respectively, and $1,991 for test year O&M.

Q. What additional project is Staff witness Zichi proposing adjustments for in this case?

A. On page 4, lines 4 through 17, of her direct testimony, Staff witness Zichi is proposing an adjustment for the HR Support Pack and Business Software Inc Upgrade 2025 project.

Q. What amount is Staff witness Zichi proposing to adjust for the HR Support Pack and Business Software Inc Upgrade 2025 project?

A. Based on Staff witness Zichi's Exhibit S-19.0, line 2, she is proposing an adjustment of $20,119 for the projected test year O&M for the HR Support Pack and Business Software Inc Upgrade 2025 project.

Q. Do you agree with Staff witness Zichi's proposed adjustment to the HR Support Pack and Business Software Inc Upgrade 2025 project?

A. Yes. The Company agrees with the basis of the proposed adjustment as explained in its response to Staff Audit request U21806-SA-CE-049-Revised (Exhibit S-19.1, pages 3 and 4) that the O&M costs were overstated by $20,119 for the projected test year O&M. As a result, the expenses for the test year O&M should be adjusted by $20,119.

Q. What additional project is Staff witness Zichi proposing adjustments for in this case?

A. On page 4, line 18, through page 5, line 9, of her direct testimony, Staff witness Zichi is proposing an adjustment for the HR Support Pack and Business Software Inc Upgrade 2026 project.

Q. What amount is Staff witness Zichi proposing to adjust for the HR Support Pack and Business Software Inc Upgrade 2026 project?

A. Based on Staff witness Zichi's Exhibit S-19.0, line 3, she is proposing an adjustment of $40,454 for the projected test year O&M for the HR Support Pack and Business Software Inc Upgrade 2026 project.

Q. Do you agree with Staff witness Zichi's proposed adjustment to the HR Support Pack and Business Software Inc Upgrade 2026 project?

A. Yes. The Company agrees with the basis of the proposed adjustment as explained in its response to Staff Audit request U21806-SA-CE-049-Revised (Exhibit S-19.1, pages 3 and 4) that the O&M costs were overstated by $40,454 for the projected test year O&M. As a result, the expenses for the test year O&M should be adjusted by $40,454.

Q. What additional project is Staff witness Zichi proposing adjustments for in this case?

A. On page 5, line 16, through page 6, line 12, of her direct testimony, Staff witness Zichi is proposing an adjustment for the Application Currency-Electric & Gas Shared-Capital project.

Q. What amount is Staff witness Zichi proposing to adjust for the Application Currency-Electric & Gas Shared-Capital project?

A. Based on Staff witness Zichi's Exhibit S-19.0, line 9, she is proposing an adjustment of $19,146 for the projected bridge period, $22,975 for the projected test year of capital

expenditures, and $7,962 for the projected test year O&M for the Application Currency-Electric & Gas Shared-Capital project.

Q. Do you agree with Staff witness Zichi's proposed adjustment to the Application Currency-Electric & Gas Shared-Capital project?

A. Yes. The Company agrees with the basis of the proposed adjustment as explained in its response to Staff Audit request U21490-ST-CE-0003 CONF (Exhibit S-19.2, page 1) that the 2025 and 2026 capital hardware/storage upgrade costs in each year were overstated by $19,146 for the bridge year, $22,975 for the projected test year, and $7,962 for the projected test year O&M. As a result, the capital expenditures for the projected bridge period and projected test year should be adjusted by $19,146 and $22,975, respectively, and $7,962 for test year O&M.

Q. What additional project is Staff witness Zichi proposing adjustments for in this case?

A. On page 6, line 13, through page 7, line 1, of her direct testimony, Staff witness Zichi is proposing an adjustment for the Standard Work Plan project.

Q. What amount is Staff witness Zichi proposing to adjust for the Standard Work Plan project?

A. Based on Staff witness Zichi's Exhibit S-19.0, line 10, she is proposing an adjustment of $70,665 for the projected test year O&M for Standard Work Plan project.

Q. Do you agree with Staff witness Zichi's proposed adjustment to the Standard Work Plan project?

A. Yes. The Company agrees with the basis of the proposed adjustment as explained in its response to Staff Audit request U21806-SA-CE-075 (Exhibit S-19.1, page 5 and 6) that the O&M costs were overstated by $70,665 due to ongoing support costs being inadvertently

added for the projected test year O&M. As a result, the expenses for the test year O&M should be adjusted by $70,665.

Q. What additional project is Staff witness Zichi proposing adjustments for in this case?

A. On page 7, lines 2 through 19, of her direct testimony, Staff witness Zichi is proposing an adjustment for the Next Generation electronic Shift Operations Management System (eSOMS) Replacement project.

Q. What amount is Staff witness Zichi proposing to adjust for the Next Generation electronic Shift Operations Management System (eSOMS) Replacement project?

A. Based on Staff witness Zichi's Exhibit S-19.0, line 11, she is proposing an adjustment of $125,746 for the projected test year capital expenditures, and $8,243 for the projected test year O&M for the Next Generation electronic Shift Operations Management System (eSOMS) Replacement project.

Q. Do you agree with Staff witness Zichi's proposed adjustment to the Next Generation electronic Shift Operations Management System (eSOMS) Replacement project?

A. Yes. The Company agrees with the basis of the proposed adjustment as explained in its response to Staff Audit request U21806-SA-CE-076 (Exhibit S-19.1, page 7) that the projected gas allocation capital and O&M should be reduced by $125,746 for the projected test year, and $8,243 for the projected test year O&M. As a result, the capital expenditures for the projected test year should be adjusted by $125,746 and $8,243 for test year O&M.

Q. What additional project is Staff witness Zichi proposing adjustments for in this case?

A. On page 8, lines 4 through 17, of her direct testimony, Staff witness Zichi is proposing an adjustment for the ARP-Collaboration project.

Q. What amount is Staff witness Zichi proposing to adjust for the ARP-Collaboration project?

A. Based on Staff witness Zichi's Exhibit S-19.0, line 13, she is proposing an adjustment of $6,015 for the projected bridge period, and $7,219 for the projected test year capital expenditures for the ARP-Collaboration project.

Q. Do you agree with Staff witness Zichi's proposed adjustment to the ARP-Collaboration project?

A. Yes. The Company agrees with the basis of the proposed adjustment as explained in its response to Staff Audit request U21806-SA-CE-178 (Exhibit S-19.1, page 8 and 9) that the 2025 and 2026 capital hardware/storage upgrade costs in each year were overstated by $6,015 for the bridge year and $7,219 for the projected test year. As a result, the capital expenditures for the projected bridge period and projected test year should be adjusted by $6,015 and $7,219, respectively.

Q. What additional project is Staff witness Zichi proposing adjustments for in this case?

A. On page 13, lines 9 through 21, of her direct testimony, Staff witness Zichi is proposing an adjustment for the ARP-Physical Security project.

Q. What amount is Staff witness Zichi proposing to adjust for the ARP-Physical Security project?

A. Based on Staff witness Zichi's Exhibit S-19.0, line 17, she is proposing an adjustment of $72,640 for the projected bridge period, $108,960 for the projected test year of capital expenditures for the ARP-Physical Security project.

Q. Do you agree with Staff witness Zichi's proposed adjustment to the ARP-Physical Security project?

A. Yes. The Company agrees with the basis of the proposed adjustment as explained in its response to Staff Audit request U21806-SA-CE-018-Revised (Exhibit S-19.1, page 1 and 2) that the 2025 and 2026 capital hardware/storage upgrade costs in each year were overstated by $72,640 for the bridge year and $108,960 for the projected test year. As a result, the capital expenditures for the projected bridge period and projected test year should be adjusted by $72,640 and $108,960, respectively.

Q. What adjustments is Staff witness Zichi proposing for the ARP-FDAM project in this case?

A. On page 8, line 18, through page 9, line 4, of her direct testimony, Staff witness Zichi is proposing full disallowance of the new field device purchases of $831,046 for the 10-month bridge period ending 10/31/2025 and $999,543 for the projected test year ending 10/31/2026 as a part of the ARP-FDAM project.

Q. What is Staff witness Zichi's rationale for proposing full disallowance of the new field device purchases for the ARP-FDAM project?

A. On page 9, line 5, through page 10, line 19, of her direct testimony, Staff witness Zichi provides the rationale that the Company has not provided clear evidence to support the expenditures for new purchases for the ARP-FDAM project and there are conflicting rationales in the Company's testimony and audit responses regarding how the costs were projected.

Q. Did the Company provide the method for projecting the new field device purchases costs and clarify in audit how the costs were projected?

A. Yes. The Company provided in the audit response at Exhibit S-19.1, page 12 (U21806-SA-CE-325), that the Company projected the Total Company new purchases of $997,255 and $1 million for 2025 and 2026, which the basis was historical spend. The Company provided the historical actuals to validate the reasonableness of the projected 2025 and 2026 new purchase costs for ARP-FDAM, which historically had been included in ARP-WAM. Additionally, Exhibit S-19.1, page 12, references audit response Exhibit S-19.1, page 11 (U21806-SA-CE-288), that indicates that further investigation revealed that the Company did not use People and Culture hiring estimates to project new purchases for 2025 and 2026. Furthermore, Exhibit S-19.1, page 11, provides support that the four-year historical average for new purchases for 2020 – 2023 for ARP-FDAM and ARP-WAM exceeds what is being requested in this case for ARP-FDAM and ARP-WAM new purchases for 2025 and 2026.

Q. What is the impact of co-workers not having a field device to perform work in service of customers?

A. The absence of field devices for co-workers can significantly impact their ability to perform work effectively. Without field devices, co-workers face productivity losses due to the need to access information through less efficient means, such as using paper-based resources. This can lead to delays in work initiation and completion. The lack of access to electronic safety manuals and resources can increase safety risks. Workers may not have the most up-to-date safety information readily available, which is crucial for maintaining a safe working environment. Field devices facilitate better communication, especially

during emergencies or unexpected events. Without them, there is a risk of losing business continuity and effective communication, which can hinder timely responses to customer needs. Field devices provide access to online training and Company resources, which are essential for continuous learning and skill development. Without these devices, workers may miss out on training, leading to a gap in knowledge and skills. Sharing devices among employees can pose cybersecurity risks. Field devices help mitigate these risks by providing individual access to necessary resources, reducing the need for device sharing. Overall, the lack of field devices can lead to decreased efficiency, increased safety risks, and hindered communication, all of which negatively impact the service provided to customers.

Q. If Staff witness Zichi's proposed disallowance for the ARP-FDAM project is nonetheless adopted, has the Company identified any necessary adjustments to the disallowance?

A. Yes. The Company has identified necessary adjustments for the ARP-FDAM project. The projected gas allocation capital expenditures for this project are $261,198 for the 10-month bridge period ending 10/31/2025 and $314,156 for the projected test year ending 10/31/2026, as provided in Exhibit A-22 (SHB-7), page 4, column (h), lines 4 through 6, for the test year. The capital expenditure amounts that Staff witness Zichi references in Exhibit A-22 (SHB-7), page 4, columns e and g, in her direct testimony on page 9, line 2, are the Total Company amounts and not the gas allocation. Therefore, if the Commission were to disallow this project based on Staff witness Zichi's position, which it should not, the gas projected capital expenditure disallowance of $261,198 for the 10-month bridge

period ending 10/31/2025 and $314,156 for the projected test year ending 10/31/2026, would be the correct disallowance amount.

Q. What adjustments is Staff witness Zichi proposing for the ARP-WAM project in this case?

A. On page 10, line 20, through page 11, line 7, of her direct testimony, Staff witness Zichi is proposing full disallowance of the new workstation purchases of $831,077 for the 10-month bridge period ending 10/31/2025 and $997,292 for the projected test year ending 10/31/2026 as a part of the ARP-WAM project.

Q. What is Staff witness Zichi's rationale for proposing full disallowance of the new workstation purchases for the ARP-WAM project?

A. On page 11, line 8, through page 13, line 4, of her direct testimony Staff witness Zichi provides the rationale that the Company has not provided clear evidence to support the expenditures for new purchase for the ARP-WAM project and there are conflicting rationales in the Company's testimony and audit responses regarding how the costs were projected.

Q. Did the Company provide the method for projecting the new workstation purchases costs and clarify in audit response how the costs were projected?

A. Yes. The Company provided in audit response Exhibit S-19.1, page 11 (U21806-SA-CE-288), that the Company projected the Total Company new purchases of $1 million for 2025 and 2026, which the basis was historical spend. The Company provided historical actuals to validate the reasonableness of the projected 2025 and 2026 new purchase costs for ARP-WAM, which historically had been included in ARP-FDAM. Additionally, the Company indicated that further investigation revealed that the Company did not use People and

Culture hiring estimates to project new purchases for 2025 and 2026. Furthermore, Exhibit S-19.1, page 11, provides support that the four-year historical average for new purchases for 2020 – 2023 for ARP-WAM and ARP-FDAM exceeds what is being requested in this case for ARP-WAM and ARP-FDAM new purchases for 2025 and 2026.

Q. What is the impact of co-workers not having a workstation to perform work in service of customers?

A. The absence of a workstation for co-workers can significantly impact their ability to perform work effectively. Without access to a workstation, co-workers face productivity losses due to the need to access systems to perform their work. This can lead to delays in work initiation and completion. Additionally, the inability to access electronic processes and systems significantly impacts their ability to perform work effectively, such as performing essential diagnostics, monitoring, and planning of critical systems. Workers may not have the most up-to-date safety and compliance information readily available, which is crucial for maintaining a safe working environment and regulatory compliance. Workstations facilitate better communication, especially during emergencies or unexpected events. Without them, there is a risk of losing business continuity and effective communication, which can hinder timely responses to customer needs. Workstations provide access to online training and Company resources, which are essential for continuous learning and skill development. Without these workstations, workers may miss out on training, leading to a gap in knowledge and skills. Sharing devices among employees can pose cybersecurity risks. Workstations help mitigate these risks by providing individual access to necessary resources, reducing the need for device sharing. Overall, the lack of workstations can lead to decreased efficiency, increased safety and

compliance risks, and hindered communication, all of which negatively impacts the service provided to customers.

Q. If Staff witness Zichi's proposed disallowance for the ARP-WAM project is nonetheless adopted, has the Company identified any necessary adjustments to the disallowance?

A. Yes. The Company has identified necessary adjustments for the ARP-WAM project. The projected gas allocation capital expenditures for this project are $261,197 for the 10-month bridge period ending 10/31/2025 and $314,300 for the projected test year ending 10/31/2026, as provided in Exhibit A-22 (SHB-7), page 12, column (h), lines 8 through 18, for the test year. The capital expenditure amounts that Staff witness Zichi used in the adjustment calculations are the Total Company amounts and not the gas allocation. Therefore, if the Commission were to disallow this project based on Staff witness Zichi's position, which it should not, the gas projected capital expenditure disallowance of $261,197 for the 10-month bridge period ending 10/31/2025 and $314,300 for the projected test year ending 10/31/2026, would be the correct disallowance amount.

Q. Did Staff provide any recommendations regarding the SAP S/4HANA Implementation project?

A. Yes. On page 14, lines 6 through 18, of her direct testimony, Staff witness Zichi proposed two recommendations regarding the SAP S/4HANA Implementation project.

First, Staff is recommending the Commission direct the Company to meet with Staff quarterly to provide progress of the SAP S/4HANA Implementation project, including any advancements and/or setbacks in project implementation, budget adherence,

changes to project scope, timeline, expenses, and any problems the Company has experienced or anticipates experiencing with any operations or customer interactions.

Second, Staff is recommending the Company include in future rate case filings until implementation is complete, any over and under recovery of each projected expense for the project compared to the 80% base (Rough Order of Magnitude ("ROM") Adjusted Amount).

Q. Does the Company agree with Staff witness Zichi's recommendations regarding the SAP S/4HANA Implementation project?

A. Yes. The Company agrees with Staff witness Zichi's recommendations regarding the SAP S/4HANA Implementation project as described above.

Q. What projects is Staff witness Klocke proposing adjustments for in this case?

A. As stated on page 5, lines 15 through 19, of her direct testimony, Staff witness Klocke is proposing adjustments for the Click to Chat project and Product Family Enhancements-Customer-Capital projects that includes Web Chat AI, Self-Service Mobile Application, and Low Moderate Income ("LMI") Customer Support enhancements. Company witness Jessica R. Byrom and I will address each proposed adjustment.

Q. What amount is Staff witness Klocke proposing to disallow for the Click to Chat project?

A. On page 5, line 30, through page 6, line 2, of her direct testimony, Staff witness Klocke is proposing full disallowance of the capital expenditures requested in this case for the Click to Chat project of $48,641, with $45,683 in the historical year ended December 31, 2023 and $2,958 in the bridge year ended December 31, 2024.

Q. Do you agree with Staff witness Klocke's proposal of full disallowance of the Click to Chat project?

A. No. The Company does not agree with Staff witness Klocke's proposal of full disallowance of the Click to Chat project. First, this project was included in the gas rate Case No. U-21308 and in electric rate Case No. U-21389, and no parties recommended disallowance of the project in those cases. Thus, the projections approved in those cases included approval of Click to Chat project costs. In the Commission's March 21, 2025 Order in Case No. U-21585, pages 183 through 186, the Commission approved the Click to Chat project 2023 historical year costs on the basis that although the Click to Chat function does not save money, it contributes to the provision of utility service. This same rationale should apply to the bridge period costs. Company witness Byrom's rebuttal testimony further addresses this project's value.

Q. What amount is Staff witness Klocke proposing to disallow for the Product Family Enhancements-Customer-Capital project related to the Web Chat AI, Customer Self-Service Mobile Application, and LMI Customer Support enhancements?

A. On page 8, lines 6 through 13, of her direct testimony, Staff witness Klocke is proposing full disallowance of the capital expenditures requested in this case for the Web Chat AI, Customer Self-Service Mobile Application, and LMI Customer Support enhancements that are part of Product Family Enhancements-Customer-Capital project of $1,905,494 ($61,562 for 2023, $274,116 for 2024, $699,355 10 months ending 10/31/2025, and $870,461 for the projected test year) in capital expenditures and $21,439 IT Investments O&M expense for the projected test year.

Enhancements	Capital				O&M
	Historical 12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	Projected Test Year 12 Mos Ending 10/31/2026	Projected Test Year
Web Chat AI	$0	$0	$0	$180,565	$14,929
Customer Self-Service Mobile Application	$61,562	$274,116	$498,727	$649,770	$6,510
LMI Customer Support	$0	$0	$200,628	$40,126	$0

Q. What adjustment is Staff witness Klocke proposing for the Web Chat AI enhancements that is part of the Product Family Enhancements-Customer-Capital project?

A. On page 8, lines 14 through 20, of her direct testimony, Staff witness Klocke is proposing an adjustment of $180,565 in capital expenditures and $14,929 in IT Investments O&M expense for the projected test year for the Web Chat AI enhancements that is part of the Product Family Enhancements-Customer-Capital project.

Q. Do you agree with Staff witness Klocke's proposal of full disallowance of the Web Chat AI enhancements that is part of the Product Family Enhancements-Customer-Capital project?

A. No. The Company does not agree with Staff witness Klocke's proposal of full disallowance of the Web Chat AI enhancements that is part of the Product Family Enhancements-Customer-Capital project. Company witness Byrom's rebuttal testimony further addresses this project's value.

Q. What adjustment is Staff witness Klocke proposing for the Customer Self-Service Mobile Application enhancements that is part of the Product Family Enhancements-Customer-Capital project?

A. On page 11, lines 6 through 18, of her direct testimony, Staff witness Klocke is proposing an adjustment of $61,562 for historical year 2023, $274,116 for 2024, $498,727 for the 10 months ending 10/31/2025 ($598,472/12 *10), and $649,770 ($598,472/12*2 + $550,025) for the projected test year in capital expenditures and $14,929 in IT Investments O&M expense for the projected test year for the Customer Self-Service Mobile Application enhancements that are part of the Product Family Enhancements-Customer-Capital project.

Q. Do you agree with Staff witness Klocke's proposal of full disallowance of the Customer Self-Service Mobile Application enhancements that is part of the Product Family Enhancements-Customer-Capital project?

A. No. The Company does not agree with Staff witness Klocke's proposal of full disallowance of the Customer Self-Service Mobile Application enhancements that are part of the Product Family Enhancements-Customer-Capital project. Company witness Byrom's rebuttal testimony further addresses this project's value.

Q. What adjustment is Staff witness Klocke proposing for the LMI enhancements that are part of the Product Family Enhancements-Customer-Capital project?

A. On page 14, lines 2 through 5, of her direct testimony, Staff witness Klocke is proposing an adjustment of $200,628 for the 10 months ending 10/31/2025, and $40,126 for the projected test year in capital expenditures for the projected test year for the LMI Customer Support enhancements that are part of the Product Family Enhancements-Customer-Capital project.

Q. Do you agree with Staff witness Klocke's proposal of full disallowance of the LMI enhancements that is part of the Product Family Enhancements-Customer-Capital project?

A. No. The Company does not agree with Staff witness Klocke's proposal of full disallowance of the LMI enhancements that are part of the Product Family Enhancements-Customer-Capital project. Company witness Byrom's rebuttal testimony further addresses this project's value.

Q. What is the current status of the Company's website redesign project Staff witness Klocke discusses in her direct testimony related to Web Chat AI, Customer Self-Service Mobile Application, and LMI Customer Support enhancements that are part of Product Family Enhancements-Customer-Capital project?

A. As discussed in Staff Audit Response U21806-SA-CE-409 (Exhibit A-109 (SHB-12), the Company has put the website redesign on hold due to extended support of the current on-premises Sitecore web content management system and the Company's SAP S/4HANA planned implementation.

The previous timing for the website redesign was developed with the expectation that the Company would need to migrate to the cloud/Software-as-a-Service ("SaaS") version of the Sitecore system based on Sitecore's published product support lifecycle at that time. This would have been a major reason to initiate the website redesign. Since then, Sitecore has extended mainstream support for the on-premises version 10.4 to December 31, 2027, giving the Company more flexibility in its migration schedule.

In addition, the Company's implementation of the SAP S/4HANA system will be a major undertaking, which will significantly impact the design of integration between the

Company's website and SAP. The Company plans to complete the S/4HANA implementation before starting the website redesign.

It is important to note that improvements to the Company's website design, content, navigation, accessibility, and features are not static or stopped until the website redesign project is undertaken. The Company is regularly prioritizing and executing updates to web pages, content, and flows based on customer needs and challenges. An example of this is for the LMI Customer Support Enhancement. On page 15 of her direct testimony regarding LMI, Staff witness Klocke says, "Staff strongly feels that the Company updating their website to make information such as this standard would be a much better use of money." In fact, much of the investment in this enhancement is being achieved through updates to website design, content, features, and navigation, without the full re-architecture associated with the eventual website redesign project.

Q. Do you agree that the Company's website redesign would negate the need to make investments in Customer Self-Service Mobile Application and Web Chat AI?

A. No. The Website Redesign would not negate the need to make investments in the Customer Self-Service Mobile Application, Web Chat AI, or any other channels preferred by customers for specific needs, as discussed in Company witness Byrom's rebuttal testimony.

Q. Are there any adjustments needed to the proposed adjustments for the Product Family Enhancements-Customer-Capital provided in Staff Exhibit S-19.0, line 6, for IT Investments O&M expense for the projected test year?

A. Yes. Based on the amounts provided in Staff witness Klocke's direct testimony, on page 8, lines 17 through 18, for the Web Chat AI enhancement of $14,929 in IT Investments O&M expense for the projected test year and on page 11, lines 13 through 14, for the Self-Service

Mobile Application enhancements of $6,510 in IT Investments O&M expense for the projected test year, the total IT Investments O&M expense on Staff Exhibit S-19.0, line 6 should be $21,439.

ATTORNEY GENERAL

Q. What projected capital expenditures and O&M expense adjustments is Attorney General witness Coppola proposing for the Tracking and Traceability project identified on pages 85 through 87 of his direct testimony?

A. Attorney General witness Coppola is proposing on page 87, lines 4 through 6, of his direct testimony to remove $2,218,000 for the projected bridge period for the 10 months ending October 2025, and $5,295,000 for the projected test year of the Company's capital expenditures and $509,000 of the Company's projected test year Investments O&M expense for the Tracking and Traceability project.

Q. What is the first argument Attorney General witness Coppola describes for adjustments to the Tracking and Traceability project?

A. The first argument Attorney General witness Coppola describes on page 86 of his direct testimony for removing amounts for the Tracking and Traceability project, is his claim that, based on the Company's cost benefit analysis, it appears that the Company is not expecting any significant cost savings from the new system.

Q. Does the Company agree that the Tracking and Traceability project must provide significant cost savings in order to be viable?

A. No. The project is required to meet Pipeline and Hazardous Materials Safety Administration ("PHSMSA") proposed regulatory requirements (PHSMSA-2014-0098), also known as the Plastic Pipe rule, as described in Company witness Lincoln D.

Warriner's direct testimony on pages 76 and 77. Company witness Warriner's rebuttal testimony further addresses this project's value.

Q. What is the second argument Attorney General witness Coppola describes for removing amounts for the Tracking and Traceability project?

A. The second argument Attorney General witness Coppola describes on page 86, line 18, through page 87, line 3, of his direct testimony for removing amounts for the Tracking and Traceability project is that the project is currently in the Origination Phase or Investment Planning stage.

Q. Does the Company agree the Tracking and Traceability project should be disallowed because it is in the Investment Planning phase?

A. No. This project should not be disallowed on the basis that it is in the Investment Planning phase. Investment Planning is the phase a project remains in while it is waiting for funding and does not indicate that it is incomplete or lacking information. An IT business case was completed and approved for this project prior to consideration for inclusion in the Company rate case, following the Company's business case process. Even though the business case is complete and approved, projects remain in this Investment Planning Phase and are not released for further planning and implementation activities until funding is approved through rate case and budget disposition. Therefore, significant requirements are complete, and the project should be included and approved as the Company fully plans to spend the projected expenditures based on the project timeline in this case.

Q. What projected capital expenditures adjustments is Attorney General witness Coppola proposing for the SAP S/4HANA Implementation project identified on page 90 of his direct testimony?

A. Attorney General witness Coppola is proposing on page 90, lines 7 through 9, of his direct testimony proposed to remove [redacted] for the 10 months ending October 2025 and [redacted] for the projected test year of the Company's capital expenditures for the SAP S/4HANA Implementation project.

Q. What is Attorney General witness Coppola proposing for SAP S/4HANA Implementation project O&M costs identified on page 90 of his direct testimony?

A. Attorney General witness Coppola is proposing on page 90, lines 9 through 11, that the Commission reject the Company's proposal to defer [redacted] O&M costs into a regulatory asset.

Q. What is the argument Attorney General witness Coppola describes for capital expenditures adjustments and rejecting the proposal for deferral of O&M costs to a regulatory asset for the SAP S/4HANA Implementation project?

A. The first argument Attorney General witness Coppola describes on page 89, line 16, through page 90, line 4, of his direct testimony for removing capital amounts and rejecting deferral of O&M costs for the SAP S/4HANA Implementation project is his claim that the current Enterprise Resource Planning ("ERP") system still functions well and meets the operating needs, and that it appears that the option exists for the Company to continue to operate the system into 2030 and potentially past the date with system support by SAP.

Q. Does the Company agree that the option exists to continue to operate the current system into 2030 and potentially past the date with system support by SAP?

A. No. The project will take approximately three years to complete and extended support for the Company's current SAP version is only available until 2030, as discussed in my direct testimony, on page 108, lines 10 through 17. There is also an increased risk of cyberattacks if the SAP S/4HANA project is not executed, because SAP has stated that after maintenance ends, standard patches will no longer be available, as discussed on page 108, line 18, through page 109, line 10, of my direct testimony.

Q. What is the second argument Attorney General witness Coppola describes for capital expenditure adjustments and rejecting the proposal for deferral of O&M costs to a regulatory asset for the SAP S/4HANA Implementation project?

A. The second argument Attorney General witness Coppola describes on page 86, line 18, through page 87, line 3, of his direct testimony for removing capital amounts and rejecting deferral of O&M costs for the SAP S/4HANA Implementation project is his contention that the project is premature.

Q. Does the Company agree the SAP S/4HANA Implementation project capital expenditures should be disallowed and proposal for deferral of O&M costs be rejected because it is premature and in the Investment Planning phase?

A. No. This project's capital expenditures should not be disallowed and proposal for deferral of O&M costs rejected on the basis that it is in the Investment Planning phase. Investment Planning is the phase a project remains in while it is waiting for funding and does not indicate that it is premature or incomplete or lacking information. Although the Company plans to issue a request for proposal in May 2025 for implementation partners, the

Company leveraged a third party that specializes in preparing for S/4HANA upgrades to develop the cost estimates for the business case, as stated in my direct testimony on page 109, lines 11 through 15. The IT business case was completed and approved for this project prior to consideration for inclusion in the Company rate case, following the same strict business case process. Even though the business case is complete and approved, projects remain in this Investment Planning Phase and are not released for further planning and implementation activities until funding is approved through rate case and budget disposition. Therefore, significant requirements are complete, and the project should be included and approved as the Company fully plans to spend the projected expenditures based on the project timeline in this case.

Q. What is the argument Attorney General witness Coppola describes for removing the O&M amounts for the SAP S/4HANA Implementation project?

A. Similar to the capital expenditures, the argument Attorney General witness Coppola describes on page 180, lines 3 through 6, of his direct testimony for removing amounts for the SAP S/4HANA Implementation project is his contention that the project is premature.

Q. Did Attorney General witness Coppola make any additional recommendations related to the SAP S/4HANA Implementation project?

A. Yes. Attorney General witness Coppola, on page 180, lines 7 through 10, made two recommendations. First, that the Commission not approve a regulatory asset to record the deferred IT Investments O&M expense for this project. Second, that the Commission not approve a 15-year amortization for the cloud implementation costs. Refer to Company witness Heidi J. Myers' rebuttal testimony for further information on these requests.

Q. Does the Company agree the SAP S/4HANA Implementation project should be disallowed because it is premature?

A. No, for the same reasons discussed above.

Q. What is Attorney General witness Coppola's proposed adjustment to IT Investments O&M expense related to cloud computing?

A. On page 108, line 2 through 4, and page 180, line 12, through page 181, line 2, Attorney General witness Coppola indicates that the Company made an error in calculating the amortization expense for cloud computing fees and costs that have been deferred and that the difference of $5,478,000 should be removed from the expense forecasted by the Company for the projected test year.

Q. Do you agree that the Company made an error in calculating the amortization expense for cloud computing fees?

A. No. The Company did not make an error in calculating the amortization expense for cloud computing fees. In response to Discovery request No. U21806-AG-CE-0852, Attachment 2 (Exhibit A-158 (SHB-17)), the Company provided an updated Exhibit A-18 (SHB-2) excluding some non-cloud computing pre-payments and expenses that were included inadvertently in that exhibit. The update to Exhibit A-18 (SHB-2) did not result in an error in the calculation of the amortization expense for cloud computing fees and costs included in the case for either IT Investments O&M or IT Operations O&M. Attorney General witness Coppola's conclusion is inaccurate and unvalidated. The Company provides a detailed list of projects in Exhibit A-20 (SHB-5) that supports the IT Investments O&M amounts in Exhibit A-19 (SHB-3), and the detailed exhibit does not include any line items for the amortization expense for cloud computing fees and costs. In addition, the original

Exhibit A-18 (SHB-2) was not used to project the amortization expense in IT Operations O&M expense; therefore, an update to Exhibit A-18 (SHB-2) would not result in a change to IT Operations O&M expense either. The Commission should not approve the removal of $5,478,000 from IT Investments O&M expense.

Q. What is Attorney General witness Coppola's proposal regarding reducing the Company's working capital for the deferred costs for the SAP S/4HANA Implementation project and Prepaid Cloud Computing?

A. On page 106, line 5, through page 107, line 4, and page 107, lines 5 through 18, Attorney General witness Coppola is proposing to reduce the Company's working capital adjustment for the deferred costs for the SAP S/4HANA Implementation project by $1.7 million and the Prepaid Cloud Computing by $1.0 million.

Q. Do you agree with Attorney General witness Coppola's proposed adjustment to working capital for the SAP S/4HANA Implementation project and Prepaid Cloud Computing costs?

A. Yes. The Company agrees with the basis of the proposed adjustment as explained in its response to Attorney General Discovery request U21806-AG-CE-0628 CONF (Exhibit AG-37, page 1) that the SAP S/4HANA Cloud Implementation Costs were inadvertently provided as Total Company rather than the gas allocation. Also, the Company agrees with the basis of the proposed adjustment as explained in its response to Attorney General Discovery request U21806-AG-CE-0852 (Exhibit AG-38, page 4) that the cloud computing prepaid balances inadvertently included some non-cloud computing pre-payments and expense.

Q. Do you agree with Attorney General witness Coppola's proposal, at page 91, of his direct testimony, to reduce capital expenditures for the 10 months ending October 2025 to $423,000, and for the projected test year to $519,000 for the ARP-OT Support Gas project?

A. No. Attorney General witness Coppola is basing the projections on a three-year historical average plus an adjustment for forecasted inflation. This does not consider that the cost projected for each year for the ARP-OT Support Gas project is for specific hardware that requires replacement based on timing of when it was installed and risk if it were not replaced in the five-year refresh cycle. As described in the response to Discovery request U21806-AG-CE-0615 (Exhibit A-110 (SHB-13)), the increase in the projected test year costs are due to the need to refresh assets implemented as a part of the Pipeline Supervisory Control and Data Acquisition ("SCADA") project. Maintaining a reliable control system is critical for ensuring continuous and safe gas flow.

Q. Do you agree with Attorney General witness Coppola's proposal, at page 92, of his direct testimony, to reduce capital expenditures for the projected test year by $747,000 for the ARP-Physical Security project?

A. No. Attorney General witness Coppola's proposal would result in running critical hardware to failure based on broad generalizations that the Company already has security cameras, gate and lock systems, and other security equipment in place. This does not consider that the costs projected for each year for the ARP-Physical Security project are for specific hardware that requires replacement based on timing of when it was installed and risk if it were not replaced based on the refresh cycle. In addition, this argument does not consider that this critical hardware is required to avoid physical security vulnerabilities

and to comply with state, federal, and Federal Energy Regulatory Commission ("FERC") requirements, as discussed in my direct testimony on pages 62 and 63, as well as the response to Discovery request U21806-AG-CE-0616-Revised (Exhibit A-111 (SHB-14)).

Q. Do you agree with Attorney General witness Coppola's proposal, at page 93 of his direct testimony, to reduce capital expenditures by $939,000 and O&M expense by $180,000 for the projected test year for the Forward Web Proxy Services project?

A. No. Attorney General witness Coppola's argument is that the project is not necessary at this time and not a priority that should be undertaken for the projected test year. Mr. Coppola indicates that the Company has been working with the vendor and acknowledged service improvement with some lingering issues. This does not consider that the Company no longer uses some of the functionality of the current product and that additional controls to mitigate risk had to be put in place in order to reduce impact and improve stability, as indicated in response to Discovery request U21806-AG-CE-0630 (Exhibit AG-31).

Q. Does the Company agree that the Forward Web Proxy Services project must provide significant cost savings in order to be viable?

A. No. The project is critical to filtering out unwanted or harmful content from the internet, protecting the Company's systems from cyberattacks. The project is also critical as the Company continues to leverage more SaaS solutions to provide consistent access and communication, while protecting the Company from cyber threats to avoid disruption to business operations. Refer to my direct testimony, page 115, line 36, through page 116, line 42, for further project value.

Q. Has the Company identified any necessary adjustments to Attorney General witness Coppola's proposed adjustments for the Forward Web Proxy Services project?

A. Yes. The Company has identified necessary adjustments for the Forward Web Proxy Services project. The projected test year gas allocation O&M expense for this project is $149,967 as stated on page 115, line 37, of my direct testimony. Therefore, if the Commission were to disallow this project based on Attorney General witness Coppola's position, which it should not, the projected test year gas allocation O&M expense of $149,967 would be the correct disallowance amount.

Q. What projected capital expenditures and O&M expense adjustments is Attorney General witness Coppola proposing for the OT Datacenter Migration project identified on pages 95 through 97 of his direct testimony?

A. Attorney General witness Coppola is proposing on page 95, lines 10 through 11, of his direct testimony to remove $1,441,000 for the projected test year of the Company's capital expenditures and $716,000 of the Company's projected test year Investments O&M expense for the OT Datacenter Migration project.

Q. What is the first argument Attorney General witness Coppola describes for adjustments to the OT Datacenter Migration project?

A. The first argument Attorney General witness Coppola describes on page 95, lines 12 through 17, of his direct testimony for removing amounts for the OT Datacenter Migration project is his claim that it is not clear why the Company could not resolve the water infiltration risk and the aging climate equipment at a lower cost than $11 million.

Q. Does the Company agree that the water infiltration risk and aging climate equipment are the only risks the Company is resolving with the OT Datacenter Migration project?

A. No. The project is planned to remove the risk of systems critical to the control of gas pipelines and the electric grid so they are no longer in close proximity to a railway system and the main water pipe for the building as described in my direct testimony on pages 100 and 101.

Q. What is the second argument Attorney General witness Coppola describes for removing amounts for the OT Datacenter Migration project?

A. The second argument Attorney General witness Coppola describes on page 95, lines 15 through 17, and page 97, lines 8 through 11, of his direct testimony for removing amounts for the OT Datacenter Migration project is that the project is currently in the Investment Planning stage.

Q. Does the Company agree the OT Datacenter Migration project should be disallowed because it is in the Investment Planning phase?

A. No. This project should not be disallowed on the basis that it is in the Investment Planning phase. Investment Planning is the phase a project remains in while it is waiting for funding and does not indicate that it is incomplete or lacking information. An IT business case was completed and approved for this project prior to consideration for inclusion in the Company's rate case, following the same strict business case process. Even though the business case is complete and approved, projects remain in this Investment Planning Phase and are not released for further planning and implementation activities until funding is approved through rate case and budget disposition. Therefore, significant requirements are

complete, and the project should be included and approved in this rate case as the Company fully plans to spend the projected expenditures based on the project timeline in this case.

Q. What projected capital expenditures and O&M expense adjustments is Attorney General witness Coppola proposing for the Physical Access Management and Alarm Response project identified on pages 95 through 97 of his direct testimony?

A. Attorney General witness Coppola is proposing on page 96, lines 10 through 12, of his direct testimony to remove $678,000 for the projected test year of the Company's capital expenditures and $102,000 of the Company's projected test year Investments O&M expense for the Physical Access Management and Alarm Response project.

Q. Does the Company agree that the Physical Access Management and Alarm Response project must provide significant cost savings in order to be viable?

A. No. Failing to move to new technology carries a growing risk of system failure which could result in unauthorized physical access and/or impact the Company's ability to efficiently function. Refer to my direct testimony, page 117, line 1, through page 118, line 28, for further project value.

Q. What is the second argument Attorney General witness Coppola describes for removing amounts for the Physical Access Management and Alarm Response project?

A. The second argument Attorney General witness Coppola describes on page 95, lines 15 through 17, and page 97, lines 8 through 11, of his direct testimony for removing amounts for the Physical Access Management and Alarm Response project is that the project is currently in the Investment Planning stage.

Q. Does the Company agree that the Physical Access Management and Alarm Response project should be disallowed because it is premature and in the Investment Planning phase?

A. No. This project should not be disallowed on the basis that it is in the Investment Planning phase. Investment Planning is the phase a project remains in while it is waiting for funding and does not indicate that it is premature or incomplete or lacking information. An IT business case was completed and approved for this project prior to consideration for inclusion in the Company rate case, following the same strict business case process. Even though the business case is complete and approved, projects remain in this Investment Planning Phase and are not released for further planning and implementation activities until funding is approved through rate case and budget disposition. Therefore, significant requirements are complete, and the project should be included and approved in this rate case.

Q. Does the Company oppose Attorney General witness Coppola's recommendation on page 97, line 14, through page 98, line 4, of his direct testimony, that the Commission disallow $5,668,000 in capital expenditures for 2024 based on actual information?

A. The Company will not oppose the reduction of $5,668,000 in capital for 2024 based on actual capital expenditures.

CITIZENS UTILITY BOARD

Q. What observations does CUB witness Denzler provide for the Gas SCADA Software Solution project?

A. On page 8, line 6, through page 10, line 13, CUB witness Denzler discusses changes that were made to the planned project and costs, and argues that the issues in planning of this project are evidence of a deficient estimation and planning process.

Q. How do you respond to CUB witness Denzler's observations related to estimation and planning for the Gas SCADA Software Solution project based on changes from the project's initial ROM estimate?

A. As discussed on page 33, line 12, through page 34, line 8, of my direct testimony, the Company performs the preliminary project stage activities that are essential to ensure the Company makes prudent investments in technology that benefit customers. In addition, as discussed on page 45, line 10, through page 46, line 3, IT's investment forecasts evolve over time. Factors may arise during project execution that results in funding being lower or higher than initially estimated. In the PMBOK (Project Management Body of Knowledge), ROM estimates have cost estimate bounds of -25% to +75%; this means that a ROM estimated project could end up costing between 25% less to 75% more than the initial estimate.

Q. What other concerns does CUB witness Denzler indicate for the Gas SCADA Software Solution project?

A. On page 10, line 14, through page 11, line 18, CUB witness Denzler argues that the merits and necessity of the project are not sufficiently justified.

Q. Do you agree with CUB witness Denzler's concerns regarding the merits of the Gas SCADA Software Solution project?

A. No. First, the Company's concerns with the current system are not based primarily on "hypothetical" future risks. As discussed on page 50, lines 11 through 22, of my direct testimony, the original Gas SCADA system implemented in 2000 was based on the gas system requirements at that time. The current system has capability gaps and requires custom interim fixes and integrations which adds complexity and cost to the current solution. The Gas SCADA system is critical in controlling and monitoring the Company's gas system. While Mr. Denzler argues that there is limited evidence to suggest that the current system is defective, it would be expected that defects are limited for such a critical system. If the system is unstable or not functioning, it would impact the Company's ability to operate and monitor real-time system conditions, maintain safe operations, and comply with regulatory requirements.

Additionally, the Company provided detailed explanation of incremental costs in my direct testimony, on page 54, line 1, through page 55, line 11, and the responses to Discovery requests provided in Exhibit A-113 (SHB-16).

Q. What amount does CUB witness Denzler recommend the Commission disallow for the Gas SCADA Software solution project?

A. On page 12, lines 1 through 7, of his direct testimony, CUB witness Denzler recommends that the Commission hold the total allowed capital at $11,491,200 as previously approved in Case No. U-21490. This would be a disallowance of $6,524,840.

Q. Do you agree with CUB witness Denzler's recommendation to the Commission to hold the total allowed capital at $11,491,200 as previously approved in Case No. U-21490?

A. No. Not allowing recovery of the costs required to complete this project, as previously discussed, would have a significant impact on the Company's ability to operate and monitor real-time system conditions, maintain safe operations, and comply with regulatory requirements. It is also important to note that Attorney General witness Coppola's proposed disallowance of $5,558,000 related to 2024 actuals, which the Company is not opposing as previously discussed, already includes a reduction of $4,623,400 in 2024 Gas SCADA Software Solution costs from an originally projected $8,027,542 to an actual amount of $3,404,142.

Q. What concerns does CUB witness Denzler have with the methodology the Company utilizes to apply a 20% reduction on its projects with ROM estimates?

A. On page 12, line 15, through page 13, line 3, of CUB witness Denzler's direct testimony, he indicates a concern that the Company has routinely underspent its ROM estimates by much more than 20%.

Q. How do you respond to CUB witness Denzler's concern?

A. Business objectives and priorities and customer needs and expectations can evolve. This may require IT projects to be reprioritized and may require the Company to shift capital funding between projects, which could account for spending changes on ROM projects. Reducing capital expenditures for an incremental 20% could negatively impact other planned and approved projects.

Q. What recommendation does CUB witness Denzler provide for the ROM projections?

A. On page 13, lines 4 through 10, of CUB witness Denzler's direct testimony, he recommends the Commission disallow a total of 40% of the ROM projections for 2025 and 2026. This is an incremental 20% over the Company's 20% ROM Adjustment for projects identified with the ROM estimate type. He indicates this level results in an incremental disallowance of $8.21 million (20% of $41.04 million) in 2025 capital spend and an incremental disallowance of $11.59 million (20% of $57.46 million) in 2026 capital spend.

Q. Do you agree with CUB witness Denzler's proposal to disallow an incremental 20% over the Company's 20% ROM Adjustment for the specified projects based on ROM estimate classification?

A. No. An incremental 20% reduction in capital for the specified projects imposes a shortfall in the projected funding required to deliver the scope and expected outcomes of those projects. The Company's IT & Security projects plan and execute on a budget. These budgets are based on the analysis resulting from the ROM estimate. This shortfall in recovery may require the Company to shift capital funding between projects and could negatively impact other planned and approved projects.

Q. If CUB witness Denzler's proposed disallowance for an incremental 20% over the Company's 20% ROM Adjustment for the specified projects based on ROM estimate classification is nonetheless adopted, has the Company identified any necessary adjustments to the disallowance?

A. Yes. The Company has identified necessary adjustments for the proposed disallowance for an incremental 20% over the Company's 20% ROM Adjustment for the specified projects based on ROM estimate classification. Based on Exhibit A-20 (SHB-5), the

projected gas allocation capital expenditures for the 2025 spend year (column a) with a ROM estimate classification (column k) is $13,569,004 (column l) and the projected gas allocation capital expenditures for the 2026 spend year (column a) with a ROM estimate classification (column k) is $40,545,837 (column 1). Therefore, if the Commission were to disallow the 20% incremental amount over the Company's 20% ROM Adjustment for the specified projects with ROM estimate classification based on CUB witness Denzler's position, which it should not, the gas projected capital expenditure disallowance of $2,261,501 (20% of $13,569,004/12*10) for the 10-month bridge period ending 10/31/2025 and $7,209,940 (20% of $13,569,004/12*2 + 20% of $40,545,837/12*10) for the projected test year ending 10/31/2026, would be the correct disallowance amounts.

Q. Explain CUB witness Denzler's argument related to the ARP-Collaboration project.

A. On page 14, lines 1 through 19, of CUB witness Denzler's direct testimony, he states that Company Exhibit A-22 (SHB-7) outlines unit volumes and costs for actual purchases in 2023-2024 and projected purchases for 2025-2026, and shows increasing unit costs without sufficient explanation. Mr. Denzler recommends that that historic unit cost adjusted for productivity and inflation ("PAI") should be used to determine the projected unit costs for 2025-2026.

Q. Do you agree with CUB witness Denzler's arguments related to the ARP-Collaboration project.

A. No. The costs in the ARP-Collaboration project can vary based on the requirements for the specific location the collaboration equipment will be installed. For example, based on vendor quotes, replacing a Surface HUB with a Microsoft Teams Room in a conference room at our Jackson location requires $7,243 where replacing the same equipment in a

conference room at our Grand Rapids location requires $9,269, due to varying sizes of conference rooms that require different wiring, among other differences.

Additionally, CUB witness Denzler's analysis contains inaccuracies. For example, when he calculated the Company Historical Average Unit Cost for the Hub 85" replacements, he only used historical unit costs in Exhibit A-22 (SHB-7), line 34, column b, of $16,679. There are two more instances of 85" Hub purchases on Exhibit A-22 (SHB-7), lines 35 and 114, that contain the historical unit costs of $16,679 and $24,436. Thus, the average unit cost for these three purchases is $19,264, not $16,679. Similarly, he also calculated the Company Historical Average Unit Cost for Hub 50" replacements and PolyCom Refresh using only one historical unit cost, rather than averaging all the historical unit costs.

While Mr. Denzler calls into question the increase in ARP-Collaboration project costs by pointing out that there was no increase in projected Field Device unit costs, field devices tend to be more standard and do not have the complexity of significantly different requirements based on where the equipment will be installed.

Finally, the Company does not agree that projected unit costs should be based on historical costs plus inflation adjusted by PAI. Refer to Company witness Myers' rebuttal testimony.

Q. What adjustment for the ARP-Collaboration project is CUB witness Denzler recommending?

A. On page 14, lines 10 through 12 of his direct testimony, CUB witness Denzler is proposing adjustments of $57,599 in 2025 and $88,718 in 2026 for the ARP-Collaboration project.

Q. Do you agree with the amounts that CUB witness Denzler is proposing adjustments in the ARP-Collaboration project?

A. No. The Company does not agree with the proposed gas allocation adjustments of $57,599 for the projected year 2025 and $88,718 for the projected year 2026 for the reasons stated previously for the ARP-Collaboration project.

Q. Are there any adjustments needed to CUB witness Denzler's proposed adjustments for the ARP-Collaboration project?

A. Yes. The projected test year for the case is 11/1/2025 through 10/31/2026. Therefore, the Company is not requesting the full projected year 2026 amount as stated by CUB witness Denzler. Therefore, if the Commission were to agree with the proposed gas allocation adjustments of $57,599 for the projected year 2025 and $88,718 for the projected year 2026, which it should not, the gas allocation adjustment for the 10 months ending 10/31/2025 should be $47,999 and the projected test year should be $83,532. In addition, as discussed above in response to Staff witness Zichi, the Company has already agreed to the reduction of $6,015 for the bridge period (10 months ending 10/31/2025) and $7,219 for the projected test year for the ARP-Collaboration project.

Q. Explain CUB witness Denzler's arguments related to the ARP-Local Area Network ("LAN") project.

A. On page 14, line 20, through page 15, line 5, of CUB witness Denzler's direct testimony, he argues that a similar situation exists for ARP-LAN as ARP-Collaboration in that in 2023 and 2024, the Company replaced 1,091 LAN switches at a cost of $2,793,094, which is an average unit cost of $2,560 per switch. However, for 2025 and 2026, the Company projected a unit cost of over $5,000 per switch. He argues that the increase in projected

costs lacks sufficient explanation, and that historic unit cost adjusted for PAI should be used to determine the projected unit costs for 2025-2026.

Q. Do you agree with CUB witness Denzler's arguments related to the ARP-LAN project?

A. No. The Company does not agree with CUB witness Denzler's arguments related to the ARP-LAN project. The type of LAN switch that requires replacement determines the unit cost, and the Company's cost projections were based on these specific requirements. For example, a Juniper EX4100 switch has a unit cost of $8,132, where a Juniper EX4400 has a unit cost of $20,512. To simply take the total historical costs and divide them by the total number of historical switches is not a sufficient methodology for projecting these types of costs. As provided in response to Staff Audit request No. U21806-SA-CE-176 (Exhibit A-112 (SHB-15)), the material naming convention used (e.g., LAN Switch A, LAN Switch B, etc.) is solely to differentiate each model within a given calendar year. The actual models associated with these designations may change from year to year, resulting in variations in unit pricing.

The Company also does not agree that projected unit costs should be based on historical costs plus inflation adjusted by PAI. Refer to Company witness Myers' rebuttal testimony.

Q. What adjustment is CUB witness Denzler proposing for the ARP-LAN project?

A. On page 15, lines 3 through 5, of his direct testimony, CUB witness Denzler is proposing adjustments of $55,911 in 2025 and $86,881 in 2026 for the ARP-LAN project.

Q. Do you agree with the amounts that CUB witness Denzler is proposing adjustments for the ARP-LAN project?

A. No. The Company does not agree with the proposed gas allocation adjustments of $55,911 for the projected year 2025 and $86,881 for the projected year 2026 for the reasons stated previously for the ARP-LAN project.

Q. Are there any adjustments needed to CUB witness Denzler's proposed adjustments for the ARP-LAN project?

A. Yes. The projected test year for the case is 11/1/2025 through 10/31/2026; therefore, the Company is not requesting the full projected year 2026 amount as stated by CUB witness Denzler. Therefore, if the Commission were to agree with the proposed gas allocation adjustments of $55,911 for the projected year 2025 and $86,881 for the projected year 2026, which it should not, the gas allocation adjustment for the 10 months ending 10/31/2025 should be $46,593 and the projected test year should be $81,719.

Q. Explain CUB witness Denzler's overall recommendation for the Asset Refresh Programs.

A. On page 15, lines 6 through 14, of his direct testimony, CUB witness Denzler argues that the Company overestimated costs for the ARP-Collaboration devices and ARP-LAN switches, which he argues raises concerns about the Company's methods for estimating costs of other devices. Mr. Denzler recommends that the Commission treat the Asset Refresh program estimates as Class III AACE estimates and disallow 20% of the remaining ARP spend.

Q. Do you agree with CUB witness Denzler's overall recommendation for the Asset Refresh Programs?

A. No. The Company does not agree with CUB witness Denzler's overall recommendation to disallow 20% of the remaining ARP projected expenditures. On page 56, line 10, through page 57, line 12, of my direct testimony, I explain that the Company refreshes hardware based on industry standards recommended refresh cycles to reduce security risk, avoid costs, avoid customer frustration, avoid lost productivity, and ensure continued vendor support. The Company also provides detailed projected actual capital expenditures for each ARP in Exhibit A-22 (SHB-7) and on pages 58 through 75 of my direct testimony. I provided detailed project summaries including refresh cycles, which is the basis for which annual costs are projected and detailed variance explanations for several of the ARPs. The unit costs for ARPs are typically based on either actual historical costs, quotes, or current agreements with vendors. In addition, the basis for CUB witness Denzler's recommendation to disallow 20% of the remaining ARPs, namely, that the Company "overestimated" costs for the ARP-Collaboration devices and ARP-LAN switches is incorrect as previously discussed.

Q. What adjustment is CUB witness Denzler proposing for the remaining ARPs?

A. On page 15, lines 12 through 14, of his direct testimony, CUB witness Denzler is proposing adjustments of $1,413,753 in 2025 and $1,579,067 in 2026 for the remaining ARPs.

Q. Do you agree with these adjustments for the remaining ARPs?

A. No. The Company does not agree with the proposed gas allocation adjustments of $1,413,753 for the projected year 2025 and $1,579,067 for the projected year 2026 for the

reasons stated previously for the ARP-Collaboration project, ARP-LAN project, and remaining ARPs.

Q. Are there any adjustments needed to CUB witness Denzler's proposed adjustments for the remaining ARPs?

A. Yes. The projected test year for the case is 11/1/2025 through 10/31/2026; therefore, the Company is not requesting the full projected year 2026 amount as stated by CUB witness Denzler. Therefore, if the Commission were to agree with the proposed gas allocation adjustments of $1,413,753 for the projected year 2025 and $1,579,067 for the projected year 2026, which it should not, the gas allocation adjustment for the 10 months ending 10/31/2025 should be $1,178,128 and the projected test year should be $1,551,515.

Q. Explain CUB witness Denzler's arguments regarding the Asset Accounting Tax Upgrade project.

A. On page 16, lines 1 through 12, of his direct testimony, CUB witness Denzler argues that the Company did not evaluate other software options and recommends that the Commission disallow the requested $126,165 in O&M for this project in the test year. If the Commission does not disallow the entire project, Mr. Denzler recommends the Commission treat this estimate as a Class III AACE estimate and disallow 20% of the projected test year O&M costs, or $25,233.

Q. Do you agree with CUB witness Denzler's arguments regarding the Asset Accounting Tax Upgrade project?

A. No. The Company does not agree with CUB witness Denzler's arguments regarding the Asset Accounting Tax Upgrade project. On page 76, lines 27 through 28, of my direct testimony, I explain that the Company plans as a part of the scope of the project to evaluate

the current vendor/project solution with market leaders to ensure that it is the best solution. Further on page 76, line 35, through page 77, line 1, I explain that moving to the SaaS version of the current software will reduce hardware and server support costs, and avoid database and server upgrades as a result of this project.

Q. Do you agree with CUB witness Denzler's proposed adjustments for the Asset Accounting Tax Upgrade project?

A. No. The Company does not agree with the proposed gas allocation adjustments of $126,165 in O&M for the projected test year, and does not agree with treating the Asset Accounting Tax Upgrade project like an AACE Class III estimate and disallow $25,233 (20% of $126,165). As stated in my direct testimony on page 76, lines 12 through 21, in 2025 the standard vendor support ends for the current system. This project is critical to ensuring compliance with regulated and financial accounting for fixed assets. In addition, the Company will not have the opportunity to recover these O&M expenses in subsequent years for this project. Unlike capital expenditures, which can be recovered in future cases, O&M expenses generally are not recoverable once the test year has passed.

Q. Explain CUB witness Denzler's arguments regarding spending on IT Enhancements.

A. On page 16, line 15, through page 17, line 12, of his direct testimony, CUB witness Denzler argues that the Company has not sufficiently demonstrated the necessity or benefit of these projects, and many larger-cost projects should be standalone projects and not included as Enhancements.

Q. Do you agree with CUB witness Denzler's arguments regarding spending on IT Enhancements?

A. No. The Company does not agree with CUB witness Denzler's arguments regarding spending on IT Enhancements. As stated in my direct testimony on page 92, lines 9 through 11, and page 93, lines 4 through 6, the Enhancement Worklist Detail Report (Exhibit A-25 (SHB-10)) provides a summary of the Enhancements queue of work requests, it is not intended to be a prioritized list of work. Prioritization of enhancements is ongoing and is completed by cross-functional teams based on the most critical needs. The Company considers enhancements to be up to $500,000 and it could be more if the work is low complexity and low risk. The one item that was included for $2.1 million is Mobile App enhancements, which is broken down into several smaller enhancements.

The Company has demonstrated the necessity and benefit of the projects. As described in my direct testimony on page 95, lines 3 through 15, the Company uses two methods to ensure projected enhancements expenditures and expenses in the test year are reasonable and prudent: (1) three-year historical average and (2) total cumulative demand. For the three-year historical average method, the Company calculates the actual three-year historical average plus known incremental work and compares it to the projected Test Year enhancement expenditures to validate the Test Year projects are in line with historical spend and known incremental work. The second method, total cumulative demand, compares the Total Gas Allocation Cumulative Worklist amount to the projected Test Year enhancement expenditures and expenses to validate the projections are in line with the projected demand.

Q. Did the Company provide further information and value for several of the incremental enhancements in this case?

A. Yes. See Company witness Byrom's rebuttal testimony for further discussion of the value for the Web Chat AI, Customer Self-Service Mobile Application, and LMI enhancements as a part of the Product Family Enhancements-Customer-Capital project.

Q. What adjustments for IT Enhancements is CUB witness Denzler proposing?

A. On page 17, lines 17 through 20, of his direct testimony, CUB witness Denzler is proposing an adjustment of $2,651,057 in 2025 and $2,062,093 in 2026 for IT Enhancements.

Q. Do you agree with CUB witness Denzler's proposed adjustments for IT Enhancements?

A. No. The Company does not agree with the proposed gas allocation adjustments of $2,651,057 in 2025 and $2,062,093 in 2026 for IT Enhancements.

Q. Are there any adjustments needed to CUB witness Denzler's proposed adjustments for IT Enhancements?

A. Yes. The projected test year for the case is 11/1/2025 through 10/31/2026; therefore, the Company is not requesting the full projected year 2026 amount as stated by CUB witness Denzler. Therefore, if the Commission were to agree with the proposed gas allocation adjustments of $2,651,057 for the projected year 2025 and $2,062,093 for the projected year 2026, which it should not, the gas allocation adjustment for the 10 months ending 10/31/2025 should be $2,209,214 and the projected test year should be $2,160,254.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

EXHIBITS

OF

STACY H. BAKER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

U21806-SA-CE-409
Requested By: Brittney M. Klocke (BMK-11 - 1)
Respondent: Stacy H. Baker
Date of Response: 3/19/2025
Page **1** of **1**

Question:

1) What is the current status of the Company's website redesign?

Response:

The Company has put the website redesign on hold due to extended support of the current on-premises Sitecore web content management system and the Company's SAP S/4HANA planned implementation.

The previous timing for the website redesign was developed with the expectation that the Company would need to migrate to the cloud/Software-as-a-Service (SaaS) version of the Sitecore system based on Sitecore's published product support lifecycle at that time. This would have been a major reason to initiate the website redesign. Since then, Sitecore has extended mainstream support for the on-premises version 10.4 to December 31, 2027, giving the Company more flexibility in its migration schedule.

In addition, the Company's implementation of the SAP S/4HANA system will be a major undertaking, which will significantly impact the design of integration between the Company's website and SAP. The Company plans to complete the S/4HANA implementation before starting the website redesign.

U21806-AG-CE-0615
Page **1** of **1**

Question:

233. Refer to lines 26-38 on page 61 of Ms. Baker's direct testimony on the ARP-OT Support Gas. Please:

a. Describe the problems experienced with servers in the last three years and identify the number of problems experienced.

b. Explain why a 5-year replacement cycle is necessary and whether it could be extended to 7 years with no significant repercussions.

c. If the Company is on a 5-year replacement cycle, why is there a significant variance in capital expenditures from year to year, which vary from $245,000 in 2023 to $2.5 million for the projected test year.

Response:

Objection of Counsel: Consumers Energy Company objections to this discovery request because it is argumentative and requires the adoption of an assumption. Without waiving this objection, Consumers Energy responds as follows:

a. Following are the incidents experienced with servers in the last three years for the ARP-OT Support Gas.

Incident Description	Number of Incidents
Memory and storage failures	5
Power Supply issues	3
Network and connectivity issues	5
Hardware faults and failures	4

b. A five-year refresh cycle for server hardware is considered necessary due to increased risks of hardware failure, performance degradation, and the expiration of support. For a natural gas compressor station, maintaining a reliable local control system is critical for ensuring continuous and safe gas flow.

Extending the refresh cycle to seven years has potential risks such as increased hardware failures, higher maintenance costs, security vulnerabilities, and performance issues. Compliance with TSA regulatory requirements, such as those outlined in API 1164, is crucial. API 1164 mandates regular updates to control system software and firmware to protect against known vulnerabilities and threats.

c. The costs vary from 2023 to the projected test year for the ARP-OT Support Gas project due to the need to refresh assets implemented as a part of the Pipeline SCADA project.

Witness: Stacy H. Baker
Date: March 21, 2025

U21806-AG-CE-0616 Revised
Page **1** of **1**

Question:

234. Refer to lines 16-40 on page 62 and lines 1-5 on page 63 of Ms. Baker's direct testimony on the ARP-Physical Security. Please:

a. Identify the problems experienced with security assets in the last three years and the number of problems experienced.

b. Explain why the Company needs advanced door systems and how these systems differ from current door systems.

c. Regarding security cameras, gate and lock systems, confirm that these devices and systems are already in place at the Company. If confirming, explain what is being proposed for the additional expenditures. If not confirming, explain why these devices and systems are not already being used.

d. Regarding Alternatives 1 and 2, what are the specific risks that would exist?

Response:

a. Incidents experienced with physical security assets include cameras no longer working, wiring issues, require cleaning, transmitter failures, hard drive failures, reader failures, door strike failures, and control board failures. Following is a table with the number of incidents for the last three years related to physical security assets.

Year	Number of Incidents
2022	758
2023	554
2024	568

b. Referring to the ARP-Physical Security project starting on page 62, line 16 through page 63, line 5, the Company ~~requires~~ needs to refresh advanced door systems to avoid physical security vulnerabilities and meet FERC requirements. These systems are the same as the current door systems.~~, as the current badges can be easily cloned by off the shelf equipment leading to security vulnerabilities. This project would upgrade badge readers and control boards with encryption.~~

c. Yes, the Company currently uses security cameras, motorized gates, and exterior pedestrian doors at occupied facilities controlled by badge readers for access. Referring to the ARP-Physical Security project starting on page 62, line 16 through page 63, line 5, this project refreshes existing devices to reduce physical security vulnerabilities and meet FERC requirements. ~~This project would upgrade badge readers and control boards with encryption to reduce security vulnerabilities.~~

d. By not refreshing physical security assets or deferring a portion of the asset refreshes, the Company risks utilizing older, unsupported equipment, which results in continued security vulnerabilities and increased O&M costs to maintain older equipment.

Witness: Stacy H. Baker
Date: ~~3/21/2025~~ 5/6/2025

U21806-SA-CE-176
Requested By: Emma Zichi (EZ-4 - 41)
Respondent: Stacy H. Baker
Date of Response: 2/7/2025
Page **1** of **1**

Question:

41. Regarding A-22 (SHB-7), the "ARP-Local Area Network" project:
a. Please provide a breakdown for the costs in line 11 and 30 "Software, labor, contractor and overhead and other costs" to show which categories make up the total cost for 2024, 2025 and 2026.
b. Why did the "Avg. Unit Cost" (column b) for the following significantly increase for 2025 and 2026, compared to 2023 and 2024?
i. Line 1 "LAN Switch A", line 2 "LAN Switch B", line 3 "LAN Switch C", line 5 "LAN Switch E".
c. Why are the materials costs the exact same in Exhibit A-20 (SHB-5) when the breakdown of materials shown in Exhibit A-22 is $225,000 for 2025 and $375,000 for 2026

Response:

a. The gas allocation cost breakdown for software, labor, contractor, non-labor overhead, and non-labor other costs in Exhibit No. A-22 (SHB-7), page 6, lines 11 and 30 for 2024, 2025, and 2026 for the ARP-Local Area Network project are provided in Exhibit A-20 (SHB-5), lines 178, 269, and 349 in columns m, o, p, q, and r.

b. The material naming convention used – for example, LAN Switch A, LAN Switch B, LAN Switch C, etc. - is solely to differentiate each model within a given calendar year. The actual models associated with these designations may change from year to year, which can result in variations in unit pricing.

    i. Refer to part b response.

c. In Exhibit A-20 (SHB-5), lines 269 and 349, column n, the gas allocation material costs for 2025 and 2026 are $108,518 and $180,863 respectively. These amounts are not the same. In Exhibit A-22 (SHB-7), page 6, lines 1 through 10, columns e and f, the total Company material costs for 2025 and 2026 are $225,000 and $375,000 respectively. Exhibit A-20 (SHB-5) provides the gas allocation amounts, while Exhibit A-22 (SHB-7) provides the total Company amounts.

Question:

17. Refer to Baker, pp. 54-55, discussing changes in the projected costs of the Gas SCADA Software Solutions project from previous projections in Case No. U-21490. Baker states, "The contractor costs increased because the vendor professional services were underestimated in the ROM estimate." Please explain how and why the contractor costs were underestimated.

Response:

17. The contractor costs for the vendor professional services were not fully known until the Company conducted a Request for Proposal and received vendor cost estimates based on detailed requirements. Additionally, as discussed in my direct testimony on page 55, lines 4-5, the Company determined that additional third-party resources were required to support testing this new technology.

Witness: Stacy H. Baker
Date: February 20, 2025

U21806-CUB-CE-0122
Page **1** of **1**

Question:

18. Refer to Baker, pp. 54-55, discussing changes in the projected costs of the Gas SCADA Software Solutions project from previous projections in Case No. U-21490. Baker states, "The contractor costs increased because the vendor professional services were underestimated in the ROM estimate." Please explain what services the contractors perform.

Response:

18. The professional services vendor is responsible for providing product and industry experience, building the new solution, which includes, but is not limited to, configuring their products, creating new SCADA screen displays, developing an automated, repeatable process to migrate SCADA information from the current system, configuring and building interfaces to the Historian and Geographic Information System (GIS) systems, and conducting the corresponding testing and project management to ensure a quality solution. Additionally, the Company found that it lacked sufficient internal resources and skills to support user acceptance and parallel testing. Therefore, the Company contracted a third-party to provide additional resources to assist, guide, and support testing of the solution.

Witness: Stacy H. Baker
Date: February 20, 2025

U21806-CUB-CE-0123
Page **1** of **1**

Question:

19. Refer to Baker, pp. 54-55, discussing changes in the projected costs of the Gas SCADA Software Solutions project from previous projections in Case No. U-21490. Baker states, "The contractor costs increased because the vendor professional services were underestimated in the ROM estimate." Please explain why the services the contractors perform cannot be performed in-house.

Response:

19. Building and implementing the new solution requires a level of expertise and resources that necessitates leveraging outside services. The Company lacks the internal gas resources with the necessary expertise and experience to implement the software products.

Witness: Stacy H. Baker
Date: February 20, 2025

U21806-CUB-CE-0124
Page **1** of **1**

Question:

20. Refer to Baker, pp. 54-55, discussing changes in the projected costs of the Gas SCADA Software Solutions project from previous projections in Case No. U-21490. Baker states, "The software licensing costs increased because the ROM estimate planned for a five-year period, but the project required six years of software subscriptions due to the length of the implementation." Please explain why the implementation is taking longer than planned.

Response:

20. The reason the software licensing costs increased is not because the implementation is taking longer than planned, but rather because the planned implementation is more than two years. The Company requires that a software asset have at least a three-year expected life after implementation for capitalization. As the Company refined the initial cost projections it identified that due to the implementation being more than two years, the Company was required to purchase six years of software subscriptions to ensure there was a three-year expected life.

Witness: Stacy H. Baker
Date: February 20, 2025

U21806-CUB-CE-0125
Page **1** of **1**

Question:

21. Refer to Baker, pp. 54-55, discussing changes in the projected costs of the Gas SCADA Software Solutions project from previous projections in Case No. U-21490. Baker states, "The material costs increased because the ROM estimate planned to purchase physical servers, but the Company decided to purchase virtual servers. The Company utilizes virtual servers because they provide cost efficiency, maximize the use of available resources, and offer more flexibility." Please explain how switching to more cost-efficient virtual servers resulted in increased material costs.

Response:

21. The virtual servers cost more upfront due to the hypervisor software licensing required for the hardware to function. The cost efficiencies gained are less on-going support and the flexibility to maximize the use of available server resources without purchasing additional servers. Managing the life cycle of virtual servers is more efficient. For example, rolling out firmware, operating system (OS) upgrades, and patches is more efficient with virtual servers, as it can be done once and deployed automatically and dynamically across many virtual servers. In contrast, physical servers require scheduling an outage, taking down each server, and applying the firmware and OS upgrades one by one.

Witness: Stacy H. Baker
Date: February 20, 2025

U21806-CUB-CE-0126
Page **1** of **1**

Question:

22. Refer to Baker, pp. 54-55, discussing changes in the projected costs of the Gas SCADA Software Solutions project from previous projections in Case No. U-21490. Baker states, "The material costs increased because the ROM estimate planned to purchase physical servers, but the Company decided to purchase virtual servers. The Company utilizes virtual servers because they provide cost efficiency, maximize the use of available resources, and offer more flexibility." Please explain why the Company did not identify virtual servers as the better option during the ROM estimate phase.

Response:

22. The Company did not identify virtual servers during the initial cost projection development because it implemented the new operational technology standard to utilize virtual servers afterward.

Witness: Stacy H. Baker
Date: February 20, 2025

U21806-AG-CE-0613
Page **1** of **1**

Question:

231. Refer to page 54 of Ms. Baker's direct testimony on the SCADA project. Please:

a. Provide the current phase of development of the project.

b. Identify the start and completion dates of the detailed requirements phase of the project.

c. Provide the actual amount spent in 2024 for capital expenditures and O&M expense and the forecasted amount of capital expenditures for the 10 months ending October 2025 and for the projected test year.

d. Provide the amount of capital expenditures and O&M expense to be incurred in future years past 2025 by year.

Response:

a. The Gas SCADA Software Solution project is currently in the Execute phase.

b. The detailed requirements occurred from 04/1/22 to 10/31/22.

c. Refer to Attachment No. U21806-AG-CE-0613_ATT 1 for the updated total projected project costs including the preliminary actual 2024 capital expenditures and O&M expense. The projected gas allocation capital expenditures for the 10 months ending October 2025 are $4,220,803 and $3,080,968 for the projected test year.

d. Refer to part c response.

Witness: Stacy H. Baker
Date: 3March 21, 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Gas SCADA Software Solution

Attachment: U21806-AG-CE-0613_ATT 1
Witness: SHBaker
Date: March 2025

Gas SCADA Software Solution				
Cost Category	**Total Company Capital**	**Gas Allocation Capital**	**Total Company O&M**	**Gas Allocation O&M**
2023 Actuals				
Software	$708,742	$708,742	$0	$0
Material	$946,533	$946,533	$0	$0
Labor	$53,782	$53,782	$149,361	$149,361
Contractor Costs	$219,054	$219,054	$1,788	$1,788
Non-Labor Overhead	$4,241	$4,241	$10,211	$10,211
Non-Labor Other	$17,212	$17,212	$0	$0
Total 2023 Actuals	**$1,949,564**	**$1,949,564**	**$161,360**	**$161,360**
2024 Preliminary Actuals				
Software	$433,785	$433,785	$88,847	$88,847
Material	$866,626	$866,626	$137,912	$137,912
Labor	$584,162	$584,162	$17,382	$17,382
Contractor Costs	$1,284,033	$1,284,033	$86	$86
Non-Labor Overhead	$0	$0	$0	$0
Non-Labor Other	$235,536	$235,536	$4,111	$4,111
Total 2024 Preliminary Actuals	**$3,404,142**	**$3,404,142**	**$248,338**	**$248,338**
2025 Projected				
Software	$2,609,645	$2,609,645	$91,513	$91,513
Material	$7,264	$7,264	$167,070	$167,070
Labor	$916,466	$916,466	$161,195	$161,195
Contractor Costs	$1,071,798	$1,071,798	$79,625	$79,625
Non-Labor Overhead	$0	$0	$0	$0
Non-Labor Other	$459,791	$459,791	$33,233	$33,233
Total 2025 Projected	**$5,064,964**	**$5,064,964**	**$532,636**	**$532,636**
2026 Projected				
Software	$197,951	$197,951	$291,343	$291,343
Material	$0	$0	$0	$0
Labor	$161,195	$161,195	$35,544	$35,544
Contractor Costs	$2,081,008	$2,081,008	$418,977	$418,977
Non-Labor Overhead	$0	$0	$0	$0
Non-Labor Other	$244,015	$244,015	$74,586	$74,586
Total 2026 Projected	**$2,684,169**	**$2,684,169**	**$820,450**	**$820,450**
Total Actuals/Projected				
Software	$3,950,123	$3,950,123	$471,703	$471,703
Material	$1,820,423	$1,820,423	$304,982	$304,982
Labor	$1,715,605	$1,715,605	$363,483	$363,483
Contractor Costs	$4,655,893	$4,655,893	$500,475	$500,475
Non-Labor Overhead	$4,241	$4,241	$10,211	$10,211
Non-Labor Other	$956,555	$956,555	$111,931	$111,931
Total Actuals/Projected	**$13,102,839**	**$13,102,839**	**$1,762,785**	**$1,762,785**

U21806-AG-CE-0614
Page **1** of **2**

Question:

232. Refer to pages 50 and 51 of Ms. Baker's direct testimony on the SCADA project. Please:

a. Identify by how much and by what percentage the contractor costs were underestimated and explain why.

b. Confirm that the SCADA project was competitively bid to various vendors. Identify the number of vendors contacted, the number of bids received, and which vendor was selected and why.

c. Provide a copy of the bids received and the analysis showing why the chosen vendor was selected.

d. Explain why a third-party consultant is needed for expertise with the technology when the vendor should provide the needed expertise for the technology they sell.

e. Provide the name pf the third-party and the amount to be paid to this party by year and whether it is included in O&M expense or capital expenditures.

f. Explain whether the Company issued requests for proposals for the third-party, the number of bids received. Provide a copy of the bids received and the analysis showing why the chosen vendor was selected.

g. Identify the length of the implementation. Did the Company consider spreading the implementation over a longer time period to reduce the impact on capital expenditures in the next few years?

h. Explain how the Company uses virtual servers and with whom. If virtual servers are cost efficient, why did they increase the cost of the project?

Response:

a. Refer to Attachment No. U21806-AG-CE-0613_ATT 1 for the updated total projected project costs including the preliminary actuals 2024 capital expenditures and O&M expense. The current projected contractor costs are $4.66 million, which is consistent with the $4.63 million projected in Case No. U-21490.

b. The Gas SCADA Software Solution project conducted a Request for Proposal (RFP) to competitively bid to six vendors. Of the six vendors, three elected not to participate, one vendor could not meet the full requirements, and the vendor selected was Open Systems International, Inc. (now Aspentech).

c. Refer to Attachments U21806-AG-CE-0614_ATT_1_CONF, U21806-AG-CE-0614_ATT_2_CONF, U21806-AG-CE-0615_ATT_3_CONF, and U21806-AG-CE-0615_ATT_4_CONF for a copy of the bids received and the analysis showing why the chosen vendor was selected.

d. Black and Veatch is uniquely qualified to perform the execution and testing support services. Their prior services were key to building the project's detailed requirements that were used in the RFP to ultimately select the best solution. A large part of their services are requirements traceability, ensuring that all requirements have been met in the vendor-built solution and that all testable requirements are indeed tested. Black and Veatch will be building and executing scripts to do parallel

testing, validation to ensure the new solution behaves the same as the existing solution for retrieval of SCADA data from our many endpoints. Further, they will be creating the User Acceptance Test (UAT) testing scripts for the Company to perform to ensure a fully tested solution and readiness for go-live. Both require a deep understanding of our existing gas SCADA environment as well as a solid understanding of our Gas SCADA project requirements. Given the Black and Veatch history on this project, along with the continuity of their personnel, Black and Veatch is uniquely positioned for this testing work.

e. The table below provides the third-party consultant, Black and Veatch, costs total company capital expenditures and O&M expense by year.

Year	Capital	O&M
2025	$625,000	$35,000
2026	$75,000	$35,000
Total	**$700,000**	**$70,000**

f. The Company did not conduct a request for proposal for the third-party.

g. The capital expenditures started for this project in 2023 and are currently planned through February 2026. The original planned Go Live in December 2025 has been extended to February 2026 due to resource availability during the field construction season. Refer to my direct testimony, page 50, line 7 through page 51, line 33, for why the Company determined the current implementation timeline was necessary, as the current system is operating well beyond its original design specifications.

h. The virtual servers cost more upfront due to the hypervisor software licensing required for the hardware to function. The cost efficiencies gained are less on-going support and the flexibility to maximize the use of available server resources without purchasing additional servers. Managing the life cycle of virtual servers is more efficient. For example, rolling out firmware, operating system (OS) upgrades, and patches is more efficient with virtual servers, as it can be done once and deployed automatically and dynamically across many virtual servers. In contrast, physical servers require scheduling an outage, taking down each server, and applying the firmware and OS upgrades one by one.

Witness: Stacy H. Baker
Date: March 24, 2025

U21806-AG-CE-0847
Page **1** of **2**

Question:

397. Refer to discovery response AG-CE-0614 on the SCADA IT project. Please:

a. The answer to subpart (a) is not responsive to the question. Line 1 of page 55 of Ms. Baker's direct testimony states that contractor costs represented $4.4 million of the $6.6 million total increase in costs. Provide the initial contractor costs before the $4.4 million increase.

b. Regarding the response to subpart (h), who owns and runs the virtual servers? Explain how virtual servers differ from cloud computing.

c. Provide the total SCADA project costs by component as originally estimated at time of approval compared to the costs now and justify in detail any variance of 10% or greater in Excel.

Response:

a. The total Company and gas allocation initial contractor costs from the initial estimate of the Gas SCADA Software Solution project in Case No. U-21308 was $1,800,000 capital expenditures.

b. The Company owns and operates the virtual servers on-premises in our data center for the Gas SCADA Software Solution project because the system is critical for providing safe and reliable gas service. These virtual servers are physically located in the Company's data center, while virtual servers in the cloud are located in Azure's data center, for example, that the Company would subscribe to.

c. The table below provides increase/decrease between the total project costs for the initial estimate provided in Case No. U-21308 and the current estimate provided in response No. U21806-AG-CE-0614. Following are explanations for cost category increases greater than 10%.

The software licensing costs increased because they were initially underestimated and the initial estimate planned for a five-year period, but the project required six years of software subscriptions due to the length of the implementation. The material costs increased because the initial estimate planned to purchase physical servers, but the Company decided to purchase virtual servers. The Company utilizes virtual servers because they provide cost efficiency, maximize the use of available resources, and offer more flexibility. The contractor costs increased because the vendor professional services were underestimated in the initial estimate. Additionally, the Company determined that a third-party was required to support internal resources with testing, as the technology is new to the Company. In U-21308 Overheads & Other Costs were one cost category. In this case, U-21806, the Company began using two cost categories, Non-Labor Overhead and Non-Labor Other. There is a net decrease between the initial estimate for Overheads & Other Costs and the current estimate for Non-Labor Overhead and Non-Labor Other.

Refer to U21806-CUB-CE-0123 through U218096-CUB-CE-0126, for additional variance explanation.

U21806-AG-CE-0847
Page **2** of **2**

Refer to Attachment No. U21806-AG-CE-0847_ATT_1 for the detailed total Company and gas allocation initial estimate by year for the Gas SCADA Software Solution project in Case No. U-21308. Refer to Attachment No. U21806-AG-CE-0614_ATT_1 for the current detailed total Company and gas allocation estimate by year for this project.

	U-21308		Current Estimate		Increase/(Decrease)	
Cost Category	**Total Company/ Gas Allocation Capital**	**Total Company/ Gas Allocation O&M**	**Total Company/ Gas Allocation Capital**	**Total Company/ Gas Allocation O&M**	**Capital**	**O&M**
Software	$2,100,000	$40,000	$3,950,123	$471,703	$1,850,123	$431,703
Material	$400,000	$-	$1,820,423	$304,982	$1,420,423	$304,982
Labor	$1,718,125	$725,000	$1,715,605	$363,483	($2,520)	($361,517)
Contractor Costs	$1,800,000	$-	$4,655,893	$500,475	$2,855,893	$500,475
Overheads & Other Costs	$2,792,750	$139,585	$-	$-	($2,792,750)	($139,585)
Non-Labor Overhead	$-	$-	$4,241	$10,211	$4,241	$10,211
Non-Labor Other	$-	$-	$956,555	$111,931	$956,555	$111,931
Total Project	**$8,810,875**	**$904,585**	**$13,102,839**	**$1,762,785**	**$4,291,964**	**$858,200**

Witness: Stacy H. Baker
Date: April 15, 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Historical 13 Month Average of IT Cloud Computing Prepaid Balance
For the years 2023 - 13 months balance ending June 30, 2024
Gas Allocation

Attachment No.: U21806-AG-CE-0852_ATT_2
Page: 1 of 2
Witness: SHBaker
Date: April 2025

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
Line No.	**Description**	**Bal. Ending 6/30/2023**	**Bal. Ending 7/31/2023**	**Bal. Ending 8/31/2023**	**Bal. Ending 9/30/2023**	**Bal. Ending 10/31/2023**	**Bal. Ending 11/30/2023**	**Bal. Ending 12/31/2023**	**Bal. Ending 1/31/2024**	**Bal. Ending 2/29/2024**	**Bal. Ending 3/31/2024**	**Bal. Ending 4/30/2024**	**Bal. Ending 5/31/2024**	**Bal. Ending 6/30/2024**	**13 mos. Average**
1	**IT Cloud Computing Prepaid**	$ (4,508,233)	$ (4,265,049)	$ (3,836,559)	$ (3,489,259)	$ (2,822,343)	$ (2,551,776)	$ (2,236,121)	$ (5,664,387)	$ (5,035,475)	$ (5,296,007)	$ (4,860,516)	$ (4,279,397)	$ (3,880,393)	**$ (4,055,809)**
2	**Total**	**$ (4,508,233)**	**$ (4,265,049)**	**$ (3,836,559)**	**$ (3,489,259)**	**$ (2,822,343)**	**$ (2,551,776)**	**$ (2,236,121)**	**$ (5,664,387)**	**$ (5,035,475)**	**$ (5,296,007)**	**$ (4,860,516)**	**$ (4,279,397)**	**$ (3,880,393)**	**$ (4,055,809)**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected 13 Month Average of IT Cloud Computing Prepaid Balance
For the years 2025 - 13 months balance ending October 31, 2026
Gas Allocation

Attachment No.: U21806-AG-CE-0852_ATT_2
Page: 2 of 2
Witness: SHBaker
Date: April 2025

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
Line No.	**Description**	**Bal. Ending 10/31/2025**	**Bal. Ending 11/30/2025**	**Bal. Ending 12/31/2025**	**Bal. Ending 1/31/2026**	**Bal. Ending 2/28/2026**	**Bal. Ending 3/31/2026**	**Bal. Ending 4/30/2026**	**Bal. Ending 5/31/2026**	**Bal. Ending 6/30/2026**	**Bal. Ending 7/31/2026**	**Bal. Ending 8/31/2026**	**Bal. Ending 9/30/2026**	**Bal. Ending 10/31/2026**	**13 mos. Average**
1	**IT Cloud Computing Prepaid**	$ 6,274,952	$ 5,341,887	$ 4,420,469	$ 8,600,347	$ 7,727,563	$ 6,831,587	$ 6,960,145	$ 6,123,929	$ 6,143,438	$ 6,789,702	$ 6,076,659	$ 5,610,842	$ 4,812,040	**$ 6,285,659**
2	**Total**	**$ 6,274,952**	**$ 5,341,887**	**$ 4,420,469**	**$ 8,600,347**	**$ 7,727,563**	**$ 6,831,587**	**$ 6,960,145**	**$ 6,123,929**	**$ 6,143,438**	**$ 6,789,702**	**$ 6,076,659**	**$ 5,610,842**	**$ 4,812,040**	**$ 6,285,659**

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

REBUTTAL TESTIMONY

OF

MARC R. BLECKMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Q. Please state your name and business address.

A. My name is Marc R. Bleckman, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Marc R. Bleckman who previously filed direct testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to provide rebuttal to certain aspects of the direct testimonies of: (i) Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witnesses Kirk D. Megginson and Justin J. Hecht; (ii) Attorney General Dana Nessel ("AG") witness Sebastian Coppola; and (iii) Association of Businesses Advocating Tariff Equity ("ABATE") witness Christopher C. Walters.

Q. How is your rebuttal testimony organized?

A. In Section I, I will provide rebuttal to portions of the direct testimony of Staff witness Megginson and Staff witness Hecht. In Section II, I will provide rebuttal to portions of the direct testimony of AG witness Coppola. In Section III, I will provide rebuttal to portions of the direct testimony of ABATE witness Walters.

Q. Are you sponsoring any exhibits in connection with your rebuttal testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-114 (MRB-17)	S&P January 14, 2025 Report;
Exhibit A-115 (MRB-18)	MPSC Staff's Answer to Consumers Energy's Second Discovery Request;
Exhibit A-116 (MRB-19)	S&P August 20, 2024 Credit Report;

Exhibit A-117 (MRB-20)	Moody's May 31, 2024 Credit Report; and
Exhibit A-118 (MRB-21)	Attorney General's Answer to Consumers Energy's Third Discovery Request.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

I. REBUTTAL OF STAFF WITNESSES MEGGINSON AND HECHT

A. Overview of Areas of Disagreement Addressed

Q. What aspects of Staff's recommendations are you rebutting?

A. I am rebutting Staff's projected common equity balance and the resulting common equity ratio. I am also rebutting Staff's projected cost of long-term debt. Finally, I am responding to Staff's proposed adjustment to the Company's working capital cash balance.

Q. Are there any other aspects of Staff's recommended capital structure that the Company disagrees with?

A. Yes. Consumers Energy does not agree with Staff's recommended Return on Equity ("ROE") of 9.75%. This issue, however, is addressed in the rebuttal testimony of witness Ann E. Bulkley, the Company's ROE witness in this case.

B. Rebuttal to Staff's Recommendation Regarding the Common Equity Ratio

Q. Do you agree with Staff's projected common equity ratio of 50.00%?

A. No. Staff's recommended common equity ratio for the test year in this case is understated. My rebuttal testimony to Staff's recommended equity ratio is organized as follows:

i. Staff Incorrectly Interprets the Company's Credit Ratings and Regulatory Environment

ii. Staff Fails to Consider New Circumstances That Justify a Deviation From a Balanced Capital Structure

iii. Staff Ignores the Potential Negative Financial Impacts of a Lower Equity Ratio

iv. Staff Fails to Consider the Average Equity Ratios of Peer Group Companies

v. Summary

i. Staff Incorrectly Interprets the Company's Credit Ratings and Regulatory Environment

Q. On page 6 of his direct testimony, Mr. Megginson minimizes the importance of Moody's downgrade of the Company's credit rating by stating that the downgrade "put the Company's credit rating more in line with the other two agencies ratings." Mr. Megginson also concludes that "the prior Moody's rating appeared to be an outlier." Do you agree with these statements?

A. No. Each of the credit rating agencies maintains its own ratings methodology and credit rating scale. It is not a universal measure in which the specific credit rating assigned by Moody's, for example, can be directly compared to the credit rating assigned by Standard and Poor's ("S&P") or Fitch. If Mr. Megginson's assertion were true, there would not be a need for more than one rating agency, as all credit rating methodologies and credit rating scales would be the same. Also, Mr. Megginson's attempt to downplay the credit ratings downgrade by implying that it was an inconsequential action should be rejected by the Commission. Each of the Company's debt offerings are rated by the three main rating agencies – Moody's, S&P, and Fitch. A lower credit rating indicates higher risk which, in turn, necessitates a higher interest rate to compensate for that risk. Regardless of the presumed comparative credit ratings between the different credit rating agencies, the fact that the Company's credit rating was downgraded by Moody's was a negative event that had negative financial consequences for the Company and for customers who bear the cost of capital.

Q. Starting on page 6 of his direct testimony, Mr. Megginson describes the impact of the Company's regulatory environment on its credit rating. Mr. Megginson also references credit reports in which the Company's regulatory environment has been described as positive. Does this give support to Mr. Megginson's recommendation to reduce the Company's equity ratio to 50.00% for the test year in this case?

A. No. I believe that Mr. Megginson's assessment of the Company's regulatory environment is incomplete. In his direct testimony, Mr. Megginson references aspects of Michigan's regulatory framework that have been established for several years under the 2008 and 2016 energy legislation, including items such as a forward-looking test year and the 10-month rate case process. Mr. Megginson's assessment fails to capture the results from the Company's most recent rate cases which demonstrate a sharp decline in authorized weighted rate of return (ROE times equity ratio) following a long period of stability. This recent shift is illustrated in the table on page 15 of my direct testimony. In addition, while rating agencies have described the Company's regulatory environment in a positive light, this rating is continuously evaluated. The persistent decline in the Company's authorized weighted rate of return since 2020 could be seen as a material deterioration in the credit supportiveness of the Michigan regulatory environment. Mr. Megginson fails to acknowledge that the Company's positive regulatory environment in past years has been fueled in large part by authorized ROE and equity ratios that were significantly higher than currently proposed by Staff for the Company in this case. In fact, the trend in rate orders with regard to authorized ROE and equity ratio was a cause for concern for Moody's in its downgrade of the Company's credit rating. An equity ratio of 50.75% and an ROE of

10.25% is better aligned with rate of return levels prior to the Company's credit rating downgrade and is therefore supportive of adequate credit quality at this time.

Q. Is there evidence that analysts have started to recognize a decline in the state of the Company's regulatory environment?

A. Yes. Refer to Exhibit A-36 (MRB-14), S&P's State Regulatory Evaluations – Energy. In August 2024, S&P lowered its ranking of Michigan's regulatory environment from "Above Average" to "Average." In downgrading its state regulatory rating, S&P referenced recent rate case decisions in Michigan including authorized ROEs which "compare less favorably" to prevailing industry averages and a "tightening in the regulatory climate." Also refer to pages 20 to 21 of my direct testimony. In updating its regulatory rankings for U.S. utilities in May 2023, UBS moved Michigan down a level from Tier 1 to Tier 2. In describing the negative change, UBS specifically mentioned authorized ROEs as well as a lowering of their "subjective factor" for the Michigan regulatory jurisdiction, which is based on UBS's "knowledge of current commission actions." Refer to Exhibit A-106 (MRB-15). It is apparent that rating agencies and analysts have taken note of the recent trend in the Company's regulatory outcomes with regard to capital structure. A continuation or, even worse, a further degradation of the authorized weighted rate of return puts the Company at risk of dropping further in its regulatory environment rankings which could negatively impact the Company's credit quality and credit rating. Michigan's regulatory standing needs to be protected and bolstered rather than drawn upon to push the Company toward over-leveraging. Broadly speaking, an above average regulatory standing translates into increased potential investment which continues to support affordable utility infrastructure financing for the state of Michigan.

Q. On page 8 of his direct testimony, Mr. Megginson references a report from S&P's Regulatory Research Associates on state regulatory evaluations. Has S&P provided additional insight with regard to the future credit quality of regulated utilities including Consumers Energy?

A. Yes. Refer to Exhibit A-107 (MRB-16). In a February 2024 report "Rising Risks: Outlook for North American Investor-Owned Regulated Utilities Weakens," S&P updated their outlook of the regulated utility industry to negative, citing "headwinds to credit quality" including increased cash flow deficits that are funded to a higher extent with debt versus equity. Also refer to Exhibit A-114 (MRB-17). In a January 2025 report on North American regulated utilities, S&P highlighted lower ratings headroom as "a high percentage of companies are operating with only minimal financial cushion from our downgrade threshold." S&P also notes that, in 2024, downgrades among North America's investor-owned regulated utilities outpaced upgrades for the fifth consecutive year. With regards to the industry credit outlook for 2025, S&P identifies the following risks to utilities' credit quality:

- The portion of equity in the industry has been weak and consistently below expectations and thus pressuring the industry's financial measures. S&P states that "without significantly more common equity issuance, we expect the industry's financial measures will continue to weaken, albeit gradually, supporting our negative outlook;"
- Tax legislation could weaken financial measures if the new Republican administration lowers the corporate tax rate, reduces tax credits, or eliminates their transferability; and
- Robust capital spending and challenging regulatory constructs will persist for 2025, further pressuring the industry's credit quality.

S&P also cites Michigan as one of the regulatory jurisdictions that they "continue to carefully monitor." It is apparent from these rating agency reports that an ROE and equity

ratio combination higher than the current authorized level, and certainly higher than the continued degradation proposed by Staff, is critical to protect the Company from receiving a credit downgrade in the light of the credit risks as described above.

Q. On page 9 of his direct testimony, Mr. Megginson includes a chart showing Consumers Energy's net income from 2010 to 2024 noting that "the Company's net income has risen steadily over the years" which has "enabled Consumers to access credit markets to the tune of billions in short and long-term financing at very competitive rates." Do you agree with Mr. Megginson's interpretation of this data?

A. No. Mr. Megginson reviews the Company's annual change in net income in complete isolation, without considering the changes in investment over time or the changes in rate base. To the extent that the Company has invested in the system over the period from 2010 through 2024, its net income should increase. However, the analysis does nothing to demonstrate that the increases in net income are sufficient to satisfy the investor-required return on that investment, nor does it conclude anything meaningful about the Company's financial integrity. The Company's access to capital markets and its ability to raise capital at competitive rates is not based on net income, but rather is largely based on the Company's credit quality as determined by credit rating agencies. Since net income can be skewed by non-cash transactions, rating agencies instead look to the Company's cash flow metrics, including its Funds From Operation ("FFO")-to-Debt ratio. Rating agencies also look at the strength of the Company's balance sheet, including its equity ratio. These financial measures are a better indicator of the Company's credit quality and credit rating. It should be noted that the Company's "billions in short and long-term financing" over the years was executed during a period in which the Company's authorized equity ratio was

significantly higher than currently proposed by Staff for the Company in this case. As the Company will continue to rely heavily on capital markets to fund capital investment, the Company's proposed equity ratio of 50.75% will help to maintain strong credit ratings and obtain financing at lower interest rates.

Q. On page 9 of his direct testimony, Mr. Megginson points to the Company's debt issuances in 2023 and 2024 and projected debt issuances in this case as evidence that the Company has not been negatively impacted by Moody's credit rating downgrade. Do you agree with this conclusion?

A. No. Neither the Company's ability to issue debt in 2023 and 2024 nor the projection of continued debt issuances in this case is evidence that there has been no negative impacts from Moody's credit rating downgrade. As explained earlier in my rebuttal testimony, a lower credit rating results in negative financial impacts associated with a higher cost of capital. In addition, the Company's debt issuances in 2023 and 2024 do not prove that the Company will undoubtedly have access to capital markets at reasonable rates in the future, especially with a lower weighted rate of return as proposed by Mr. Megginson.

Q. On page 10 of his direct testimony, Mr. Megginson states that "Consumers currently has a revenue decoupling mechanism in place that allows it to collect revenues, including a return on investment, that is unrelated to the amount of gas sold to its customer base." Mr. Megginson also states that "the Company also has several gas infrastructure improvement and replacement programs in place with surcharge payment mechanisms." Mr. Megginson concludes that programs such as this improve the Company's cash flow expectancy and reduce the Company's risk which,

in turn, justifies a reduction in the Company's ROE. Does the Company currently have these mechanisms in place as Mr. Megginson claims?

A. No, revenue decoupling is no longer a regulatory mechanism that the Company has in place. Refer to Staff's discovery response included as Exhibit A-115 (MRB-18). When asked to identify the MPSC proceeding which authorizes the revenue decoupling mechanism currently in place, Staff changes its position stating that the Company's revenue decoupling mechanism "may have discontinued." In addition, the Company does not have any gas infrastructure improvement and replacement programs with surcharge mechanisms. Again refer to Staff's discovery response included as Exhibit A-115 (MRB-18). When asked to identify the "several gas infrastructure improvement and replacement programs" currently in place, Staff referenced the Company's Enhanced Infrastructure Replacement Program. However, there is no surcharge mechanism in place for this program. Staff also identifies the Company's Gas Cost Recovery mechanism which is simply a method for the Company to recover its cost of gas and is clearly not a gas infrastructure improvement and replacement program. Finally, Staff identifies the Company's Energy Waste Reduction program which is also not a gas infrastructure improvement and replacement program but a state-mandated program aimed at reducing energy consumption and improving energy efficiency. Since Mr. Megginson's claims and references to the existence of recovery mechanisms are false, his argument that such programs reduces risk and thus justifies a lower authorized ROE or equity ratio should be rejected by the Commission.

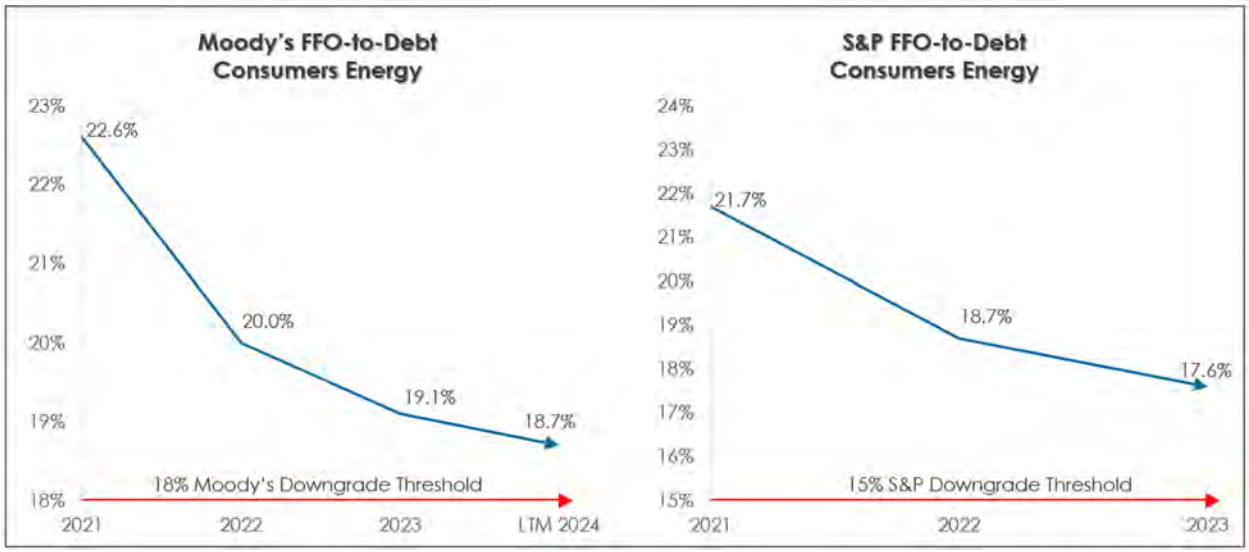
Q. On pages 10 to 11 of his direct testimony, Mr. Megginson references recent credit opinions from S&P and Moody's which describe the rating agencies' expectations with respect to the Company's FFO-to-Debt ratio in future years. Because the rating agencies' expectations are above the credit downgrade thresholds, Mr. Megginson concludes that "rating agencies don't foresee any major deterioration or long-lasting decline in the FFO-to-Debt ratio for Consumers Energy in the foreseeable future." Do you agree with Mr. Megginson's conclusion?

A. No. In assessing credit quality, rating agencies must make certain assumptions with respect to the Company's outlook, including future financial results and regulatory outcomes. However, the assumption of credit metrics holding above the downgrade threshold should not be interpreted as assurance that these assumptions will ultimately materialize, with no risk of a credit rating downgrade. For example, in June 2019, Moody's issued a credit opinion for the Company stating that "Consumers' stable outlook reflects our expectation that the Michigan legislative and regulatory environments will remain constructive." Moody's also stated that they expected the Company's FFO-to-Debt ratio to "range between 20% and 24% over the next few years." In May 2021, Moody's downgraded Consumers Energy's credit rating "due to its weakened credit metrics." Moody's also referenced the outcome of recent rate cases which put pressure on the Company's credit metrics. While rating agencies may assume that the Company will continue to operate in a constructive regulatory environment with credit metrics above the downgrade threshold, the Company's credit rating is continuously evaluated. A reduction in the Company's rate of return lowers cash flow, increases debt, and thereby weakens the Company's FFO-to-Debt ratio. These negative credit metric impacts place the Company's credit quality and

credit ratings at risk. The authorized ROE and equity ratio in this case will be a key component of future rating agency evaluations.

Q. In his assessment of the Company's credit ratings and credit quality did Mr. Megginson take into account the trend in the Company's FFO-to-Debt ratio in recent years?

A. No. Refer to page 5 of S&P's August 2024 credit opinion shown on Exhibit A-116 (MRB-19). The Company's FFO-to-Debt ratio as calculated by S&P has been trending down in recent years from 21.7% in 2021 to 17.6% in 2023, a decrease of 410 basis points and, for 2023, just 60 basis points above the low end of S&P's expected range outlined in its report. In addition, refer to page 2 of Moody's May 2024 credit opinion shown on Exhibit A-117 (MRB-20). The Company's FFO-to-Debt ratio as calculated by Moody's has also been trending down in recent years from 22.6% in 2021 to 19.1% in 2023, a decrease of 350 basis points. Moody's May 2024 credit report also shows a further decline to 18.7% for the 12 months ended March 2024. It is clear from this report that the Company's FFO-to-Debt ratio as calculated by Moody's is trending down and was well below the low end of Moody's expected range (20-21%) for the Company for 2023 and for the 1st quarter of 2024. These credit metric results are shown in the following chart:



The Company's FFO-to-Debt ratio has been trending down in recent years, moving closer to the rating agencies' credit downgrade thresholds. As the credit metric cushion decreases, the Company's credit rating becomes more at risk for a downgrade. The ROE and equity ratio combination proposed by the Company in this case is critical in protecting the Company from a credit downgrade in the light of the credit metric degradation shown above.

ii. Staff Fails to Consider New Circumstances That Justify a Deviation From a Balanced Capital Structure

Q. On pages 13 to 15 of his direct testimony, Mr. Megginson references the Commission's Orders in prior rate cases which reflected its desire for the Company to have a balanced equity ratio. Is this evidence that the Company's equity ratio in the current case should necessarily be 50% as Mr. Megginson proposes?

A. No. The appropriate equity ratio for the Company should be based on the facts and circumstances presented in the current case and not predetermined based on prior Commission orders. While the Commission voiced its desire for the Company to move

toward a balanced capital structure in the cases referenced by Mr. Megginson, the Commission has also made clear that there should be flexibility in its assessment, allowing for a deviation from a balanced capital structure when circumstances warrant it. This approach is illustrated in the following Commission Orders:

> **Case No. U-17990** – "A more complete analysis should be included to explain why such a result is reasonable and prudent" (when referring to an unbalanced capital structure). [MPSC Case No. U-17990, February 28, 2017 Order, page 64.]
>
> **Case No. U-20963** - "The Commission maintains its goal of a capital structure evenly balanced between debt and equity, while continuing to allow a utility to present arguments why a deviation from this ratio is appropriate. As it has done in previous rate cases, the Commission will continue to consider all evidence and circumstances in each rate case to determine the appropriate capital structure." [MPSC Case No. U-20963, December 22, 2021 Order, page 200.]
>
> **Case No. U-21585** - "The Commission, like the ALJ, acknowledges that there is some degree of flexibility and 'that the aspirational goals expressed in previous Commission orders are not permanently binding and that any target for the Company's capital structure should change if evolving circumstances indicate that the target is no longer a sound policy.'" [MPSC Case No. U-21585, March 21, 2025 Order, page 232.]

It is clear from previous orders that the Commission does not consider a balanced capital structure a mandate to be followed blindly, but rather as a basis from which a deviation may be justified upon consideration of the evidence and circumstances of each rate case.

Q. Has the Company presented evidence in this case that an equity ratio of 50.75%, slightly above a balanced capital structure, is warranted?

A. Yes. Refer to pages 10 through 23 of my direct testimony in which I outline reasons why an equity ratio of 50.75% and an ROE of 10.25% as proposed by the Company in this case are well-measured for both the Company and its customers, while still mindful of the Commission's previous orders. This capital structure results in a modest effect on customer rates while bringing the Company more in-line with the authorized weighted rate

of return experienced toward the beginning of the COVID-19 pandemic and prior to the most recent credit rating downgrade. The weighted rate of return as proposed in this case strengthens the Company's balance sheet and credit quality, which will be critical in delivering the Reliability Roadmap investments while doing so in the midst of an elevated interest rate environment.

Q. Are there any new circumstances that give weight to the Company's contention that a deviation from a balanced capital structure to 50.75% equity is justified at this time?

A. Yes. A high degree of volatility and economic uncertainty has emerged in recent months with respect to financial markets, interest rates, and geopolitical tensions. The Trump administration, signaling a significant shift in American trade policy, has placed significantly higher tariffs on imported goods, causing a substantial impact on the U.S. economy. Companies reliant on global supply chains faced elevated input costs, which translated into higher consumer prices and contributed to sustained inflationary pressures. In addition, the heightened trade tensions created an atmosphere of uncertainty that negatively affected business investment and led to heightened volatility in financial markets. An April 2025 Wall Street Journal article titled "Huge Stock Swings Are the New Normal for Frazzled Investors" stated that April 2025 is poised to be the most-volatile calendar month since the COVID crash in 2020. The VIX, a stock market index that measures investors' expectation of volatility, peaked at 52.33 on April 8, 2025. The VIX has not reached 50.00 since April 2020 during the height of the COVID-19 pandemic. Fears of a sharp economic downturn have also dramatically increased. In April 2025, J.P. Morgan Research raised the probability of a U.S. recession occurring in 2025 to 60%.

These developments represent a material change in the Company's risk environment since the previous Commission orders that will most likely continue through the test year of this case. During this period of heightened risk and volatility, it will be critical for the Company to have an authorized ROE and equity ratio that is supportive of its good credit quality. This will be instrumental in the Company's ability to maintain uninterrupted access to needed liquidity and better withstand potential impacts from fuel price spikes, inflationary pressures, and tightening capital markets. As provided for in previous Commission orders, an equity ratio of 50.75% (slightly above a balanced capital structure) is warranted given the facts and circumstances present in the current case.

iii. Staff Ignores the Potential Negative Financial Impacts of a Lower Equity Ratio

Q. Starting on page 15 of his direct testimony, Mr. Megginson references the relatively higher cost of equity compared to debt as justification for a lower equity ratio. Does Staff also discuss the potential negative financial impacts of a lower equity ratio?

A. No. Staff merely states that it is important to "establish a proper equity to debt ratio to maintain reasonable costs to ratepayers." Staff makes this conclusion without analyzing or quantifying the increased costs to the Company and customers that would certainly result from further credit downgrades. Additionally, Mr. Megginson does not provide quantifiable justification as to why his chosen equity ratio of 50.00% is appropriate. This outcome-based conclusion, which is void of an evidentiary analysis of the resulting financial impacts to the Company and its customers, should not be accepted by the Commission.

Q. Mr. Megginson argues that because equity is more expensive than debt, it necessitates a lower equity ratio. Does this rationale have merit?

A. No. Taken to extreme, this rationale would lead to Staff simply recommending that because customers would benefit most from 0% equity, the Commission should authorize a completely debt financed capital structure for the Company. Such a result would clearly ruin the financial soundness of the Company and a recommendation based on such a rationale should be given no merit. Staff's argument points out the obvious fact that the cost of equity is greater than the cost of debt – but no business can or should fund itself with an excessive level of debt. This simplistic argument adds nothing of value for the Commission to consider.

Q. Although Mr. Megginson chooses to ignore the possibility of another credit downgrade and presents no analysis or discussion of the impacts of a credit downgrade on the Company, what would be the effect of a credit downgrade?

A. As explained earlier in my rebuttal testimony, lowering the equity ratio and authorized ROE reduces the Company's overall cost of capital and rate of return. This, in turn, lowers the Company's cash flow and FFO-to-Debt ratio. The Company would also have to increase its long-term debt to achieve a lower equity ratio thereby weakening the Company's FFO-to-Debt ratio. The negative impacts could cause the Company's FFO-to-Debt ratio to drop below the established rating agency thresholds, placing both the Company's credit quality and credit ratings at risk. While it may seem attractive for the benefit of customers in the near-term to minimize the equity layer of the Company, such a move, and the potential resulting credit rating downgrade, could lead to the Company's customers paying higher financing costs over the long term, and it could put at risk the

Company's ability to execute on its critical investment plan on behalf of customers. Thus, it is of great importance for the regulatory response to be balanced and thoughtful, as the financial health of the Company is a critical element of its ability to implement the capital plan needed to deliver safe, reliable, and clean energy to its customers.

Q. What are the customer benefits of the Company maintaining the needed financial cushion to avoid a credit rating downgrade?

A. A higher credit rating ensures that the Company is able to obtain financing at lower interest rates, resulting in long-term customer rate stability. As shown in Exhibit A-35 (MRB-13), the Company has saved customers $153 million annually as a result of improved credit ratings and lowered interest costs. But the customer benefits extend far beyond this long-term rate stability. As set forth in the testimony and exhibits of the Company's multiple capital witnesses, the Company is making significant capital investments to maintain and improve utility infrastructure to improve reliability and resiliency to the benefit of customers. During this time, the Company must rely heavily on the capital markets to fund these investments. Therefore, it will be especially important for the Company to maintain strong credit ratings to ensure beneficial access to capital markets for funding to deliver these critical customer investments and enable the Company to do so at the lowest possible financing cost on their behalf.

iv. Staff Fails to Consider the Average Equity Ratios of Peer Group Companies

Q. How does Mr. Megginson's recommended 50.00% equity ratio compare to equity ratios authorized by other commissions?

A. Mr. Megginson's recommended 50.00% equity ratio is significantly lower than equity ratios authorized by other commissions. I researched all rate case decisions from 2020

through September 2024 of peer companies and determined the authorized or approved equity ratio for each. This is reflected on Exhibit A-32 (MRB-10). The average authorized equity ratio for the peer group was 54.05%, 405 basis points higher than the 50.00% proposed by Mr. Megginson for Consumers Energy in this case. Despite this higher peer average, I am proposing a ratio of 50.75%, which balances the higher peer average with capital investment plans, credit metrics, customer rate impacts, and the guidance of this Commission, and which continues to support affordable utility infrastructure financing for the state of Michigan.

Q. Are the equity ratios reflected on Exhibit A-32 (MRB-10) based on historical financial data or commission-authorized equity ratios?

A. The equity ratios were taken directly from commission orders and public filings and represent actual regulatory equity ratios authorized or approved by the various commissions across the country, as specifically requested by the Commission on page 218 of its Order in Case No. U-20963. It is clear from this analysis that, on average, regulatory commissions of the Company's peer group are granting equity ratios that are much higher than the 50.75% requested by the Company in the current case, and higher still than the 50.00% equity ratio chosen by Mr. Megginson.

Q. Did Mr. Megginson perform an analysis of the national average peer company authorized ROEs consistent with previous rate cases?

A. Yes. Staff considered average gas utility authorized ROE decisions across the U.S. to support its ROE recommendation for the Company in this case.

Q. Did Mr. Megginson also perform an analysis of average peer company authorized equity ratios?

A. Yes. On page 2 of his Exhibit S-4, Schedule D-5, Mr. Megginson calculated an average authorized equity ratio of 53.62%. This is 362 basis points higher than Mr. Megginson's recommended equity ratio in this case of 50.00% and 287 basis points higher than the Company's recommended equity ratio in this case of 50.75%.

Q. Is Mr. Megginson's peer equity ratio analysis a valid basis for purposes of authorizing a permanent equity ratio?

A. No. According to Mr. Megginson's exhibit, the source of the equity ratio data is S&P Global Market Intelligence. S&P Global Market Intelligence tracks the authorized equity ratio as a percentage of <u>total</u> capitalization. Total capitalization can be higher (thereby under-reporting an equally comparable equity ratio) because, in addition to permanent capital components, items such as short-term debt, deferred taxes, and customer deposits can be included. For example, as reflected on Exhibit A-14 (MRB-1), the Company's 50.75% permanent equity ratio in this instant case translates to only 42.58% on a total capitalization basis that would be reported in Staff's referenced database, which is a difference of 817 basis points. The Company's equity ratio, which is based on a percentage of permanent capital, should only be compared to equity ratios of peer utilities based on percentage of permanent capital in order for the comparison to be at all meaningful. The actual commission-authorized equity ratios provide the required data for a comparable analysis and were relied upon in my analysis shown in Exhibit A-32 (MRB-10) which shows the average equity ratio for the peer group utilizing this method to be 54.05%.

Q. Did Mr. Megginson consider his calculation of peer average authorized equity ratios in determining his recommended equity ratio for the Company in this case consistent with his consideration of peer averages to support his ROE recommendation?

A. No, his recommended equity ratio for the Company in this case was inconsistent with even his own substandard peer equity ratio analysis. According to both the Company's calculations as well as Staff's own analysis, Mr. Megginson's recommended equity ratio of 50.00% is drastically understated.

Q. Are there any other reasons why it is appropriate to consider peer company equity ratio averages and trends in determining the appropriate equity ratio for the Company in this case?

A. Yes. In its Order in Case No. U-20963, the Commission cited Staff's average ROE analysis as one of the factors considered in determining the Company's approved ROE. In addition, in Case No. U-21585, the Administrative Law Judge ("ALJ") also considered average authorized ROEs in determining the appropriate ROE for the Company. In its Order, the Commission found that the ALJ appropriately considered the record evidence, weighing the vast testimony, methodologies and proposed ROEs on the record. It is apparent that the Commission considers peer averages an important piece of evidence to inform the ratemaking process. To be consistent with that philosophy, it is appropriate to consider peer company equity ratio averages and trends in determining the equity ratio for the Company in this case.

v. Summary

Q. Please summarize your rebuttal testimony to Staff witness Megginson's recommendation of an equity ratio of 50.00% for the test year in this case.

A. In my rebuttal testimony, I have shown that Mr. Megginson's position on equity ratio is largely not evidence based and that the evidence which he does provide is unsound and should not be relied upon. Further, I have shown that, based on the recent dramatic increase in risk and volatility, a deviation from a balance structure is justified at this time. I have also shown that Staff's recommended equity ratio for the test year in this case is below what is considered supportive of the Company's credit quality and also significantly lower than the average equity ratio of peer group companies. For these reasons, Staff's recommended equity ratio of 50.00% for the test year in this case should be rejected.

C. Rebuttal of Staff's Recommendation Regarding the Cost of Long-Term Debt

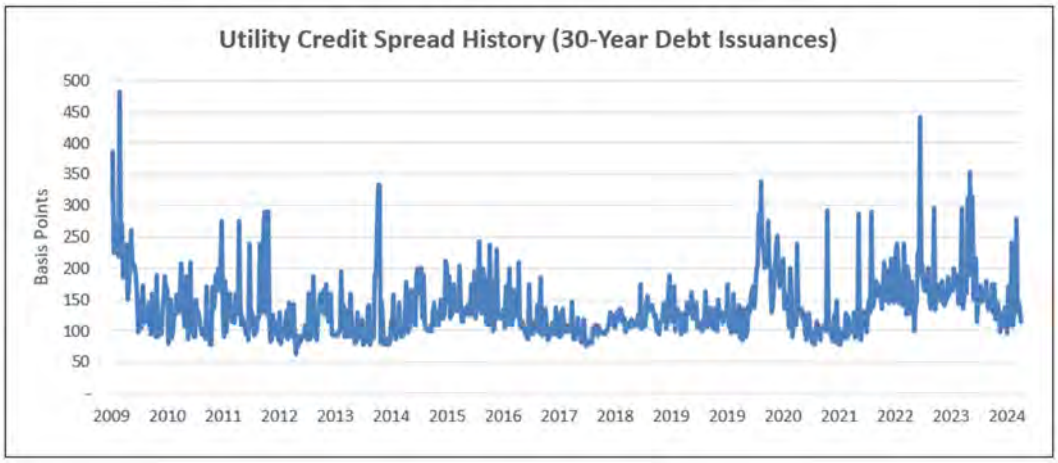
Q. Please explain your disagreement with Staff's cost of long-term debt recommendation of 4.33% as reflected on Mr. Megginson's Exhibit S-4, Schedule D-1.

A. Mr. Megginson's assumed credit spread (added to the U.S. Treasury rate to calculate the total projected interest rate on the new debt issuances) is also unreasonably low.

Q. Mr. Megginson uses the credit spreads on the Company's recent long-term debt issuances as a basis for projecting a 100 basis point credit spread on the Company's forecasted debt issuances through the test year in this case. Is this a reasonable approach?

A. No. As explained on page 33 of my direct testimony, credit spreads for long-term debt issuances are very difficult to predict and can be quite volatile in short periods of time. This is because credit spreads are based on a number of factors, most notably the

Company's credit rating and the market conditions at the time of the debt issuance, including both same-day and short-term supply/demand dynamics. The volatility of credit spreads is illustrated on the following chart:



Mr. Megginson's 100 basis point credit spread is also quite obviously at the very low end of the historical spreads for 30-year debt issuances, as evidenced in the chart above. In addition, as shown in Staff's discovery response included as Exhibit A-115 (MRB-18), Mr. Megginson includes credit spreads on the Company's recent long-term debt issuances which are <u>not</u> 30-year maturities as a basis for projecting the credit spreads on forecasted debt issuances that <u>are</u> assumed to be 30-year maturities. Credit spreads on debt issuances vary based on the tenure or maturity of the debt issuance (for example, a 10-year bond versus a 30-year bond). For these reasons, Mr. Megginson's methodology for estimating the credit spread on the Company's projected long-term debt issuances is faulty and should be rejected by the Commission. Alternatively, the Company has provided a very sound approach to projecting credit spreads. Given the lack of a reliable source for projected credit spreads, I applied the calculated average credit spread on a 30-year debt issuance for investment grade utilities from the last 15 years which was approximately 136 basis points.

Since credit spreads can be volatile in the short-term, a longer-term historical average is a rational approach with regard to credit spreads.

D. Staff's Recommendation Regarding the Projected Working Capital Cash Balance

Q. Does Staff recommend a working capital cash balance for the test year in this case that is lower than the Company's projection?

A. Yes. On page 5 of Staff witness Hecht's direct testimony, he recommends an adjustment to reduce the Company's projected cash balance by $5,263,000. Mr. Hecht states that the Company used incorrect data to calculate the cash balance in its original filing and that the balance should be $23,130,000 rather than $28,393,000.

Q. Does the Company object to Staff's adjustment to the working capital cash balance?

A. No. The Company's methodology of projecting the cash balance of 1% of test year revenues is not in dispute, but rather the correct test year revenues that the 1% should be applied to. The Company agrees that the 1% was applied to the incorrect revenues amount in the Company's original filing and therefore accepts Staff's cash working capital adjustment.

II. REBUTTAL OF AG WITNESS COPPOLA

A. Overview of Areas of Disagreement Addressed

Q. What aspects of AG witness Coppola's recommendations are you rebutting?

A. I am rebutting Mr. Coppola's recommendation regarding the common equity ratio. I am also rebutting Mr. Coppola's recommendation regarding the Company's working capital cash balance.

Q. Are there any other aspects of Mr. Coppola's recommended capital structure that the Company disagrees with?

A. Yes. Consumers Energy does not agree with Mr. Coppola's recommended ROE of 9.75%. This issue, however, is addressed in the rebuttal testimony of Company witness Bulkley.

B. Rebuttal to Mr. Coppola's Recommendation Regarding the Common Equity Ratio

Q. On page 110 of his direct testimony, Mr. Coppola references the Commission's Orders in Case No. U-21585 and Case No. U-21389, the Company's two most recent fully-contested cases, in which both orders authorized a balanced equity ratio. Mr. Coppola then concludes that the Company's capital structure in the current case should "similarly mirror" the common equity ratio last approved by the Commission. Do you agree with this conclusion?

A. No. The appropriate equity ratio for the Company should be based on the facts and circumstances presented in the current case and not predetermined based on prior Commission orders. Refer to my earlier rebuttal testimony to Staff witness Megginson (ii. Staff Fails to Consider New Circumstances That Justify a Deviation From a Balanced Capital Structure). While the Commission authorized a balanced capital structure in the cases referenced by Mr. Coppola, the Commission has also made clear that there should be flexibility in its assessment, allowing for a deviation from a balanced capital structure when circumstances warrant it. It is clear from these orders that the Commission does not consider a balanced capital structure a mandate to be followed blindly, but rather as a basis from which a deviation may be justified upon consideration of the evidence and circumstances of each rate case.

Q. Has the Company presented evidence in this case that an equity ratio of 50.75%, slightly above a balanced capital structure, is warranted?

A. Yes. Refer to pages 10 through 23 of my direct testimony in which I outline reasons why an equity ratio of 50.75% and an ROE of 10.25% as proposed by the Company in this case are well-measured for both the Company and its customers, while still mindful of the Commission's previous orders. Also refer to my earlier rebuttal testimony to Staff witness Megginson. There have been new circumstances that gives credence to the Company's contention that a deviation from a balanced capital structure is justified at this time including extreme financial market volatility, supply chain impacts, inflationary pressures, and increased fears of a U.S. recession in 2025. As provided for in previous Commission orders, an equity ratio of 50.75% (slightly above a balanced capital structure) is warranted given the facts and circumstances present in the current case.

Q. On page 113 of his direct testimony, Mr. Coppola references recent credit opinions from Moody's and S&P, noting that the Company's FFO-to-Debt ratio in recent years for both rating agencies was higher than the threshold that could lead to a further downgrade if the Company fell below. For S&P, Mr. Coppola concludes that "these coverage ratios are not indicative of any concerns about a possible debt rating downgrade." Is the Company's FFO-to-Debt ratio in recent years evidence that the Company is not at risk for further credit rating downgrade?

A. No. First, as explained on pages 15 to 16 of my direct testimony and earlier in my rebuttal testimony to Staff witness Megginson, the Company's FFO-to-Debt ratio as calculated by rating agencies has been trending down in recent years – a decrease of 410 basis points for S&P and a decrease of 350 basis points for Moody's. This sizable amount of credit ratio

deterioration, which is brushed off by Mr. Coppola, should be troubling to the Commission. Second, while the Company's FFO-to-Debt ratios in previous years were higher than the downgrade threshold, the results cover a time when the Company's equity ratio was significantly higher than Mr. Coppola recommends for the Company in this case - 52.7% in 2021 and 53.2% in 2022. Therefore, Mr. Coppola's statement that there is no concern of downgrade should be discounted by the Commission.

Q. On page 114 of his direct testimony, Mr. Coppola references the increase in the Company's net income in 2024. Mr. Coppola concludes that this will have a positive impact on the Company's credit metrics. Do you agree with this conclusion?

A. No. Refer to my earlier rebuttal testimony to Staff witness Megginson on this issue. Higher net income is not necessarily indicative of higher credit metrics or credit quality. Since net income can be skewed by non-cash transactions, rating agencies instead look to the Company's cash flow metrics, including its FFO-to-Debt ratio. Rating agencies also look at the strength of the Company's balance sheet, including its equity ratio. Finally, rating agencies evaluate the supportiveness of the Company's regulatory environment, including the authorized ROE and equity ratio. These measures are a better indicator of the Company's credit quality and credit rating. Based on rating agencies' criteria, the weighted rate of return authorized in this case, and not net income, will be a significant factor in determining the Company's credit quality.

Q. On pages 114 to 115 of his direct testimony, Mr. Coppola refers to the Company's direct testimony which showed that the Company's FFO-to-Debt ratio as calculated by S&P and Moody's has been trending down in recent years. Mr. Coppola dismisses these sharp declines as "temporary" and the result of "unusual and short-term issues." Do you agree with this assessment?

A. No. Mr. Coppola describes events such as unfavorable weather, storm activities, and higher gas prices as the main cause for the Company's decline in credit metrics in recent years. First of all, Mr. Coppola omits that, as explained on pages 15 to 16 of my direct testimony, the decline in the Company's FFO-to-Debt ratio has coincided with recent rate cases which have resulted in a sharp decline in rate of return (ROE multiplied by equity ratio) having a directly negative result on credit metrics, both historic and future. Secondly, there is no guarantee that these issues that Mr. Coppola describes as "temporary" such as storms, will not persist in future years. For example, from the end of March 2025 through the beginning of April 2025, the Company's service territory was hit with the worst ice storm in northern Michigan in over 100 years, as confirmed by the National Weather Service. At the same time, the lower peninsula of Michigan was hit by thunderstorm systems strong enough to produce 13 confirmed tornados. The Company estimates this combined storm event will result in approximately $96 million in operating and maintenance ("O&M") expense, significantly higher than any other Consumers Energy storm event O&M amount in at least the last 20 years. This cost of this storm will have a significant detrimental impact on the Company's credit metrics in 2025 and 2026. In fact, Mr. Coppola's testimony highlighting the negative impact of these events demonstrates the

importance of maintaining strong credit metrics in preparation for such events and not managing the Company toward the lower margins.

Q. On pages 115 to 116 of his direct testimony and his Exhibit AG-49, Mr. Coppola references his calculation of the Moody's FFO-to-Debt ratio for the Company for 2023 assuming a 9.75% ROE and a 50.0% equity ratio. According to Mr. Coppola's calculations, the Company's FFO-to-Debt ratio would have been 20.1%, or 100 basis points higher in 2023 with these assumptions. Do you agree with Mr. Coppola's calculations?

A. No. In his calculations, Mr. Coppola mixes the Company's authorized ROE with the Company's earned ROE, greatly distorting the pro forma FFO-to-Debt impacts. First, Mr. Coppola calculates the Company's actual earned ROE of 8.25% in 2023. Next, Mr. Coppola makes two assumptions: (1) that the Company's authorized ROE was 15 basis points lower in 2023 (9.75% versus 9.90%); and (2) that the Company actually earned that authorized ROE in 2023 (9.75% versus 8.25%). Mr. Coppola's second assumption is false in that he is attempting to show the FFO-to-Debt ratio for the Company for 2023 only assuming an authorized ROE of 9.75% and an equity ratio of 50.0%. In essence, Mr. Coppola is suggesting that if the Company's authorized ROE in 2023 was 15 basis points lower (9.75% versus 9.90%), the Company's FFO would have been $155 million higher. This lacks logical sense and results in a pro-forma FFO-to-Debt ratio that is significantly overstated. Therefore, Mr. Coppola's pro forma FFO-to-Debt analysis for Moody's in 2023 is faulty and should therefore be rejected by the Commission.

Q. On pages 117 to 118 of his direct testimony, Mr. Coppola references recent credit opinions from S&P and Moody's which indicate a stable outlook for the Company. Is this evidence that the Company is not at risk for further credit rating downgrade?

A. No. In assessing credit quality, rating agencies must make certain assumptions with respect to the Company's outlook, including future financial results and regulatory outcomes. However, the assumption of a stable outlook should not be interpreted as assurance that these assumptions will ultimately materialize, with no risk of a credit rating downgrade. For example, Mr. Coppola highlights the rating agencies' assumption that the Company will continue to operate in a constructive regulatory environment. However, the Company's credit rating is continuously evaluated, and the authorized ROE and equity ratio in this case will be a key component of future evaluations. As shown on page 15 of my direct testimony, the results from the Company's most recent rate cases demonstrate a sharp decline in authorized weighted rate of return (ROE times equity ratio) following a long period of stability. The persistent decline in the Company's authorized weighted rate of return since 2020 could be seen as a material deterioration in the credit supportiveness of the Michigan regulatory environment. In addition, refer to my earlier rebuttal testimony to Staff witness Megginson. In August 2024, S&P lowered its ranking of Michigan's regulatory environment from "Above Average" to "Average" referencing less favorable authorized ROEs and a "tightening in the regulatory climate." In updating its regulatory rankings for U.S. utilities in May 2023, UBS also moved Michigan down a level from Tier 1 to Tier 2. In describing the negative change, UBS specifically mentioned authorized ROEs as well as a lowering of their "subjective factor" for the Michigan regulatory jurisdiction, which is based on UBS's "knowledge of current commission actions." It is

apparent that analysts have taken note of the recent trend in the Company's regulatory outcomes with regard to capital structure. A continuation or, even worse, a further degradation of the authorized equity ratio and ROE puts the Company at risk of dropping further in its regulatory environment rankings which could negatively impact the Company's credit quality and credit rating.

Q. On pages 118 to 119 of his direct testimony, Mr. Coppola references the Company's Exhibit A-107 (MRB-16), a report by S&P "Rising Risks: Outlook for North American Investor-Owned Regulated Utilities Weakens." Mr. Coppola argues that this report should be dismissed because it is "generic" and not "directly applicable to Consumers Energy." Do you agree with Mr. Coppola's assessment of this report?

A. No. While certain aspects of this report are not applicable to Consumers Energy, there are also key portions that are directly relevant to the appropriate equity ratio for the Company in this case. For example, in the report S&P cites "headwinds to credit quality" including increased cash flow deficits that are funded to a higher extent with debt versus equity. This concern is relevant in the current case given that the Company's authorized equity ratio has decreased 205 basis points from 2019 to present, weakening credit quality and putting the Company's credit rating at risk. S&P also notes utilities as having "strained financial cushion," defined as an FFO-to-Debt ratio less than 100 basis points above a company's downgrade threshold. This is also relevant to the Company in this case given that, as explained in my direct testimony and earlier in my rebuttal testimony, the Company's FFO-to-Debt ratio as calculated by S&P and Moody's has been trending down in recent years, moving closer to the downgrade thresholds for the Company. Finally, the report cites multiple additional credit headwinds that all utilities (including Consumers Energy) are

facing including higher interest rates, a narrowing spread between U.S. Treasuries and authorized ROE's, and elevated inflation rates. Therefore, Mr. Coppola's assertion that the Commission should dismiss this relevant industry report should be rejected.

Q. On page 119 of his direct testimony, Mr. Coppola references the Company's testimony on the credit metric impact of potential new tax legislation. Mr. Coppola states that this issue should not be considered as a factor in determining the Company's ROE rate and equity ratio in this case. Do you agree with this assertion?

A. No. As explained on pages 16 to 17 of my direct testimony, the new tax legislation, if enacted, would have direct and significant impacts on the Company's cash flow, resulting in a weakening of the Company's financial metrics. These potentially credit harmful legislative actions were highlighted in S&P's January 2025 report on North American regulated utilities which stated that "tax legislation could weaken financial measures." Refer to Exhibit A-114 (MRB-17). With this potential new tax legislation looming during the test year of this case, it is especially important for the Commission to authorize an ROE and equity layer that will be supportive of the Company's credit quality. The authorized ROE and equity ratio are integral components of the Company's financial credit metrics and will be a key factor in combating the negative impacts of this potential tax legislation.

Q. Beginning on page 120 of his direct testimony, Mr. Coppola states that "common equity capital infusions into Consumers Energy by the parent company are being funded to some extent by long term debt." He cites "financial transactions" between Consumers Energy and CMS Energy. Do you agree with these statements?

A. No. Mr. Coppola's assertion that equity investments into the Company from Consumers Energy's parent company, CMS Energy, are the result of CMS Energy borrowing debt and

investing the proceeds into the Company is inaccurate and unsupported. The timing and amounts of long-term debt and equity issued by CMS Energy have no bearing on the timing and amount of equity infusions made into Consumers Energy. Equity infusions are determined after considering the capital spending and financing needs of Consumers Energy. The goals of the parent company include maintaining a strong and healthy utility, capable of serving the needs of its customers. This commitment is reflected in the equity infusions from the parent company to Consumers Energy over the last several years and the resulting actual equity ratio.

Q. On page 122 of his direct testimony, Mr. Coppola provides an analysis of the capital structure of CMS Energy and Consumers Energy from 2010 to 2024, attempting to link changes in long-term debt and equity between the two companies. Does this analysis have any merit in the current case?

A. No. As explained above, the timing and amounts of long-term debt and equity issued by CMS Energy have no bearing on the timing and amount of equity infusions made into Consumers Energy. Also, in Case No. U-18124 the AG made this same argument that Consumers Energy's equity balance is, at least in part, funded by long-term debt from its parent company. In its July 31, 2017 Order in Case No. U-18124, the Commission adopted the findings and recommendations of the ALJ, who determined this argument from the AG "has been considered and rejected by the Commission." Mr. Coppola's analysis has been found to have no merit in the past and should again be rejected.

Q. On page 124 of his direct testimony, Mr. Coppola's argument for setting a 50.00% equity ratio in this case is that the common equity ratio of his peer group was 47.3% in 2024, as shown on his Exhibit AG-44. Is this an appropriate comparison to the projected common equity ratio in this case?

A. No. The average equity ratio calculation for the proxy group on Mr. Coppola's Exhibit AG-44 uses the equity ratio at the parent holding company level and is, thus, a misleading and inappropriate comparison. As the Company has repeatedly explained in response to this exact same argument by the AG over the years, ratios at the parent holding company level may be distorted by other, non-regulated balance sheet items and provides a completely inappropriate point of comparison. Mr. Coppola continues to avoid addressing this discrepancy. Perhaps the 270 basis point differential between the results of his analysis on Exhibit AG-44 and his own recommendation points to Mr. Coppola's recognition that the analysis does not provide a relevant comparison. In addition, Mr. Coppola's analysis is further skewed because the sources for Mr. Coppola's debt and equity balances are Securities and Exchange Commission reported financial statements, which are prepared under Generally Accepted Accounting Principles ("GAAP"). There are major differences in how components of the capital structure are classified on a ratemaking basis and on a financial basis. These differences could easily further distort the equity ratios calculated on Mr. Coppola's Exhibit AG-44.

Q. Is Mr. Coppola's average peer group equity ratio analysis in line with the Commission's stated expectations?

A. No, the Company is the only party in this case that has provided peer equity ratio analysis that is in line with the Commission's stated expectations. In its Order in Case No. U-20963,

the Commission stated that "regulatory and financial data should not be combined" with such an analysis. Further, the Commission deemed in its Order in Case No. U-20963 that such an analysis is invalid assuming one "could not verify that its data contained equity ratios set by a regulatory commission in a rate case." In his analysis of a proper equity ratio for the Company, Mr. Coppola ignores this Commission's ask by consistently utilizing equity ratios based, in part, on financial, and not regulatory, data. He consistently utilizes equity ratios that do not arise out of Commission orders, and he further fails to explain the basis or rationale for doing so. As a result, the AG's equity ratio analysis should be rejected as outside the methodology required by the Commission.

Q. If equity ratios on a financial basis are not considered relevant, what is the more appropriate comparison of average utility equity ratios?

A. It is clear from the Commission's Order in Case No. U-20963 that actual commission-authorized equity ratios is the preferred data source for an average equity ratio analysis. I refer to my Exhibit A-32 (MRB-10) in which I researched all rate case decisions from 2020 through September 2024 of peer regulated companies and determined the authorized or approved equity ratio for each. The equity ratios used for comparison purposes were taken from commission orders and public filings and represent actual regulatory peer equity ratios authorized or approved by different commissions across the country. The average equity ratio for the peer group was 54.05%. This is significantly higher than the equity ratio recommended for Consumers Energy's capital structure in my rebuttal testimony and is also 405 basis points higher than the equity ratio Mr. Coppola recommends for the Company in this case. Despite this higher peer average, I am proposing a ratio of 50.75%, which balances the higher peer average with capital

investment plans, credit metrics, customer rate impacts, and the guidance of this Commission, and which continues to support affordable utility infrastructure financing for the state of Michigan.

Q. On pages 125 through 127 of his direct testimony, Mr. Coppola attempts to discredit the Company's calculation of the peer group average commission-authorized equity ratios reflected on Exhibit A-32 (MRB-10). Do these arguments have merit?

A. No. The Company adhered to an established selection criteria outlined on Exhibit A-32 (MRB-10). Mr. Coppola's claims are false and divert attention away from his own lack of meaningful comparisons, meaningful criteria, and meaningful analyses of various utilities, commission decisions, and basis for equity ratios. As explained in my direct testimony and earlier in my rebuttal testimony, the Company's data source is responsive to previous Commission orders and serves as a valid benchmark for the appropriate equity ratio for the Company in this case. As I will show in my following rebuttal testimony, Mr. Coppola's "problems" with Exhibit A-32 (MRB-10) are completely baseless and are an attempt to devalue the compelling evidence put forth by the Company that average peer company equity ratios are significantly higher than what Mr. Coppola proposes for the Company in this case.

Q. On page 125 of his direct testimony, Mr. Coppola notes that three proxy group companies listed on Exhibit A-32 (MRB-10) are not included as part of the Company's ROE proxy group in the current case. Does this in any way discredit the Company's peer authorized equity ratio analysis?

A. No. As explained earlier in my rebuttal testimony, the Company adhered to an established selection criteria outlined on Exhibit A-32 (MRB-10) which included a scope of all

regulated subsidiaries of the Company's ROE proxy group in Case No. U-21490, the Company's most recent gas rate case before the current case. The purpose of the Company's Exhibit A-32 (MRB-10) is to provide a benchmark of equity ratios recently authorized by other commissions across the country. The fact that three of the proxy group companies included in the Company's analysis were included in the ROE proxy group in Case No. U-21490 and not the current case does not discredit or minimize the value of the analysis, as it is still a representative sample of recent rate case decisions.

Q. On page 125 of his direct testimony, Mr. Coppola claims that the average peer equity ratio calculated on Exhibit A-32 (MRB-10) is overstated due to several of the companies included in the exhibit using short-term debt as a form of permanent financing which, when considered permanent (long-term) debt in the company's capital structure, results in a lower equity ratio. Are Mr. Coppola's claims valid?

A. No. First, as shown on Exhibit A-14 (MRB-1), Schedule D-1, the Company's equity ratio of 50.75% excludes short-term debt. Therefore, in order to produce a comparable and relevant analysis, the peer company authorized equity ratios also exclude short-term debt (as well as other capital structure components such as deferred taxes). Second, Mr. Coppola makes the assumption that companies employ short-term debt as a permanent layer of financing. This is not always the case, a prime example being Consumers Energy which has short-term debt as a component of its capital structure but is not considered "permanent" capital. In a discovery response, the AG explains that the claim of companies in the exhibit using short-term debt as a form of permanent financing was not based on the companies included in the exhibit, but rather for four companies at the parent holding company level, based on Securities and Exchange Commission reported financial

statements. Exhibit A-118 (MRB-21). This invalidates Mr. Coppola's argument entirely. The average peer equity ratio on Exhibit A32 (MRB-10) is appropriately calculated at the regulated subsidiary level based on state commissions' rate case dockets. This is comparable to Consumers Energy's projected capital structure considered in the current case. Conversely, debt held outside of these companies, at the parent holding company level or otherwise, is completely irrelevant to this analysis. As an example, short-term debt balances held by CMS Energy, Consumers Energy's parent company, is irrelevant to the appropriate capital structure for the Company in the current rate case proceeding. Even if the short-term debt of his four proxy group companies is representative of their regulated subsidiaries, as Mr. Coppola argues, he does not provide evidence showing how this impacts the equity ratios of the regulated subsidiaries reflected on the Company's Exhibit A-32 (MRB-10). As with his calculation of the average peer group equity ratio, Mr. Coppola again attempts to introduce parent holding company data in an attempt to obfuscate the Company's sound analysis. Mr. Coppola's comparisons are inappropriate and should be rejected by the Commission.

Q. On page 126 of his direct testimony, Mr. Coppola claims that the Company's peer average authorized equity ratio reflected on Exhibit A-32 (MRB-10) is overstated as a result of the inclusion of smaller companies which "tend to have higher equity ratios to sustain them during potential volatility in their business, which larger utilities can better manage." Do you agree with this conclusion?

A. No. Mr. Coppola presents no evidence showing a correlation between a company's size and its authorized equity ratio. Refer to Exhibit A-118 (MRB-21). When asked in discovery for analyses, studies, or reports supporting this statement, Mr. Coppola indicated

that he "relied on his knowledge and experience." In his discovery response 3-CE-AG-6 Attach 1 (see Exhibit A-118 (MRB-21), Mr. Coppola also included an excerpt from Dr. Robert Morin's book New Regulatory Finance which discusses the relationship between company size and investment risk and return. This is a separate issue from the impact of a company's size on its authorized equity ratio and does not support Mr. Coppola's claim. Therefore, Mr. Coppola's assumption that the inclusion of certain "smaller" companies results in an overstatement of the peer average is unsupported and should be rejected. In addition, Exhibit A-32 (MRB-10) is intended to be an informative survey of all commission-authorized equity ratios for utilities across the country and not filtered to adjust for or exclude companies with certain characteristics (customer count, rate base size, etc.). Finally, Mr. Coppola again presents a criticism of the Company's peer equity ratio analysis without offering an alternative analysis that he believes to be more representative of commission-authorized equity ratios. Mr. Coppola performs no analysis at all, but rather simply relies on the average equity ratio calculation for the parent holding companies of his proxy group of 47.3%. As explained earlier in my rebuttal testimony, this approach is flawed and should not be relied upon in this case.

C. Rebuttal to Mr. Coppola's Recommendation Regarding the Working Capital Cash Balance

Q. On page 103 of his direct testimony, Mr. Coppola references the Company's approach to projecting the cash balance for the test year in this case equal to approximately 1% of test year revenues. Mr. Coppola argues that, if the Company were to instead base its projection on current revenues, the test year cash balance would yield a lower result. Is using current revenues appropriate in projecting the test year cash balance in this case?

A. No. The Company uses a forward looking test year in this case, projecting an adequate level of cash for the test year ending October 2026. Therefore, basing the projected cash balance on current or historical revenues would not be appropriate.

Q. On page 103 of his direct testimony, Mr. Coppola attempts to discredit the Company's approach to projecting the cash balance for the test year in this case, stating that "cash on hand is not used to pay for revenues. It is used to pay operating expenses, capital expenditures and dividends to the parent company." Is this a valid argument against the Company's 1% of test year revenues rule of thumb?

A. No. The Company's cash estimation method is not intended to project all future cash outflows in order to determine a required cash balance. Rather, the 1% of test year revenues is a simple, efficient, and easily calculated benchmark that is useful in estimating a reasonable level of cash for the Company. As the size of the Company grows along with its associated operating revenues, the appropriate level of cash on hand also grows. Thus, the various uses of the Company's cash is not a valid argument against the Company's cash projection methodology.

Q. On page 103 of his direct testimony, Mr. Coppola again attempts to discredit the Company's approach to projecting the cash balance in this case by stating that "utilities maintain different levels of cash on hand during different months of the year depending on their seasonal needs for cash to pay for gas purchases, fund gas inventories and pay for operating expenses and construction costs." Does the seasonality of cash expenditures invalidate the Company's 1% of test year revenues rule of thumb?

A. No. Refer to pages 27 to 29 of my direct testimony which describes the Company's liquidity and financing strategy. Due to the seasonal nature of utility cash inflows and outflows, the Company generally holds more cash in the spring and summer months and relies on short-term borrowing in the fall and winter months. However, the Company is not projecting the cash balance for a point in time, but rather an average cash balance for the entire test year in this case. Therefore, the seasonal nature of cash outflows is already factored into the Company's position.

Q. On pages 103 and 104 of his direct testimony, Mr. Coppola refers to the Company's cash projection methodology of 1% of test year revenues as being based on "an analysis it performed a few years ago for a group of utilities." Mr. Coppola argues that this analysis was based on cash balances presented in GAAP financial statements and is therefore inappropriate. Is this argument valid?

A. No. Refer to Exhibit A-93 (AJD-13) in Case No. U-17990, the Company's 2016 electric rate case. In this exhibit, the Company performed an analysis of the average cash balance as a percentage of operating revenue for the Company's peer group at the regulated subsidiary level. This analysis resulted in a peer average of 1.9%, showing that the

projected test year cash balance in that case was reasonable and appropriate compared to other utilities. While the peer companies' cash balances reflected in that analysis may or may not have included temporary cash investments, the peer average was 90 basis points higher than projected for the Company in the current case. This is another example of Mr. Coppola attempting to muddle the valid analysis that the Company has performed.

Q. On page 104 of his direct testimony, Mr. Coppola argues that the Company's cash analysis from Exhibit A-93 (AJD-13) in Case No. U-17990 was inappropriate because it used data on a GAAP financial basis. Does Mr. Coppola perform an analysis based on GAAP financial data in his testimony and exhibits?

A. Yes. Refer to my earlier rebuttal testimony to Mr. Coppola's peer group equity ratio calculation of 47.3%. Mr. Coppola's analysis is skewed because the sources for Mr. Coppola's debt and equity balances are Securities and Exchange Commission reported financial statements, which are prepared under GAAP. There are major differences in how components of the capital structure are classified on a ratemaking basis and on a financial basis. These differences could easily distort the equity ratios calculated in Mr. Coppola's peer group equity ratio analysis. Following Mr. Coppola's own reasoning on page 104 of his direct testimony, his peer group equity ratio calculation of 47.3% is misleading and should not be used in determining the appropriate equity ratio for the Company in this case.

Q. On page 104 of his direct testimony, Mr. Coppola again attempts to discredit the Company's approach to projecting the cash balance by stating that "every utility has different short-term borrowing facilities and different practices as to how they use or do not use them and may retain more or less cash on hand depending on those circumstances." Does the fact that different utilities have different practices with respect to short-term borrowing and cash on hand invalidate the Company's 1% of test year revenues rule of thumb?

A. No. Refer to the description of the Company's liquidity and financing strategy on pages 27 to 29 of my direct testimony. The Company's 1% of test year revenues rule of thumb is not intended to match other utilities' liquidity and financing practices. The Company acknowledges that different utilities hold different levels of cash and short-term debt based on their individual preferences and liquidity risk tolerance levels. The Company projects its cash balance at a level that is reasonable and appropriate for Consumers Energy, which equates to approximately 1% of test year revenues.

Q. On page 105 of his direct testimony, Mr. Coppola recommends that the level of cash in working capital in this case be equal to the average of the actual cash balances for 2022, 2023, and 2024. This equates to a balance of $12.3 million, $16.1 million lower than forecasted by the Company. Do you agree with this proposal?

A. No. Using the average of actual cash balances from 2022, 2023, and 2024 results in a cash balance much lower than is normally expected and required for the Company in the test year of this case. The spike in natural gas prices in 2022 resulted in cash balances that were lower than what is normally expected and required for the Company and are therefore not representative of typical cash balances historically or in the test year of this case. In

addition, the Company experienced unfavorable weather in 2023, as well as storm restoration activity well beyond the five-year historical average. Both of these conditions negatively affected the Company's operating cash flows and cash balance. It is inconsistent that Mr. Coppola cites those "temporary" issues when discussing the Company's credit metrics from that period of time but ignores them for this argument. Since the Company's cash balance was abnormally low in 2022 and 2023, the average from those years should not be used in projecting the cash balance in this case. Also refer to my earlier rebuttal testimony in which I explain why the use of historical cash balances is not appropriate. Instead, the projected cash balance for the test year in this case should equate to approximately 1% of test year gas revenues, which results in a cash balance of $23.13 million which is reflective of normal levels of cash on hand.

Q. What are the risks associated with the Company maintaining an unreasonably low cash balance of $12.3 million, or 0.5% of test year revenues, as Mr. Coppola recommends?

A. Maintaining an insufficient cash balance would force the Company to rely more heavily on its short-term borrowing facilities. Short-term financing markets can be volatile and, at times, access to those markets completely disappear, as was witnessed during the 2008 credit crisis, again in March 2020 as a result of pandemic-related market fear, and again in March 2023 during the banking industry turmoil. Based on the experience and judgment of the Company's Treasury Department, as well as members of the Financial Planning and Analysis Department, the Company does not pursue a strategy that maintains a permanent balance of short-term debt. However, the Company does fund seasonal fluctuations in its working capital with short-term debt. The Company's projected cash balance for the test

year in this case is reflective of normal levels of cash that are expected and necessary for the Company to manage working capital requirements and manage financial risk.

Q. In addition to managing financial risk, what are some benefits associated with the Company maintaining a cash balance equal to approximately 1% of test year revenues as projected by the Company?

A. In order to obtain an attractive interest rate for long-term bond financing and to minimize the refinancing risk, the Company at times issues new bonds a few months in advance of the actual maturity. Having adequate levels of cash on hand allows the Company additional flexibility in securing the lowest interest rate on its long-term debt issuances which benefits the Company and customers. In addition, given the Company's large capital expenditure program, the Company aims to maintain an overall liquidity that is sufficient to carry out not only the day-to-day operations but also have the flexibility to meet investing activities should there be a delay in accessing long-term capital from capital markets. For these reasons, the Company's projected cash balance included in working capital for the test year in this case is reasonable and is supportive of the Company's operating, investing, and financing activities.

Q. Does the Company's cash balance impact its credit rating and credit quality?

A. Yes. For example, S&P uses a quantitative measure in assessing liquidity in its evaluation of the Company's credit quality. With this measure, S&P looks at cash on hand and projected cash sources and uses in determining the Company's "liquidity cushion." In its ratings methodology document, S&P describes liquidity as "an important component of our financial risk assessment across the entire rating spectrum… In our view, unlike most other rating factors that we blend together in assessing an issuer's risk profile, a lack of

liquidity could precipitate the default of an otherwise healthy entity." Another rating agency, Moody's, has commented on liquidity as saying "we consider liquidity a key element of our analysis of regulated electric and gas utilities." In assessing the Company's credit quality, Moody's performs a similar analysis of the Company's liquidity cushion and flexibility as S&P, estimating the Company's ability to meet near-term cash requirements using its available sources. The third major credit rating agency, Fitch, also has a liquidity measure which is calculated as the amount of readily available cash and credit capacity to service or meet debt maturities and interest obligations. This score indicates if the Company has adequate headroom with cash on hand to cover its operating and short-term liquidity requirements. It is apparent that all three major credit rating agencies consider the level of cash on hand to be an important component of their assessment of the Company's credit quality and credit rating.

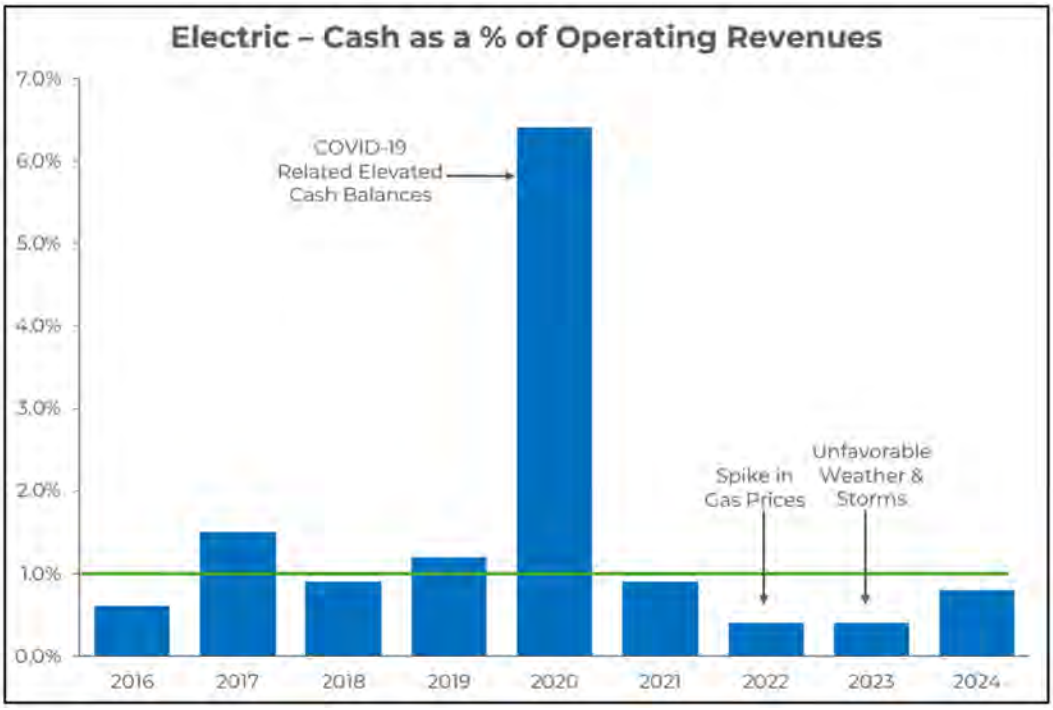
Q. In prior rate cases, has the Company proposed an adjustment to <u>reduce</u> its projected cash balance to a more reasonable level?

A. Yes. Refer to Case No. U-21148 and Case No. U-20963. In those cases, the historical period included several months in 2020, in which the country experienced extreme volatility, disruption, and illiquidity in the financial markets related to the COVID-19 pandemic. During this time, the Company took a proactive approach by issuing long-term debt and temporarily holding elevated cash balances. These actions limited the Company's risk of being unable to raise needed capital, strengthened the Company's liquidity, and ensured funding for the continued operations of the Company during this uncertain time. As a result of these actions, however, using the historical period that included 2020 in those cases would have resulted in a cash balance that was higher than what is normally expected

and required for the Company. As a result, in those cases the Company used cash balances from an alternative historical period that more appropriately reflected normal, lower levels of cash balances.

Q. Has the Company shown that its actual cash balances have approximated 1% of operating revenues over the last several years?

A. Yes. Refer to the following chart which shows a history of the Company's actual cash balances as a percentage of operating revenues from 2016 to 2024:



The chart shows that the Company's actual cash balances have approximated 1% of operating revenues with the exception of 2020, 2022, and 2023. In 2020, as described earlier in my rebuttal testimony, the Company temporarily held elevated cash balances related to the COVID-19 pandemic. In 2022 and 2023, higher gas prices and unfavorable weather and storm restoration activity negatively affected the Company's operating cash flows and cash balances. For the years in which the Company's cash balances were

unusually higher or lower than normally expected, the Company adjusted its rate case projected cash balance (higher or lower) to account for these deviations.

Q. In conclusion, what is the appropriate cash balance for the Company for the test year in this case?

A. As explained in my earlier rebuttal testimony, the Company accepts Staff witness Hecht's working capital adjustment to reduce the Company's projected cash balance by $5,263,000 to $23,130,000. This equates to approximately 1% of test year gas revenues and, as I have shown in my rebuttal testimony, results in a level that is needed, reasonable, and adequately minimizes the Company's financial risk.

III. REBUTTAL OF ABATE WITNESS WALTERS

Q. On page 6 of his direct testimony, Mr. Walters presents Table CCW-2 – Trends in State Authorized Common Equity Ratios which lists average equity ratios by year from 2013 to 2025. What trend does the data in this table reveal?

A. As shown in Mr. Walters' Table CCW-2, the average equity ratio has increased 246 basis points from 49.79% in 2015 to 52.25% in 2024, clearly an upward trend. In fact, Mr. Walters' table shows that the Company's projected equity ratio of 50.75% in this case is below industry averages for the past nine years (2016 through 2024) and is also below the industry average of all years listed (51.64%). Mr. Walters' table shows that his recommended equity ratio for the Company in this case of 50% is significantly understated when compared to his own calculation of industry average equity ratios and trends.

Q. Are the average equity ratios reflected in Mr. Walters' Table CCW-2 understated?

A. Yes. According to footnote 1 of Mr. Walters' Table CCW-2, the source of the equity ratio data is "S&P Global Market Intelligence." S&P Global Market Intelligence tracks the

authorized equity ratio as a percentage of total capitalization. Total capitalization can be higher (making the equity ratio lower) because, in addition to permanent capital components, items such as short-term debt and customer deposits can be included. As described earlier in my rebuttal of Staff witness Megginson, the Company's proposed equity ratio in this instant case as a percentage of total capitalization is 42.58%, 817 basis points lower than the 50.75% proposed as a percentage of permanent capitalization. Excluding short-term debt to be consistent with the equity ratio projected by the Company in this case (as a percentage of permanent capital), the order results in a higher equity ratio. Again, in order to make proper comparisons, the Company's equity ratio, based on a percentage of permanent capital, should be compared to utilities also using an equity ratio based on percentage of permanent capital. By utilizing utility equity ratios that are based on a percentage of total capitalization to support his recommended equity ratio for the Company in this case, Mr. Walters is not making a direct like-for-like comparison at all, and thereby understating his results, which therefore should not be relied upon.

Q. If the equity ratios reflected on Mr. Walters' Table CCW-2 are understated, what is the more appropriate comparison of average utility equity ratios?

A. Refer to my earlier rebuttal testimony to AG witness Coppola in which I explain that actual commission-authorized equity ratios is the preferred data source for an average equity ratio analysis. I refer to my Exhibit A-32 (MRB-10) in which I researched all rate case decisions from 2020 through September 2024 of peer regulated companies and determined the authorized or approved equity ratio for each. Consistent with the Commission's Order in Case No. U-20963, the equity ratios used for comparison purposes were taken from commission orders and public filings and represent actual regulatory peer equity ratios

authorized or approved by different commissions across the country. As stated above, the average equity ratio for the peer group was 54.05%. This is significantly higher than the equity ratio of 50.75% projected by the Company and is also 405 basis points higher than the equity ratio Mr. Walters recommends for the Company in this case.

Q. On page 8 of his direct testimony, Mr. Walters shows S&P ratings data from 2009 to 2024 in Table CCW-3 attempting to show that regulated utility companies have been able to maintain relatively strong credit ratings during periods of declining authorized ROEs. Has S&P commented recently on the credit quality of utilities?

A. Yes. As highlighted on page 17 of Mr. Walters' direct testimony, in a January 2025 report on North American regulated utilities, S&P highlighted lower ratings headroom as "a high percentage of companies are operating with only minimal financial cushion from our downgrade threshold." Refer to Exhibit A-114 (MRB-17). S&P also notes that, in 2024, downgrades among North America's investor-owned regulated utilities outpaced upgrades for the fifth consecutive year. With regard to the industry credit outlook for 2025, S&P identifies risk that will pressure the industry's financial measures, including weak equity ratios, potential new tax legislation, and robust capital spending in challenging regulatory constructs. S&P also sights Michigan as one of the regulatory jurisdictions that they "continue to carefully monitor." It is apparent from this report that an ROE and equity ratio combination higher than the current authorized level, and certainly higher than the continued degradation proposed by Mr. Walters, is critical to protect the Company from receiving a credit downgrade in the light of the credit risks as described above.

Q. Have rating agencies other than S&P also commented on the credit quality of regulated utilities?

A. Yes. As referenced on page 18 of Mr. Walters' direct testimony, Moody's issued a report which it revised its outlook on the U.S. regulated utilities sector from stable to negative citing "increasingly challenging business and financial conditions stemming from higher natural gas prices, inflation and interest rates." In addition, on page 19 of his direct testimony, Mr. Walters references a report by another credit rating agency, Fitch. In describing a "deteriorating outlook for North American utilities, power & gas in 2024," Fitch cited credit headwinds that are putting pressure on utilities' credit metrics. Specifically, Fitch concluded that "the sharp escalation in interest rates has significantly narrowed the headroom in FFO fixed-charge coverage for the sector." It is clear from these reports that rating agencies have recognized a deterioration in credit metrics and credit quality for regulated utilities following what Mr. Walters describes as "periods of declining authorized ROEs." These rating agency comments highlight the importance for the Company to maintain strong financial metrics and to not manage toward the perceived low end of the credit metric bands.

Q. On page 23 of his direct testimony, Mr. Walters states that the Company's projected equity ratio of 50.75% is "relatively higher than the equity ratio for the proxy group used to estimate the cost of equity for Consumers Energy." Mr. Walters then references his Exhibit AB-7, which shows a proxy group average equity ratio of 46.3% (including short-term debt) and 50.4% (excluding short-term debt). This is also highlighted on page 31 of Mr. Walters' direct testimony. Are either of Mr. Walters'

average equity ratios reflected on Exhibit AB-7 in any way relevant or comparable to the Company's projected equity ratio of 50.75% in this case?

A. No. Refer to my earlier rebuttal testimony to AG witness Coppola's Exhibit AG-44. Like Mr. Coppola's Exhibit AG-44, the average equity ratio calculations for the proxy group on Mr. Walters' Exhibit AB-7 uses the equity ratio at the parent holding company level which may be distorted by other non-regulated balance sheet items and provides a completely inappropriate point of comparison. Mr. Walters' equity ratio analysis is clearly not based on the Commission's regulatory authorization and is therefore not comparable or relevant in determining the appropriate equity ratio for the Company in this case. Further, it is not clear which peer average Mr. Walters recommends should be used in determining the appropriate equity ratio for the Company in this case. Earlier in his direct testimony at page 6, Mr. Walters references average state authorized equity ratios in his Table CCW-2 which reflects an average of 52.25% in 2024. While the average equity ratios in this table are understated as explained earlier in my rebuttal testimony, they are dramatically higher than the 46.3% and 50.4% reflected on Mr. Walters' Exhibit AB-7 which Mr. Walters then references on page 23 of his direct testimony. For these reasons, Mr. Walters' comparison of the average equity ratios on his Exhibit AB-7 to the Company's projected equity ratio of 50.75% is not comparable or relevant and should be disregarded.

Q. On page 23 of his direct testimony, Mr. Walters again compares the Company's projected equity ratio of 50.75% to his average equity ratio calculations of 46.3% and 50.4% as shown on his Exhibit AB-7. Mr. Walters references an order from the Arkansas Public Service Commission for the Southwestern Electric Power Company in which an imputed average capital structure of companies with comparable risk was used in determining the overall cost of capital. Does this order give weight to Mr. Walters' recommended equity ratio of 50.0%?

A. No. First, page 23 of the Arkansas Public Service Commission order referenced by Mr. Walters states that "the Arkansas Court of Appeals has upheld that in instances where the utility's capital structure is unsound or out of sync with industry standards, a regulatory commission may calculate the cost of capital based not on the utility's actual capital structure but on a hypothetical capital structure." On Exhibit A-32 (MRB-10), the Company has shown that the average equity ratio for the Company's peer group is 54.05%. Based on this evidence, the only way in which the Company's equity ratio is "unsound or out of sync with industry standards" is that it is too low. Regardless, the Company is not aware of any instances in which the MPSC has accepted the use of an imputed average capital structure of ROE proxy group parent holding companies in developing the projected test year capital structure in a rate case proceeding. Therefore, the Arkansas Public Service Commission's Order for the Southwestern Electric Power Company referenced by Mr. Walters does not give support to his recommended equity ratio of 50.0% in this case and should be disregarded.

Q. Does this conclude your rebuttal testimony?

A. Yes.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

EXHIBITS

OF

MARC R. BLECKMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Industry Credit Outlook 2025

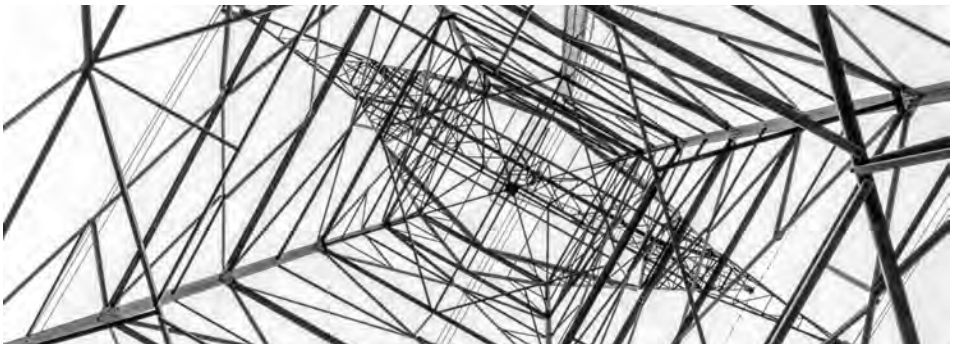
S&P Global Ratings

North America Regulated Utilities

Capex and climate change pressures credit quality

January 14, 2025

This report does not constitute a rating action.



Contacts

Gabe Grosberg
New York
+1 212 438 6043
gabe.grosberg
@spglobal.com

Gerrit Jepsen
New York
+1 212 438 2529
gerrit.jepsen
@spglobal.com

Obioma Ugboaja
New York
+1 212 438 7406
obioma.ugboaja
@spglobal.com

Matthew O'Neill
New York
+1 212 438 4295
matthew.oneill
@spglobal.com

What's changed?

Lower ratings headroom. A high percentage of companies are operating with only minimal financial cushion from our downgrade threshold.

Rising capital spending, higher cash flow deficits, and increased wildfire risks led to downgrades outpacing upgrades for the fifth consecutive year.

Data centers spur electricity sales growth at about 1% annually, which will provide modest support to credit quality.

What are the key assumptions for 2025?

High cash flow deficits of about $100 billion, which could harm financial performance if not funded in a credit-supportive manner.

Robust dividends of about $50 billion for 2025 and at a dividend payout ratio of about 60%.

Record amount of hybrid securities. The industry issued $26 billion of them in 2024, and we expect this trend will persist.

What are the key risks around the baseline?

Rising wildfire risks stemming from climate change.

Tax legislation could weaken financial measures if the new Republican administration lowers the corporate tax rate, reduces tax credits, or eliminates their transferability.

Common equity issuance is below our base-case expectations, and has been for the last several years, leading to weaker financial measures.

Ratings Trends: North America Regulated Utilities

Chart 1

Ratings distribution

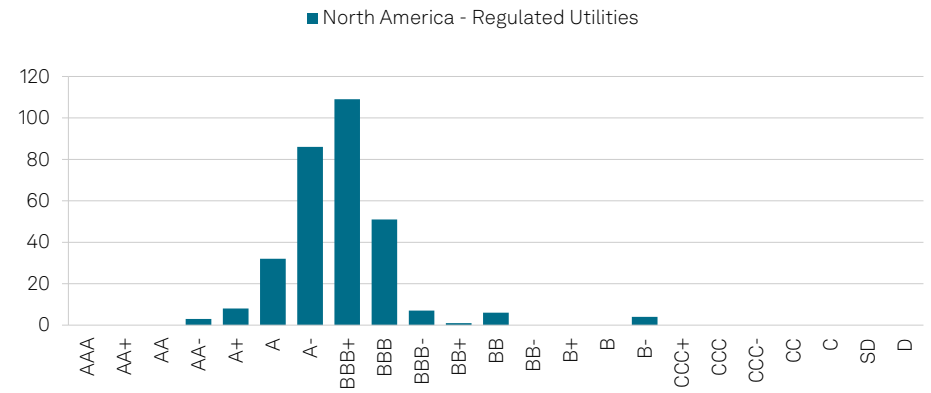


Chart 2

Ratings outlooks

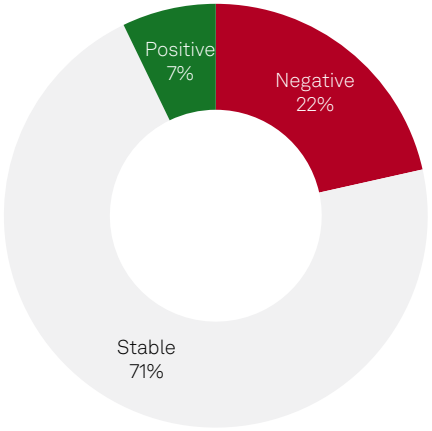
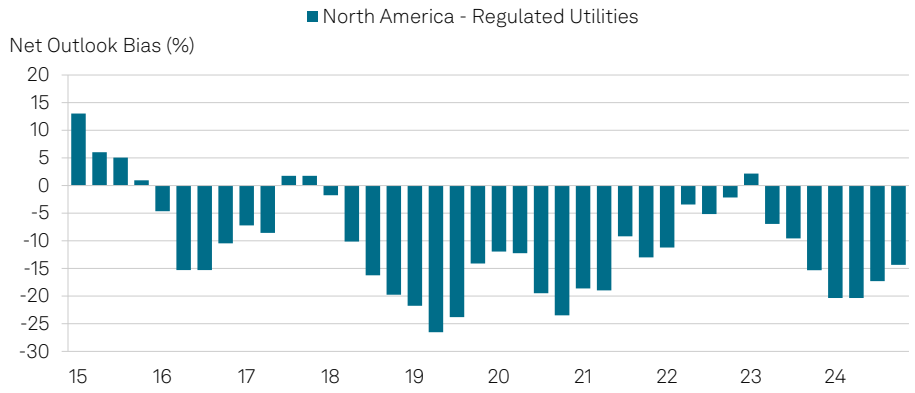


Chart 3

Ratings outlook net bias



Source: S&P Global Ratings. Ratings data measured at quarter-end.

Industry Credit Metrics: North America Regulated Utilities

Chart 4

Debt / EBITDA (median, adjusted)

Chart 5

FFO / Debt (median, adjusted)

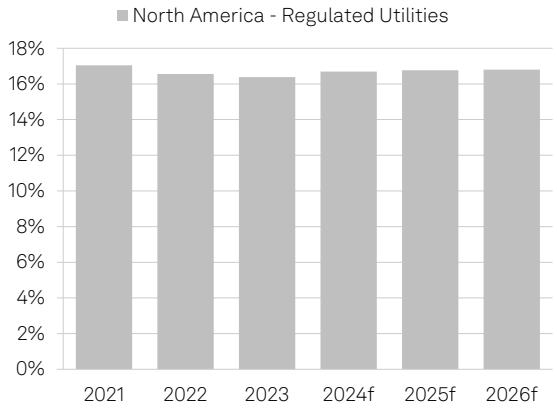


Chart 6

Cash flow and primary uses

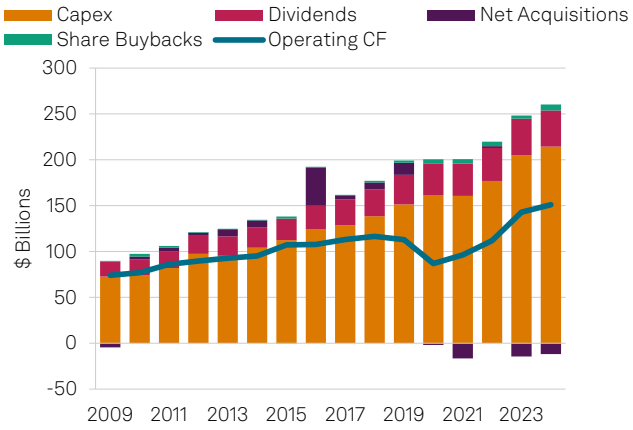
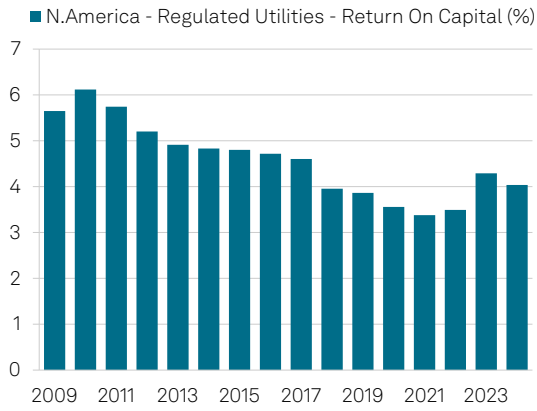


Chart 7

Return on capital employed



Source: S&P Global Ratings, S&P Capital IQ.
Revenue growth shows local currency growth weighted by prior-year common-currency revenue share. All other figures are converted into U.S. dollars using historic exchange rates. Forecasts are converted at the last financial year-end spot rate. FFO—Funds from operations. Most recent (2024) figures for cash flow and primary uses and return on capital employed use the last 12 months' data.

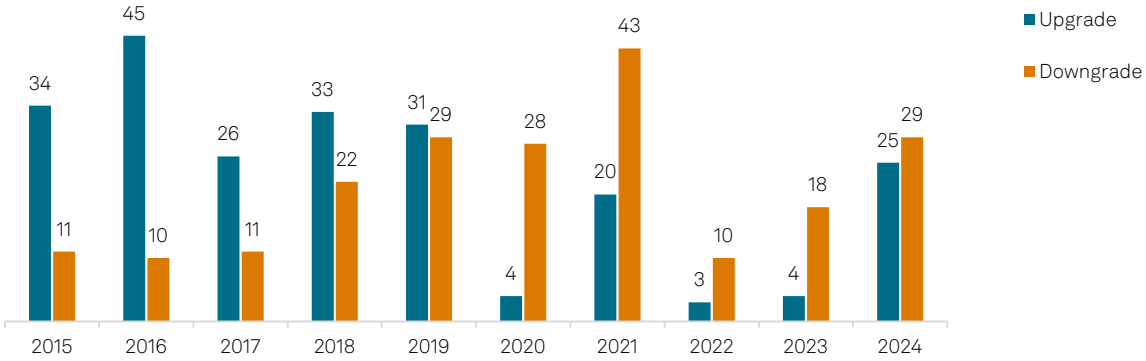
Industry Outlook

Ratings trends and outlook

In 2024, downgrades among North America's investor-owned regulated utilities outpaced upgrades for the fifth consecutive year (see chart 8). Most were directly attributable to rising wildfire risks, robust capital spending, and challenging regulatory constructs. We expect these risks will persist for 2025, further pressuring the industry's credit quality.

Chart 8

North America regulated utilities' upgrades and downgrades



Source: S&P Global Ratings.

Main assumptions about 2025 and beyond

1. Record capital spending.

The industry is heavily investing in safety, reliability, energy transition, and data centers. We expect this spending will exceed $300 billion before the end of the decade.

2. Management of regulatory risk.

This includes constructive rate case orders, minimizing regulatory lag, and earning the authorized return on equity (ROE).

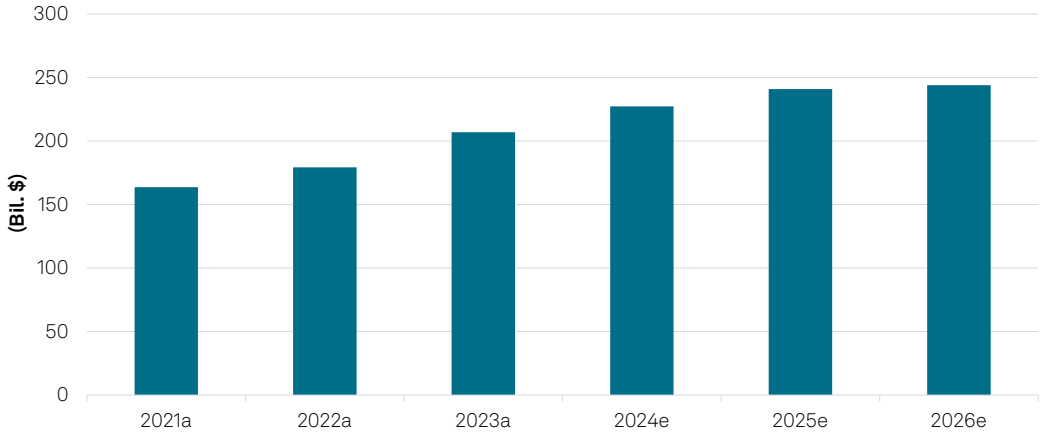
3. Climate change increases risks.

The growing frequency of devastating physical events, including hurricanes, storms, and wildfires, is elevating the industry's credit risks.

Capital spending continues to break records. We expect capital spending for North America's electric, gas, and water utilities will grow by a compound annual growth rate (CAGR) of about 10%. Accordingly, we expect 2025 capital spending to reflect about $240 billion (see chart 9). To date, the industry's capital spending has been primarily focused on safety, reliability, and energy transition.

Chart 9

North America regulated utilities' rising capital expenditures

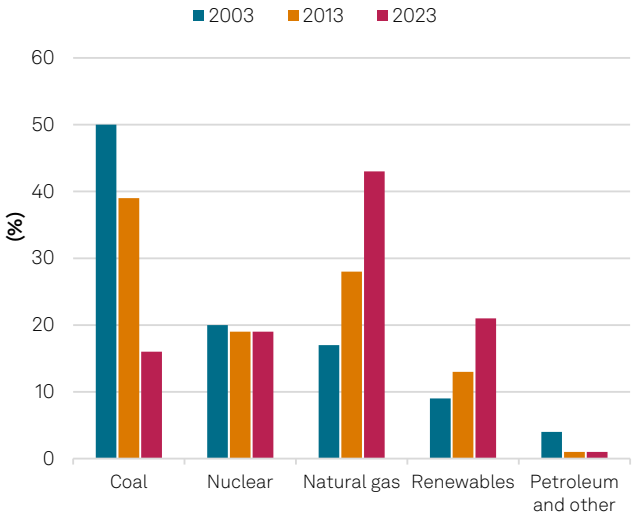


a—Actual. e—Estimate. Capital expenditures represent North American investor-owned electric gas, and water utilities.
Source: S&P Global Ratings.

Energy transition remains key. Over the past decade the industry has invested billions on reducing its reliance on coal-fired generation by about 50% (see chart 10), and today, coal represents only about 15% of total electric generation. Most of the coal was replaced with natural gas, which has about half the carbon emissions. We expect the industry will replace most of its remaining coal-fired generation by about 2030 with renewables and batteries, further reducing its carbon and greenhouse gas (GHG) emissions. The industry has reduced its GHG emissions by nearly 30% over the past decade (see chart 11), and we expect it will reduce them by another 30% by 2035.

Chart 10

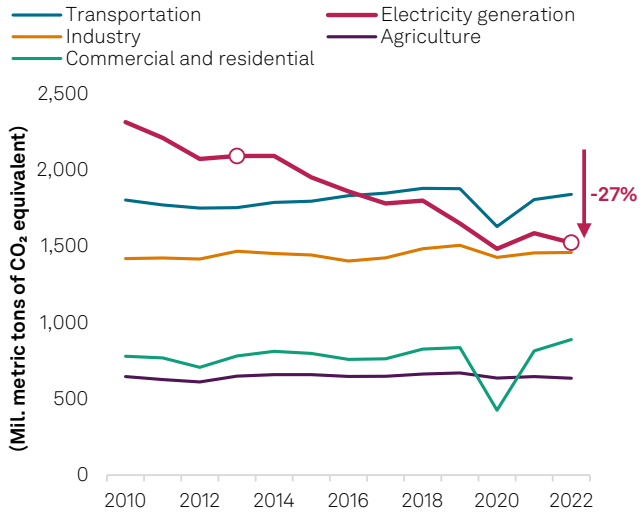
U.S. generation transformation



Source: U.S. Energy Information Administration.

Chart 11

GHG emissions by economic sector (2010-2022)

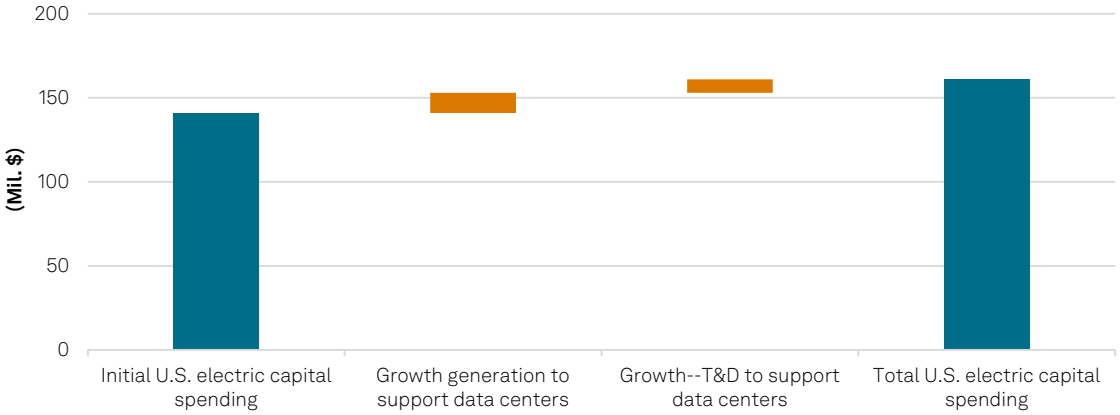


Source: U.S. Environmental Protection Agency.

Data center growth is relatively new, and our current base-case assumptions do not fully incorporate the incremental spending necessary for it. The higher spending for data centers is more likely to begin in 2026. Accordingly, 2026 capex could potentially increase by about another 15% above our current base case (see chart 12).

Chart 12

Data center growth will increase U.S. electric utility annual capital spending by about 15%

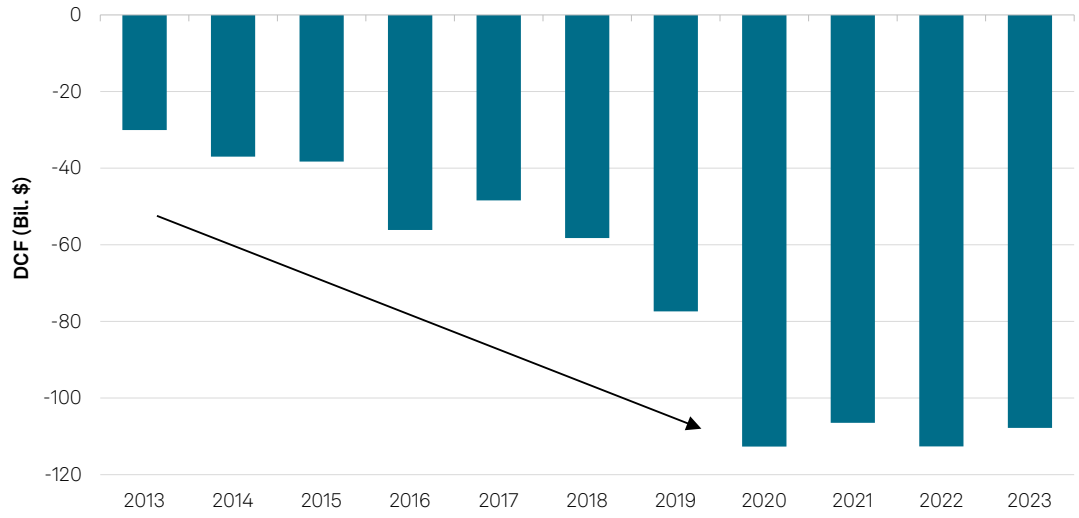


T&D—Transmission and distribution. Source: S&P Global Ratings.

Cash flow deficits will rise as a result, increasing the pressure on the industry's credit quality. Over the past decade the industry's cash flow deficits have grown from about $50 billion to consistently over $100 billion (see chart 13), and we expect this trend will continue.

Chart 13

North America regulated utilities' cash flow deficits



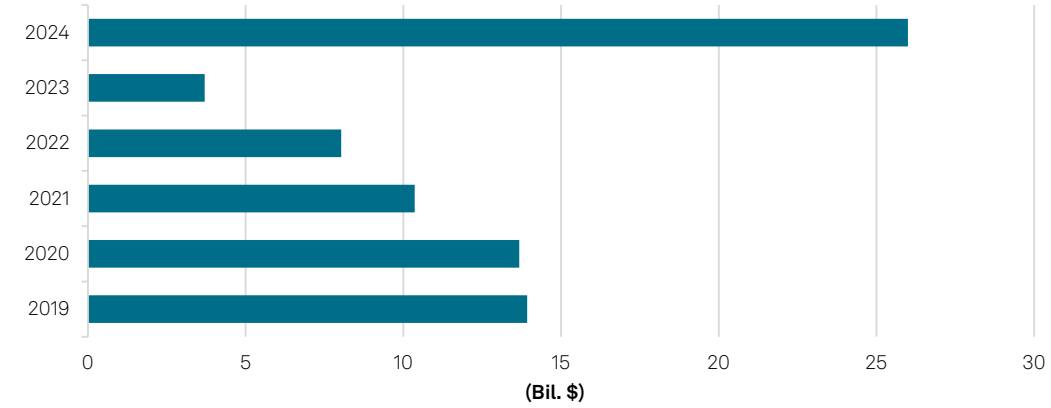
DCF—Discretionary cash flow. Sources: S&P Global Capital IQ, S&P Global Ratings.

Hybrid security issuance reached an all-time high of about $26 billion in 2024, far exceeding the previous record of about $14 billion in 2019 (see chart 14). We expect the industry will maintain this level of issuance in 2025 given its increased capital spending. This robust issuance supported the industry's 2024 financial measures because we typically assess hybrid securities as more

credit supportive than debt, with most of these securities having intermediate (50%) or high (100%) equity content.

Chart 14

North America regulated utilities' annual hybrid securities issuance

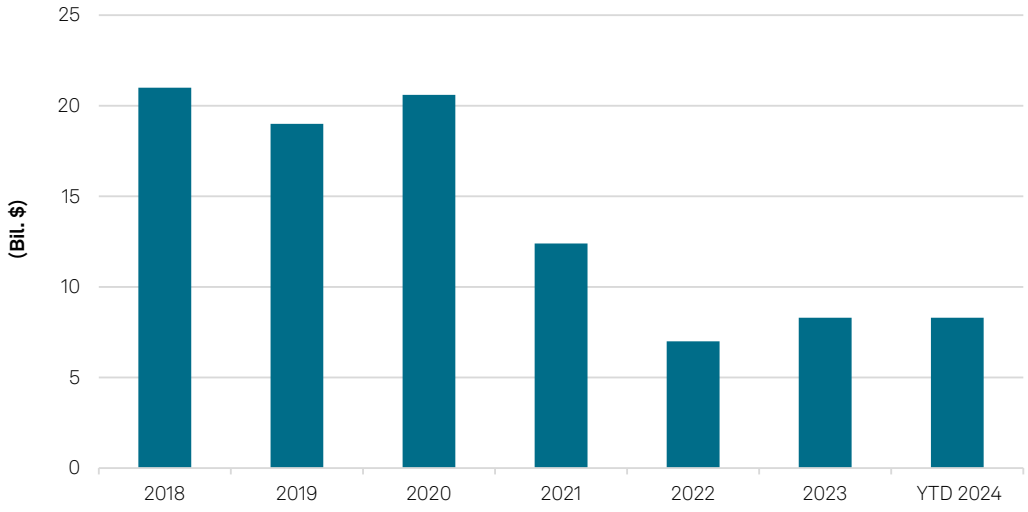


Sources: S&P Global Ratings, S&P Global Market Intelligence.

Common equity issuance has been weak and consistently below our expectations since 2021, pressuring the industry's financial measures. It raised only about $8 billion in 2024, and we estimate that the full year will reflect only about $10 billion. This is well below the industry's average run rate of about $20 billion annually between 2018-2020 (see chart 15). We expect 2025 common equity issuance will again be relatively weak and more reflective of 2024 levels. Without significantly more common equity issuance, we expect the industry's financial measures will continue to weaken, albeit gradually, supporting our negative outlook.

Chart 15

North America regulated utilities' common equity issuance



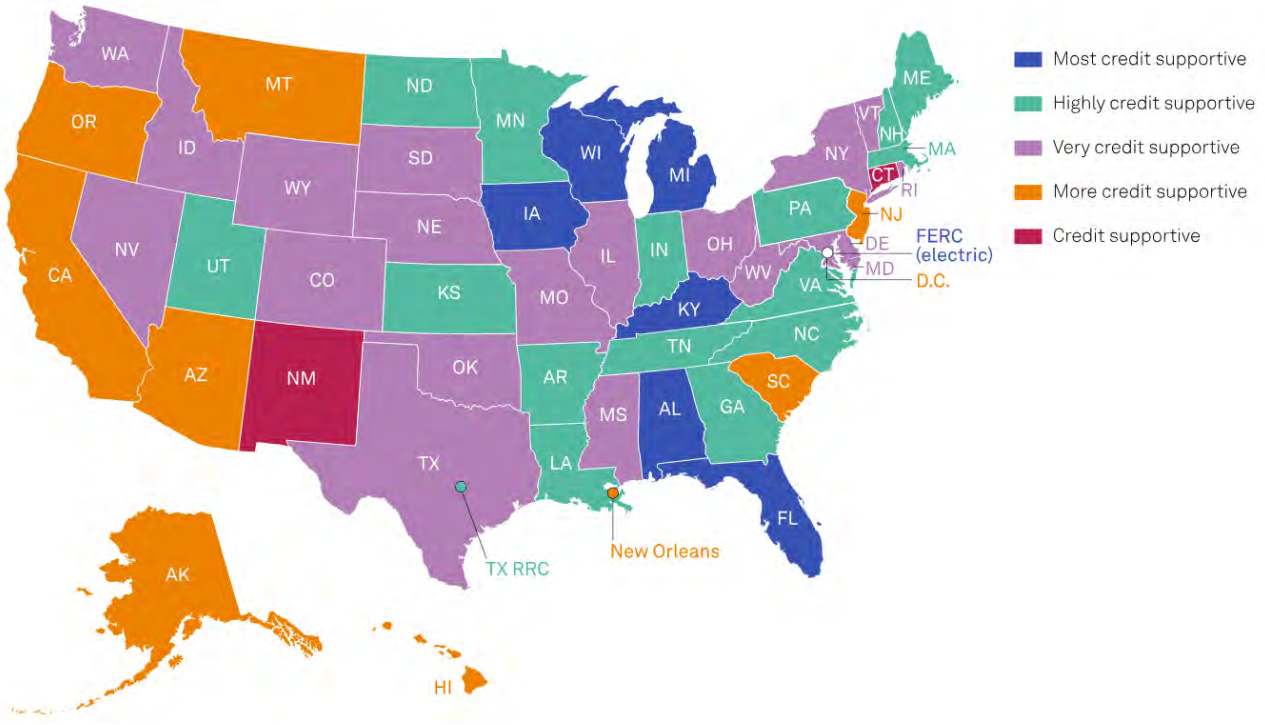
YTD—Year-to-date as of Dec. 15, 2024. Sources: S&P Global Ratings, S&P Global Market Intelligence.

Effective management of regulatory risk will continue. We assess all North America's regulatory jurisdictions as credit supportive or better, reflecting the industry's generally stable and predictable cash flows (see chart 16). Over the past decade much of the industry has implemented regulatory mechanisms such as decoupling, interim rates, capital trackers, formula rate plans, forward test years, muti-year rate case filings, and regulatory riders to significantly improve cash flow stability while minimizing regulatory lag (that is, the timing difference between when a utility incurs costs and when it's recovered from ratepayers).

Chart 16

Regulatory assessment by state

As of November 2024



Source: S&P Global Ratings.

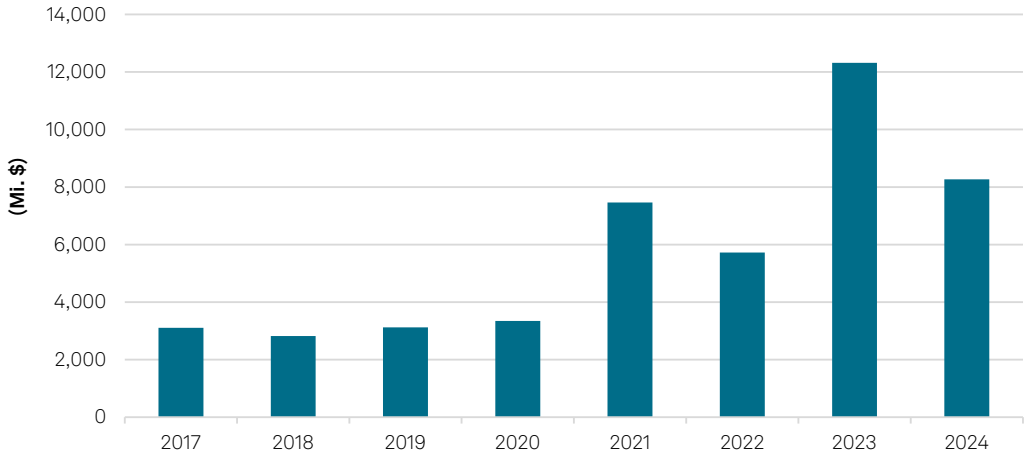
In general, we expect utilities will operate in a regulatory jurisdiction that is supportive of their credit quality by allowing for the full recovery of all their operating and capital costs in a timely manner. We also expect the regulatory jurisdiction will provide a consistent and predictable regulatory framework that results in cash flow stability. Our view of the industry's regulatory constructs supports the industry's mostly investment-grade ratings despite the industry continuing to operate with material cash flow deficits.

Recently, we revised downward our assessment of Connecticut's regulatory construct to credit supportive from more credit supportive. We now expect the state's regulated utilities will be increasingly subject to below-average authorized ROEs, regulatory lag, and an inconsistent ability to earn their lower authorized ROEs. These developments will increase the utilities' cash flow volatility, decrease the stability of their financial performances, and weaken their ability to consistently manage regulatory risk. Other regulatory jurisdictions that we continue to carefully monitor include Arizona, Colorado, District of Columbia, Illinois, Maryland, Michigan, New Mexico, Texas, and West Virginia.

Regulatory rate case order increases have substantially risen over the past four years, reflecting the industry's robust capital spending. Rate case increases for 2021-2024 have increased by more than 2.5x compared to 2017-2020 (see chart 17), and there are more than 100 U.S. rate cases pending, for which utilities are requesting over $16 billion more in revenue. This is in line with our base case that this year's rate case orders will again be robust and most likely in the top three years for rate case order increases.

Chart 17

U.S. rate case orders

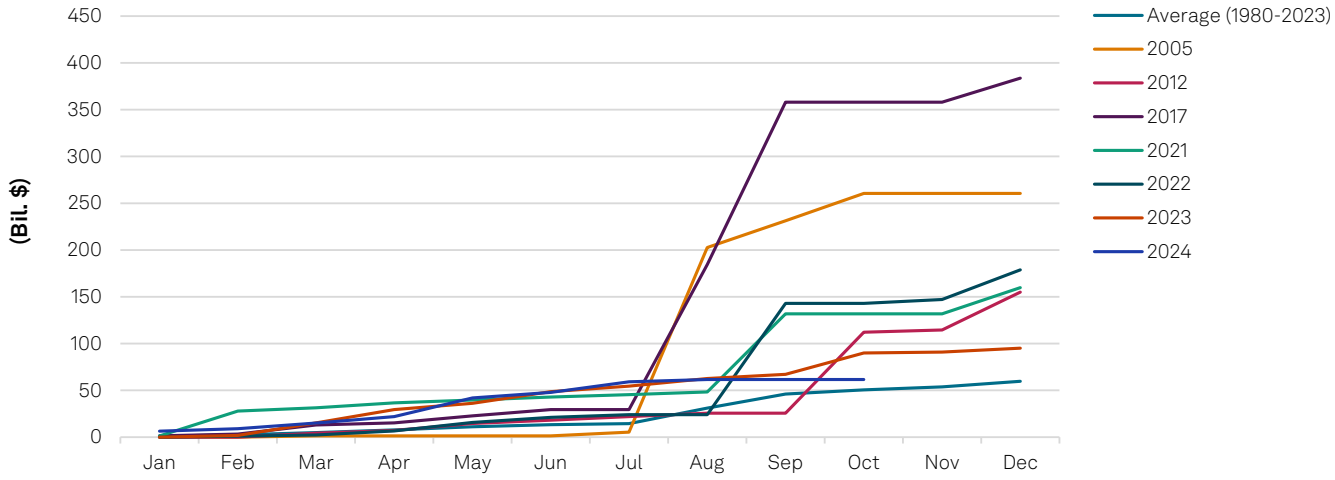


Source: S&P Global Commodity Insights.

Utilities' exposure to physical risks are increasing. According to the National Oceanic and Atmospheric Administration (NOAA), on an inflation-adjusted basis, 2021 and 2022 represent two of the most destructive years for extreme weather events since 1980 (see chart 18). We assume these trends will persist, magnifying physical risks for the utility industry.

Chart 18

U.S. billion-dollar weather disaster year-to-date event cost (CPI-adjusted)



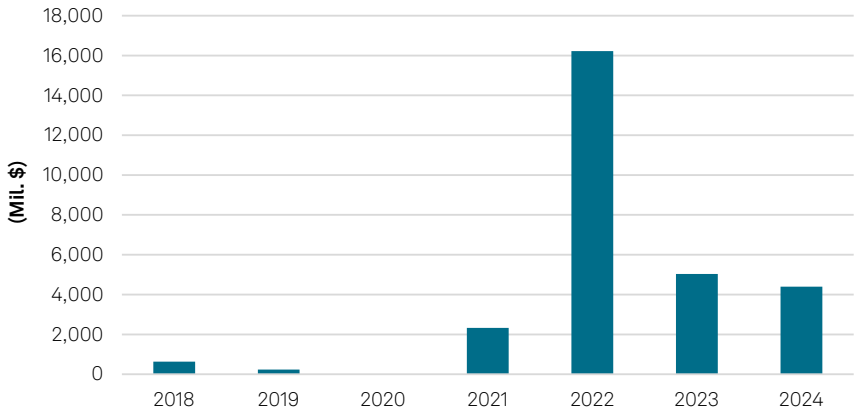
Source: National Ocean and Atmospheric Administration.

Drier, hotter weather has increased the acreage designated as high-fire-risk across the U.S. This is already taking a toll on credit ratings. For example, in 2024 we downgraded parent Xcel Energy Inc. and subsidiary Southwestern Public Service Co. (SPS) because of the scale and severity of the wildfires in the Texas panhandle, which highlights their increasing wildfire exposure. Overall, because of climate change, we expect the industry's wildfire risk will increase.

Securitization increased, which we assess as supportive of credit quality (see chart 19). Securitization allows for the issuance of debt secured by a non-bypassable charge to the customer's bill, allowing the utility to fully recover storm-related costs at a lower interest rate for customers. Because the debt is secured by the high likelihood of customers paying their bills, the associated interest costs are typically lower. We often deconsolidate such debt, resulting in stronger credit measures.

Chart 19

S&P Global Ratings-rated utility-related securitization issuance (2018-2024)



Source: S&P Global Ratings.

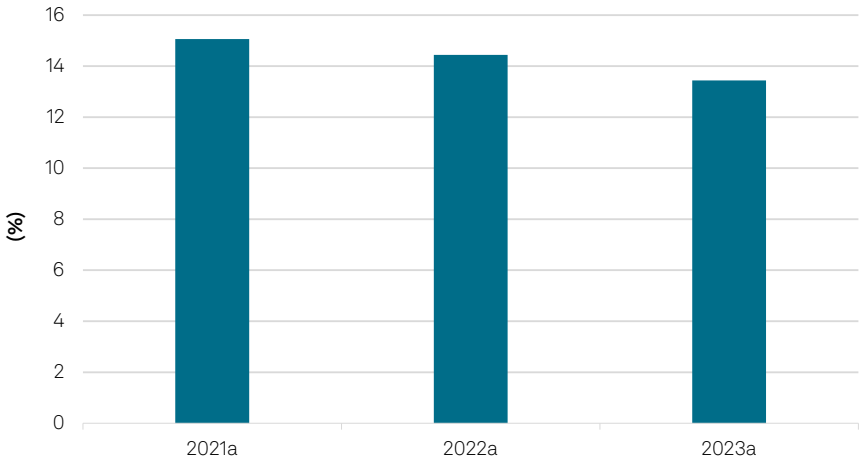
We expect securitization will remain an effective tool that the industry will continue to use. Our base case includes increasing severe natural disasters and weather events as well as continued efforts to decarbonize the energy sector, which sometimes requires securitization to fully recover under-depreciated retiring fossil-fuel generating plants.

Credit metrics and financial policy

We expect rising capital spending and increasing cash flow deficits that are not sufficiently funded in a credit-supportive manner will continue to pressure the industry's financial performance. Its average funds from operations (FFO) to debt was about 15% in 2021 and has gradually fallen to about 13.5%, primarily reflecting rising leverage (see chart 20). Given our expectations for continued increasing capital spending over the next decade, we expect financial performance and credit quality will continue to be pressured.

Chart 20

North American regulated utilities' average FFO to debt



a—Actual. Source: S&P Global Ratings.

Key risks or opportunities around the baseline

1. Wildfire mitigation efforts.

Wildfire risk mitigation, while clearly a credit positive, may not fully address the threats associated with extreme weather events.

2. Data centers and sales growth.

Data center electricity demand will likely boost revenues at North American investor-owned regulated utilities and provide modest support for the industry's credit quality.

3. Managing the customer bill.

The average electric customer bill is about 2% of U.S. median household income, which represents good value for customers relative to other typical household bills. Preserving this value is critical for the industry to maintain credit quality.

Wildfire risk has expanded. Recent events in the Northeast U.S. lead us to believe wildfire risk has spread and now potentially affects nearly every utility across North America. (About 15 years ago, it was primarily limited to just Southern California.)

Wildfire risk is highly negative for credit quality. The scale of potential liabilities, unpredictable nature of exposures, and frequency of events have materially increased wildfire risk for many utility stakeholders. From a credit standpoint, litigation risk is more problematic than risk of damage to infrastructure because it is difficult to predict or quantify and is so far without sufficient mitigation or containment. Also, wildfire-related litigation payments are typically not recoverable in rates or through other regulatory mechanisms, making them more problematic than physical risk.

Additional wildfire risks to credit quality include:

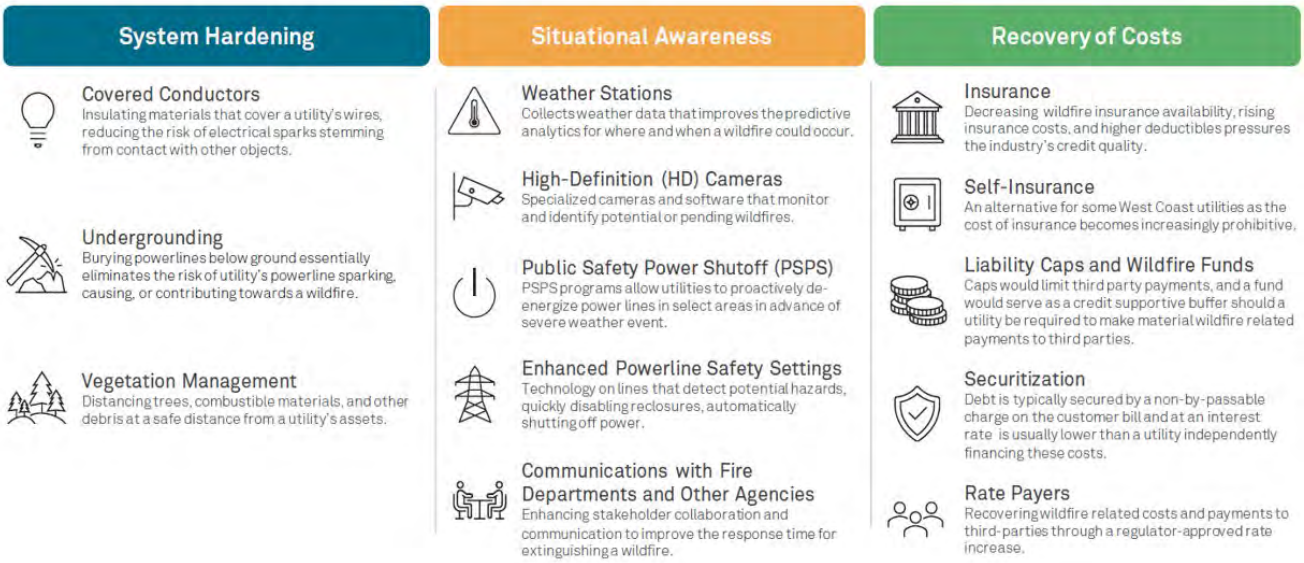
- Insurance is becoming more expensive and less available.
- It only requires a relatively small percentage of damaged or destroyed structures from a wildfire to have a material negative effect on a utility's credit quality.

- The utility industry's relatively high leveraged balance sheets and modest authorized ROEs are not a backstop for wildfire risk.
- Utilities that are impacted by a catastrophic wildfire and material third-party claims typically cannot implement other strategic initiatives.

Mitigation strategies. We expect the industry will develop plans that reduce damages, minimize litigation risk, and expand capabilities for cost recovery from wildfires. We believe the industry will be able to implement much of these strategies over the nearer term because most are not predicated on the development of new technologies or products. That said, because the industry operates in many different service territories and topographies, we expect each utility's mitigation plan will be customized to its unique exposure. Chart 21 represents an array of wildfire mitigation strategies that either have or are being implemented by many utilities across North America.

Chart 21

North American regulated utilities' wildfire mitigation efforts



Source: S&P Global Ratings.

Data centers will likely deliver a return to electricity sales growth. We expect electricity sales will increase at a CAGR of about 1.1%. This reflects our view that systematic and careful planning across the investor-owned utility sector will likely limit its realistic capability to grow at a substantially faster pace. In general, the expansion of utility infrastructure assets is a long-term planning process that requires permitting, siting, and regulatory approvals.

However, even a 1% CAGR for electricity sales will likely prove transformative for the utility industry, which has experienced flat sales growth over the past two decades. In particular, the growing number of data centers will allow the industry to spread its fixed costs over a wider base. We anticipate this will provide some cushion for the industry to effectively manage regulatory risk and maintain credit quality without necessarily requiring that every rate case order is highly supportive of credit quality.

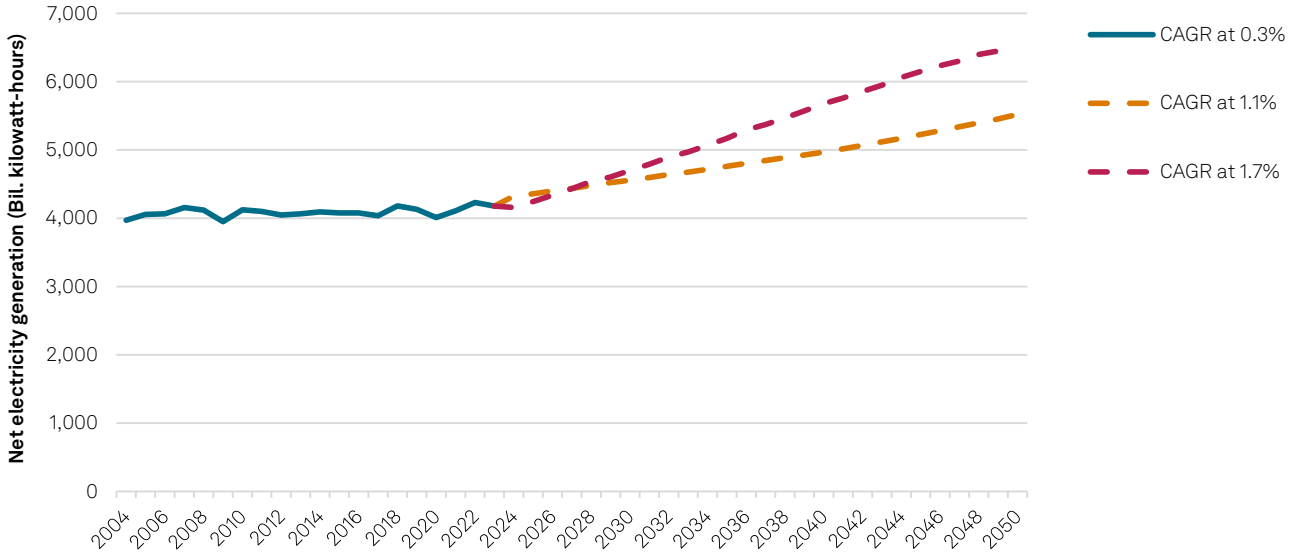
We also expect electric utilities' sales CAGR will be maintained over the longer term (see chart 22), which will support the industry's long-term credit quality. We expect growth in data center numbers will support most of the industry's growth through 2030. In the following decade,

increased onshoring of manufacturing and wider spread adoption of electric vehicles will also support growth.

Chart 22

Growth will be transformative for utilities used to stagnation

Electricity demand: U.S. regulated electric utilities



Data as of June 2024. CAGR—Compound annual growth rate. Sources: U.S. Energy Information Administration (historical and 1.1% CAGR) and S&P Global Commodity Insights (1.7% CAGR).

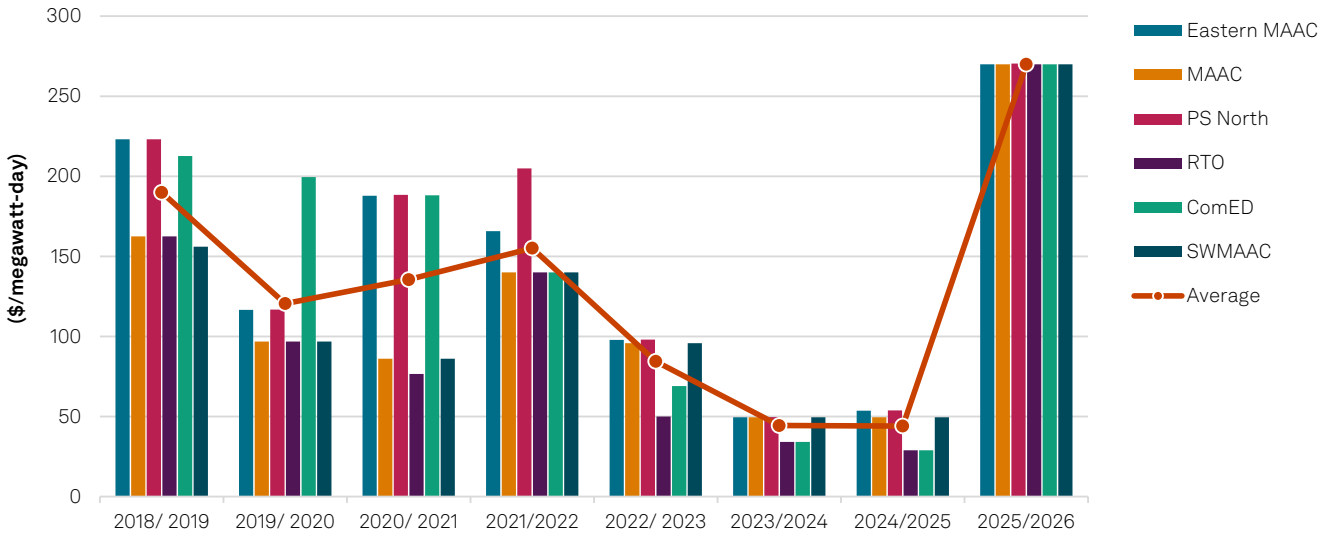
Data center credit risks. The industry must structure rates and contracts to ensure that the new data center customers are paying their share of electricity costs. Meeting the demands of relatively few, but very large, data center customers will require significant capital spending and infrastructure investments. If utilities assign a significant portion of data center-related infrastructure costs to existing residential customers, customer bills would increase. This, in turn, pressures regulators to limit rate case increases, which can negatively affect the industry's ability to effectively manage regulatory risk.

Therefore, we expect the increased capital spending needed to accommodate data center growth will be primarily recovered from data center customers over decades. Such a plan comes with risks. For example, a technological breakthrough that reduces or eliminates the need for data centers could shift the recovery of these long-term infrastructure investments onto residential customers.

Capacity prices. Pennsylvania-New Jersey-Maryland (PJM) Interconnection capacity prices materially increased during its latest capacity auction (see chart 23). These higher prices are directly passed onto customers, significantly increasing the electric utility bill. If these higher prices persist, it will likely result in higher customer complaints, pressuring regulators to limit increases to other areas of the customer bill that could potentially pressure a utility’s ability to effectively manage regulatory risk.

Chart 23

PJM capacity auction results



Source: PJM website.

U.S. Environmental Protection Agency (EPA). In 2024 the EPA released final rules aimed at reducing pollution from fossil fuel-fired power plants, which included carbon pollution standards and effluent limitation guidelines and standards for coal-fired power plants. These rules would have increased costs for utilities, specifically regarding the requirement to install carbon capture and sequestration or storage technology on coal-fired power plants intending to operate beyond 2039.

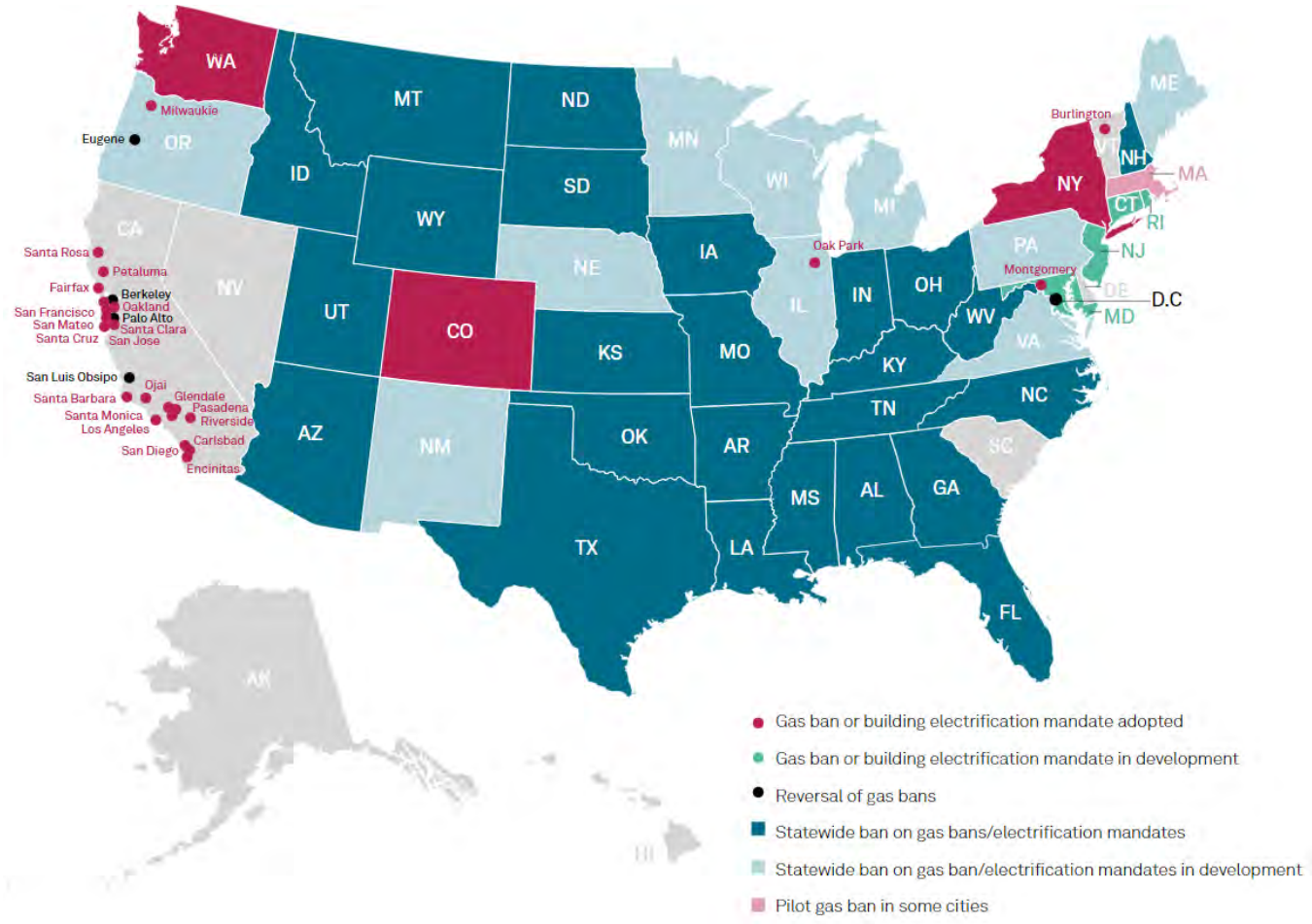
However, we note that the incoming U.S. presidential administration and Republican majority in congress could modify or eliminate these rules. We will monitor executive, legislative, or legal actions that could impact the industry's credit quality.

Full electrification. We expect the longer-term credit quality for some natural gas local distribution companies (LDC) will become increasingly challenging, especially for utilities that operate in warmer climates or whose cities or states have banned new gas connections, severely limiting the growth of natural gas LDCs (see chart 24). We expect this trend will also gradually persist through the passage of local city and town building codes that limit carbon and other emissions.

Offsetting some of this risk is that a majority of states have imposed a ban on the ban of new gas connections. Furthermore, gas LDCs are attempting to reduce their environmental risks by decreasing their carbon footprint through investing in renewable natural gas, blending hydrogen, and initiating various hydrogen infrastructure projects.

Chart 24

Gas bans and electrification mandates



Data as of April 26, 2024. *Municipalities shown on map are a subset of municipalities in the U.S. that have gas ban policies or electric reach codes in place. §Colorado and Burlington mandates target emissions requirements set out in respective laws or regulations. Source: S&P Global Commodity Insights.

Cybersecurity. While cybersecurity breaches against infrastructure assets have been relatively low, we believe the threat of cyberattacks remains high. The 2024 cybersecurity breach against American Water Works Co. Inc. underscores the risks. But the sector has heavily invested to limit this risk. We believe the sector's ongoing vigilance in this area is critical to maintaining credit quality.

Related Research

- Wildfire-Exposed U.S. Investor-Owned Utilities Face Increasing Credit Risks Without Comprehensive Solutions, Nov. 6, 2024
- Data Centers: Rapid Growth Creates Opportunities And Issues, Oct. 30, 2024
- Evolving Risks In North American Corporate Ratings: Climate Change, Oct. 29, 2024
- Data Centers: Welcome Electricity Growth Will Fall Short Of U.S. Data Center Demand, Oct. 22, 2024
- Energy Transition: U.S. Investor-Owned Regulated Electric Utilities Face Hurdles With The EPA's Finalized Rules For Fossil-Fueled Power Plants, Oct. 17, 2024
- North American Utility Regulatory Jurisdictions Update: Some Notable Developments, Sept. 24, 2024

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STATE OF MICHIGAN
DEPARTMENT OF ATTORNEY GENERAL

7109 W. SAGINAW HWY., 3RD FL.
LANSING, MICHIGAN 48917

DANA NESSEL
ATTORNEY GENERAL

May 7, 2025

Anne M. Uitvlugt
Consumer Energy Company
One Energy Plaza
Jackson, MI 49201

Re: In the matter of **Consumers Energy Company** for authority to increase its rates for the distribution of natural gas and for other relief.
MPSC Case No. U-21806

Dear Ms. Uitvlugt:

Attached are Staff's responses to Consumer Energy Company's second round of discovery to Staff in this case. The responses are being served by e-mail. In providing these responses, Staff does not necessarily concede that the requested information is relevant or material to these proceedings. Staff reserves the right to raise objections to the introduction into evidence, through cross-examination or otherwise, of any material supplied in response to discovery.

Staff intends to supplement a prior response if it becomes aware of a material error in the response or if it becomes aware that there has been a significant change in circumstances that would change the prior response in a material way. Staff does not, however, keep prior responses under continuous review.

Sincerely,

Anna B. Stirling
Assistant Attorney General
Public Service Division
Telephone: (517) 284-8140

Attachment
c: Parties of Record

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **Consumers Energy Company** for authority to increase its rates for the distribution of natural gas and for other relief.

Case No. **U-21806**
(e-file paperless)

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MICHIGAN PUBLIC SERVICE COMMISSION STAFF'S ANSWER TO CONSUMERS ENERGY COMPANY'S SECOND DISCOVERY REQUEST

Respectfully submitted,

MICHIGAN PUBLIC SERVICE COMMISSION STAFF

Anna B. Stirling (P84919)
Amit T. Singh (P75492)
Michael J. Orris (P51232)
Alena M. Clark (P73252)
Assistant Attorneys General
Public Service Division
7109 W. Saginaw Hwy., 3rd Floor
Lansing, MI 48917
Telephone: (517) 284-8140

DATED: May 7, 2025

MPSC Staff's Answer to the Company's Second Discovery Request
MPSC Case No. U-21806
May 7, 2025

Question:

21806-CE-ST-0004: Refer to the box at the bottom of Mr. Megginson's Exhibit S-4, Schedule D-2. Please provide support for the 2025 and 2026 projected credit spread of 1.00%.

Answer:

The Company's last 30-year debt issuance was in August 2022, with a credit spread of 125 basis points. The Company's recent $700 million debt issuances in August 2024 was a 6-year issuance at a credit spread of 68 basis points. The Company's January 2024, 5-year issuance was at a credit spread of 73 basis points. The Company averaged an 83 basis points spread for its 2023 debt issuances. Thus, a reasonable credit spread is somewhere between 75-125 basis points. Staff provides a 100 basis-point credit spread in its long-term debt cost rate projections in this case.

Respondent: Kirk Meggison

MPSC Staff's Answer to the Company's Second Discovery Request
MPSC Case No. U-21806
May 7, 2025

Question:

21806-CE-ST-0005: Refer to page 10, lines 5 through 13 of Mr. Megginson's direct testimony which refers to a revenue decoupling mechanism and several gas infrastructure improvement and replacement programs with surcharge payment mechanisms in place at Consumers Energy:

i. Please identify the MPSC case number which authorizes the revenue decoupling mechanism currently in place as referenced in Mr. Megginson's testimony.

ii. Please individually list the "several gas infrastructure improvement and replacement programs" the Company has in place as referenced in Mr. Megginson's testimony along with the associated MPSC case numbers.

Answer:

As Staff explained on page 7, lines 13-16 of Mr. Megginson's testimony on the Company's enhanced infrastructure replacement program (EIRP) was authorized by the Commission in Case No. U-20322. The Company also provided a January 29, 2025 audit response (U21806-SA-CE-101), with respect to the Company's riders and other revenue recovery mechanisms currently in place in Consumers' gas division. The Company responded that it currently has a Gas Cost Recovery mechanism as well as an Energy Waste mechanism in place. Staff also provided the Company's response in Case No. U-21148 to the Company's Gas Utility - Regulatory Assets & Liabilities as Exhibit S-4, Schedule D-6, page 1 of 2.

Respondent: Kirk Meggison

MPSC Staff's Answer to the Company's Second Discovery Request
MPSC Case No. U-21806
May 7, 2025

The Company's revenue decoupling mechanism (RDM) was approved by the Commission in Case No. U-20322 and reapproved in Case No. U-20650. The Company requested an updated RDM in December 2021 in its gas rate case, Case No. U-21148, which was approved by the Commission and took effect on October 1, 2023. In the Company's December 2022 gas rate case, Case No. U-21308, the Company did not request an updated RDM because the Company noted that the RDM was discovered to be immaterial given the cadence of filing annual rate cases. (See audit response U21308-SA-CE-128-Partial-Wehner). Thus, the RDM may have discontinued sometime in 2024.

Respondent: Kirk Meggison

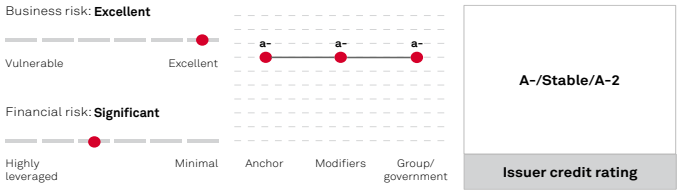
S&P Global Ratings

RatingsDirect®

Consumers Energy Co.

August 20, 2024

Ratings Score Snapshot



Primary contact

Ruchi Agrawal
Toronto
14372252983
ruchi.agrawal
@spglobal.com

Secondary contacts

Sloan Millman, CFA, FRM
New York
1-212-438-2146
sloan.millman
@spglobal.com

Obioma Ugboaja
New York
1-212-438-7406
obie.ugboaja
@spglobal.com

Credit Highlights

Overview

Key strengths	Key risks
Monopolistic vertically integrated electric utility and gas distribution utility operations.	Lack of operating diversity that makes the company largely depend on Michigan regulators to sustain its credit quality.
Favorable regulatory construct in Michigan.	Energy transition risks due to its dependence on natural gas and coal-fired generation (about 75% of electricity generated or purchased in 2023), partially mitigated by a plan to retire coal in 2025.
Large customer base of 1.9 million electric and 1.8 million gas customers.	Negative discretionary cash flow, reflecting robust capital spending, which indicates external funding needs.
Insulated subsidiary of its parent, CMS Energy Corp., allowing us to rate it one notch above the parent.	Susceptibility to adverse weather events, including winter storms and convective storms.
	Exposure to cyclical commercial and industrial customers, which account for about 45%-50% of electric utility revenues and 20%-25% of gas utility revenues.

We expect Consumers Energy Co. (CE) to continue to effectively manage its regulatory risk. We believe Michigan's regulatory construct is above average compared with peers because of the benefit of a streamlined 10-month rate case process. Other constructive rate mechanisms include the use of forward test-years, power supply cost rider adjustments, and natural gas

cost rider adjustments. These mechanisms help the company earn its allowed return on equity (ROE) and minimize regulatory lag.

CE is in the middle of an electric rate case and just received a settlement approval in its recent gas rate case. The company filed for a $325 million electric rate increase based on a 10.25% ROE in May and reached a settlement with various intervenors and received an order from the Michigan Public Service Commission (MPSC) for a $35 million gas rate increase based on a 9.90% ROE. The gas rate increase granted was about only a quarter of the rate increase requested. However, this difference was partially because the commission authorized bill credits of $27.5 million per year over four years related to the gain on the sale of CE's appliance service plan business, which happened after and was not a part of the company's case filing.

Consumers Energy Co. rate case details

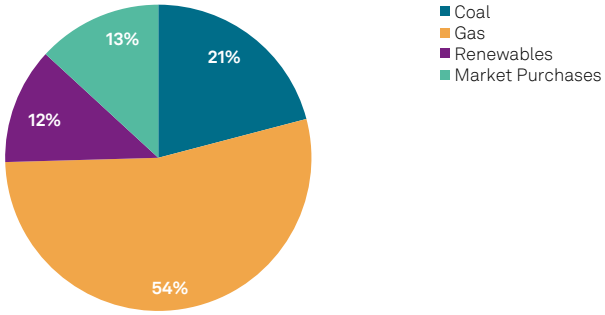
	Electric rate case		Gas rate case	
	Present case: requested by company 5/31/2024	Previous case: authorized by MPSC 3/1/2024	Authorized by MPSC 7/23/2024	Requested by company 12/15/2023
Rate change amount (mil. $)	325	92.0	35.0	136.0
Rate base (mil. $)	15,571.5	13,669	10,850*	10,970
Rate base valuation method	Average	Average	Average	Average
Return on equity (%)	10.25	9.90	9.90	10.25
Common equity to total capital (%)	42.36	41.13	41.48*	42.73
Rate of return (%)	6.21	5.86	5.93*	6.20
Rate case test year end date	2/28/2026	2/28/2025	9/30/2025	9/30/2025

*Company assumption under settlement. Source: S&P CapitalIQ Pro. MPSC--Michigan Public Service Commission.

The company's elevated capital spending plan prioritizes infrastructure upgrades, and its energy transition plans. Over the next five years, CE plans to spend about $17 billion to maintain and upgrade its gas infrastructure and electric distribution systems and reduce its carbon emissions. The capital plan includes investment of about $6.3 billion in the gas segment and about $10.7 billion in electric (of which, about two thirds are dedicated to distribution-related spending). The company also intends to reduce its carbon exposure in line with its Integrated Resource Plan (IRP), which the MPSC approved in June 2022. The plan includes a goal to reach net-zero carbon emission by 2040 and a goal to retire CE's owned coal-fired generation plants in 2025. Furthermore, the company's IRP targets a gradual reduction in its gas-fired generation dependence after 2025, as well as meeting 90% of its customer needs with clean energy sources by 2040. The company also announced a net-zero greenhouse gas emissions target by 2050 and a zero methane emissions target by 2030 for its gas distribution system.

Consumers Energy Co.

CE's 2023 generated and purchased electricity supply by source



Source: Company filings.

The company's credit metrics were weak in 2023, largely because of weather-related issues. Mild weather impaired sales for the company's gas operations, and the company saw heightened winter and convective storm activities. While the company has effectively recovered storm costs in past rate case proceedings, it has not been able to defer storm costs into regulatory assets, which introduced regulatory lag.

A portion of CE's service territory has a relatively high wildfire risk classification from the Federal Emergency Management Agency (FEMA). This area is contiguous and has a population of about 10,000-15,000 people, 7,000-9,000 housing units, of which about 40%-60% are occupied, and median home values if $100,000-$150,000 according to U.S. Census data. Part of the company's capital spending plan is focused on smart electric systems and anticipates pursuing further undergrounding pilots, with the potential to underground up to 400 miles of electric lines per year, starting in 2027, to address some of its climate-related risks. While CE has not been found culpable for any wildfires in its service territory and is not currently party to any such litigation, we will continue to monitor the company's ability to effectively manage its risks associated with adverse weather events.

We expect CE's credit measures to remain within the significant financial risk profile category. Throughout our base-case scenario, we expect funds from operations (FFO) to debt of 17%-19%.

Outlook

The stable rating outlook on CE reflects our expectation that management will focus on its core utility operations and reach constructive regulatory outcomes to avoid increasing business risk. We expect CE will maintain stand-alone financial measures consistent with the middle of the range for its financial risk profile category, specifically FFO to debt of 17%-19%.

Downside scenario

We could lower our rating on CE if:

- The stand-alone financial measures weaken such that FFO to debt weakens to consistently below 15%; or

- We lower our rating on parent CMS Energy.

Upside scenario

Although less likely, we could raise our rating on CE if we raise our rating on CMS Energy and CE's stand-alone financial measures improve, reflecting FFO to debt consistently above 20%.

Our Base-Case Scenario

Assumptions

- Consistent rate case filings and use of existing regulatory mechanisms;
- Elevated capital spending over the forecast period averaging $2.8 billion-$3.0 billion annually;
- Annual dividends averaging about $1 billion-$1.1 billion annually;
- All debt maturities refinanced; and
- Continued negative discretionary cash flow financed in a balanced manner to support the regulated capital structure.

Key metrics

Consumers Energy Co.--Forecast summary

Period ending	Dec-31-2020	Dec-31-2021	Dec-31-2022	Dec-31-2023	Dec-31-2024	Dec-31-2025	Dec-31-2026	Dec-31-2027
(Mil. $)	2020a	2021a	2022a	2023a	2024e	2025f	2026f	2027f
Revenue	6,155	6,987	8,117	7,129	8,230	8,803	9,333	9,879
EBITDA (reported)	2,244	2,252	2,321	2,405	2,795	3,081	3,337	3,582
Plus: Operating lease adjustment (OLA) rent	9	8	6	6	6	6	6	6
Plus/(less): Other	139	146	70	74	(39)	(40)	(40)	(22)
EBITDA	2,392	2,406	2,397	2,485	2,762	3,047	3,303	3,566
Less: Cash interest paid	(373)	(376)	(343)	(454)	(480)	(559)	(620)	(684)
Less: Cash taxes paid	(51)	10	2	(31)	(112)	3	1	(9)
Plus/(less): Other	--	--	--	--	--	--	--	--
Funds from operations (FFO)	1,968	2,040	2,057	2,000	2,169	2,491	2,685	2,873
EBIT	1,268	1,246	1,262	1,349	1,625	1,826	1,993	2,172
Interest expense	393	381	375	496	512	591	652	716
Cash flow from operations (CFO)	1,265	2,013	984	2,415	2,316	2,529	2,662	2,802
Capital expenditure (capex)	2,254	2,136	2,275	2,279	2,892	3,318	2,897	2,890
Free operating cash flow (FOCF)	(989)	(124)	(1,291)	136	(576)	(789)	(235)	(88)
Dividends	639	723	770	696	865	951	1,047	1,129
Share repurchases (reported)	--	--	--	--	--	--	--	--
Discretionary cash flow (DCF)	(1,628)	(847)	(2,061)	(560)	(1,441)	(1,740)	(1,282)	(1,217)
Debt (reported)	8,429	8,810	10,287	11,285	12,331	13,437	14,319	15,172

Consumers Energy Co.

Consumers Energy Co.--Forecast summary

Plus: Lease liabilities debt	88	74	81	41	26	19	15	12
Plus: Pension and other postretirement debt	--	--	--	--	--	--	--	--
Less: Accessible cash and liquid Investments	(20)	(22)	(43)	(35)	(100)	(100)	(100)	(100)
Plus/(less): Other	616	553	699	80	167	282	404	532
Debt	9,113	9,415	11,024	11,371	12,423	13,637	14,638	15,616
Equity	8,556	9,261	10,137	10,782	11,564	12,735	13,667	14,580
Adjusted ratios								
Debt/EBITDA (x)	3.8	3.9	4.6	4.6	4.5	4.5	4.4	4.4
FFO/debt (%)	21.6	21.7	18.7	17.6	17.5	18.3	18.3	18.4
FFO cash interest coverage (x)	6.3	6.4	7.0	5.4	5.5	5.5	5.3	5.2
EBITDA interest coverage (x)	6.1	6.3	6.4	5.0	5.4	5.2	5.1	5.0
CFO/debt (%)	13.9	21.4	8.9	21.2	18.6	18.5	18.2	17.9
FOCF/debt (%)	(10.9)	(1.3)	(11.7)	1.2	(4.6)	(5.8)	(1.6)	(0.6)
DCF/debt (%)	(17.9)	(9.0)	(18.7)	(4.9)	(11.6)	(12.8)	(8.8)	(7.8)
Annual revenue growth (%)	(2.9)	13.5	16.2	(12.2)	15.4	7.0	6.0	5.9
EBITDA margin (%)	38.9	34.4	29.5	34.9	33.6	34.6	35.4	36.1
Return on capital (%)	7.5	6.9	6.3	6.2	7.0	7.3	7.3	7.4
Debt/debt and equity (%)	51.6	50.4	52.1	51.3	51.8	51.7	51.7	51.7
Debt fixed-charge coverage (x)	6.1	6.3	6.4	5.0	5.4	5.2	5.1	5.0

All figures are adjusted by S&P Global Ratings, unless stated as reported. a--Actual. e--Estimate. f--Forecast. $--U.S. dollar.

Company Description

CE is a subsidiary of CMS Energy and operates as an electric and gas utility serving about 1.9 million electric and 1.8 million natural gas million customers in Michigan. CE's electric business operates as a vertically integrated utility that generates, distributes, and sells electricity. The electric utility sources about 40%-50% of its generation from purchased power, rather than from its own plants. The company also sells, stores, and transports natural gas. It is based in Jackson, Mich. CE contributes to about 95% of CMS' EBITDA.

Peer Comparison

Consumers Energy Co.--Peer Comparisons

	Consumers Energy Co.	DTE Electric Co.	Wisconsin Power & Light Co.	Wisconsin Electric Power Co.	Consolidated Edison Co. of New York Inc.
Foreign currency issuer credit rating	A-/Stable/A-2	A-/Stable/A-2	A/Negative/A-1	A-/Stable/A-2	A-/Stable/A-2
Local currency issuer credit rating	A-/Stable/A-2	A-/Stable/A-2	A/Negative/A-1	A-/Stable/A-2	A-/Stable/A-2
Period	Annual	Annual	Annual	Annual	Annual
Period ending	2023-12-31	2023-12-31	2023-12-31	2023-12-31	2023-12-31

Consumers Energy Co.

Consumers Energy Co.--Peer Comparisons

Mil.	$	$	$	$	$
Revenue	7,129	5,729	1,827	4,045	13,476
EBITDA	2,485	2,715	760	1,716	4,232
Funds from operations (FFO)	2,000	2,282	544	1,056	3,276
Interest	496	623	152	383	1,032
Cash interest paid	454	418	166	561	983
Operating cash flow (OCF)	2,415	1,534	558	1,028	2,250
Capital expenditure	2,279	3,076	999	1,183	4,010
Free operating cash flow (FOCF)	136	(1,542)	(441)	(155)	(1,760)
Discretionary cash flow (DCF)	(560)	(2,544)	(625)	(524)	(2,816)
Cash and short-term investments	35	15	7	6	1,138
Gross available cash	35	15	7	6	1,138
Debt	11,371	12,009	3,748	5,657	22,824
Equity	10,782	10,224	3,897	5,068	19,146
EBITDA margin (%)	34.9	47.4	41.6	42.4	31.4
Return on capital (%)	6.2	6.8	7.6	12.2	5.6
EBITDA interest coverage (x)	5.0	4.4	5.0	4.5	4.1
FFO cash interest coverage (x)	5.4	6.5	4.3	2.9	4.3
Debt/EBITDA (x)	4.6	4.4	4.9	3.3	5.4
FFO/debt (%)	17.6	19.0	14.5	18.7	14.4
OCF/debt (%)	21.2	12.8	14.9	18.2	9.9
FOCF/debt (%)	1.2	(12.8)	(11.8)	(2.7)	(7.7)
DCF/debt (%)	(4.9)	(21.2)	(16.7)	(9.3)	(12.3)

Business Risk

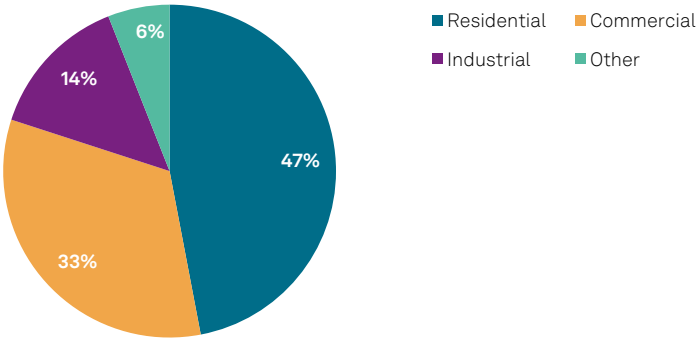
Our assessment of CE's business risk profile reflects the company's monopolistic electric and natural gas utility operations and effective management of regulatory risk. The MPSC regulates CE, and we view the regulatory environment in Michigan as above average compared with peers. This is demonstrated through the company's use of forward-looking test years and a streamlined 10-month rate case process. Furthermore, CE benefits from other constructive rate mechanisms, such as the Power Supply Cost Recovery adjustment rider, and the Gas Cost Recovery adjustment rider.

In 2023, the state also passed a law that allows electric utilities in the state to earn a return equal to their pre-tax weighted average cost of capital on payments made under new purchased-power agreements. These constructive rate mechanisms enable CE to generally earn its allowed ROE and minimize regulatory lag.

The company actively manages its gas supply to reduce the effects of price volatility and to support its gas system operations by injecting natural gas into storage during the summer months for use during the winter months. During 2023, 45% of the natural gas supplied to all customers during the winter months came from storage. Additionally, CE's large customer base

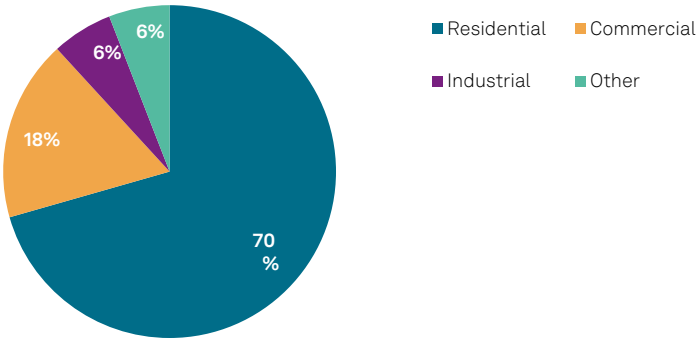
of about 1.9 million electric customers and about 1.8 million natural gas customers throughout Michigan bolsters the company's business risk profile. This said, the company is exposed to cyclical commercial and industrial customers for its electric operations, which contribute about 45%-50% of the company's electric revenues.

CE's 2023 electrical revenue by customer class



Source: Company filings.

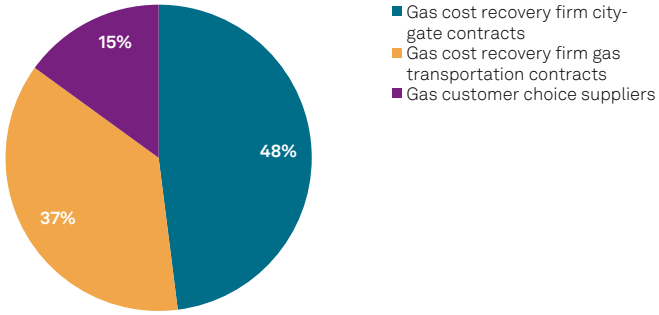
CE's 2023 gas revenue by customer class



Source: Company filings

Consumers Energy Co.

CE's 2023 gas supply sources



Source: Company filings

Financial Risk

We assess CE's financial measures using our medial volatility table, reflecting the company's lower-risk regulated electric and gas utility operations and its effective management of regulatory risk. Under our base-case scenario, we expect:

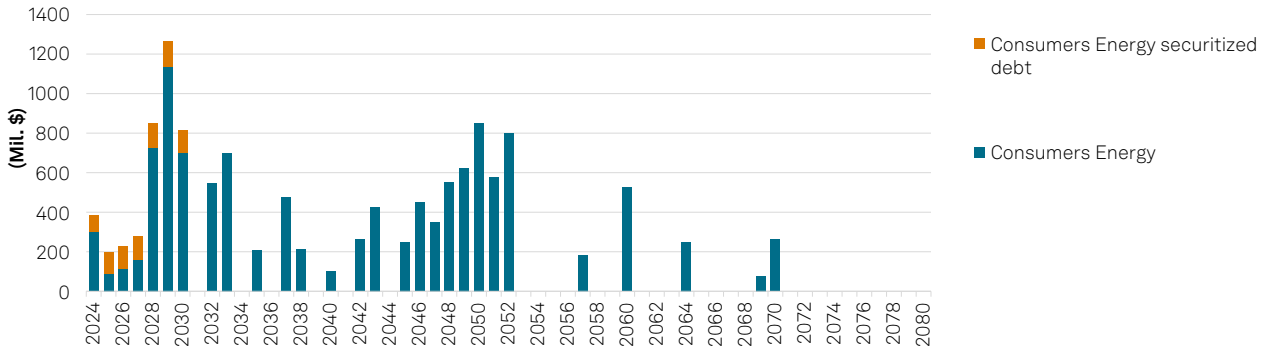
- Elevated capital spending averaging $2.8 billion-$3.0 billion annually over the forecast period;
- Dividends averaging $1 billion-$1.1 billion annually;
- Equity injections by the parent to maintain the company's capital structure;
- Continued use of existing regulatory mechanisms;
- Negative discretionary cash flow; and
- The refinancing of all debt maturities.

As such, we anticipate financial measures to be consistent with the middle of the range for the significant financial risk category. Specifically, we forecast FFO to debt of 17%-19%.

Consumers Energy Co.

Debt maturities

Consumers Energy debt maturities



Source: Company filings and S&P Global Ratings.

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Consumers Energy Co.--Financial Summary

Period ending	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022	Dec-31-2023
Reporting period	2018a	2019a	2020a	2021a	2022a	2023a
Display currency (mil.)	$	$	$	$	$	$
Revenues	6,430	6,341	6,155	6,987	8,117	7,129
EBITDA	2,152	2,252	2,392	2,406	2,397	2,485
Funds from operations (FFO)	1,665	1,823	1,968	2,040	2,057	2,000
Interest expense	355	335	393	381	375	496
Cash interest paid	331	296	373	376	343	454
Operating cash flow (OCF)	1,533	1,688	1,265	2,013	984	2,415
Capital expenditure	1,920	2,191	2,254	2,136	2,275	2,279
Free operating cash flow (FOCF)	(387)	(502)	(989)	(124)	(1,291)	136
Discretionary cash flow (DCF)	(918)	(1,094)	(1,628)	(847)	(2,061)	(560)
Cash and short-term investments	39	11	20	22	43	35
Gross available cash	39	11	20	22	43	35
Debt	7,774	8,238	9,113	9,415	11,024	11,371
Common equity	6,920	7,737	8,556	9,261	10,137	10,782
Adjusted ratios						
EBITDA margin (%)	33.5	35.5	38.9	34.4	29.5	34.9
Return on capital (%)	7.9	7.7	7.5	6.9	6.3	6.2
EBITDA interest coverage (x)	6.1	6.7	6.1	6.3	6.4	5.0
FFO cash interest coverage (x)	6.0	7.2	6.3	6.4	7.0	5.4
Debt/EBITDA (x)	3.6	3.7	3.8	3.9	4.6	4.6
FFO/debt (%)	21.4	22.1	21.6	21.7	18.7	17.6
OCF/debt (%)	19.7	20.5	13.9	21.4	8.9	21.2

Consumers Energy Co.

Consumers Energy Co.--Financial Summary

FOCF/debt (%)	(5.0)	(6.1)	(10.9)	(1.3)	(11.7)	1.2
DCF/debt (%)	(11.8)	(13.3)	(17.9)	(9.0)	(18.7)	(4.9)

Reconciliation Of Consumers Energy Co. Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Financial year	Dec-31-2023									
Company reported amounts	11,285	10,800	7,166	2,405	1,268	448	2,485	2,430	697	2,248
Cash taxes paid	-	-	-	-	-	-	(31)	-	-	-
Cash interest paid	-	-	-	-	-	-	(438)	-	-	-
Lease liabilities	41	-	-	-	-	-	-	-	-	-
Operating leases	-	-	-	6	1	1	(1)	5	-	-
Intermediate hybrids (equity)	19	(19)	-	-	-	1	(1)	(1)	(1)	-
Accessible cash and liquid investments	(35)	-	-	-	-	-	-	-	-	-
Capitalized interest	-	-	-	-	-	3	(3)	(3)	-	(3)
Share-based compensation expense	-	-	-	26	-	-	-	-	-	-
Securitized stranded costs	(787)	-	(37)	(37)	(8)	(8)	8	(29)	-	-
Power purchase agreements	358	-	-	53	19	19	(19)	34	-	34
Asset-retirement obligations	584	-	-	32	32	32	-	-	-	-
Nonoperating income (expense)	-	-	-	-	37	-	-	-	-	-
Reclassification of interest and dividend cash flows	-	-	-	-	-	-	-	(21)	-	-
Debt: other	(93)	-	-	-	-	-	-	-	-	-
Total adjustments	86	(19)	(37)	80	81	48	(485)	(15)	(1)	31
S&P Global Ratings adjusted	**Debt**	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from Operations**	**Operating cash flow**	**Dividends**	**Capital expenditure**
	11,371	10,782	7,129	2,485	1,349	496	2,000	2,415	696	2,279

Liquidity

We assess CE's liquidity as adequate, with sources covering uses by 1.1x over the coming 12 months, and that its sources cover uses even if forecast consolidated EBITDA declines 10%. We believe the supportive regulatory framework provides manageable cash flow stability for the company even in times of economic stress, supporting our use of slightly lower thresholds to assess liquidity.

In addition, CE can absorb high-impact, low-probability events, in our view, as the company maintains about $1.1 billion in committed credit facilities through 2027, another $250 million in committed credit facilities through November 2025, and can likely lower its capital spending (averaging $2.8 billion-$3.0 billion annually) during stressful periods, indicating a limited need for refinancing under such conditions. CE can borrow $500 million from the parent CMS Energy as per its renewed credit agreement in December 2023.

Furthermore, our assessment reflects the company's prudent risk management and sound relationships with its banking group. Overall, we believe that the company can withstand adverse market circumstances over the next 12 months with sufficient liquidity to meet its obligations. The company has around $200 million of long-term debt maturities in 2025, and we expect the company to proactively address these maturities well in advance of their scheduled due dates.

Principal liquidity sources

- Cash FFO of about $2.4 billion;
- Credit facilities of about $1.3 billion;
- Working capital inflows of about $70 million; and
- Available cash of about $1.3 billion following the company's recent debt issuance.

Principal liquidity uses

- Debt maturities of about $772 million over the next 12 months;
- Estimated maintenance capital spending of about $2.7 billion; and
- Dividends of about $900 million.

Covenant Analysis

Requirements

CE's credit agreements contain a covenant for CE to maintain debt to capitalization below 65%.

Compliance expectations

In our base-case scenario, we expect CE to remain compliant with this covenant and have sufficient headroom.

Environmental, Social, And Governance

Environmental factors are a negative consideration in our credit rating analysis of CE. The company's use of fossil fuel generation sources exposes it to heightened energy transition risks. Its generation portfolio's capacity comprises about 36% natural gas, 20% coal, 17%

hydroelectric, 17% oil and gas, and 9% wind and solar as of Dec. 31, 2023. The company's accelerated coal retirement plan for its utility slightly mitigates this risk. It includes a goal to be coal-free in 2025 and have 90% of its utility's capacity portfolio sourced from clean energy resources by 2040.

Furthermore, the company has experienced heightened winter and convective storm activities in recent years. While the company has effectively recovered storm costs in past rate case proceedings, it has not been able to defer storm costs into regulatory assets, which could introduce regulatory lag especially if costs are outsized.

While CMS has not been found culpable for any wildfires in its service territory and is not currently party to any litigation concerning these matters, a portion of its service territory has a relatively high wildfire risk classification from FEMA. This area is contiguous and has a population of about 10,000-15,000 inhabitants, 7,000-9,000 housing units, of which about 40%-60% are occupied, and median home values of $100,000-$150,000 according to U.S. Census data. Part of the company's capital spending plan is focused on smart electric systems and anticipates pursuing further undergrounding pilots, with the potential to underground up to 400 miles of electric lines per year starting in 2027. We will continue to monitor the company's ability to effectively manage its risks associated with adverse weather events.

Group Influence

Under our group rating methodology, we consider CMS Energy to be the parent of the group with a group credit profile (GCP) of 'bbb+'. We assess CE as a core subsidiary of CMS Energy largely because we view the utility as integral to the group's identity, highly unlikely to be sold and having a strong commitment from management, given the company's emphasis on maintaining the size of the regulated utility operations relative to the nonutility businesses.

Given CE's stand-alone credit profile, and because CE is operationally separate and maintains sufficient insulating measures, we rate the utility one notch above the GCP. Some of the key insulating measures are:

- CE is a separate and stand-alone legal entity that functions independently (both financially and operationally), files its own rate cases, and is independently regulated by MPSC;
- CE has its own records and books, including stand-alone audited financial statements;
- The utility has its own funding arrangements, including issuing its own long-term debt, and it has a separate committed credit facility to cover its short-term funding needs;
- CE does not comingle funds, assets, or cash flow with parent CMS Energy or its other subsidiaries, and it does not participate in a money pool;
- We believe there is a strong economic basis for CMS Energy to preserve CE's credit strength, reflecting CE's low-risk, profitable, and regulated utility business model. CE is also a significant portion of CMS Energy, accounting for about 95% of the consolidated company; and
- There are no cross-default provisions between parent CMS Energy and CE that could directly lead to a default at the utility.

Issue Ratings--Subordination Risk Analysis

Capital structure

CE's capital structure consists of about $12.5 billion of long-term debt, including about $11.7 billion in first-mortgage bonds (FMBs), $787 million of securitized debt (all of which is deconsolidated from our credit metrics), and about $110 million of tax-exempt revenue bonds.

Analytical conclusions

We rate the company's senior unsecured debt 'A-', in-line with the long-term issuer credit rating on CE as the rated issuances are senior unsecured debt issued by a qualifying investment grade utility as per our criteria.

We base our 'A-2' short-term rating on our 'A-' issuer credit rating.

Issue Ratings--Recovery Analysis

Key analytical factors

- We assign recovery ratings to FMBs issued by U.S. utilities, which can result in issue ratings being notched above an issuer credit rating on a utility, depending on the rating category and the extent of the collateral coverage. The FMBs issued by U.S. utilities are a form of secured utility bonds that qualify for a recovery rating as defined in our criteria.
- CE's FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+' and an issue rating one notch above the issuer credit rating.

Rating Component Scores

Foreign currency issuer credit rating	A-/Stable/A-2
Local currency issuer credit rating	A-/Stable/A-2
Business risk	Excellent
Country risk	Very Low
Industry risk	Very Low
Competitive position	Excellent
Financial risk	Significant
Cash flow/leverage	Significant
Anchor	a-
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)
Liquidity	Adequate (no impact)
Management and governance	Neutral (no impact)
Comparable rating analysis	Neutral (no impact)
Stand-alone credit profile	a-
Group credit profile	bbb+
Entity status within group	Insulated (no impact on SACP)

Consumers Energy Co.

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, April 4, 2024
- Criteria | Corporates | General: Corporate Methodology, Jan. 7, 2024
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7, 2024
- General Criteria: Hybrid Capital: Methodology And Assumptions, March 2, 2022
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings Detail (as of August 20, 2024)*	
Consumers Energy Co.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Secured	A
Issuer Credit Ratings History	
30-Oct-2019	A-/Stable/A-2
03-Dec-2014	BBB+/Stable/A-2
11-Sep-2014	BBB/Positive/A-2
Related Entities	
CMS Energy Corp.	
Issuer Credit Rating	BBB+/Stable/A-2
Junior Subordinated	BBB-
Preferred Stock	BBB-
Senior Unsecured	BBB

Consumers Energy Co.

Ratings Detail (as of August 20, 2024)*

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings credit ratings on the global scale are comparable across countries. S&P Global Ratings credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

Consumers Energy Co.

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Infrastructure And Project Finance

CREDIT OPINION
31 May 2024

Update

Send Your Feedback

RATINGS

Consumers Energy Company

Domicile	Jackson, Michigan, United States
Long Term Rating	(P)A3
Type	Senior Unsec. Shelf - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

Contacts

Jairo Chung +1.212.553.5123
VP-Sr Credit Officer
jairo.chung@moodys.com

Lily Cochran +1.212.553.4795
Ratings Associate
lily.cochran@moodys.com

Michael G. Haggarty +1.212.553.7172
Associate Managing Director
michael.haggarty@moodys.com

Jim Hempstead +1.212.553.4318
MD - Global Infrastructure & Cyber Risk
james.hempstead@moodys.com

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

Consumers Energy Company

Update to credit analysis

Summary

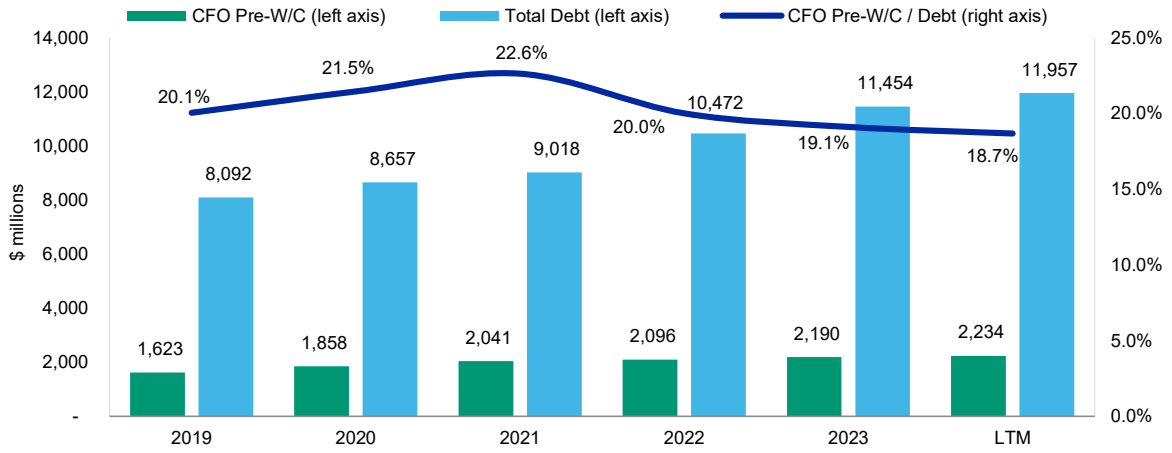
Consumers Energy Company's (Consumers Energy) credit profile reflects its business risk as a vertically integrated electric and gas utility operating in the credit supportive regulatory environment of Michigan. We expect the utility to maintain a stable financial profile with cash flow from operations before changes in working capital (CFO pre-WC) to debt averaging around 20-21%, including an adjustment to exclude securitization debt, over the next 2-3 years. At the end of the latest twelve month (LTM) period ending 31 March 2024, Consumers Energy's CFO pre-WC to debt ratio was 20%, including the adjustment to exclude securitization bonds. The company will continue to execute its robust capital investment plan and have an active regulatory calendar over this period. Based on the Michigan regulatory framework, we expect the utility to recover its investment costs on a timely basis and to earn an appropriate return on its investments.

Consumers Energy's stand-alone financial performance has historically been affected by the significant debt at its parent company CMS Energy Corporation (CMS, Baa2 stable). However, CMS has made notable progress in reducing the percentage of parent debt in its capital structure in recent years. We now estimate that the percentage of parent debt will remain below 25% of total consolidated debt. All of Consumer Energy's outstanding debt obligations are secured.

Recent development

In November 2023, Michigan enacted a new energy law (2023 Energy Law), which raised the state's renewable energy standard while providing additional authority to the Michigan Public Service Commission (MPSC). Consumer Energy's operations are under the purview of MPSC. In general, we view this development to be constructive because the utilities in the state will now outline a renewable energy plan with greater transparency, and the MPSC will have an expanded scope of consideration for various factors influencing Consumers Energy' plan to decarbonize.

Exhibit 1
Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt



When we adjust the total debt to exclude securitization debt, Consumers Energy's CFO pre-WC/debt would be 20.3%, 20.4% and 20.0% in 2022, 2023 and LTM ending 31 March 2024, respectively.
Source: Moody's Financial Metrics

Credit strengths

» Credit supportive regulatory environment in Michigan

» Transparent and timely cost recovery

» Stable financial profile

Credit challenges

» Robust capital investment plan

» Maintaining regulatory support for these capital investments

» Lack of geographic and regulatory diversity with single state service territory

Rating outlook

The stable outlook reflects our expectation that financial metrics will remain stable and that Consumers Energy will continue to benefit from a consistent and generally credit supportive regulatory environment. The stable outlook also incorporates our view that Consumers Energy will maintain prudent financial policies while managing through its robust investment cycle and that debt levels at the parent will not increase materially.

Factors that could lead to an upgrade

A rating upgrade could be considered if credit metrics improve such that CFO pre-WC to debt is above 21% on a sustained basis. In addition, if the Michigan regulatory framework becomes even more formulaic, transparent or timely with its suite of cost recovery mechanisms for Consumers Energy, a rating upgrade could be possible.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the issuer/deal page on https://ratings.moodys.com for the most updated credit rating action information and rating history.

Factors that could lead to a downgrade

A rating downgrade could be considered if there is a material deterioration in the credit supportiveness of the Michigan regulatory environment; or if the CFO pre-WC to debt ratio declines below 18% on a sustained basis.

Key indicators

Exhibit 2

Consumers Energy Company

	2019	2020	2021	2022	2023	LTM
CFO Pre-W/C + Interest / Interest	6.2x	6.6x	7.5x	7.1x	5.8x	5.6x
CFO Pre-W/C / Debt	20.1%	21.5%	22.6%	20.0%	19.1%	18.7%
CFO Pre-W/C – Dividends / Debt	12.7%	14.1%	14.6%	12.7%	13.0%	13.0%
Debt / Capitalization	46.0%	44.9%	43.7%	45.1%	45.8%	46.7%

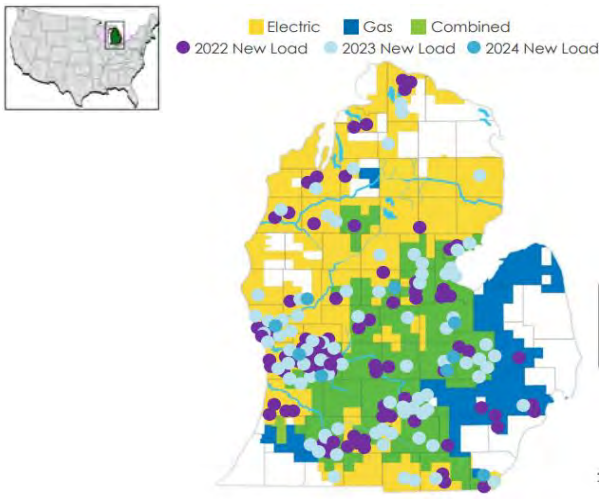
All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Credit metrics included in the exhibit include securitization bonds. When we adjust the total debt to exclude securitization debt, Consumers Energy's CFO pre-WC/debt would be 20.3%, 20.5% and 20.0% in 2022, 2023 and LTM ending 31 March 2024, respectively.
Source: Moody's Financial Metrics

Profile

Consumers Energy is a vertically integrated electric and gas utility serving approximately 1.9 million electric and 1.8 million gas customers in the state of Michigan with an average rate base of $25 billion in 2023. Consumers Energy's electric operations account for approximately two thirds of its revenue, cash flow and asset base. The utility is a wholly-owned subsidiary of CMS and, as the primary subsidiary of the parent company, it represents over 95% of CMS's consolidated earnings. In addition to Consumers Energy, CMS has a subsidiary called NorthStar Clean Energy, a non-utility domestic independent power producer and marketer.

Exhibit 3

Consumers Energy's Service Territory



Source: Company Presentations

Detailed credit considerations

Credit supportive regulatory environment

Consumers Energy is regulated by the MPSC, which has a regulatory framework that we view to be more credit supportive than most other states. As a result of 2008 and 2016 energy legislation in Michigan, the regulatory framework has been streamlined, improving both the rate case process and the timeliness of cost recovery. The 2016 legislation provided additional assurance of utility investment recovery by expanding the certificate of necessity (CON) process, which had already included pre-construction approval for large

generating resources, into an integrated resource planning (IRP) process. The IRP process considers a wide range of factors including fuel costs, demand forecasts, resource adequacy, competitive pricing, environmental mandates and transmission options before the construction of major projects.

In November 2023, new energy legislation (2023 Energy Law) was enacted. Under the new law, the state's renewable energy standards were raised to 50% by 2030 and 60% by 2035 from the previous 15% by 2021 requirement. It also set a clean energy standard of 80% by 2035 and 100% by 2040. Under the law, zero to low-carbon emitting sources, such as nuclear generation and natural gas generation with carbon capture, are considered clean energy sources. Along with these new standards, the new legislation expanded the authority of the MPSC to oversee their implementation. CMS's utility subsidiary Consumers Energy will file updates to its renewable energy plans in 2024 and its Clean Energy Plan in or before 2027. Given the existing regulatory framework in Michigan, we expect the company's collaborative dialogue with both stakeholders and regulator to continue under the new legislation.

In June 2022, Consumers Energy and key stakeholders in Michigan reached a settlement related to the company's latest IRP. The settlement included the retirement of all of its remaining coal power plants (all three units at the Campbell power plant site) in 2025 as a result of the 2021 IRP. Consumers Energy will be able to record approximately $1.3 billion of the remaining book value of these power plants as a regulatory asset and earn a 9% return on equity (ROE) through the remaining life. Instead of securitizing the remaining book value, the settlement will minimize the impact of the accelerated coal retirements on Consumers Energy's credit metrics. We view this settlement to be constructive and evidence of continued credit supportiveness in Michigan.

Timeliness of cost recovery based on a prescriptive suite of recovery mechanisms

Michigan utilities benefit from numerous formulaic rate adjustment mechanisms that provide a high degree of cash flow stability and assurance of recovery. For example, Consumers Energy has forward-looking Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) mechanisms that are intended to ensure that it can recover prudently incurred power and gas supply costs. The PSCR covers fuel and purchased power costs as well as transmission and emission allowance costs. Differences between actual and forecast costs are deferred for recovery or refunded in the following year. The PSCR is a surcharge mechanism and provides a degree of base rate and cash flow stability, a credit positive. The GCR mechanism may be adjusted monthly within a capped range to minimize over/under recoveries, although interim gas inventory buildup could substantially increase the company's working capital financing when gas prices increase sharply.

Gas utilities in the state also benefit from programs designed to assure recovery of needed infrastructure improvements. Consumers Energy's RDM compares and adjusts for differences between weather normalized actual and authorized revenues. The company's enhanced infrastructure replacement program (EIRP) is a MPSC authorized 25-year incremental investment program to upgrade natural gas infrastructure, including replacing less than 250 miles of cast iron pipe and other high-risk components.

Active rate case filing cadence

Consumers Energy maintains an active regulatory schedule with its electric and gas general rate cases typically filed annually in an alternating pattern. The utility currently has its gas rate case pending before the MPSC, and filed its request for an electric rate increase on 31 May 2024. Over the last three years, Consumers Energy experienced downward pressure on its allowed ROE in its rate cases although the company was able to maintain a 9.9% allowed ROE. We expect Consumers Energy to maintain a stable financial profile because there are other offsetting mechanisms such as usage of forward test year to allow the utility to earn appropriate returns and to recover investment costs on a timely basis. However, further deterioration of the allowed ROE is likely to put negative pressure on the company's overall financial profile.

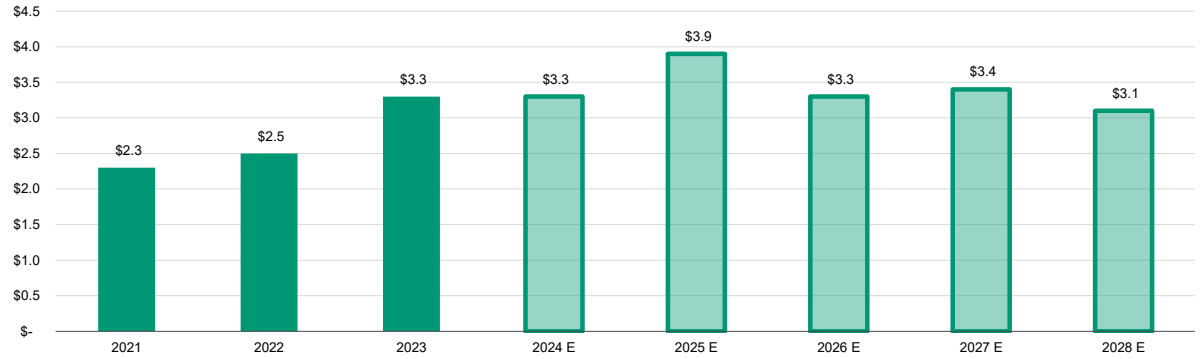
On 1 March 2024, the commission authorized a $92 million increase based on a 9.9% ROE, 50.02%% equity capital structure and a $13.67 billion rate base value. Also, the final order approved an Investment Recovery Mechanism (IRM) rider for distribution reliability projects totaling $99 million over two years.

On 15 December 2023, the utility filed a gas rate case, seeking a $136 million increase based on a projected test year for the 12-month period ending 30 September 2025, requesting a 10.25% ROE, 51.5% equity capital structure and a rate base value estimated around $10.97 billion. In April 2024, the MPSC Staff recommended an $70.77 million increase based on a 9.85% ROE, 49.92% equity capital structure and a $10.88 billion rate base value. A final decision is expected by 15 October 2024.

Stable credit metrics expected to be maintained through its high capital investment cycle

Consumers Energy's capital spending continues to be robust as it is currently in the midst of a large capital investment plan. The company increased its five-year capital expenditure plan through 2028 to $17 billion, approximately $1.5 billion higher than the previous plan. Consumers Energy will invest approximately $6.3 billion primarily to maintain and upgrade its gas utility infrastructure; $7.3 billion related to its electric distribution and other infrastructure; and $3.4 billion related to clean energy generation. These investments should enhance the company's reliability and safety as well as help it execute its decarbonization plan.

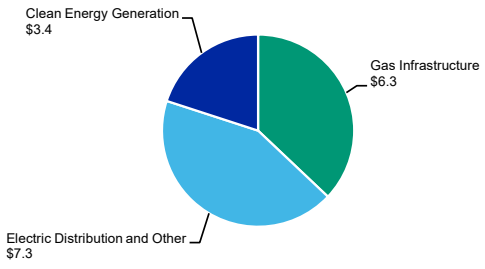
Exhibit 4
Consumers Energy's elevated capital program will extend at least through 2028
$ billions



Source: Company 10K

Through this period, Consumers Energy plans to keep rate increases modest, which should help to maintain regulatory support for investment cost recovery. Funding for these investments will be provided by internally generated cash flow, the issuance of debt at Consumers Energy and equity contributions from CMS. We expect Consumers Energy to maintain its CFO pre-WC to debt at around 20%-21% on average over the next 2-3 years. At the end of 2023 and for the LTM period ending 31 March 2024, Consumers Energy produced a CFO pre-WC to debt ratio of 20.5% and 20%, respectively, excluding securitization debt.

Exhibit 5
Planned Capital Expenditures 2024 - 2028
$ billions



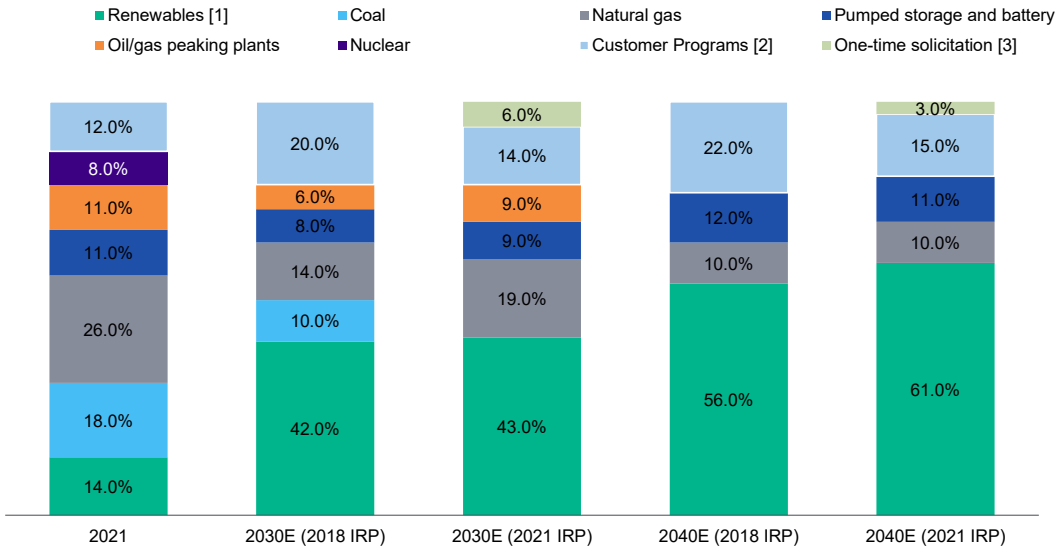
Source: Company 10K

Based on Consumers' latest IRP approved in 2022, the utility will add up to 8 GW of solar power, which is 2 GW more than what was approved in the company's 2018 IRP. As a result, by 2040, more than 60% of Consumers Energy's generation capacity will be from renewable sources. In order to replace the retiring coal capacity, the utility acquired the Covert natural gas-fired power plant for

approximately $815 million in 2023. It issued requests for proposals (RFP) for two purchased power agreements (PPA) for 500 MW of dispatchable generation and 200 MW of clean energy sources.

Exhibit 6

Based on the latest IRP settlement, more than 60% of Consumers Energy's generation sources will be renewables by 2040



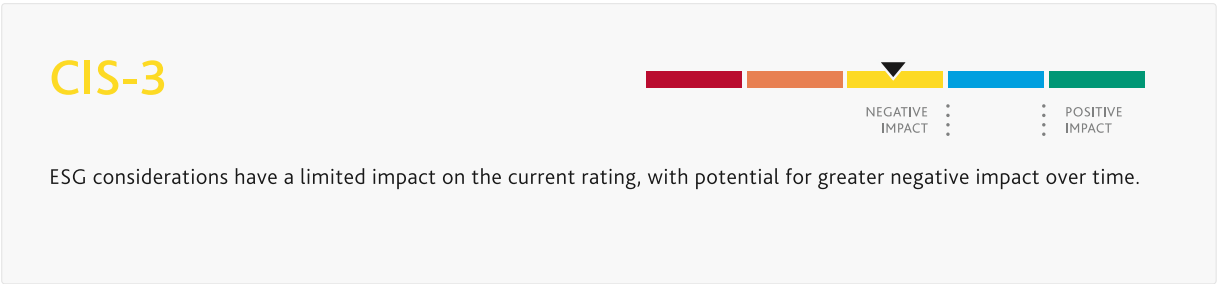
[1] Does not include renewable RECs.
[2] Includes energy waste reduction, demand response, and conservation voltage reduction program.
[3] One-time solicitation to acquire approximately 700 MW of capacity from sources in Michigan's Lower Peninsula beginning in 2025.
Source: Company's 10-K in 2022 and 2021, and latest investor presentation

ESG considerations

Consumers Energy Company's ESG credit impact score is CIS-3

Exhibit 7

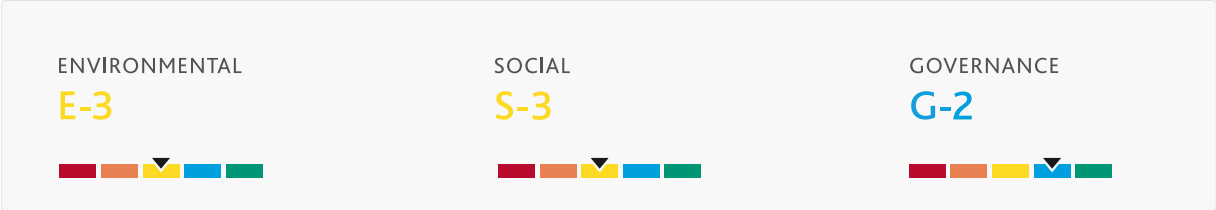
ESG credit impact score



Source: Moody's Ratings

Consumers Energy's **CIS-3** indicates that ESG considerations have limited impact on the current credit rating with greater potential for negative impact over time. It reflects some exposure to physical climate risk and moderating carbon transition risk. It also incorporates social risks stemming from inherent risk associated with regulated utilities and governance risk that is not a material driver.

Exhibit 8
ESG issuer profile scores



Source: Moody's Ratings

Environmental

Consumers Energy's **E-3** issuer profile score reflects its moderate position for the carbon transition with tangible strategies and plans in place that substantially mitigate its carbon transition exposure. The utility is currently in a transition to phase out its coal-fired generation and targets zero coal-fired generation output in 2025, accelerated from its prior target of 2039. The utility also established a goal of net zero methane emission for its gas delivery system by 2030; net zero carbon emissions for its electric business by 2040, including MISO market purchases and PPAs; and net zero greenhouse gas emissions for its entire business, including customer and supplier emissions, by 2050. Michigan's regulatory framework supports the utility's transition plan by allowing certain investment cost recovery and renewable energy plan surcharges, for example.

Social

S-3 issuer profile score for Consumers Energy is primarily related to its customer and regulatory relations as well as demographic and societal trends. The utility's regulatory environment, as well as its interaction with the Michigan Public Service Commission, are important in considering the utility's social risk. Also, the safety and reliability of its operations are important social considerations.

Governance

Consumers Energy's **G-2** issuer profile score reflects our view that its governance does not pose a particular risk and is not a material driver in the company's overall credit profile. It also incorporates its position as a subsidiary of CMS whose corporate governance considerations including financial policy and risk management influence Consumers Energy.

ESG Issuer Profile Scores and Credit Impact Scores for the rated entity/transaction are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for the entity/transaction on MDC and view the ESG Scores section.

Liquidity analysis

We expect Consumers Energy's liquidity profile to be adequate over the next 12-18 months.

Consumers Energy's external liquidity sources include a $1.1 billion secured revolving credit facility expiring in December 2027 and, as of 31 March 2024, net availability was $1.073 billion with $27 million of letters of credit outstanding. Consumers Energy also maintains a $250 million secured credit facility terminating in November 2025 and had $197 million available as of 31 March 2024. Both facilities are secured by first mortgage bonds. These credit facilities provide support for working capital needs and act as a backstop to Consumer Energy's $500 million commercial paper program. At 31 March 2024, the company had no commercial paper notes outstanding under the program. The credit facilities do not include a material adverse change representation for new borrowings, and have only one financial covenant, setting the maximum debt to capital at 65%. At 31 March 2024, debt to capital was 50%.

These facilities includes sustainability linked pricing metrics, which permits pricing adjustments for meeting targets related to sustainability. Targets include renewable generation and diverse supplier spend, highlighting its commitment to shifting its exposure to a greater renewable content and to supplier diversity.

The utility's continuing capital expenditure program and dividend policy will result in negative free cash flow for the foreseeable future. However, the company has a reasonable amount of external liquidity, demonstrated market access, and regularly receives capital contributions from its parent.

For the LTM period ended 31 March 2024, Consumers generated approximately $2.3 billion of cash from operations, invested $3.2 billion and distributed $673 million of dividends to CMS, resulting in negative free cash flow of approximately $1.6 billion. Given its robust investment plan, we expect Consumers Energy to maintain its negative free cash flow position over the 12-18 months.

In January 2024, Consumers Energy issued $600 million first mortgage bonds with 4.6% rate maturing in May 2029.

Rating methodology and scorecard factors

Exhibit 9

Methodology Scoring Factors
Consumers Energy Company

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 3/31/2024		Moody's 12-18 Month Forward View As of 5/19/2024 [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	Aa	Aa	Aa	Aa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.5x	Aa	5x - 6x	A
b) CFO pre-WC / Debt (3 Year Avg)	20.4%	Baa	20% - 21%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	13.4%	Baa	13% - 14%	Baa
d) Debt / Capitalization (3 Year Avg)	44.5%	A	45% - 46%	Baa
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A2		A3
HoldCo Structural Subordination Notching	0	0	0	0
a) Scorecard-Indicated Outcome		A2		A3
b) Actual Rating Assigned				A3

* Senior Secured Rating.
[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 3/31/2024.
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics

Appendix

Exhibit 10

Cash Flow and Credit Metrics

CF Metrics (in $ millions)	2019	2020	2021	2022	2023	LTM
FFO	**1,752**	**1,994**	**2,054**	**2,125**	**2,065**	**2,136**
+/- Other	(129)	(136)	(13)	(29)	125	98
CFO Pre-WC	**1,623**	**1,858**	**2,041**	**2,096**	**2,190**	**2,234**
+/- ΔWC	(15)	25	(53)	(1,098)	243	108
CFO	**1,608**	**1,883**	**1,988**	**998**	**2,433**	**2,342**
- Div	593	638	723	770	696	674
- Capex	2,100	2,184	2,066	2,256	2,260	2,289
FCF	(1,085)	(939)	(801)	(2,028)	(523)	(621)
(CFO Pre-W/C) / Debt	20.1%	21.5%	22.6%	20.0%	19.1%	18.7%
(CFO Pre-W/C - Dividends) / Debt	12.7%	14.1%	14.6%	12.7%	13.0%	13.0%
FFO / Debt	21.6%	23.0%	22.8%	20.3%	18.0%	17.9%
RCF / Debt	14.3%	15.7%	14.8%	12.9%	12.0%	12.2%
Revenue	6,376	6,189	7,021	8,151	7,166	7,053
Interest Expense	312	332	315	342	455	482
Net Income	725	798	838	883	802	842
Total Assets	23,699	25,399	27,140	29,916	31,852	32,209
Total Liabilities	16,053	16,862	17,880	19,780	21,071	21,418
Total Equity	7,647	8,538	9,261	10,137	10,782	10,792

All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months
Source: Moody's Financial Metrics

Exhibit 11

Peer Comparison Table

	Consumers Energy Company (P)A3 Stable			DTE Electric Company (P)A2 Stable			DTE Gas Company A3 Stable			Northern States Power Company (Minnesota) A2 Stable			Wisconsin Power and Light Company Baa1 Stable		
(In $ millions)	FY Dec-22	FY Dec-23	LTM Mar-24	FY Dec-22	FY Dec-23	LTM Mar-24	FY Dec-22	FY Dec-23	LTM Mar-24	FY Dec-22	FY Dec-23	LTM Mar-24	FY Dec-22	FY Dec-23	LTM Mar-24
Revenue	8,151	7,166	7,053	6,397	5,804	5,895	1,894	1,726	1,736	6,684	6,043	5,913	1,856	1,827	1,817
CFO Pre-W/C	2,096	2,190	2,234	2,164	2,565	2,726	575	638	580	2,034	2,259	2,306	317	602	595
Total Debt	10,472	11,454	11,957	11,408	12,523	12,612	2,602	2,642	2,565	7,292	7,692	8,212	3,323	3,700	3,679
CFO Pre-W/C + Interest / Interest	7.1x	5.8x	5.6x	6.5x	6.7x	6.8x	7.2x	7.2x	6.4x	8.2x	7.8x	7.7x	4.5x	7.4x	6.6x
CFO Pre-W/C / Debt	20.0%	19.1%	18.7%	19.0%	20.5%	21.6%	22.1%	24.1%	22.6%	27.9%	29.4%	28.1%	9.5%	16.3%	16.2%
CFO Pre-W/C – Dividends / Debt	12.7%	13.0%	13.0%	12.3%	12.5%	13.6%	15.8%	16.9%	14.9%	20.2%	21.0%	20.2%	4.2%	11.3%	11.1%
Debt / Capitalization	45.1%	45.8%	46.7%	47.4%	48.4%	48.6%	44.5%	42.3%	39.4%	43.4%	43.0%	43.2%	43.8%	44.0%	43.5%

All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End; LTM = Last Twelve Months.
Source: Moody's Financial Metrics

Ratings

Exhibit 12

Category	Moody's Rating
CONSUMERS ENERGY COMPANY	
Outlook	Stable
Sr Sec Bank Credit Facility	A1
First Mortgage Bonds	A1
Senior Secured Shelf	(P)A1
LT IRB/PC	A3
Pref. Stock	Baa1
Commercial Paper	P-2
PARENT: CMS ENERGY CORPORATION	
Outlook	Stable
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Jr Subordinate	Baa3
Pref. Stock	Ba1

Source: Moody's Ratings

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REPORT NUMBER 1409540

CLIENT SERVICES

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Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

MPSC Case No.	**U-21806**
Responding Party:	Attorney General
Respondent:	Sebastian Coppola
Requestor:	CECo
Question No.:	**3-CE-AG-5**

3-CE-AG-5

On page 125 of his direct testimony, Mr. Coppola addresses Company witness Bleckman's Exhibit A-32 (MRB-10) - Peer Company Commission Authorized Equity Ratios. Mr. Coppola claims that "commissions in those jurisdictions also included a permanent layer of short-term debt as part of the permanent capital structure." With regard to this statement, please:

i. Identify all companies included in Mr. Bleckman's Exhibit A-32 (MRB-10) that employ short-term debt as a permanent financing tool along with supporting evidence.

ii. What criteria did Mr. Coppola apply to determine whether or not a given company's short-term debt is "permanent"?

Response:
i and ii.

In the past two years, the companies and related utility subsidiaries that have used short-term debt to meet permanent financing (long-term) needs are NiSource, One Gas, Spire Missouri, and WEC Energy. My criterion in evaluating each individual situation was that if a company had substantial short-term debt for five consecutive quarter ends, then the company was using short-term debt to supplement long-term debt. This is similar to how the accounting profession views long-term liabilities. All of these companies meet this criterion. The quarterly balances below for each of the companies were sourced from SEC filings. It should be recognized that WEC Energy, and NiSource act as the financing arm for their utility subsidiaries and therefore it is these companies' financial statements that are relevant and not the subsidiaries where debt coming in from the parent companies can also be categorized as common equity capital at the utility subsidiary. Similarly, One Gas operates on a divisional basis and therefore its financial statements are the relevant source of debt/equity capitalization for the utility divisions. Spire Missouri's financial statements are filed with its parent company on Form 10-K and 10-Q reports.

Quarter End Short-Term Debt (Millions of Dollars)

	WEC Energy 2023-2024	NiSource 2023-2024	One Gas 2023-2024	Spire Mo. 2023-2024
December	$ 2,021	$ 3,049	$ 89	$ 633
March	2,574	1,222	953	444
June	761	644	1,032	418
September	597	257	951	495
December	1,017	605	915	581

Date: 5/2/2025

MPSC Case No.	**U-21806**
Responding Party:	Attorney General
Respondent:	Sebastian Coppola
Requestor:	CECo
Question No.:	**3-CE-AG-6**

3-CE-AG-6

Refer to page 126 of Mr. Coppola's direct testimony which states that "Smaller utilities tend to have higher equity ratios to sustain them during potential volatility in their business, which larger utilities can better manage." Please provide all analyses, studies, or reports Mr. Coppola relied on in making this statement.

Response:

In establishing that smaller utilities tend to have higher equity ratios, Mr. Coppola relied on his knowledge and experience accumulated over the past nearly 50 years that he has been involved in the utility industry. Appendix A to Mr. Coppola's direct testimony shows his vast background as Chief Financial Officer, Treasurer, and financial manager involved in various aspects of financing and managing large and small utilities.

Mr. Coppola has also relied on research and a publication issued by financial expert, Dr. Roger A. Morin. The attached excerpt from Dr. Morin's book New Regulatory Finance provides supporting evidence on the higher business and financial risks faced by smaller utilities. See 3-CE-AG-6 Attach 1.

Date: 5/2/2025

MPSC Case No.	**U-21806**
Responding Party:	Attorney General
Respondent:	Sebastian Coppola
Requestor:	CECo
Question No.:	**3-CE-AG-7**

3-CE-AG-7

On page 127 of his direct testimony, Mr. Coppola addresses Company witness Bleckman's Exhibit A-32 (MRB-10) – Peer Company Commission Authorized Equity Ratios. Mr. Coppola claims that the Company's analysis is inflated due to the fact that "utilities on the east coast of the United States were not represented in Mr. Bleckman's exhibit, where equity ratios and ROEs tend to be lower and more conservative." Please provide all analyses, studies, or reports Mr. Coppola relied on in making this statement.

Response:

The following information sourced from S&P Global (Regulatory Research Associates Division) shows ROE decisions from regulatory commissions pertaining to several east coast utilities. This information is also included in Exhibit AG-48. The Common Equity ratios reported by Regulatory Research Associates from related rate cases are also shown below.

	Utility	State	ROE Date	ROE	Equity Ratio
a.	Consolidated Edison of NY	NY	Jul 20, 2023	9.25%	48%
b.	Northern Utilities	ME	Sep 20, 2023	9.35%	52%
c.	New York State Elec. & Gas	NY	Oct 12, 2023	9.20%	48%
d.	Rochester Gas & Electric	NY	Oct 12, 2023	9.20%	48%
e.	Central Hudson Gas & Elec.	NY	Jul 18, 2024	9.50%	48%
f.	KeySpan Gas East	NY	Aug 15, 2024	9.35%	48%
g.	Brooklyn Union Gas	NY	Aug 15, 2024	9.35%	48%
h.	Connecticut Nat. Gas	CT	Nov 9, 2024	9.15%	53%
i.	Southern Connecticut Gas	CT	Nov 9, 2024	9.15%	53%
j.	New Jersey Natural Gas	NJ	Nov 16, 2024	9.60%	54%
k.	National Fuel Gas	NY	Dec 4, 2024	9.70%	48%

Date: 5/2/2025

MPSC Case No.	**U-21806**
Responding Party:	Attorney General
Respondent:	Sebastian Coppola
Requestor:	CECo
Question No.:	**3-CE-AG-8**

3-CE-AG-8

Refer to page 103, lines 1 through 4, and page 104, lines 5 through 11, of Mr. Coppola's direct testimony which refers to an analysis that the Company performed to use as a basis for its 1% of revenues measure for projecting the test year cash balance. Please state the specific testimony and/or exhibit along with the relevant case number that contains the Company's analysis Mr. Coppola is referring to.

Response:

Refer to the direct and rebuttal testimony of Company witness Andrew Donato and Exhibit A-93 filed in Case No. U-17990. This information should already be available to the Company.

Date: 5/2/2025

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

REBUTTAL TESTIMONY

OF

LUTHER A. BONNER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Q. Please state your name and business address.

A. My name is Luther A. Bonner, and my business address is 530 West Willow Road, Lansing, Michigan 48906.

Q. In what capacity are you employed?

A. I am employed as Senior Manager of Engineering Support for Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your educational background?

A. I earned an Associates of Business Administration from Baker College in 2003. I also hold an associate certificate in Project Management from George Washington University.

Q. What have your job responsibilities entailed with Consumers Energy?

A. I began working for Consumers Energy in 2003 and have held positions of increasing responsibility over my 21 years with the Company. My roles have included Senior Manager Engineering Support, Manager Engineering Support, Senior Engineering Technical Analyst Lead, Senior Business Support Consultant III, Regional Project Coordination Manager, Customer Energy Specialist Principal Team Lead, Customer Energy Specialist Team Leader III, Senior Customer Energy Specialist, Customer Energy Specialist III, Customer Energy Specialist II, and Customer Energy Specialist I. From 2003 through 2014 prior to my leadership roles, my responsibilities included designing electric and natural gas systems, planning customer requested projects, project management, facilitating easements, permitting, and generating costs estimates. These tasks were undertaken in the service of providing natural gas and electric services to residential customers, new developments, commercial & industrial customers, and municipal electric generating facilities from natural gas. From 2014 through 2019, my

experience was in leading teams that designed, planned, and managed those various types of projects. Since 2019, my responsibilities have included developing processes and procedures used across the work management stream, and developing technology platforms for project management.

Q. Please summarize your experience with Rule C8. Customer Attachment Tariff.

A. Since the beginning of my career with the Company in 2003, I have followed and administered Rule C.8, Customer Attachment Tarriff, which is the regulatory requirement for this process. My experience includes running customer requested scenarios through the model, and reviewing projects modeled by others to ensure compliance. This modeling involved the determination of any revenue deficiency and assessing the amount that a customer requesting service under Rule C8 needed to pay as an upfront contribution in aid of construction based on the model's output.

Q. Please summarize your experience with the use of, administration, and development of the Gas Engineering Model that is used to calculate gas line extensions and service contributions for new connecting customers, which is part of the New Business Mains, Services, and Meters Program and follows the Customer Attachment Tariff, Rule C.8.

A. From 2003 through 2014, part of my responsibilities involved the use of the original Gas Engineering Model to calculate estimates for the natural gas projects I was assigned to as a Customer Energy Specialist for the Company in support of customers who requested service, line extensions, and/or new developments and generation facilities. During 2014 through 2022, my responsibilities included reviewing and approving cost estimates to validate compliance with RuleC.8 Customer Attachment Tariff and identifying ways to improve the technology used. In 2022, I was assigned overall responsibility of the Gas

Engineering Model. During 2022, my team and I developed the most current version of the model using a web-based application.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. No, I have not.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-119 (LAB-1)	Footage Allowance & Excess Service Charge Trends 2003-2025;
Exhibit A-120 (LAB-2)	Excess Service Cost Formula;
Exhibit A-121 (LAB-3)	CE Gas Consumption Jan2020-Jan2025;
Exhibit A-122 (LAB-4)	Customer Gas Service Retirement Trend;
Exhibit A-123 (LAB-5)	MPSC-MNS CAP Conversion Update Sep 2022;
Exhibit A-124 (LAB-6)	Average Vintage Year Gas Retirements;
Exhibit A-125 (LAB-7)	Customer Gas Alteration Trend; and
Exhibit A-126 (LAB-8)	MPSC CAP Pricing Update March 2023.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut certain assertions and recommendations made by Michigan Environmental Council and Sierra Club (collectively "MEC") witness Alice Napoleon regarding Consumers Energy's Line Extension Policy. My testimony specifically rebuts claims that (1) the Company is providing increasing footage allowances that are subsidized by existing customers, (2) the Company's model uses outdated data and assumptions to calculate customers contributions, (3) the Company overstates the period

of time that customers will receive natural gas service in the modeling of customer contributions, and (4) the Company has not fulfilled its requirements resulting from a settlement agreement in a prior gas rate case.

I. MEC WITNESS NAPOLEON

Q. On page 20, lines 5 through 9, of her direct testimony, MEC witness Napolean discussed the Company's line footage allowance and claimed that longer footage allowances result in lower costs for new customers and greater costs spread across ratepayers. Do you agree with this assessment?

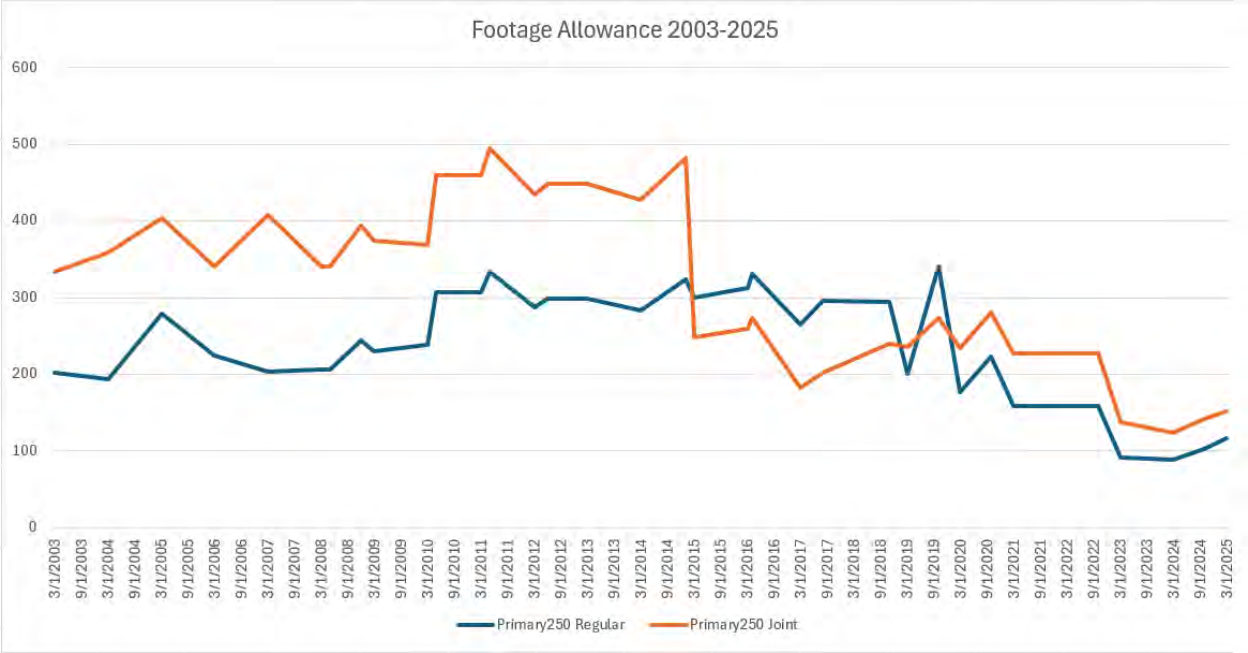
A. No. While I can confirm that the footage allowances of 88 feet (for gas only service) and 124 feet (for joint gas and electric service) that were implemented on March 1, 2024 increased to 117 feet and 152 feet, respectively, on March 1, 2025, the Company has significantly decreased its footage allowances since 2003 thereby increasing upfront costs for connecting services and reducing costs that are being recovered through the new service revenue included in the 20-year modeling period. In 2024, the footage allowance was at its lowest point in the past two decades. This is demonstrated in Exhibit A-119 (LAB-1).

From 2003 through 2024, the footage allowance decreased for various classifications of metering. For example, for the most common services with 250 class gas meters (for gas only service), there has been a footage allowance decrease of 42.08% (202 ft to 117 ft) from 2003 to its current value and a 65.69% (341 ft to 117 ft) decrease from its highest point in October 2019. For the most common services with 250 class meters (with joint gas/electric service), there has been a footage allowance decrease of 54.35% (333 ft to 117 ft) to its current value and a 69.29% (495 ft to 117 ft) decrease from its highest point in May 2011.

Some metering classifications, such as a 3M meter with joint gas/electric service, no longer offer footage allowances based on average revenue. Instead, a customer specific revenue deficiency amount using the net present value ("NPV") calculation is performed to ensure that the Company will recover its costs using the appropriate amount of revenue over the first 20 years.

In addition, the recent slight increases in footage allowances also reflect the Company's ongoing efforts to reduce its actual unit costs, which results in lower plant in service cost amounts input to the model calculations. The plant in service cost is one of the inputs to the model that influences the NPV calculation. The Company uses the model to determine the amount of footage allowance that results in a model calculation of NPV that is greater than $0. Reductions in service installations costs would cause the footage allowance to increase (based on the previous three years of actual costs incurred).

For example, the most current model update estimates that the Company will recover 100% of the annual revenue requirements from the new service attachment of a 117-foot gas only service based on average annual consumption of 94 mcf over 20 years. In this 117-foot service scenario, the NPV is $5.65. In that scenario, there is no calculated revenue deficiency to recover upfront costs from this attaching service.



The Company has continued to make necessary adjustments to the footage allowances since 2003 to ensure that new service revenues will recover the costs of installing new services as required by Rule C.8.

Q. On page 20, line 11, through page 21, line 2, of her direct testimony, Ms. Napoleon asserts that residential customers who exceed the footage allowance are responsible for a flat $200 revenue deficiency charge, an excess footage charge for gas-only connections of $21.26 per foot beyond the footage allowance ($17.28 for joint gas and electric hookups), and a connection fee and direct charges for things such as permitting and inspections. Is this accurate?

A. No. Customers with footage less than the footage allowance will pay a $200 connection fee and any direct charges such as permitting and inspections. Customers that exceed the footage allowance will pay a $200 connection fee, as well as any excess footage charges (or revenue deficiency) and any other direct charges. For example, a customer requesting service that is 55 feet long and requires work in a municipal road right-of-way with a permit

fee of $320 would be responsible for a $200 connection fee and the permit fee of $320, totaling $520. A customer requesting service of 150 feet for gas only, with the same permit costs, would be responsible for a $200 connection fee, an excess service fee of $701.58 (150 feet - 117 feet = 33 feet x $21.26 = $701.58), and a permit fee of $320, totaling $1,221.58.

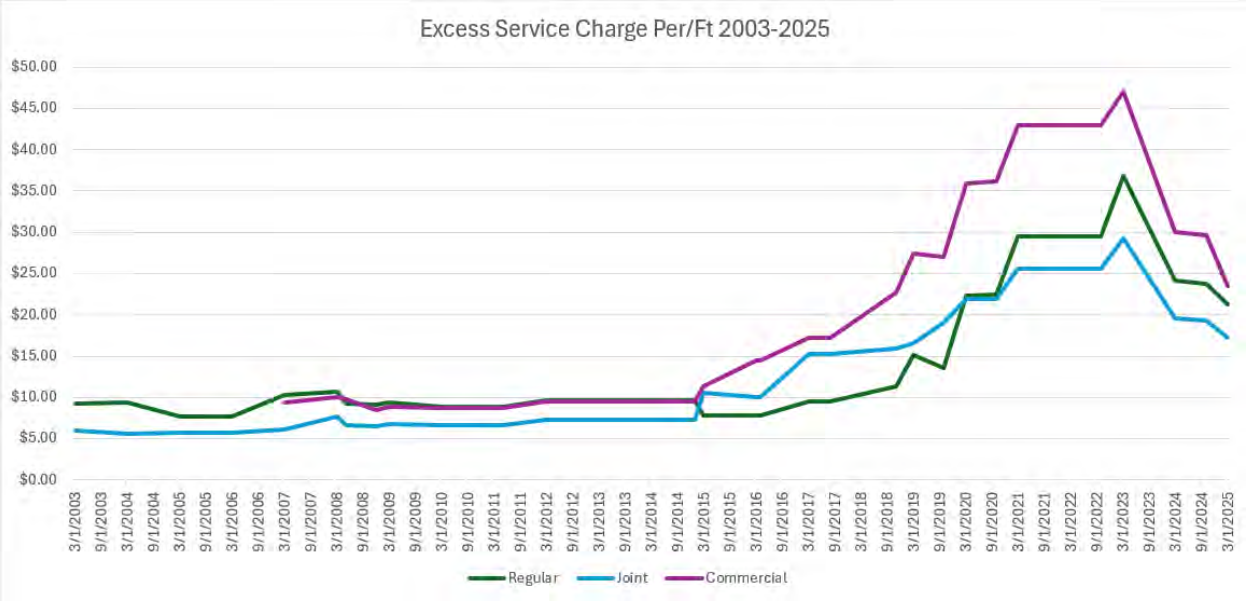
Q. On page 23, line 9, of her direct testimony, Ms. Napoleon indicates that it is not clear how the $200 flat charge for residential customers was determined and what it covers. Can you explain the Company's $200 connection fee?

A. The $200 connection fee is outlined in the Company's tariff and is separate from the revenue deficiency calculation. Every connecting customer is required to pay this direct connection fee per the Rule C.8 Customer Attachment Tariff.

Q. On page 23, lines 10 through 19 of her direct testimony, MEC witness Napoleon claims it is unclear what data Consumers used to produce these calculations, how frequently the Company updates excess footage charges, and why Consumers Energy decided to switch to a fixed model in the first place. Can you clarify the excess service charge calculation, how frequently they are updated, and why the Company uses a fixed model?

A. Yes, the calculation used to determine the excess service charge is (NetPresentValueProjectCost at X Feet - NetPresentValueProjectCost at Y Feet) / (X-Y) as referenced in Exhibit A-120 (LAB-2) to show how the $21.26 per ft charge was determined. The Company updates the excess footage charges at a minimum annually, the exception to this was during Covid where the Company opted not to update costs to support the building industry during those unprecedented times. In 2023, the excess service charge

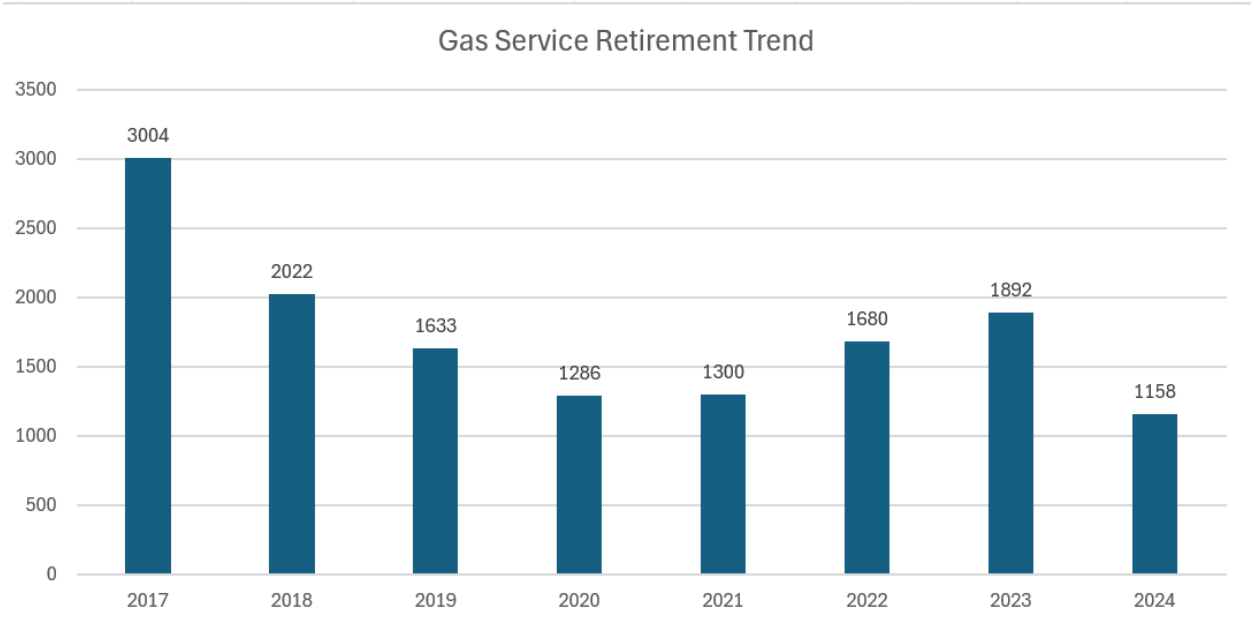
was at its highest point in the past two decades, as referenced in Exhibit A-119 (LAB-1). The Company uses a fixed model of footage allowance and excess footage charge to simplify the NPV calculation for customers, builders, and internal employees calculating invoices. The long-range trends of footage allowances and excess footage charges indicate that the Company is increasing costs for the customers requesting service and reducing the costs that are estimated to be recovered from the expected incremental revenue over 20 years. The chart below demonstrates the trend of excess footage charges from 2003 through 2025 as referenced in Exhibit A-119 (LAB-1).



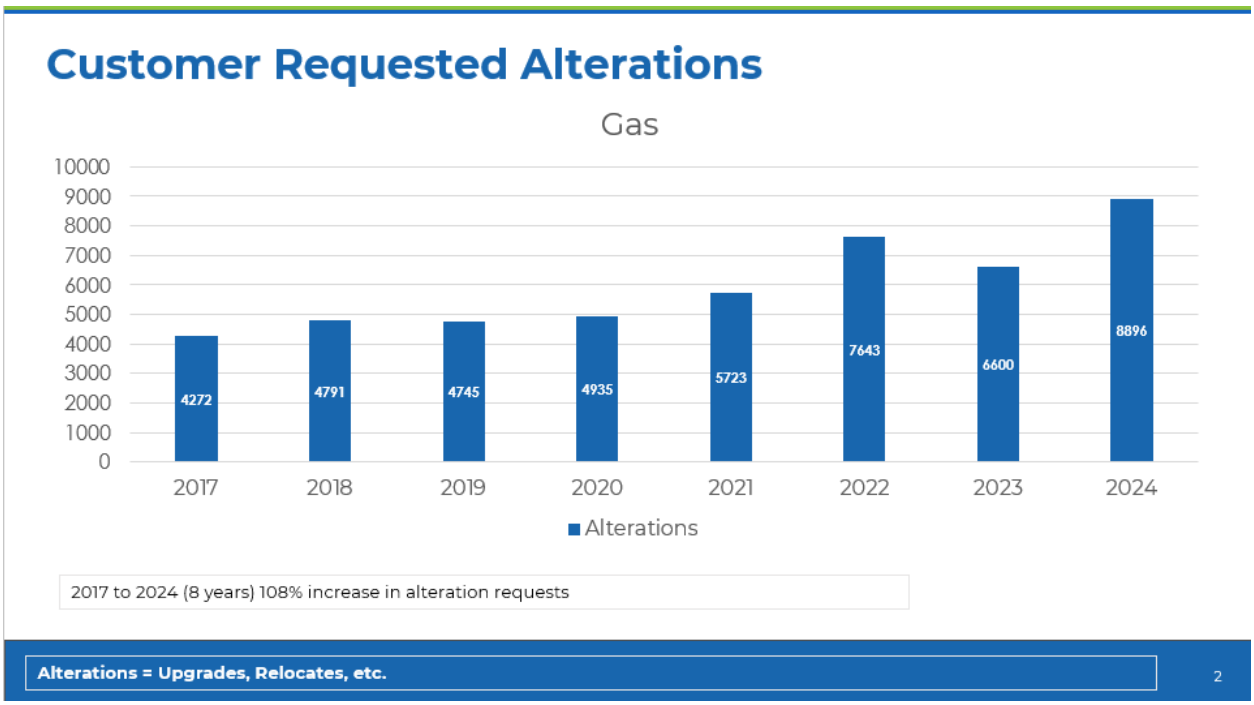
Annually the Company uses the model to determine what the footage allowance should be based on the previous three years of historical service installation cost and customer usage data. The calculated footage allowance is the point where the Company expects to recover all its service installation revenue requirements from the attaching customer over the 20-year period modeled per Rule C.8 Customer Attachment Tariff.

Q. On page 24, lines 1 through 8, of her direct testimony, Ms. Napoleon discusses calculating the revenue deficiency charge for non-residential customers and indicates that the Company takes into account equipment specifications, load diversification, and annual usage patterns to calculate a constant level of new customer sales, and the Company assumes the customer will remain connected to the gas system for 20 years. Could you share how the model accounts for non-residential revenue and the volume of service retirements?

A. The Company designs the natural gas distribution system for a minimum life span of 50 years, the sizing of the services and meters that attach to the distribution system are sized based on the current equipment specifications to be attached to the service, the load is diversified if deemed necessary based on those specifications and the Company accounts for the annual usage patterns provided by the customer for revenue that is accounted for in the NPV calculations. The Company does assume that the service will remain active for a minimum of 20 years in that calculation and the revenue received will remain constant. This assumption is based on the fact that the Company has only received requests from customers to retire on average 1463 services annually over the past five years as referenced in Exhibit A-122 (LAB-4) and the average lifespan of retired services over the past five years has been 43 years based on the vintage year the services were installed when retired as shown in Exhibit A-124 (LAB-6).



The Company also has received 8,896 gas service alteration requests in 2024; these requests are to either relocate the service or upgrade the service due to load increases. This is a 108% increase from the 4,272 alteration requests received in 2017, and the Company has experienced consistent increase in alteration requests year over year as shown in Exhibit A-125 (LAB-7). This is a clear indication that customers continue to utilize natural gas in the state of Michigan and request to utilize more natural gas even though there are alternative options available.



Q. On page 24, lines 10 through 12, of her direct testimony, Ms. Napoleon states that Consumers Energy has not provided the model, despite the terms of the Case No. U-21148 settlement which called for Consumers Energy to transition to a new model that was transparent and capable of being shared with stakeholders by the end of 2022. Did the Company meet the terms of the Case No. U-21148 settlement by transitioning to a new model that is transparent and capable of being shared?

A. Yes. The new model was built and implemented to be used to determine the annual costs on March 1, 2023. During the development of the model the Company met with MNSC and MPSC Staff to review the assumptions, the changes, and the impacts to the customers with the proposed assumption changes, referenced in Exhibits A-123 (LAB-5) and A-126 (LAB-8).

Q. Is the new model more transparent?

A. Yes. The transition to this new model was driven by several key factors:

1. **Age and Outdated Software**: The previous model was over 20 years old, and the software it was built on was outdated. This made it difficult to maintain and enhance the model.

2. **Technological Advancements**: The new .Net application allows for continuous enhancements as technology evolves, ensuring the model remains up-to-date and efficient.

3. **Transparency and Usability**: The new model is more transparent and is built on a software platform commonly used by Project Managers. This improves accessibility and usability.

4. **Updated Assumptions**: During the transition to the current model, key assumptions within the model were reviewed and updated. The new model enables annual updates to these assumptions, ensuring its accuracy and relevance.

The current model is more robust, transparent, user-friendly, and better meets the needs of the Company's team and stakeholders by providing more transparency in the calculations. For example: The most current model shows a view with a summary of the calculations as referenced Exhibit A-120 (LAB-2) The model is also built on a platform so the Company can create necessary reports or data extractions for its team and stakeholders, while no reporting or data extraction methods have been built at this time it now has that capability that the original model did not.

Q. How is the new model capable of being shared with stakeholders?

A. Yes. The model is shareable, but with certain limitations. The Company can bring external parties into its offices to demonstrate how the model works. However, since it is built on the internal network, it cannot provide external access due to security concerns.

The new model is designed to offer a more transparent view of the inputs, outputs, and calculations when shared internally. Consumers Energy has offered to arrange a meeting, invite the stakeholders, and walk them through the model, including its assumptions, calculations, and the inputs and outputs.

Q. On page 26, lines 14 through 16, of her direct testimony, Ms. Napoleon states the Company is likely using outdated assumptions for household gas consumption. Does the Company's customer contribution model use outdated assumptions for household gas consumption?

A. No, the assumptions within the model are updated annually and the average household consumption used is a rolling three-year historical average for all residential households and all residential multi-units (apartments, condos) using full heating seasons (Jul through Jun is an annual total), as shown in Exhibit A-121 (LAB-3).

Q. On page 26, lines 16 through 17, of her direct testimony, Ms. Napoleon states that there is significant risk associated with the Company's decision to subsidize new customer connections. Does the Company agree with this assertion that new connections are subsidized by other customers?

A. No. The primary objective and design of the program is to enable the expansion of cleaner, safer, more reliable, and more affordable gas utilities without requiring existing customers to subsidize these expansions. In this program, the costs of installing the necessary equipment for expansions are charged to new customers. These costs are balanced by the revenue generated by the newly attached customers over a period of 20 years. The risk of subsidization only exists if the new service is retired prematurely or the Company does not receive the forecasted revenue over the course of the next 20 years, as referenced in Exhibit A-121 (LAB-3). The volume of natural gas services is not declining, and the customers who moved in to utilize the attached services is stable (reference gas consumption).

Q. Should the Commission adopt the recommendations of Ms. Napoleon?

A. No, for the reasons stated above in my testimony, the Company believes the line extension policy is reasonable. However, if the Commission is interested in examining the Company's line extension policy, this should be done across all utilities through a work group. Using the same model across all utilities will ensure consistency across the industry.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

EXHIBITS

OF

LUTHER A. BONNER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Footage Allowance Excess Service Charge Trends 2003-2025

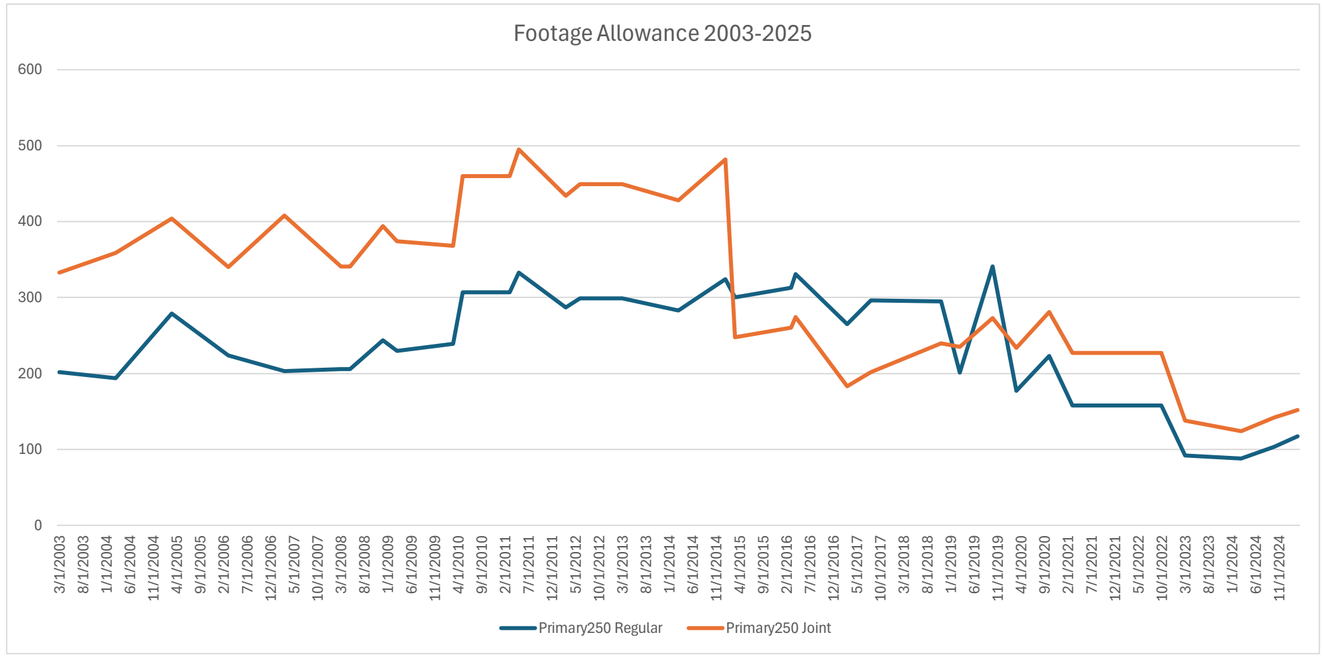
Case No.: U-21806
Exhibit No.: A-119 (LAB-1)
Page: 1 of 2
Witness: LABonner
Date: May 2025

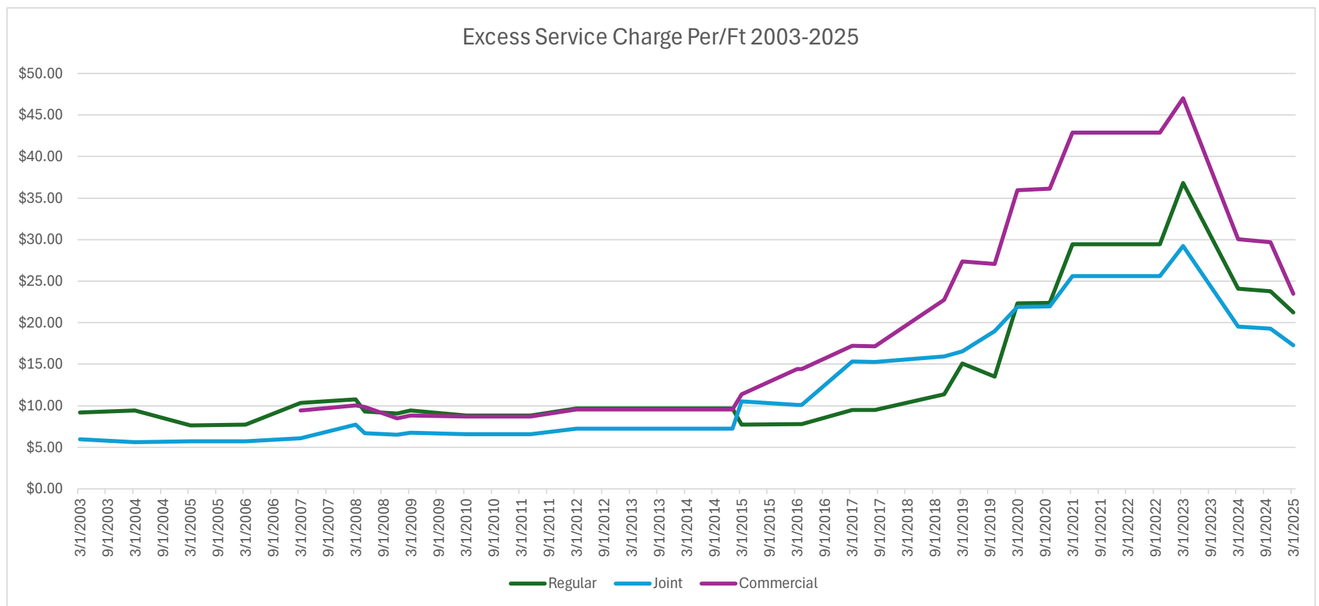
		Service Footage Allowance by Class of Metering									Excess Service Charge per/ft	Additional Directional Bore per/ft
		Primary3M	Primary2M	Primary1.5M	Primary800	Primary 630	Primary425	Primary250	Seasonal	Mobile Home		
March 1st 2025	Regular				117		117	117	117	117	$21.26	$14.91
	Joint				152		152	152	152	152	$17.28	$14.91
	Commercial										$23.46	$14.91
October 1st 2024	Regular				103		103	103	103	103	$23.81	$13.30
	Joint				142		142	142	142	142	$19.31	$13.30
	Commercial										$29.68	$13.30
March 1st 2024	Regular				88		88	88	88	88	$24.10	$13.30
	Joint				124		124	124	124	124	$19.55	$13.30
	Commercial										$30.03	$13.30
March 1st 2023	Regular				92		92	92	92	92	$36.82	$8.80
	Joint				138		138	138	138	138	$29.23	$8.80
	Commercial										$47.01	$8.80
October 1st 2022	Regular				1071		544	158	0	52	$29.47	$8.80
	Joint				1278		672	227	24	105	$25.60	$8.80
	Commercial										$42.90	$8.80
March 1st 2021	Regular				1071		544	158	0	52	$29.47	$8.80
	Joint				1278		672	227	24	105	$25.60	$8.80
	Commercial										$42.90	$8.80
October 1st 2020	Regular				1424		731	223	0	84	$22.41	$8.80
	Joint				1505		799	281	46	140	$21.99	$8.80
	Commercial										$36.12	$8.80
March 1st 2020	Regular				1210		615	177	0	57	$22.31	$8.80
	Joint				1287		681	234	30	111	$21.89	$8.80
	Commercial										$35.96	$8.80
October 1st 2019	Regular				2045		1064	341	11	143	$13.53	$8.80
	Joint				1486		787	273	37	131	$19.00	$8.80
	Commercial										$27.07	$8.80
March 1st 2019	Regular				1337		685	201	0	67	$15.08	$8.80
	Joint				1272		677	235	32	113	$16.52	$8.80
	Commercial										$27.36	$8.80
November 2nd 2018	Regular				1801		937	295	0	117	$11.37	$8.80
	Joint				1313		697	240	29	113	$15.96	$8.80
	Commercial										$22.77	$8.80
August 7th 2017	Regular				1949	1595	1002	296	0	99	$9.47	$8.80
	Joint				1226	1006	639	202	0	80	$15.30	$8.80
	Commercial										$17.18	$8.80
March 1st 2017	Regular				1800	1475	922	265	0	82	$9.49	$8.80
	Joint				1134	932	590	183	0	69	$15.32	$8.80
	Commercial										$17.22	$8.80
April 22nd 2016	Regular				2194	1800	1129	331	0	108	$7.82	$8.80
	Joint				1717	1411	892	274	0	101	$10.09	$8.80
	Commercial										$14.43	$8.80
March 1st 2016	Regular				2110	1733	1084	313	0	98	$7.82	$8.80
	Joint				1652	1359	857	260	0	94	$10.09	$8.80
	Commercial										$14.43	$8.80
March 1st 2015	Regular				2111	1730	1076	300	0	83	$7.76	$8.80
	Joint				1579	1299	819	248	0	89	$10.55	$8.80
	Commercial										$11.37	$8.80
January 21st 2015	Regular	6790	4426	3010	1773	1468	945	324	35	150	$9.70	$8.80
	Joint	9143	5976	4080	2423	2015	1314	482	95	250	$7.24	$8.80
	Commercial										$9.58	$8.80
March 1st 2014	Regular	6280	4085	2771	1625	1345	859	283	15	122	$9.68	$8.80
	Joint	8460	5520	3760	2224	1850	1199	428	68	212	$7.23	$8.80
	Commercial										$9.56	$8.80
March 1st 2013	Regular	6542	4260	2893	1698	1404	899	299	20	132	$9.68	$8.80
	Joint	8811	5754	3924	2323	1929	1253	449	75	225	$7.23	$8.80
	Commercial										$9.56	$8.80
June 8th 2012	Regular	6542	4260	2893	1698	1404	899	299	20	132	$9.68	$8.80
	Joint	8811	5754	3924	2323	1929	1253	449	75	225	$7.23	$8.80
	Commercial										$9.56	$8.80
March 1st 2012	Regular	6327	4117	2794	1639	1356	867	287	17	125	$9.68	$8.80
	Joint	8531	5568	3794	2245	1867	1211	434	71	216	$7.23	$8.80
	Commercial										$9.57	$8.80
May 27th 2011	Regular	7104	4628	3145	1850	1531	984	333	30	152	$8.84	$8.80
	Joint	9572	6253	4265	2528	2102	1367	495	89	252	$6.59	$8.80
	Commercial										$8.73	$8.80
March 1st 2011	Regular	6539	4253	2887	1697	1410	905	307	28	139	$8.84	$8.80
	Joint	8815	5750	3918	2323	1939	1261	460	85	235	$6.59	$8.80
	Commercial										$8.73	$8.80
May 18th 2010	Regular	6539	4253	2887	1697	1410	905	307	28	139	$8.84	$8.80
	Joint	8815	5750	3918	2323	1939	1261	460	85	235	$6.59	$8.80
	Commercial										$8.73	$8.80
March 1st 2010	Regular	5519	3569	2408	1404	1174	743	239	0	95	$8.84	$8.80
	Joint	7448	4833	3276	1931	1622	1044	368	48	176	$6.59	$8.80
	Commercial										$8.73	$8.80
March 1st 2009	Regular	5410	3581	2464	1321	1105	702	230	6	96	$9.44	$8.80
	Joint	7277	4728	3210	1898	1597	1033	374	62	187	$6.76	$8.80
	Commercial										$8.82	$8.80
December 24th 2008	Regular	5624	3725	2565	1378	1153	734	244	12	105	$9.09	$8.80
	Joint	7553	4909	3335	1975	1662	1078	394	71	200	$6.52	$8.80
	Commercial										$8.49	$8.80
May 27th 2008	Regular	5055	3348	2298	1229	1026	648	206	0	81	$9.31	$8.80
	Joint	6797	4414	2995	1768	1485	958	341	50	166	$6.67	$8.80
	Commercial										$9.84	$8.80
March 1st 2008	Regular	5055	3348	2298	1229	1026	648	206	0	81	$10.75	$8.80
	Joint	6797	4414	2995	1768	1485	958	341	50	166	$7.71	$8.80
	Commercial										$10.04	$8.80
March 1st 2007	Regular	5140	3397	2333	1252	1040	656	203	0	76	$10.35	$8.80
	Joint	8408	5463	3706	2183	1825	1173	408	48	192	$6.12	$8.80
	Commercial										$9.43	$8.80
March 1st 2006	Regular				1262	1074	678	224	4	92	$7.74	$8.80
	Joint				1740	1487	952	340	43	162	$5.73	$8.80
	Commercial											$8.80
March 1st 2005	Regular				1408	1079	774	279	37	134	$7.64	$8.80
	Joint				1917	1476	1068	404	81	210	$5.70	$8.80
	Commercial											$8.80
March 1st 2004	Regular				955		532	194	26	93	$9.42	$8.80
	Joint				1636		926	359	78	190	$5.62	$8.80
	Commercial											$8.80
March 1st 2003	Regular				980		547	202	30	98	$9.22	$8.80
	Joint				1528		862	333	70	175	$6.00	$8.80
	Commercial											$8.80

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Footage Allowance Excess Service Charge Trends 2003-2025

Case No.: U-21806
Exhibit No.: A-119 (LAB-1)
Page: 2 of 2
Witness: LABonner
Date: May 2025

Date	Primary250 Regular	Primary250 Joint	Excess Service Charge Regular	Excess Service Charge Joint	Excess Service Charge Commercial
3/1/2025	117	152	$21.26	$17.28	$23.46
10/1/2024	103	142	$23.81	$19.31	$29.68
3/1/2024	88	124	$24.10	$19.55	$30.03
3/1/2023	92	138	$36.82	$29.23	$47.01
10/1/2022	158	227	$29.47	$25.60	$42.90
3/1/2021	158	227	$29.47	$25.60	$42.90
10/1/2020	223	281	$22.41	$21.99	$36.12
3/1/2020	177	234	$22.31	$21.89	$35.96
10/1/2019	341	273	$13.53	$19.00	$27.07
3/1/2019	201	235	$15.08	$16.52	$27.36
11/2/2018	295	240	$11.37	$15.96	$22.77
8/7/2017	296	202	$9.47	$15.30	$17.18
3/1/2017	265	183	$9.49	$15.32	$17.22
4/22/2016	331	274	$7.82	$10.09	$14.43
3/1/2016	313	260	$7.82	$10.09	$14.43
3/1/2015	300	248	$7.76	$10.55	$11.37
1/21/2015	324	482	$9.70	$7.24	$9.58
3/1/2014	283	428	$9.68	$7.23	$9.56
3/1/2013	299	449	$9.68	$7.23	$9.56
6/8/2012	299	449	$9.68	$7.23	$9.56
3/1/2012	287	434	$9.68	$7.23	$9.57
5/27/2011	333	495	$8.84	$6.59	$8.73
3/1/2011	307	460	$8.84	$6.59	$8.73
5/18/2010	307	460	$8.84	$6.59	$8.73
3/1/2010	239	368	$8.84	$6.59	$8.73
3/1/2009	230	374	$9.44	$6.76	$8.82
12/24/2008	244	394	$9.09	$6.52	$8.49
5/27/2008	206	341	$9.31	$6.67	$9.84
3/1/2008	206	341	$10.75	$7.71	$10.04
3/1/2007	203	408	$10.35	$6.12	$9.43
3/1/2006	224	340	$7.74	$5.73	
3/1/2005	279	404	$7.64	$5.70	
3/1/2004	194	359	$9.42	$5.62	
3/1/2003	202	333	$9.22	$6.00	





MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Excess Service Cost Formula

Case No.: U-21806
Exhibit No.: A-120 (LAB-2)
Page: 1 of 3
Witness: LABonner
Date: May 2025

Line No.		(a)	(b)	(c)
1	Project Cost (- $200 connection fee)	26.91	2153.23	$21.26
2	Footage	118	218	

GEM Billables

TEST NEW RATES 2025

Go Back to GEM Project | Billable Summary | Calculate Cost

GEM Costing Setting (Admin Only)

2025 Revenue and Cost

Status

Billed

For service alterations, refer to the GDEM for billing cost.

Total Customer Cost
$226.91

Customer Main Costs:	$0
Customer Service Costs:	$26.91
Connection Fees:	$200.00

Created By	Created On	Approved By	Approved On
tthaney	5/1/2025 12:00:00 AM		

Direct Costs

Billable Type	Description	Cost
Cost	Connection Fees	200.00

Add Direct Cost

EPM Cost

0.00

Revenue Years

20

Main Costs

Add Main Billable

Add Service Similar Billable | View Example Graphics

Service Billables

Service Similar:12079

Delete Service Similar

Normal (Non-Joint)	Joint	Boring	Pre-Prop Line	Pipe Type	Pipe Size	Rate Name	Year Added
118.00	0.00	0.00	0.00	Plastic Yellow	5/8"	Residential	1 Saturation

Similar Count	Normal Cost	Boring Cost	Joint Cost	Excess FT Cost	HP Reg Billed	HP Reg Cost	Additional Cost	Conn. Fee	Total Cost
1	2691.58	0.00	0.00	0.00		0.00	0.00	200.00	4359.50

Meters Billables

Service Similar:12079

Meter Name	Pressure	Similar Count
250 TC	7"WC	1

Customer	Billing Class	Revenue MCF	Rate Name	Meter Cost	Meter Stand	Stand Cost	M&R Cost	Total Cost
Residential	Primary 250	94.00	Residential	225.90		0.00	0.00	225.90

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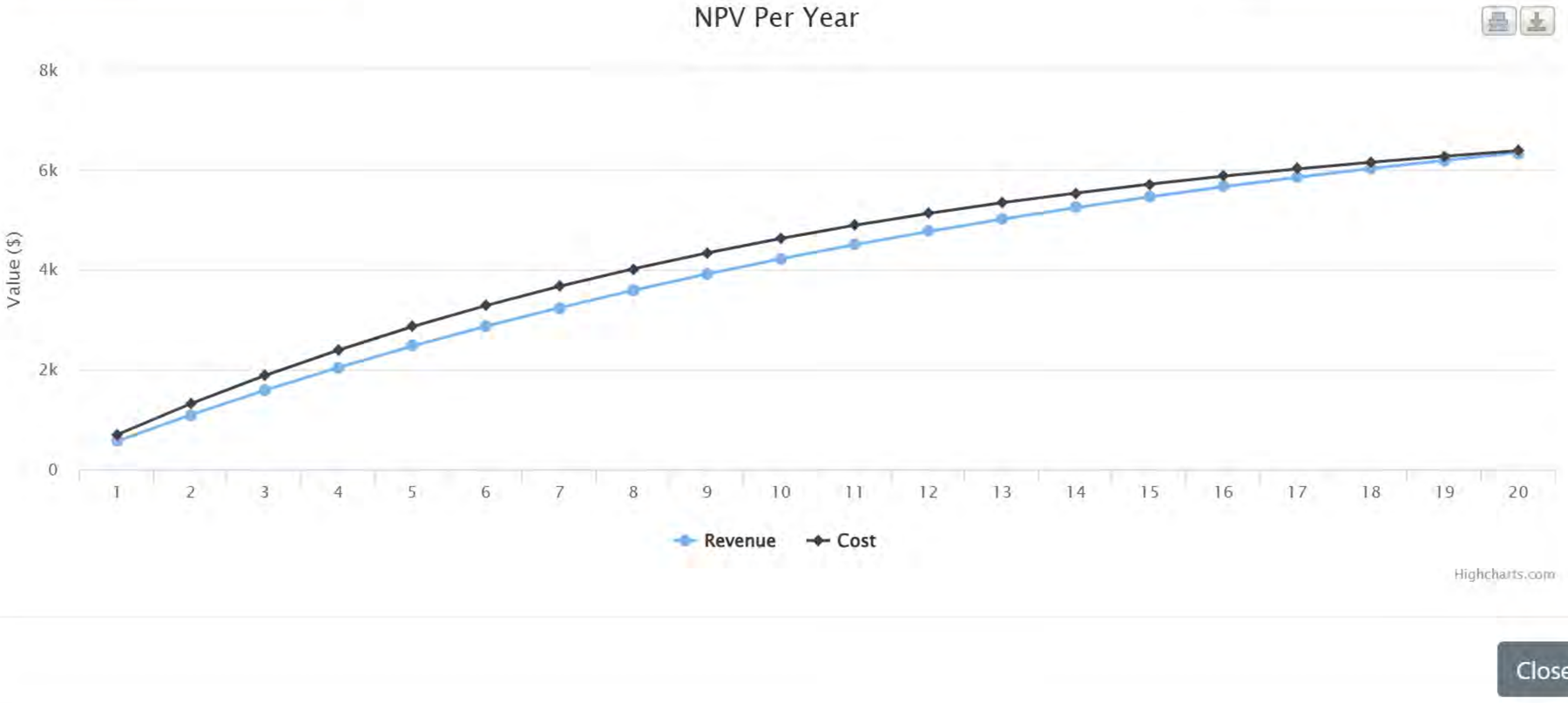
Gem Billables Summary

⚠ For Internal Use Only ⚠

Year 1 Main Cost	Year 1 Service Cost	Year 1 Meter Cost	Year 1 Direct Cost
0.00	4359.50	225.90	200.00
Total Main Cost	**Total Service Cost**	**Total Meter Cost**	**Total Direct Cost**
0.00	4359.50	225.90	200.00
Net Present Value Cost	**Net Present Value Revenue**	**Net Present Value Difference**	**Net Present Value Gross Up**
6381.76	6341.64	40.12	26.91
Total Customer Cost			**Non Recoverable Main Cost**
226.91			0.00



Close

GEM Billables

TEST NEW RATES 2025

Go Back to GEM Project | Billable Summary | Calculate Cost

GEM Costing Setting (Admin Only)

2025 Revenue and Cost

Status

Billed

For service alterations, refer to the GDEM for billing cost.

Total Customer Cost
$2353.23

Customer Main Costs:	$0
Customer Service Costs:	$2153.23
Connection Fees:	$200.00

Created By	Created On	Approved By	Approved On
tthaney	5/1/2025 12:00:00 AM		

Direct Costs

Billable Type	Description	Cost
Cost	Connection Fees	200.00

Add Direct Cost

EPM Cost

0.00

Revenue Years

20

Main Costs

Add Main Billable

Add Service Similar Billable | View Example Graphics

Service Billables

Service Similar:12079

Delete Service Similar

Normal (Non-Joint)	Joint	Boring	Pre-Prop Line	Pipe Type	Pipe Size	Rate Name	Year Added
218.00	0.00	0.00	0.00	Plastic Yellow	5/8"	Residential	1 Saturation

Similar Count	Normal Cost	Boring Cost	Joint Cost	Excess FT Cost	HP Reg Billed	HP Reg Cost	Additional Cost	Conn. Fee	Total Cost
1	4972.58	0.00	0.00	0.00		0.00	0.00	200.00	6640.50

Meters Billables

Service Similar:12079

Meter Name	Pressure	Similar Count
250 TC	7"WC	1

Customer	Billing Class	Revenue MCF	Rate Name	Meter Cost	Meter Stand	Stand Cost	M&R Cost	Total Cost
Residential	Primary 250	94.00	Residential	225.90		0.00	0.00	225.90

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MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21806
Exhibit No.: A-121 (LAB-3)
Page: 1 of 1
Witness: LABonner
Date: May 2025

report_year	report_month	rate_category	is_apartment	gas_consumption	installation_count
2020	1	A_250	Yes	1080877	152216
2020	1	A_250	No	19426122.5	1325721
2020	2	A_250	Yes	1113111.6	152313
2020	2	A_250	No	19696775.8	1327393
2020	3	A_250	No	19977397	1329209
2020	3	A_250	Yes	1116146.4	152592
2020	4	A_250	No	13899875.3	1330361
2020	4	A_250	Yes	749824.9	151045
2020	5	A_250	Yes	574236.2	148920
2020	5	A_250	No	10845771.1	1330890
2020	6	A_250	Yes	248783.7	134226
2020	6	A_250	No	5037826.6	1322128
2020	7	A_250	Yes	128923.9	105480
2020	7	A_250	No	2544849.5	1284194
2020	8	A_250	No	2224229	1274060
2020	8	A_250	Yes	112773.4	100134
2020	9	A_250	Yes	125952.8	107866
2020	9	A_250	No	2553543.3	1289671
2020	10	A_250	No	4284604.5	1325287
2020	10	A_250	Yes	224044	133543
2020	11	A_250	No	9296285.7	1337935
2020	11	A_250	Yes	508493.1	149182
2020	12	A_250	No	15143084.9	1342016
2020	12	A_250	Yes	854707.1	152959
2021	1	A_250	Yes	1160900.5	153918
2021	1	A_250	No	20647416.7	1343212
2021	2	A_250	Yes	1306263	153190
2021	2	A_250	No	22588743.8	1330945
2021	3	A_250	No	20954704.2	1343933
2021	3	A_250	Yes	1200279.6	154739
2021	4	A_250	Yes	635474.9	153064
2021	4	A_250	No	11702601.6	1349778
2021	5	A_250	No	8731410.1	1348918
2021	5	A_250	Yes	466287.5	150194
2021	6	A_250	No	4564973	1342984
2021	6	A_250	Yes	227719.7	138718
2021	7	A_250	No	2575670.2	1307306
2021	7	A_250	Yes	129571.6	110962
2021	8	A_250	Yes	112260	101727
2021	8	A_250	No	2287453.2	1288434
2021	9	A_250	No	2276470.9	1288364
2021	9	A_250	Yes	112152.9	101339
2021	10	A_250	No	2772695.8	1320072
2021	10	A_250	Yes	145629.7	120188
2021	11	A_250	Yes	430435.8	146550
2021	11	A_250	No	7656923.5	1345944
2021	12	A_250	No	16058111.6	1352830
2021	12	A_250	Yes	900098.2	152411
2022	1	A_250	No	20391006.3	1353665
2022	1	A_250	Yes	1159341.8	153083
2022	2	A_250	No	25335849.7	1355068
2022	2	A_250	Yes	1452309.8	153453
2022	3	A_250	Yes	1250098.9	153274
2022	3	A_250	No	22328350.9	1357178
2022	4	A_250	Yes	880331.4	152654
2022	4	A_250	No	16071716.9	1359907
2022	5	A_250	Yes	555352.1	150086
2022	5	A_250	No	10619781.5	1360592
2022	6	A_250	Yes	193724.2	127923
2022	6	A_250	No	3997753.5	1344080
2022	7	A_250	Yes	120083.3	103290
2022	7	A_250	No	2462662.6	1305289
2022	8	A_250	Yes	114053.6	98893
2022	8	A_250	No	2403669.1	1296292
2022	9	A_250	No	2115424.4	1181335
2022	9	A_250	Yes	102804.1	93141
2022	10	A_250	Yes	206337.3	128682
2022	10	A_250	No	3903282.1	1338221
2022	11	A_250	Yes	458399.6	146987
2022	11	A_250	No	8467112.3	1358175
2022	12	A_250	Yes	901605.2	151796
2022	12	A_250	No	15970408.2	1363526
2023	1	A_250	No	20887538.7	1365416
2023	1	A_250	Yes	1179918.3	153071
2023	2	A_250	No	20359198.2	1366638
2023	2	A_250	Yes	1144801.9	153150
2023	3	A_250	Yes	1081293.7	153061
2023	3	A_250	No	19614766.7	1367786
2023	4	A_250	Yes	780002.5	151761
2023	4	A_250	No	14578543.6	1365154
2023	5	A_250	Yes	483455.1	149025
2023	5	A_250	No	9434394.8	1367236
2023	6	A_250	Yes	192893.2	125912
2023	6	A_250	No	3906792.8	1292796
2023	7	A_250	Yes	123229.6	106208
2023	7	A_250	No	2621319.9	1318248
2023	8	A_250	Yes	107738.5	99414
2023	8	A_250	No	2297530	1302736
2023	9	A_250	No	2475618.4	1311107
2023	9	A_250	Yes	116760	103938
2023	10	A_250	Yes	184262.3	1339868
2023	10	A_250	No	3492235.4	125907
2023	11	A_250	Yes	449254.1	146863
2023	11	A_250	No	8333796.2	1364012
2023	12	A_250	Yes	834293.2	151302
2023	12	A_250	No	15079471.7	1368077
2024	1	A_250	No	17800067.15	1382994
2024	1	A_250	Yes	981678.37	157070
2024	2	A_250	No	21533608.18	1384764
2024	2	A_250	Yes	1201469.3	157226
2024	3	A_250	Yes	856356	157143
2024	3	A_250	No	15785937.81	1386304
2024	4	A_250	Yes	771465.55	157303
2024	4	A_250	No	14160500.17	1387075
2024	5	A_250	Yes	368662.45	157087
2024	5	A_250	No	7207548.02	1386823
2024	6	A_250	Yes	160459.85	156940
2024	6	A_250	No	3316558.77	1386314
2024	7	A_250	Yes	117724.85	156794
2024	7	A_250	No	2487221.75	1385822
2024	8	A_250	Yes	104878.27	156647
2024	8	A_250	No	2211320.04	1385277
2024	9	A_250	No	2351851.14	1385011
2024	9	A_250	Yes	111508.98	156620
2024	10	A_250	Yes	135301.2	157091
2024	10	A_250	No	2653522.59	1385633
2024	11	A_250	Yes	316923.58	157299
2024	11	A_250	No	5960552.91	1385837
2024	12	A_250	Yes	774204.39	158061
2024	12	A_250	No	13600633.25	1388370

Average Installation Count

	2020	2021	2022	2023	2024	3 Year
No	1,318,239	1,330,227	1,331,111	1,242,926	1,385,852	1,319,963
Yes	136,706	136,417	134,439	236,131	157,107	175,892

Average Consumption by Year

	APT	Consumption	Premise Count	Ave Consumption
2020	NO	124,930,365.20	1,318,239	95
2020	YES	6,837,874.10	136,706	50
2021	NO	122,817,174.60	1,330,227	92
2021	YES	6,827,073.40	136,417	50
2022	NO	134,067,017.50	1,331,111	101
2022	YES	7,394,441.30	134,439	55
2023	NO	123,081,206.40	1,242,926	99
2023	YES	6,677,902.40	236,131	28
2024	NO	109,069,321.78	1,385,852	79
2024	YES	5,900,632.79	157,107	38
3 Year	NO	122,072,515.23	1,319,963	92
3 Year	YES	6,657,658.83	175,892	38

Average Consumption by Heating Season (Oct-May)

	APT	Consumption	Premise Count	Ave Consumption
2020/21	NO	113,348,851.50	1,324,233	86
2020/21	YES	6,356,449.70	136,562	47
2021/22	NO	121,234,436.20	1,330,669	91
2021/22	YES	6,773,597.70	135,428	50
2022/23	NO	113,215,244.60	1,287,018	88
2022/23	YES	6,235,813.60	185,285	34
2023/24	NO	103,393,164.63	1,314,389	79
2023/24	YES	5,647,441.27	196,619	29

Average Consumption Non-Heating Season (Jun-Sep)

	APT	Consumption	Premise Count	Ave Consumption
2021	NO	11,704,567.30	1,330,227	9
2021	YES	581,704.20	136,417	4
2022	NO	10,979,509.60	1,331,111	8
2022	YES	530,665.20	134,439	4
2023	NO	11,301,261.10	1,242,926	9
2023	YES	540,621.30	236,131	2
2024	NO	10,366,951.70	1,385,852	7
2024	YES	494,571.95	157,107	3

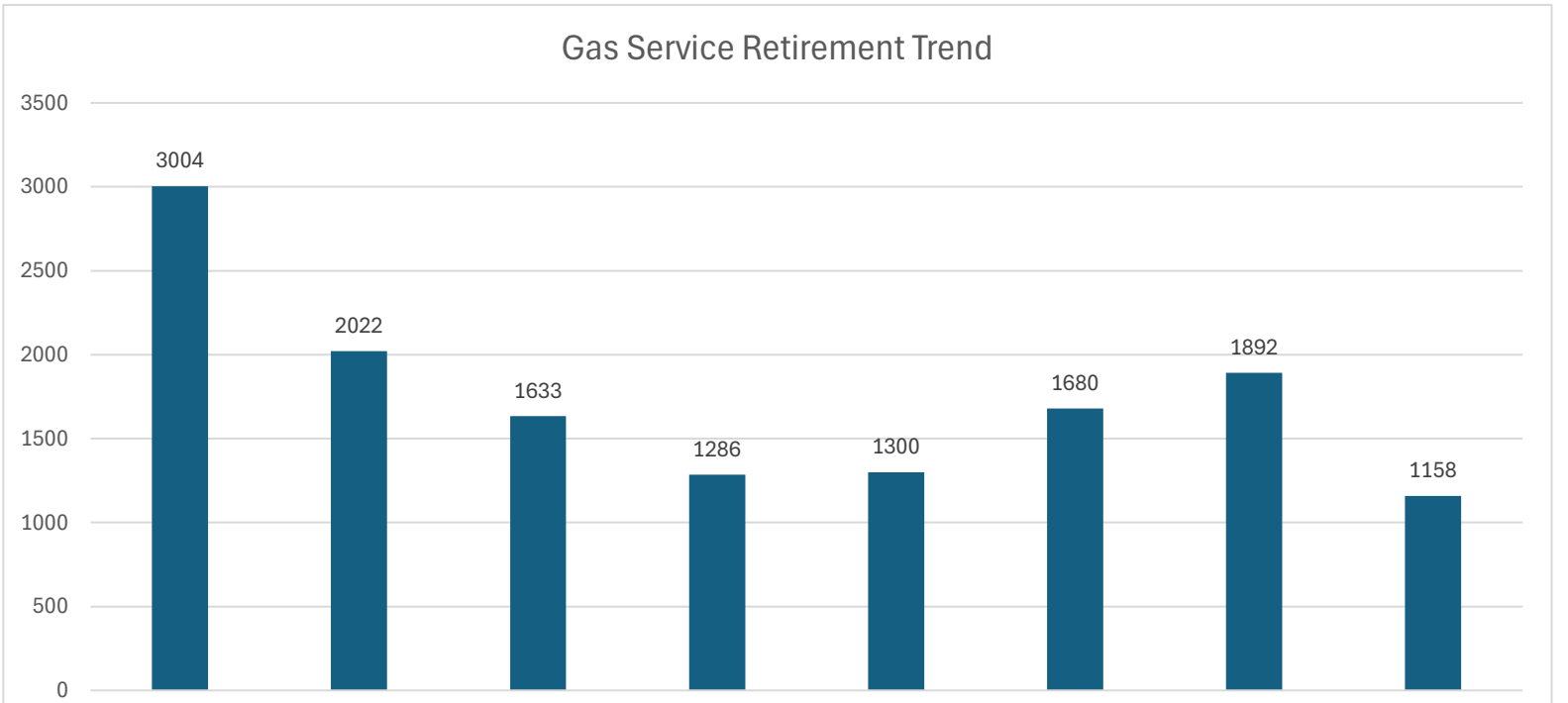
Average Consumption Previous Full Seasons (Jul-Jun)

	APT	Consumption	Premise Count	Ave Consumption
2020/21	NO	125,236,446.30	1,324,233	95
2020/21	YES	6,951,819.50	136,562	51
2021/22	NO	132,371,784.00	1,330,669	99
2021/22	YES	7,321,306.40	135,428	54
2022/23	NO	124,103,793.50	1,287,018	96
2022/23	YES	6,765,647.80	185,285	37
2023/24	NO	114,104,191.70	1,314,389	87
2023/24	YES	6,155,629.22	196,619	31
3 Year	NO	123,526,589.73	1,319,963	94
3 Year	YES	6,747,527.81	175,892	38

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21806
Exhibit No.: A-122 (LAB-4)
Page: 1 of 1
Witness: LABonner
Date: May 2025

Line No.		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
2	Gas Service Retirements	3004	2022	1633	1286	1300	1680	1892	1158



Customer Attachment Program
Line Extension Assumptions

Review with MNS & MPSC Staff
September 7, 2022

Consumers Energy
Count on Us®

Agenda

- *Introductions*
- *Meeting Purpose*
- *Review 2021-2022 CAP changes*
- *Discuss Assumptions and Updates*
- *Q&A*

Introductions

- *Dean Beach – Executive Director, Customer Energy Management*
- *Luther Bonner – CEM Process, Performance, & Technology Lead*
- *Chad Ammerman – CEM Process, Performance, & Technology*
- *Tyler Haney – CEM Data & Analytics*
- *Mike Rampe – Legal*
- *Doug Chapel – Regulatory Affairs*

Meeting Purpose

- ***July 2022 Gas Rate Case Settlement:***

  "Consumers Energy agrees to meet with MNS and Staff to review and update the line extension assumptions within 90 days of the Commission issuing and order in this case. Consumers Energy additionally agrees to transition to a new line extension model that is transparent and capable of being shared with stakeholders for review to be completed by the end of 2022."

- ***Assumptions raised in Gas Rate Case:***
  - *Free footage*
  - *Gas throughput/consumption*

- ***Today, we will discuss data underlying these assumptions and our status on analyzing this data***

2021 Rates – No Change for 2022

Residential	Service	2" Main	4" Main	6" Main
Gas Only	$ 29.47	$ 17.13	$ 54.01	$ 61.58
Joint	$ 25.60	$ 22.49	$ 68.13	$ 44.66
Directional Bore	Addl $8.80/ft	$ 53.15	$ 104.21	$ 182.17
Non-Residential				
Gas Only	$ 42.90	$ 17.13	$ 54.01	$ 61.58
Joint	$ 25.60	$ 22.49	$ 68.13	$ 44.66
Directional Bore	Addl $8.80/ft	$ 53.15	$ 104.21	$ 182.17

Residential	Allowable Footage	
Category	Gas Only	Joint
Primary 250	158	227
Primary 425	544	672
Primary 800	1071	1278
Seasonal	0	24
Mobile Home	52	105

Re-cap - Why No Change for 2022?

- ***COVID Impacts in 2020/2021***
  - *Out of normal construction practices from previous years*
    - *Review of the new normal, how this impacts costs*
  - *In Support of Providing an exceptional customer experience*
    - *Hold off on rate increase during unprecedented times*
- ***2022 will be a transition year for the model***
  - *Existing model is approx. 20 years old*
    - *Outdated software*
    - *Manual data pulls, scrubbing and calculations*
    - *3 different software tools used to provide analysis*
  - *New Model being built in 2022*
    - *Using Current software technology thru a .NET application*
      - *Ability to be enhanced as technology evolves*
    - *Updating assumptions based on data analysis and current construction practices*
    - *Synced to Company Data Tables*
      - *Consistent data structure through query of data tables*
      - *Calculations built into software to provide analysis for leadership*
      - *Simple structure for updating costs through analysis*
    - *1 tool, 1 set of data, 1 analysis with options/recommendations based on data for rate adjustments*

Current CAP Assumptions

- ***Tariff C8 Customer Attachment Program***
  - *Model Assumptions to review*
    - *Incremental Revenue*
      - *Residential - Fixed table from study completed over 20 years ago*
    - *Incremental Costs*
      - *Plant in Service*
        - » *Determined by 3-year average costs (Service/Main) Size and installation method*

Status of Incremental Revenue Assumptions

- ***Data Analysis***
  - *Building Report View of all customer consumptions from Aug 2021 – July 2022*
    - *Completed*
      - *Consumption Data identified and included (monthly/Sum to annual)*
      - *Customer Location Data identified and included (city/county)*
      - *Number of installations per premise included (quantity to determine if single family home or multi unit)*
      - *Customer Rate Code data*
    - *In Progress*
      - *Customer Meter Size and Meter Location*
      - *Date of installation or date of contract account/decision on Removal of no usage from average*
  - *Report Query will be set up to pull based on a range in time to reduce size of data set*
  - *Report will be run annually to determine if incremental revenues applied should be adjusted*
  - *Views will be built to view data in different slices*
    - *(previous 12 months/3 year average) In Progress*
      - *Average consumption during heating season for each rate/meter size*
      - *Average consumption yearly for each rate/meter size*

- ***Data analysis will help us better understand assumptions and any potential updates that are needed***

Status of Incremental Cost Assumptions

- ***Pulling data to review Cost Variability***
  - *Joint and non joint*
  - *Installation Method (trench, boring, plowing etc.)*
  - *Timing of installation (spring, summer, winter)*
  - *Contractors (contracts change) and internal crews*
  - *Variability in Volume of pipe installed year over year*
  - *Restoration costs in right of way*
  - *Location of installation and difficulty installing*
- *Cost variables will help determine the time period for an average cost*

- ***Data analysis will help us better understand assumptions and any potential updates that are needed***

Questions?

Table provides the average year services were installed that have been retired 2020 through 2024.

Line No.		(b)	(c)	(d)	(e)		
1	**Column Labels**						
Year Retired	**2020**	**2021**	**2022**	**2023**	**2024**	**Grand Total**
Average Year Installed	**Average of vintage_year**	**1980**	**1981**	**1983**	**1984**	**1982**	**1982**

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41984928	GRET	SVC	7/11/2024	1946	RET ABN	UG-SERVICE
36424940	GRET	SVC	6/9/2020	1946	RET ABN	UG-SERVICE
42706660	GRET	SVC	6/28/2024	1946	RET ABN	UG-SERVICE
40545195	GRET	SVC	8/9/2023	1946	RET ABN	UG-SERVICE
43526517	GRET	SVC	10/1/2024	1946	RET ABN	UG-SERVICE
42957323	GRET	SVC	9/19/2024	1946	RET ABN	UG-SERVICE
36204404	GRET	SVC	4/25/2020	1946	RET ABN	UG-SERVICE
36260073	GRET	SVC	3/19/2020	1947	RET ABN	UG-SERVICE
38879760	GRET	SVC	8/5/2021	1947	RET ABN	UG-SERVICE
43675355	GRET	SVC	10/3/2024	1947	RET ABN	UG-SERVICE
36559270	GRET	SVC	6/5/2020	1947	RET ABN	UG-SERVICE
42916576	GRET	SVC	9/25/2024	1947	RET ABN	UG-SERVICE
42916546	GRET	SVC	9/25/2024	1947	RET ABN	UG-SERVICE
38604503	GRET	SVC	7/7/2021	1947	RET ABN	UG-SERVICE
38346172	GRET	SVC	5/11/2021	1947	RET ABN	UG-SERVICE
38451808	GRET	SVC	5/7/2021	1947	RET ABN	UG-SERVICE
39417319	GRET	SVC	11/15/2021	1947	RET ABN	UG-SERVICE
37810140	GRET	SVC	11/24/2020	1947	RET ABN	UG-SERVICE
42524677	GRET	SVC	12/28/2023	1947	RET ABN	UG-SERVICE
41006553	GRET	SVC	12/9/2022	1947	RET ABN	UG-SERVICE
36748684	GRET	SVC	8/10/2020	1947	RET ABN	UG-SERVICE
41082588	GRET	SVC	2/2/2023	1947	RET ABN	UG-SERVICE
38550268	GRET	SVC	6/30/2021	1947	RET ABN	UG-SERVICE
40637090	GRET	SVC	8/31/2022	1947	RET ABN	UG-SERVICE
36699368	GRET	SVC	7/27/2020	1947	RET ABN	UG-SERVICE
42524180	GRET	SVC	12/29/2023	1947	RET ABN	UG-SERVICE
38365407	GRET	SVC	4/12/2021	1947	RET ABN	UG-SERVICE
38635342	GRET	SVC	6/21/2021	1947	RET ABN	UG-SERVICE
42815797	GRET	SVC	3/13/2024	1947	RET ABN	UG-SERVICE
43459021	GRET	SVC	8/20/2024	1947	RET ABN	UG-SERVICE
42957426	GRET	SVC	9/19/2024	1948	RET ABN	UG-SERVICE
41669690	GRET	SVC	5/24/2023	1948	RET ABN	UG-SERVICE
38175695	GRET	SVC	3/1/2021	1948	RET ABN	UG-SERVICE
39362214	GRET	SVC	11/1/2021	1948	RET ABN	UG-SERVICE
36028589	GRET	SVC	3/5/2020	1948	RET ABN	UG-SERVICE
38185300	GRET	SVC	2/27/2021	1948	RET ABN	UG-SERVICE
36109958	GRET	SVC	4/22/2020	1948	RET ABN	UG-SERVICE
39791769	GRET	SVC	10/7/2021	1948	RET ABN	UG-SERVICE
40564659	GRET	SVC	1/9/2023	1948	RET ABN	UG-SERVICE
42518406	GRET	SVC	12/28/2023	1948	RET ABN	UG-SERVICE
41241359	GRET	SVC	3/1/2023	1948	RET ABN	UG-SERVICE
38593716	GRET	SVC	6/23/2021	1948	RET ABN	UG-SERVICE
42481127	GRET	SVC	12/20/2023	1948	RET ABN	UG-SERVICE
36947693	GRET	SVC	9/18/2020	1948	RET ABN	UG-SERVICE
42213835	GRET	SVC	10/26/2023	1948	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36558231	GRET	SVC	7/1/2020	1948	RET ABN	UG-SERVICE
42587237	GRET	SVC	9/25/2024	1948	RET ABN	UG-SERVICE
41082944	GRET	SVC	2/2/2023	1948	RET ABN	UG-SERVICE
43715957	GRET	SVC	10/4/2024	1948	RET ABN	UG-SERVICE
32769563	GRET	SVC	7/8/2020	1948	RET ABN	UG-SERVICE
41427677	GRET	SVC	4/14/2023	1948	RET ABN	UG-SERVICE
36120608	GRET	SVC	11/5/2020	1948	RET ABN	UG-SERVICE
38089277	GRET	SVC	2/3/2021	1948	RET ABN	UG-SERVICE
39066726	GRET	SVC	9/27/2021	1948	RET ABN	UG-SERVICE
39423756	GRET	SVC	6/27/2022	1948	RET ABN	UG-SERVICE
37979767	GRET	SVC	1/5/2021	1948	RET ABN	UG-SERVICE
36100989	GRET	SVC	3/10/2020	1948	RET ABN	UG-SERVICE
36040593	GRET	SVC	2/18/2020	1948	RET ABN	UG-SERVICE
38851928	GRET	SVC	11/8/2021	1948	RET ABN	UG-SERVICE
36240447	GRET	SVC	4/29/2020	1948	RET ABN	UG-SERVICE
43184801	GRET	SVC	6/17/2024	1949	RET ABN	UG-SERVICE
40508724	GRET	SVC	9/23/2022	1949	RET ABN	UG-SERVICE
40837783	GRET	SVC	10/17/2022	1949	RET ABN	UG-SERVICE
38097111	GRET	SVC	9/2/2021	1949	RET ABN	UG-SERVICE
42264554	GRET	SVC	10/23/2023	1949	RET ABN	UG-SERVICE
42506606	GRET	SVC	3/28/2024	1949	RET ABN	UG-SERVICE
37593735	GRET	SVC	11/23/2020	1949	RET ABN	UG-SERVICE
38581221	GRET	SVC	8/24/2021	1949	RET ABN	UG-SERVICE
38664596	GRET	SVC	6/24/2021	1949	RET ABN	UG-SERVICE
41194275	GRET	SVC	1/23/2023	1949	RET ABN	UG-SERVICE
36102515	GRET	SVC	4/23/2020	1949	RET ABN	UG-SERVICE
43360848	GRET	SVC	7/29/2024	1949	RET ABN	UG-SERVICE
42337562	GRET	SVC	11/6/2023	1949	RET ABN	UG-SERVICE
40782283	GRET	SVC	11/7/2022	1949	RET ABN	UG-SERVICE
41209796	GRET	SVC	12/11/2023	1949	RET ABN	UG-SERVICE
35962536	GRET	SVC	1/29/2020	1949	RET ABN	UG-SERVICE
36107368	GRET	SVC	4/23/2020	1949	RET ABN	UG-SERVICE
38484519	GRET	SVC	5/12/2021	1949	RET ABN	UG-SERVICE
37031968	GRET	SVC	10/7/2020	1949	RET ABN	UG-SERVICE
38202573	GRET	SVC	3/9/2021	1949	RET ABN	UG-SERVICE
42360719	GRET	SVC	11/15/2023	1949	RET ABN	UG-SERVICE
38451952	GRET	SVC	3/24/2021	1949	RET ABN	UG-SERVICE
40395242	GRET	SVC	7/7/2022	1949	RET ABN	UG-SERVICE
40216874	GRET	SVC	6/7/2022	1949	RET ABN	UG-SERVICE
38165419	GRET	SVC	11/9/2021	1949	RET ABN	UG-SERVICE
32769560	GRET	SVC	7/8/2020	1949	RET ABN	UG-SERVICE
39372955	GRET	SVC	1/25/2022	1949	RET ABN	UG-SERVICE
42587235	GRET	SVC	9/25/2024	1949	RET ABN	UG-SERVICE
37917098	GRET	SVC	12/14/2020	1949	RET ABN	UG-SERVICE
40909882	GRET	SVC	12/20/2022	1949	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40012507	GRET	SVC	4/20/2022	1949	RET ABN	UG-SERVICE
40385383	GRET	SVC	7/17/2022	1949	RET ABN	UG-SERVICE
40973247	GRET	SVC	11/29/2022	1949	RET ABN	UG-SERVICE
42427396	GRET	SVC	9/19/2024	1949	RET ABN	UG-SERVICE
43742651	GRET	SVC	10/10/2024	1949	RET ABN	UG-SERVICE
37084953	GRET	SVC	10/15/2020	1949	RET ABN	UG-SERVICE
42427480	GRET	SVC	9/19/2024	1949	RET ABN	UG-SERVICE
41179277	GRET	SVC	1/19/2023	1950	RET ABN	UG-SERVICE
41873888	GRET	SVC	7/20/2023	1950	RET ABN	UG-SERVICE
37489769	GRET	SVC	11/16/2020	1950	RET ABN	UG-SERVICE
40748066	GRET	SVC	10/15/2022	1950	RET ABN	UG-SERVICE
43245051	GRET	SVC	9/11/2024	1950	RET ABN	UG-SERVICE
38121485	GRET	SVC	2/11/2021	1950	RET ABN	UG-SERVICE
38895091	GRET	SVC	8/17/2021	1950	RET ABN	UG-SERVICE
41968295	GRET	SVC	8/1/2024	1950	RET ABN	UG-SERVICE
38192568	GRET	SVC	3/30/2021	1950	RET ABN	UG-SERVICE
38033940	GRET	SVC	1/20/2021	1950	RET ABN	UG-SERVICE
43338156	GRET	SVC	7/23/2024	1950	RET ABN	UG-SERVICE
40556652	GRET	SVC	8/10/2022	1950	RET ABN	UG-SERVICE
41920885	GRET	SVC	7/31/2023	1950	RET ABN	UG-SERVICE
40644175	GRET	SVC	9/17/2022	1950	RET ABN	UG-SERVICE
40748546	GRET	SVC	9/28/2022	1950	RET ABN	UG-SERVICE
40150854	GRET	SVC	5/18/2022	1950	RET ABN	UG-SERVICE
41411952	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
40749933	GRET	SVC	9/28/2022	1950	RET ABN	UG-SERVICE
39380209	GRET	SVC	11/22/2021	1950	RET ABN	UG-SERVICE
38122135	GRET	SVC	2/11/2021	1950	RET ABN	UG-SERVICE
38814663	GRET	SVC	7/23/2021	1950	RET ABN	UG-SERVICE
43752068	GRET	SVC	12/27/2024	1950	RET ABN	UG-SERVICE
41082593	GRET	SVC	1/4/2023	1950	RET ABN	UG-SERVICE
41015741	GRET	SVC	12/8/2022	1950	RET REM	UG-SERVICE
42550981	GRET	SVC	1/8/2024	1950	RET ABN	UG-SERVICE
42497616	GRET	SVC	12/18/2023	1950	RET ABN	UG-SERVICE
37708593	GRET	SVC	11/25/2020	1950	RET ABN	UG-SERVICE
38146659	GRET	SVC	3/9/2021	1950	RET ABN	UG-SERVICE
41222690	GRET	SVC	2/2/2023	1950	RET REM	UG-SERVICE
43117176	GRET	SVC	6/6/2024	1950	RET ABN	UG-SERVICE
41082587	GRET	SVC	1/9/2023	1950	RET ABN	UG-SERVICE
41036612	GRET	SVC	12/14/2022	1950	RET REM	UG-SERVICE
36371101	GRET	SVC	5/26/2020	1950	RET ABN	UG-SERVICE
41407491	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
37044751	GRET	SVC	10/9/2020	1950	RET ABN	UG-SERVICE
43208932	GRET	SVC	6/24/2024	1950	RET ABN	UG-SERVICE
42604690	GRET	SVC	1/25/2024	1950	RET ABN	UG-SERVICE
43543397	GRET	SVC	10/4/2024	1950	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36799890	GRET	SVC	8/20/2020	1950	RET ABN	UG-SERVICE
42435905	GRET	SVC	9/19/2024	1950	RET ABN	UG-SERVICE
41407382	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
41407777	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
43324300	GRET	SVC	7/26/2024	1950	RET ABN	UG-SERVICE
41064588	GRET	SVC	12/15/2022	1950	RET ABN	UG-SERVICE
36120792	GRET	SVC	11/5/2020	1950	RET ABN	UG-SERVICE
38426623	GRET	SVC	4/26/2021	1950	RET ABN	UG-SERVICE
35871722	GRET	SVC	1/7/2020	1950	RET ABN	UG-SERVICE
41430212	GRET	SVC	9/13/2023	1950	RET ABN	UG-SERVICE
41714290	GRET	SVC	6/5/2023	1950	RET ABN	UG-SERVICE
36030678	GRET	SVC	11/5/2020	1950	RET ABN	UG-SERVICE
39831460	GRET	SVC	8/3/2022	1950	RET ABN	UG-SERVICE
36079297	GRET	SVC	3/2/2020	1950	RET ABN	UG-SERVICE
36245397	GRET	SVC	3/7/2020	1950	RET ABN	UG-SERVICE
43551131	GRET	SVC	9/18/2024	1950	RET ABN	UG-SERVICE
37874484	GRET	SVC	12/4/2020	1950	RET ABN	UG-SERVICE
43522945	GRET	SVC	9/11/2024	1950	RET ABN	UG-SERVICE
43245050	GRET	SVC	9/11/2024	1950	RET ABN	UG-SERVICE
43645279	GRET	SVC	10/4/2024	1950	RET ABN	UG-SERVICE
41407395	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
36113056	GRET	SVC	11/5/2020	1950	RET ABN	UG-SERVICE
43604589	GRET	SVC	9/30/2024	1950	RET ABN	UG-SERVICE
37972672	GRET	SVC	1/2/2021	1950	RET ABN	UG-SERVICE
39348415	GRET	SVC	10/28/2021	1950	RET ABN	UG-SERVICE
42431570	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
38034133	GRET	SVC	1/20/2021	1950	RET ABN	UG-SERVICE
39679450	GRET	SVC	1/12/2022	1950	RET ABN	UG-SERVICE
39791773	GRET	SVC	10/7/2021	1950	RET ABN	UG-SERVICE
43245112	GRET	SVC	9/19/2024	1950	RET ABN	UG-SERVICE
43600705	GRET	SVC	9/19/2024	1950	RET ABN	UG-SERVICE
36712398	GRET	SVC	8/16/2020	1950	RET ABN	UG-SERVICE
41411680	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
43032273	GRET	SVC	4/29/2024	1950	RET ABN	UG-SERVICE
41034947	GRET	SVC	1/12/2023	1950	RET REM	UG-SERVICE
41411269	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
43543490	GRET	SVC	9/30/2024	1950	RET ABN	UG-SERVICE
38561882	GRET	SVC	4/19/2021	1950	RET ABN	UG-SERVICE
41411674	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
38864555	GRET	SVC	6/25/2021	1950	RET ABN	UG-SERVICE
41411918	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
37016175	GRET	SVC	9/30/2020	1950	RET ABN	UG-SERVICE
36235919	GRET	SVC	3/8/2021	1950	RET ABN	UG-SERVICE
41407671	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
42209116	GRET	SVC	3/28/2024	1950	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
37918107	GRET	SVC	1/4/2021	1950	RET ABN	UG-SERVICE
43060517	GRET	SVC	5/16/2024	1950	RET ABN	UG-SERVICE
39831397	GRET	SVC	8/3/2022	1950	RET ABN	UG-SERVICE
41411676	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
39665946	GRET	SVC	8/3/2022	1950	RET ABN	UG-SERVICE
41411422	GRET	SVC	11/2/2023	1950	RET ABN	UG-SERVICE
36348136	GRET	SVC	5/19/2020	1950	RET ABN	UG-SERVICE
36194898	GRET	SVC	5/7/2020	1950	RET ABN	UG-SERVICE
41411672	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
38033805	GRET	SVC	1/21/2021	1950	RET ABN	UG-SERVICE
41407398	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
39247044	GRET	SVC	10/11/2021	1950	RET ABN	UG-SERVICE
36203838	GRET	SVC	4/22/2020	1950	RET ABN	UG-SERVICE
38034050	GRET	SVC	1/20/2021	1950	RET ABN	UG-SERVICE
38414186	GRET	SVC	4/29/2021	1950	RET ABN	UG-SERVICE
41064589	GRET	SVC	12/15/2022	1950	RET ABN	UG-SERVICE
36270604	GRET	SVC	5/6/2020	1950	RET ABN	UG-SERVICE
40802654	GRET	SVC	10/14/2022	1950	RET ABN	UG-SERVICE
38614330	GRET	SVC	6/21/2021	1950	RET ABN	UG-SERVICE
39828249	GRET	SVC	3/16/2022	1950	RET ABN	UG-SERVICE
40523707	GRET	SVC	8/9/2022	1950	RET ABN	UG-SERVICE
43032275	GRET	SVC	4/29/2024	1950	RET ABN	UG-SERVICE
41411671	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
38062034	GRET	SVC	1/28/2021	1951	RET ABN	UG-SERVICE
38489221	GRET	SVC	5/28/2021	1951	RET ABN	UG-SERVICE
38185531	GRET	SVC	3/1/2021	1951	RET ABN	UG-SERVICE
36739921	GRET	SVC	8/3/2020	1951	RET ABN	UG-SERVICE
36590739	GRET	SVC	7/8/2020	1951	RET ABN	UG-SERVICE
40861220	GRET	SVC	10/24/2022	1951	RET ABN	UG-SERVICE
36779224	GRET	SVC	8/26/2020	1951	RET ABN	UG-SERVICE
40249192	GRET	SVC	6/7/2022	1951	RET ABN	UG-SERVICE
38312480	GRET	SVC	10/5/2021	1951	RET ABN	UG-SERVICE
38352969	GRET	SVC	2/14/2023	1951	RET ABN	UG-SERVICE
41961169	GRET	SVC	8/8/2023	1951	RET ABN	UG-SERVICE
43928937	GRET	SVC	12/13/2024	1951	RET ABN	UG-SERVICE
37887821	GRET	SVC	12/8/2020	1951	RET ABN	UG-SERVICE
39831386	GRET	SVC	8/3/2022	1951	RET ABN	UG-SERVICE
36085668	GRET	SVC	3/2/2020	1951	RET ABN	UG-SERVICE
40674903	GRET	SVC	9/29/2022	1951	RET ABN	UG-SERVICE
42110067	GRET	SVC	12/20/2023	1951	RET ABN	UG-SERVICE
41006869	GRET	SVC	12/7/2022	1951	RET ABN	UG-SERVICE
42435910	GRET	SVC	9/19/2024	1951	RET ABN	UG-SERVICE
40252646	GRET	SVC	6/6/2022	1951	RET ABN	UG-SERVICE
40659708	GRET	SVC	9/3/2022	1951	RET ABN	UG-SERVICE
43413518	GRET	SVC	8/13/2024	1951	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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41423885	GRET	SVC	10/18/2023	1951	RET ABN	UG-SERVICE
40036632	GRET	SVC	4/25/2022	1951	RET ABN	UG-SERVICE
41088767	GRET	SVC	12/21/2022	1951	RET ABN	UG-SERVICE
43435495	GRET	SVC	8/21/2024	1951	RET ABN	UG-SERVICE
41769950	GRET	SVC	6/19/2023	1951	RET REM	UG-SERVICE
38162087	GRET	SVC	2/23/2021	1951	RET ABN	UG-SERVICE
43155106	GRET	SVC	6/3/2024	1951	RET ABN	UG-SERVICE
38707596	GRET	SVC	7/9/2021	1951	RET ABN	UG-SERVICE
38441555	GRET	SVC	1/6/2022	1951	RET ABN	UG-SERVICE
37919597	GRET	SVC	4/8/2021	1951	RET ABN	UG-SERVICE
41411439	GRET	SVC	11/2/2023	1951	RET ABN	UG-SERVICE
41556233	GRET	SVC	4/24/2023	1951	RET ABN	UG-SERVICE
41430213	GRET	SVC	9/19/2023	1951	RET ABN	UG-SERVICE
42150880	GRET	SVC	9/25/2023	1951	RET ABN	UG-SERVICE
43156895	GRET	SVC	7/5/2024	1951	RET ABN	UG-SERVICE
41423887	GRET	SVC	10/18/2023	1951	RET ABN	UG-SERVICE
38423237	GRET	SVC	4/26/2021	1951	RET ABN	UG-SERVICE
43614251	GRET	SVC	9/28/2024	1951	RET ABN	UG-SERVICE
39417387	GRET	SVC	11/14/2021	1951	RET ABN	UG-SERVICE
42538136	GRET	SVC	1/3/2024	1951	RET ABN	UG-SERVICE
41660348	GRET	SVC	5/24/2023	1951	RET ABN	UG-SERVICE
38164753	GRET	SVC	2/24/2021	1951	RET ABN	UG-SERVICE
38567744	GRET	SVC	6/7/2021	1951	RET ABN	UG-SERVICE
36760765	GRET	SVC	8/11/2020	1951	RET ABN	UG-SERVICE
40249164	GRET	SVC	6/10/2022	1951	RET ABN	UG-SERVICE
41034692	GRET	SVC	12/16/2022	1951	RET ABN	UG-SERVICE
38000817	GRET	SVC	1/13/2021	1951	RET ABN	UG-SERVICE
41832368	GRET	SVC	7/7/2023	1951	RET ABN	UG-SERVICE
40989881	GRET	SVC	11/17/2022	1951	RET REM	UG-SERVICE
40639460	GRET	SVC	8/31/2022	1951	RET ABN	UG-SERVICE
41031343	GRET	SVC	12/9/2022	1951	RET ABN	UG-SERVICE
41071955	GRET	SVC	1/3/2023	1951	RET ABN	UG-SERVICE
43905357	GRET	SVC	12/9/2024	1951	RET ABN	UG-SERVICE
41700174	GRET	SVC	5/30/2023	1951	RET ABN	UG-SERVICE
36148001	GRET	SVC	3/14/2020	1951	RET ABN	UG-SERVICE
42152819	GRET	SVC	9/25/2023	1951	RET ABN	UG-SERVICE
39809563	GRET	SVC	8/3/2022	1951	RET ABN	UG-SERVICE
40258718	GRET	SVC	6/6/2022	1951	RET ABN	UG-SERVICE
41013436	GRET	SVC	12/7/2022	1951	RET ABN	UG-SERVICE
39230073	GRET	SVC	10/26/2021	1951	RET ABN	UG-SERVICE
43867865	GRET	SVC	12/30/2024	1951	RET ABN	UG-SERVICE
39719134	GRET	SVC	1/25/2022	1951	RET ABN	UG-SERVICE
40249360	GRET	SVC	6/6/2022	1951	RET ABN	UG-SERVICE
36206659	GRET	SVC	4/23/2020	1951	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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40644729	GRET	SVC	8/31/2022	1951	RET ABN	UG-SERVICE
39706229	GRET	SVC	2/28/2022	1951	RET ABN	UG-SERVICE
40249057	GRET	SVC	6/7/2022	1951	RET ABN	UG-SERVICE
42269957	GRET	SVC	10/23/2023	1951	RET ABN	UG-SERVICE
39424067	GRET	SVC	6/27/2022	1951	RET ABN	UG-SERVICE
39772866	GRET	SVC	9/29/2021	1951	RET ABN	UG-SERVICE
39791768	GRET	SVC	10/6/2021	1951	RET ABN	UG-SERVICE
40989592	GRET	SVC	11/17/2022	1951	RET ABN	UG-SERVICE
37013066	GRET	SVC	10/20/2020	1951	RET ABN	UG-SERVICE
40610203	GRET	SVC	9/17/2022	1951	RET ABN	UG-SERVICE
36952791	GRET	SVC	9/16/2020	1951	RET ABN	UG-SERVICE
38463323	GRET	SVC	5/11/2021	1951	RET ABN	UG-SERVICE
38551597	GRET	SVC	6/2/2021	1951	RET ABN	UG-SERVICE
38161416	GRET	SVC	2/23/2021	1951	RET ABN	UG-SERVICE
41408014	GRET	SVC	4/2/2024	1951	RET ABN	UG-SERVICE
41854515	GRET	SVC	7/10/2023	1951	RET ABN	UG-SERVICE
42575676	GRET	SVC	1/18/2024	1952	RET ABN	UG-SERVICE
38538827	GRET	SVC	5/25/2021	1952	RET ABN	UG-SERVICE
42427487	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
41712850	GRET	SVC	5/22/2023	1952	RET ABN	UG-SERVICE
38595484	GRET	SVC	6/21/2021	1952	RET ABN	UG-SERVICE
41411264	GRET	SVC	4/2/2024	1952	RET ABN	UG-SERVICE
40636684	GRET	SVC	8/30/2022	1952	RET ABN	UG-SERVICE
42683248	GRET	SVC	2/13/2024	1952	RET ABN	UG-SERVICE
42742352	GRET	SVC	8/5/2024	1952	RET ABN	UG-SERVICE
39847796	GRET	SVC	3/8/2022	1952	RET ABN	UG-SERVICE
43231361	GRET	SVC	7/8/2024	1952	RET ABN	UG-SERVICE
39831205	GRET	SVC	8/3/2022	1952	RET ABN	UG-SERVICE
41258769	GRET	SVC	2/6/2023	1952	RET ABN	UG-SERVICE
43245091	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
38352923	GRET	SVC	2/17/2023	1952	RET ABN	UG-SERVICE
38655789	GRET	SVC	6/22/2021	1952	RET ABN	UG-SERVICE
37112877	GRET	SVC	10/26/2020	1952	RET ABN	UG-SERVICE
39666152	GRET	SVC	11/18/2022	1952	RET ABN	UG-SERVICE
36809920	GRET	SVC	8/20/2020	1952	RET ABN	UG-SERVICE
42427488	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
39666241	GRET	SVC	11/18/2022	1952	RET ABN	UG-SERVICE
39920968	GRET	SVC	4/14/2022	1952	RET ABN	UG-SERVICE
39666246	GRET	SVC	11/18/2022	1952	RET ABN	UG-SERVICE
39831210	GRET	SVC	8/3/2022	1952	RET ABN	UG-SERVICE
43240552	GRET	SVC	7/13/2024	1952	RET ABN	UG-SERVICE
39831209	GRET	SVC	8/3/2022	1952	RET ABN	UG-SERVICE
38097358	GRET	SVC	9/2/2021	1952	RET ABN	UG-SERVICE
38097624	GRET	SVC	9/2/2021	1952	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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42427490	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
43423336	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
42226875	GRET	SVC	10/16/2023	1952	RET ABN	UG-SERVICE
40447663	GRET	SVC	7/21/2022	1952	RET ABN	UG-SERVICE
38775680	GRET	SVC	8/15/2021	1952	RET ABN	UG-SERVICE
38352925	GRET	SVC	2/17/2023	1952	RET ABN	UG-SERVICE
39384910	GRET	SVC	11/4/2021	1952	RET ABN	UG-SERVICE
38432093	GRET	SVC	5/5/2021	1952	RET ABN	UG-SERVICE
42252864	GRET	SVC	10/31/2023	1952	RET ABN	UG-SERVICE
42427489	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
39666243	GRET	SVC	11/18/2022	1952	RET ABN	UG-SERVICE
40903399	GRET	SVC	11/7/2022	1952	RET ABN	UG-SERVICE
38356733	GRET	SVC	2/14/2023	1952	RET ABN	UG-SERVICE
38610609	GRET	SVC	8/2/2021	1952	RET ABN	UG-SERVICE
36122516	GRET	SVC	11/5/2020	1952	RET ABN	UG-SERVICE
42250860	GRET	SVC	10/20/2023	1952	RET ABN	UG-SERVICE
41731558	GRET	SVC	6/10/2023	1952	RET ABN	UG-SERVICE
41277503	GRET	SVC	2/13/2023	1952	RET REM	UG-SERVICE
39666249	GRET	SVC	11/18/2022	1952	RET ABN	UG-SERVICE
42427492	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
43245092	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
39831211	GRET	SVC	8/3/2022	1952	RET ABN	UG-SERVICE
40813279	GRET	SVC	10/14/2022	1952	RET ABN	UG-SERVICE
41407597	GRET	SVC	4/2/2024	1952	RET ABN	UG-SERVICE
38352926	GRET	SVC	2/14/2023	1952	RET ABN	UG-SERVICE
42956741	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
41283744	GRET	SVC	2/13/2023	1952	RET ABN	UG-SERVICE
39666242	GRET	SVC	11/18/2022	1952	RET ABN	UG-SERVICE
40473796	GRET	SVC	7/25/2022	1952	RET ABN	UG-SERVICE
41121720	GRET	SVC	1/4/2023	1952	RET ABN	UG-SERVICE
38162089	GRET	SVC	2/23/2021	1952	RET ABN	UG-SERVICE
43245098	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
38073256	GRET	SVC	2/1/2021	1952	RET ABN	UG-SERVICE
38352935	GRET	SVC	2/17/2023	1952	RET ABN	UG-SERVICE
41424766	GRET	SVC	10/18/2023	1952	RET ABN	UG-SERVICE
38352934	GRET	SVC	2/17/2023	1952	RET ABN	UG-SERVICE
43477225	GRET	SVC	12/19/2024	1952	RET ABN	UG-SERVICE
38441456	GRET	SVC	1/6/2022	1952	RET ABN	UG-SERVICE
40919620	GRET	SVC	11/29/2022	1952	RET ABN	UG-SERVICE
42427494	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
42555260	GRET	SVC	3/25/2024	1952	RET ABN	UG-SERVICE
38958979	GRET	SVC	8/30/2021	1952	RET ABN	UG-SERVICE
43241923	GRET	SVC	7/27/2024	1952	RET ABN	UG-SERVICE
42278991	GRET	SVC	10/25/2023	1952	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40632169	GRET	SVC	8/29/2022	1952	RET ABN	UG-SERVICE
42670289	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
36260063	GRET	SVC	3/18/2020	1952	RET ABN	UG-SERVICE
42141042	GRET	SVC	9/18/2023	1952	RET ABN	UG-SERVICE
39940806	GRET	SVC	5/11/2022	1952	RET ABN	UG-SERVICE
36122285	GRET	SVC	11/5/2020	1952	RET ABN	UG-SERVICE
38356730	GRET	SVC	2/17/2023	1952	RET ABN	UG-SERVICE
38280107	GRET	SVC	3/27/2021	1952	RET ABN	UG-SERVICE
38352924	GRET	SVC	2/17/2023	1952	RET ABN	UG-SERVICE
42427491	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
38352936	GRET	SVC	2/17/2023	1952	RET ABN	UG-SERVICE
38356732	GRET	SVC	2/14/2023	1952	RET ABN	UG-SERVICE
38289767	GRET	SVC	4/1/2021	1952	RET ABN	UG-SERVICE
39666155	GRET	SVC	11/18/2022	1952	RET ABN	UG-SERVICE
36136809	GRET	SVC	3/16/2020	1952	RET ABN	UG-SERVICE
36119732	GRET	SVC	8/31/2020	1952	RET ABN	UG-SERVICE
40031651	GRET	SVC	4/18/2022	1952	RET ABN	UG-SERVICE
42957680	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
38387047	GRET	SVC	4/23/2021	1952	RET ABN	UG-SERVICE
39230563	GRET	SVC	10/4/2021	1952	RET ABN	UG-SERVICE
36840536	GRET	SVC	9/11/2020	1952	RET ABN	UG-SERVICE
36754616	GRET	SVC	8/12/2020	1952	RET ABN	UG-SERVICE
43598920	GRET	SVC	9/26/2024	1952	RET ABN	UG-SERVICE
41407673	GRET	SVC	4/2/2024	1952	RET ABN	UG-SERVICE
38183688	GRET	SVC	2/16/2021	1952	RET ABN	UG-SERVICE
42455922	GRET	SVC	12/11/2023	1952	RET ABN	UG-SERVICE
42427493	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
41407596	GRET	SVC	4/2/2024	1952	RET ABN	UG-SERVICE
43661022	GRET	SVC	10/7/2024	1952	RET ABN	UG-SERVICE
40639165	GRET	SVC	9/26/2022	1952	RET ABN	UG-SERVICE
41398652	GRET	SVC	3/30/2023	1952	RET REM	UG-SERVICE
39666252	GRET	SVC	11/18/2022	1952	RET ABN	UG-SERVICE
36432857	GRET	SVC	6/9/2020	1952	RET ABN	UG-SERVICE
41052702	GRET	SVC	1/12/2023	1953	RET ABN	UG-SERVICE
38608396	GRET	SVC	10/19/2021	1953	RET ABN	UG-SERVICE
38190518	GRET	SVC	3/4/2021	1953	RET ABN	UG-SERVICE
38571055	GRET	SVC	6/11/2021	1953	RET ABN	UG-SERVICE
36122585	GRET	SVC	10/4/2020	1953	RET ABN	UG-SERVICE
39993535	GRET	SVC	4/11/2022	1953	RET ABN	UG-SERVICE
41052321	GRET	SVC	1/12/2023	1953	RET ABN	UG-SERVICE
42116065	GRET	SVC	9/29/2023	1953	RET ABN	UG-SERVICE
38507888	GRET	SVC	5/21/2021	1953	RET ABN	UG-SERVICE
38097113	GRET	SVC	9/2/2021	1953	RET ABN	UG-SERVICE
42138181	GRET	SVC	9/21/2023	1953	RET ABN	UG-SERVICE
43637311	GRET	SVC	10/8/2024	1953	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41121802	GRET	SVC	1/6/2023	1953	RET ABN	UG-SERVICE
38582467	GRET	SVC	6/9/2021	1953	RET ABN	UG-SERVICE
38571059	GRET	SVC	6/11/2021	1953	RET ABN	UG-SERVICE
40158955	GRET	SVC	5/12/2022	1953	RET ABN	UG-SERVICE
35873808	GRET	SVC	1/8/2020	1953	RET ABN	UG-SERVICE
35850630	GRET	SVC	1/4/2020	1953	RET ABN	UG-SERVICE
42051188	GRET	SVC	12/22/2023	1953	RET ABN	UG-SERVICE
42879031	GRET	SVC	3/27/2024	1953	RET ABN	UG-SERVICE
36255947	GRET	SVC	5/12/2020	1953	RET ABN	UG-SERVICE
38461273	GRET	SVC	5/10/2021	1953	RET ABN	UG-SERVICE
36419027	GRET	SVC	6/9/2020	1953	RET ABN	UG-SERVICE
38348120	GRET	SVC	4/22/2021	1953	RET ABN	UG-SERVICE
37032220	GRET	SVC	10/7/2020	1953	RET ABN	UG-SERVICE
38538107	GRET	SVC	5/27/2021	1953	RET ABN	UG-SERVICE
38033861	GRET	SVC	1/20/2021	1953	RET ABN	UG-SERVICE
40327471	GRET	SVC	6/21/2022	1953	RET ABN	UG-SERVICE
38352965	GRET	SVC	2/14/2023	1953	RET ABN	UG-SERVICE
38097152	GRET	SVC	9/2/2021	1953	RET ABN	UG-SERVICE
41320907	GRET	SVC	2/27/2023	1953	RET ABN	UG-SERVICE
42427240	GRET	SVC	9/19/2024	1953	RET ABN	UG-SERVICE
42205143	GRET	SVC	12/22/2023	1953	RET ABN	UG-SERVICE
41292554	GRET	SVC	2/20/2023	1953	RET ABN	UG-SERVICE
36143376	GRET	SVC	3/12/2020	1953	RET ABN	UG-SERVICE
41777457	GRET	SVC	6/15/2023	1953	RET ABN	UG-SERVICE
42957321	GRET	SVC	9/19/2024	1953	RET ABN	UG-SERVICE
37708828	GRET	SVC	11/20/2020	1953	RET ABN	UG-SERVICE
40116164	GRET	SVC	5/2/2022	1953	RET ABN	UG-SERVICE
38165030	GRET	SVC	3/5/2021	1953	RET ABN	UG-SERVICE
38260938	GRET	SVC	12/17/2021	1953	RET ABN	UG-SERVICE
43904395	GRET	SVC	12/30/2024	1953	RET ABN	UG-SERVICE
35737712	GRET	SVC	3/18/2020	1953	RET ABN	UG-SERVICE
41976814	GRET	SVC	7/11/2024	1953	RET ABN	UG-SERVICE
39831398	GRET	SVC	8/3/2022	1953	RET ABN	UG-SERVICE
36119405	GRET	SVC	11/5/2020	1953	RET ABN	UG-SERVICE
42320967	GRET	SVC	4/2/2024	1953	RET ABN	UG-SERVICE
36927452	GRET	SVC	9/12/2020	1953	RET ABN	UG-SERVICE
42069649	GRET	SVC	9/5/2023	1953	RET ABN	UG-SERVICE
39666416	GRET	SVC	11/18/2022	1953	RET ABN	UG-SERVICE
38352966	GRET	SVC	2/14/2023	1953	RET ABN	UG-SERVICE
40572029	GRET	SVC	8/16/2022	1953	RET ABN	UG-SERVICE
36331088	GRET	SVC	5/7/2020	1953	RET ABN	UG-SERVICE
40551928	GRET	SVC	8/9/2022	1953	RET ABN	UG-SERVICE
41107697	GRET	SVC	1/10/2023	1953	RET ABN	UG-SERVICE
37254383	GRET	SVC	9/21/2020	1953	RET ABN	UG-SERVICE
41321705	GRET	SVC	3/2/2023	1953	RET REM	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38515668	GRET	SVC	3/21/2022	1953	RET ABN	UG-SERVICE
36255859	GRET	SVC	7/10/2020	1953	RET ABN	UG-SERVICE
38156952	GRET	SVC	7/30/2021	1953	RET ABN	UG-SERVICE
39925433	GRET	SVC	5/9/2022	1953	RET ABN	UG-SERVICE
42120878	GRET	SVC	9/12/2023	1953	RET ABN	UG-SERVICE
41479994	GRET	SVC	4/10/2023	1953	RET ABN	UG-SERVICE
38441422	GRET	SVC	1/6/2022	1953	RET ABN	UG-SERVICE
36777969	GRET	SVC	8/12/2020	1953	RET ABN	UG-SERVICE
42589741	GRET	SVC	1/25/2024	1953	RET ABN	UG-SERVICE
39666663	GRET	SVC	11/18/2022	1953	RET ABN	UG-SERVICE
36371408	GRET	SVC	5/26/2020	1953	RET ABN	UG-SERVICE
36772130	GRET	SVC	8/12/2020	1953	RET ABN	UG-SERVICE
43762605	GRET	SVC	10/31/2024	1953	RET ABN	UG-SERVICE
40318196	GRET	SVC	6/20/2022	1953	RET ABN	UG-SERVICE
41069780	GRET	SVC	1/5/2023	1953	RET ABN	UG-SERVICE
42506330	GRET	SVC	1/25/2024	1953	RET ABN	UG-SERVICE
40253341	GRET	SVC	6/7/2022	1953	RET ABN	UG-SERVICE
38073115	GRET	SVC	2/2/2021	1953	RET ABN	UG-SERVICE
39227657	GRET	SVC	10/2/2021	1953	RET ABN	UG-SERVICE
39666662	GRET	SVC	11/18/2022	1953	RET ABN	UG-SERVICE
38034130	GRET	SVC	1/20/2021	1953	RET ABN	UG-SERVICE
40832923	GRET	SVC	10/19/2022	1953	RET ABN	UG-SERVICE
38693140	GRET	SVC	5/17/2021	1953	RET ABN	UG-SERVICE
40472927	GRET	SVC	8/8/2022	1953	RET ABN	UG-SERVICE
39786857	GRET	SVC	2/7/2022	1953	RET ABN	UG-SERVICE
36927728	GRET	SVC	9/12/2020	1953	RET ABN	UG-SERVICE
38486528	GRET	SVC	5/11/2021	1953	RET ABN	UG-SERVICE
42575673	GRET	SVC	1/10/2024	1953	RET ABN	UG-SERVICE
41755468	GRET	SVC	6/12/2023	1953	RET ABN	UG-SERVICE
39759258	GRET	SVC	8/13/2021	1953	RET ABN	UG-SERVICE
41480231	GRET	SVC	4/6/2023	1953	RET ABN	UG-SERVICE
40346165	GRET	SVC	6/28/2022	1953	RET ABN	UG-SERVICE
41407740	GRET	SVC	4/2/2024	1953	RET ABN	UG-SERVICE
41162549	GRET	SVC	1/7/2023	1953	RET ABN	UG-SERVICE
36119653	GRET	SVC	10/14/2020	1953	RET ABN	UG-SERVICE
41052701	GRET	SVC	1/12/2023	1953	RET ABN	UG-SERVICE
42077779	GRET	SVC	8/29/2023	1953	RET ABN	UG-SERVICE
42257701	GRET	SVC	10/23/2023	1953	RET ABN	UG-SERVICE
41672044	GRET	SVC	5/26/2023	1953	RET ABN	UG-SERVICE
39753780	GRET	SVC	2/10/2022	1954	RET ABN	UG-SERVICE
40685502	GRET	SVC	9/12/2022	1954	RET ABN	UG-SERVICE
41036610	GRET	SVC	12/15/2022	1954	RET ABN	UG-SERVICE
41119592	GRET	SVC	1/6/2023	1954	RET ABN	UG-SERVICE
41035399	GRET	SVC	12/8/2022	1954	RET ABN	UG-SERVICE
36118838	GRET	SVC	10/12/2020	1954	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38820078	GRET	SVC	7/27/2021	1954	RET ABN	UG-SERVICE
38153952	GRET	SVC	2/22/2021	1954	RET ABN	UG-SERVICE
42741404	GRET	SVC	2/15/2024	1954	RET ABN	UG-SERVICE
40505758	GRET	SVC	8/3/2022	1954	RET ABN	UG-SERVICE
38097645	GRET	SVC	9/2/2021	1954	RET ABN	UG-SERVICE
36771065	GRET	SVC	8/11/2020	1954	RET ABN	UG-SERVICE
40919859	GRET	SVC	11/15/2022	1954	RET ABN	UG-SERVICE
36992554	GRET	SVC	10/2/2020	1954	RET ABN	UG-SERVICE
41017133	GRET	SVC	12/5/2022	1954	RET ABN	UG-SERVICE
41411270	GRET	SVC	4/2/2024	1954	RET ABN	UG-SERVICE
39546358	GRET	SVC	1/3/2022	1954	RET ABN	UG-SERVICE
36135000	GRET	SVC	3/16/2020	1954	RET ABN	UG-SERVICE
36136116	GRET	SVC	4/20/2020	1954	RET ABN	UG-SERVICE
41831454	GRET	SVC	7/6/2023	1954	RET ABN	UG-SERVICE
43086584	GRET	SVC	6/5/2024	1954	RET ABN	UG-SERVICE
38545096	GRET	SVC	4/10/2021	1954	RET ABN	UG-SERVICE
39657146	GRET	SVC	6/28/2022	1954	RET ABN	UG-SERVICE
36112441	GRET	SVC	10/12/2020	1954	RET ABN	UG-SERVICE
41411073	GRET	SVC	4/2/2024	1954	RET ABN	UG-SERVICE
41407591	GRET	SVC	4/2/2024	1954	RET ABN	UG-SERVICE
41628218	GRET	SVC	5/18/2023	1954	RET ABN	UG-SERVICE
37088354	GRET	SVC	10/20/2020	1954	RET ABN	UG-SERVICE
39150316	GRET	SVC	9/12/2021	1954	RET ABN	UG-SERVICE
40925026	GRET	SVC	11/15/2022	1954	RET ABN	UG-SERVICE
38572300	GRET	SVC	4/21/2021	1954	RET ABN	UG-SERVICE
40333087	GRET	SVC	6/23/2022	1954	RET ABN	UG-SERVICE
43318165	GRET	SVC	8/13/2024	1954	RET ABN	UG-SERVICE
39666419	GRET	SVC	11/18/2022	1954	RET ABN	UG-SERVICE
41082948	GRET	SVC	1/5/2023	1954	RET ABN	UG-SERVICE
43770278	GRET	SVC	11/21/2024	1954	RET ABN	UG-SERVICE
36868321	GRET	SVC	8/29/2020	1954	RET ABN	UG-SERVICE
40801830	GRET	SVC	10/28/2022	1954	RET ABN	UG-SERVICE
38097643	GRET	SVC	9/2/2021	1954	RET ABN	UG-SERVICE
42115264	GRET	SVC	9/7/2023	1954	RET ABN	UG-SERVICE
41969064	GRET	SVC	8/1/2024	1954	RET ABN	UG-SERVICE
39820961	GRET	SVC	2/22/2022	1954	RET ABN	UG-SERVICE
41407752	GRET	SVC	4/2/2024	1954	RET ABN	UG-SERVICE
38597090	GRET	SVC	6/9/2021	1954	RET ABN	UG-SERVICE
42793388	GRET	SVC	3/25/2024	1954	RET ABN	UG-SERVICE
41817862	GRET	SVC	6/29/2023	1954	RET ABN	UG-SERVICE
41407744	GRET	SVC	4/2/2024	1954	RET ABN	UG-SERVICE
37959606	GRET	SVC	1/8/2021	1954	RET ABN	UG-SERVICE
36112440	GRET	SVC	10/12/2020	1954	RET ABN	UG-SERVICE
38108182	GRET	SVC	12/22/2021	1954	RET ABN	UG-SERVICE
43770740	GRET	SVC	11/21/2024	1954	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43073744	GRET	SVC	5/18/2024	1954	RET ABN	UG-SERVICE
41119744	GRET	SVC	1/6/2023	1954	RET ABN	UG-SERVICE
36348347	GRET	SVC	5/19/2020	1954	RET ABN	UG-SERVICE
41568707	GRET	SVC	4/25/2023	1954	RET ABN	UG-SERVICE
36487887	GRET	SVC	5/11/2020	1954	RET ABN	UG-SERVICE
36914875	GRET	SVC	9/14/2020	1954	RET ABN	UG-SERVICE
43752280	GRET	SVC	12/3/2024	1954	RET ABN	UG-SERVICE
40743846	GRET	SVC	10/10/2022	1954	RET ABN	UG-SERVICE
42451918	GRET	SVC	12/18/2023	1954	RET ABN	UG-SERVICE
36118837	GRET	SVC	5/5/2020	1954	RET ABN	UG-SERVICE
36302202	GRET	SVC	5/5/2020	1954	RET ABN	UG-SERVICE
36119651	GRET	SVC	10/14/2020	1954	RET ABN	UG-SERVICE
40363266	GRET	SVC	6/28/2022	1954	RET ABN	UG-SERVICE
43244747	GRET	SVC	9/13/2024	1954	RET ABN	UG-SERVICE
41411072	GRET	SVC	4/2/2024	1954	RET ABN	UG-SERVICE
43918995	GRET	SVC	12/11/2024	1954	RET ABN	UG-SERVICE
41051913	GRET	SVC	1/12/2023	1954	RET ABN	UG-SERVICE
41659508	GRET	SVC	5/22/2023	1954	RET ABN	UG-SERVICE
36451893	GRET	SVC	6/16/2020	1954	RET ABN	UG-SERVICE
36135788	GRET	SVC	4/21/2020	1954	RET ABN	UG-SERVICE
41423630	GRET	SVC	3/21/2023	1954	RET ABN	UG-SERVICE
41411076	GRET	SVC	4/2/2024	1954	RET ABN	UG-SERVICE
42020389	GRET	SVC	8/21/2023	1954	RET ABN	UG-SERVICE
41477206	GRET	SVC	4/10/2023	1954	RET ABN	UG-SERVICE
35916117	GRET	SVC	1/17/2020	1954	RET ABN	UG-SERVICE
42530677	GRET	SVC	12/20/2023	1954	RET ABN	UG-SERVICE
39666088	GRET	SVC	8/3/2022	1954	RET ABN	UG-SERVICE
42165558	GRET	SVC	9/29/2023	1954	RET ABN	UG-SERVICE
36967051	GRET	SVC	9/23/2020	1954	RET ABN	UG-SERVICE
40906312	GRET	SVC	11/10/2022	1954	RET ABN	UG-SERVICE
39916051	GRET	SVC	4/25/2022	1954	RET ABN	UG-SERVICE
39657155	GRET	SVC	6/28/2022	1954	RET ABN	UG-SERVICE
39830410	GRET	SVC	8/3/2022	1954	RET ABN	UG-SERVICE
37928576	GRET	SVC	1/8/2021	1954	RET ABN	UG-SERVICE
40332153	GRET	SVC	6/22/2022	1954	RET ABN	UG-SERVICE
42416329	GRET	SVC	12/11/2023	1954	RET ABN	UG-SERVICE
38194291	GRET	SVC	3/10/2021	1954	RET ABN	UG-SERVICE
39956460	GRET	SVC	4/5/2022	1955	RET ABN	UG-SERVICE
36906819	GRET	SVC	10/19/2020	1955	RET ABN	UG-SERVICE
40561731	GRET	SVC	10/1/2022	1955	RET ABN	UG-SERVICE
39666053	GRET	SVC	8/3/2022	1955	RET ABN	UG-SERVICE
42201119	GRET	SVC	10/9/2023	1955	RET ABN	UG-SERVICE
41569704	GRET	SVC	4/21/2023	1955	RET ABN	UG-SERVICE
43931698	GRET	SVC	12/11/2024	1955	RET ABN	UG-SERVICE
38135007	GRET	SVC	2/17/2021	1955	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
39666496	GRET	SVC	11/18/2022	1955	RET ABN	UG-SERVICE
41407666	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
40883286	GRET	SVC	11/4/2022	1955	RET ABN	UG-SERVICE
40657686	GRET	SVC	9/8/2022	1955	RET ABN	UG-SERVICE
41082591	GRET	SVC	12/21/2022	1955	RET ABN	UG-SERVICE
40113761	GRET	SVC	5/3/2022	1955	RET ABN	UG-SERVICE
43624612	GRET	SVC	10/2/2024	1955	RET ABN	UG-SERVICE
38040115	GRET	SVC	5/20/2021	1955	RET ABN	UG-SERVICE
38658669	GRET	SVC	5/10/2021	1955	RET ABN	UG-SERVICE
36349690	GRET	SVC	5/20/2020	1955	RET ABN	UG-SERVICE
42833735	GRET	SVC	3/19/2024	1955	RET ABN	UG-SERVICE
40754903	GRET	SVC	10/6/2022	1955	RET ABN	UG-SERVICE
41411067	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
42166120	GRET	SVC	9/19/2023	1955	RET ABN	UG-SERVICE
41411836	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
41036616	GRET	SVC	12/15/2022	1955	RET ABN	UG-SERVICE
41601776	GRET	SVC	6/13/2023	1955	RET ABN	UG-SERVICE
41407483	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
41411829	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
41411261	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
42599267	GRET	SVC	2/9/2024	1955	RET ABN	UG-SERVICE
39312779	GRET	SVC	11/23/2021	1955	RET ABN	UG-SERVICE
36433587	GRET	SVC	6/10/2020	1955	RET ABN	UG-SERVICE
42036129	GRET	SVC	8/26/2023	1955	RET ABN	UG-SERVICE
38191944	GRET	SVC	3/10/2021	1955	RET ABN	UG-SERVICE
39710583	GRET	SVC	1/20/2022	1955	RET ABN	UG-SERVICE
42122666	GRET	SVC	9/18/2023	1955	RET ABN	UG-SERVICE
41000447	GRET	SVC	12/2/2022	1955	RET ABN	UG-SERVICE
41411831	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
36185243	GRET	SVC	4/15/2020	1955	RET ABN	UG-SERVICE
39679664	GRET	SVC	1/12/2022	1955	RET ABN	UG-SERVICE
43129636	GRET	SVC	6/3/2024	1955	RET ABN	UG-SERVICE
42180321	GRET	SVC	10/2/2023	1955	RET ABN	UG-SERVICE
40634931	GRET	SVC	10/10/2022	1955	RET ABN	UG-SERVICE
42760744	GRET	SVC	8/1/2024	1955	RET ABN	UG-SERVICE
40802643	GRET	SVC	10/12/2022	1955	RET ABN	UG-SERVICE
41411485	GRET	SVC	11/2/2023	1955	RET ABN	UG-SERVICE
37929847	GRET	SVC	12/17/2020	1955	RET ABN	UG-SERVICE
39759440	GRET	SVC	8/16/2021	1955	RET ABN	UG-SERVICE
39880123	GRET	SVC	3/14/2022	1955	RET ABN	UG-SERVICE
43796684	GRET	SVC	11/13/2024	1955	RET ABN	UG-SERVICE
41411830	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
36193763	GRET	SVC	4/23/2020	1955	RET ABN	UG-SERVICE
40883581	GRET	SVC	11/1/2022	1955	RET ABN	UG-SERVICE
41389200	GRET	SVC	3/15/2023	1955	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36146481	GRET	SVC	5/20/2021	1955	RET ABN	UG-SERVICE
41407760	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
39317626	GRET	SVC	10/25/2021	1955	RET ABN	UG-SERVICE
39830409	GRET	SVC	8/3/2022	1955	RET ABN	UG-SERVICE
39658087	GRET	SVC	3/3/2022	1955	RET ABN	UG-SERVICE
41407542	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
39766735	GRET	SVC	11/2/2021	1955	RET ABN	UG-SERVICE
40691834	GRET	SVC	9/14/2022	1955	RET ABN	UG-SERVICE
41513774	GRET	SVC	4/25/2023	1955	RET ABN	UG-SERVICE
37106589	GRET	SVC	10/27/2020	1955	RET ABN	UG-SERVICE
42032092	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
37053960	GRET	SVC	4/16/2021	1955	RET ABN	UG-SERVICE
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41409402	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
41411481	GRET	SVC	11/2/2023	1955	RET ABN	UG-SERVICE
38260281	GRET	SVC	12/14/2021	1955	RET ABN	UG-SERVICE
38210868	GRET	SVC	3/11/2021	1955	RET ABN	UG-SERVICE
41773718	GRET	SVC	6/19/2023	1955	RET ABN	UG-SERVICE
39235481	GRET	SVC	10/10/2021	1955	RET ABN	UG-SERVICE
36098971	GRET	SVC	3/12/2020	1955	RET ABN	UG-SERVICE
42320966	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
41316684	GRET	SVC	2/27/2023	1955	RET ABN	UG-SERVICE
40265913	GRET	SVC	6/8/2022	1955	RET ABN	UG-SERVICE
38731610	GRET	SVC	7/12/2021	1955	RET ABN	UG-SERVICE
41330180	GRET	SVC	3/1/2023	1955	RET ABN	UG-SERVICE
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37108921	GRET	SVC	10/21/2020	1955	RET ABN	UG-SERVICE
41101697	GRET	SVC	1/30/2023	1955	RET ABN	UG-SERVICE
42270344	GRET	SVC	10/25/2023	1955	RET ABN	UG-SERVICE
40754901	GRET	SVC	10/6/2022	1955	RET ABN	UG-SERVICE
41408763	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
36145206	GRET	SVC	12/14/2020	1955	RET ABN	UG-SERVICE
41408902	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
40113887	GRET	SVC	5/2/2022	1955	RET ABN	UG-SERVICE
32769561	GRET	SVC	7/8/2020	1955	RET ABN	UG-SERVICE
40493095	GRET	SVC	7/25/2022	1955	RET ABN	UG-SERVICE
43244942	GRET	SVC	9/11/2024	1955	RET ABN	UG-SERVICE
40883282	GRET	SVC	11/2/2022	1956	RET ABN	UG-SERVICE
41063358	GRET	SVC	11/30/2022	1956	RET ABN	UG-SERVICE
42850084	GRET	SVC	3/25/2024	1956	RET ABN	UG-SERVICE
38514863	GRET	SVC	8/5/2021	1956	RET ABN	UG-SERVICE
36238532	GRET	SVC	3/2/2020	1956	RET ABN	UG-SERVICE
38573397	GRET	SVC	6/9/2021	1956	RET ABN	UG-SERVICE
41406921	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
39430200	GRET	SVC	11/15/2021	1956	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42205154	GRET	SVC	11/29/2023	1956	RET ABN	UG-SERVICE
38870141	GRET	SVC	8/30/2021	1956	RET ABN	UG-SERVICE
40538000	GRET	SVC	8/28/2022	1956	RET ABN	UG-SERVICE
36107008	GRET	SVC	4/27/2020	1956	RET ABN	UG-SERVICE
40141147	GRET	SVC	5/10/2022	1956	RET ABN	UG-SERVICE
41066002	GRET	SVC	12/13/2022	1956	RET ABN	UG-SERVICE
38310396	GRET	SVC	4/4/2021	1956	RET ABN	UG-SERVICE
41409118	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
40644228	GRET	SVC	9/3/2022	1956	RET ABN	UG-SERVICE
38315075	GRET	SVC	2/26/2021	1956	RET ABN	UG-SERVICE
41510569	GRET	SVC	4/17/2023	1956	RET ABN	UG-SERVICE
42337029	GRET	SVC	11/9/2023	1956	RET ABN	UG-SERVICE
41406991	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
41411754	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
36365097	GRET	SVC	6/2/2020	1956	RET ABN	UG-SERVICE
41031815	GRET	SVC	12/8/2022	1956	RET ABN	UG-SERVICE
38839771	GRET	SVC	8/2/2021	1956	RET ABN	UG-SERVICE
40522615	GRET	SVC	8/5/2022	1956	RET ABN	UG-SERVICE
38966879	GRET	SVC	8/19/2021	1956	RET ABN	UG-SERVICE
41409408	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
40026853	GRET	SVC	4/19/2022	1956	RET ABN	UG-SERVICE
38240750	GRET	SVC	3/26/2021	1956	RET ABN	UG-SERVICE
40360180	GRET	SVC	6/29/2022	1956	RET ABN	UG-SERVICE
41063473	GRET	SVC	1/18/2023	1956	RET ABN	UG-SERVICE
41409404	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
42777461	GRET	SVC	3/1/2024	1956	RET ABN	UG-SERVICE
36177531	GRET	SVC	2/14/2020	1956	RET ABN	UG-SERVICE
41411746	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
41241969	GRET	SVC	2/24/2023	1956	RET ABN	UG-SERVICE
41081183	GRET	SVC	12/20/2022	1956	RET ABN	UG-SERVICE
41408070	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
37958391	GRET	SVC	12/28/2020	1956	RET ABN	UG-SERVICE
42866881	GRET	SVC	3/22/2024	1956	RET ABN	UG-SERVICE
41064595	GRET	SVC	12/13/2022	1956	RET ABN	UG-SERVICE
40279586	GRET	SVC	6/8/2022	1956	RET ABN	UG-SERVICE
41030765	GRET	SVC	12/7/2022	1956	RET ABN	UG-SERVICE
41163173	GRET	SVC	1/13/2023	1956	RET ABN	UG-SERVICE
42817001	GRET	SVC	3/13/2024	1956	RET ABN	UG-SERVICE
35151972	GRET	SVC	1/7/2020	1956	RET ABN	UG-SERVICE
41411747	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
42166672	GRET	SVC	10/14/2023	1956	RET ABN	UG-SERVICE
42247461	GRET	SVC	11/6/2023	1956	RET ABN	UG-SERVICE
37990355	GRET	SVC	1/11/2021	1956	RET ABN	UG-SERVICE
36761549	GRET	SVC	8/14/2020	1956	RET ABN	UG-SERVICE
42385235	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36839860	GRET	SVC	9/1/2020	1956	RET ABN	UG-SERVICE
40492780	GRET	SVC	8/13/2022	1956	RET ABN	UG-SERVICE
37874343	GRET	SVC	12/7/2020	1956	RET ABN	UG-SERVICE
39830416	GRET	SVC	8/3/2022	1956	RET ABN	UG-SERVICE
36525533	GRET	SVC	6/25/2020	1956	RET ABN	UG-SERVICE
43632871	GRET	SVC	10/2/2024	1956	RET ABN	UG-SERVICE
42435906	GRET	SVC	9/19/2024	1956	RET ABN	UG-SERVICE
41289003	GRET	SVC	3/21/2023	1956	RET ABN	UG-SERVICE
38314238	GRET	SVC	3/24/2021	1956	RET ABN	UG-SERVICE
41441939	GRET	SVC	9/13/2023	1956	RET ABN	UG-SERVICE
39477405	GRET	SVC	11/29/2021	1956	RET ABN	UG-SERVICE
41411182	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
35965175	GRET	SVC	1/30/2020	1956	RET ABN	UG-SERVICE
42018667	GRET	SVC	8/21/2023	1956	RET ABN	UG-SERVICE
38370185	GRET	SVC	4/15/2021	1956	RET ABN	UG-SERVICE
41411907	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
38484125	GRET	SVC	5/14/2021	1956	RET ABN	UG-SERVICE
39817529	GRET	SVC	2/22/2022	1956	RET ABN	UG-SERVICE
41066001	GRET	SVC	1/4/2023	1956	RET ABN	UG-SERVICE
38341484	GRET	SVC	4/10/2021	1956	RET ABN	UG-SERVICE
42964245	GRET	SVC	9/19/2024	1956	RET ABN	UG-SERVICE
36119656	GRET	SVC	10/14/2020	1956	RET ABN	UG-SERVICE
40277552	GRET	SVC	4/27/2023	1956	RET ABN	UG-SERVICE
42844197	GRET	SVC	3/20/2024	1956	RET ABN	UG-SERVICE
37111303	GRET	SVC	10/22/2020	1956	RET ABN	UG-SERVICE
39999273	GRET	SVC	4/14/2022	1956	RET ABN	UG-SERVICE
40389547	GRET	SVC	12/14/2022	1956	RET ABN	UG-SERVICE
36101773	GRET	SVC	4/23/2020	1956	RET ABN	UG-SERVICE
41106883	GRET	SVC	12/30/2022	1956	RET ABN	UG-SERVICE
38813540	GRET	SVC	7/21/2021	1956	RET ABN	UG-SERVICE
41051912	GRET	SVC	1/12/2023	1956	RET ABN	UG-SERVICE
38751617	GRET	SVC	8/5/2021	1956	RET ABN	UG-SERVICE
42208441	GRET	SVC	10/13/2023	1956	RET ABN	UG-SERVICE
36741665	GRET	SVC	8/7/2020	1956	RET ABN	UG-SERVICE
39908142	GRET	SVC	3/21/2022	1956	RET ABN	UG-SERVICE
42373894	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
39772873	GRET	SVC	10/1/2021	1956	RET ABN	UG-SERVICE
42791921	GRET	SVC	3/4/2024	1956	RET ABN	UG-SERVICE
43540093	GRET	SVC	9/23/2024	1956	RET ABN	UG-SERVICE
39827711	GRET	SVC	2/24/2022	1956	RET ABN	UG-SERVICE
43451804	GRET	SVC	8/19/2024	1956	RET ABN	UG-SERVICE
42156401	GRET	SVC	3/28/2024	1956	RET ABN	UG-SERVICE
41411757	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
41408589	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
40453370	GRET	SVC	7/18/2022	1956	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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38117093	GRET	SVC	2/12/2021	1956	RET ABN	UG-SERVICE
37973593	GRET	SVC	1/5/2021	1956	RET ABN	UG-SERVICE
39092654	GRET	SVC	9/10/2021	1956	RET ABN	UG-SERVICE
39410508	GRET	SVC	11/10/2021	1956	RET ABN	UG-SERVICE
43755541	GRET	SVC	11/9/2024	1957	RET ABN	UG-SERVICE
41424260	GRET	SVC	10/18/2023	1957	RET ABN	UG-SERVICE
41430106	GRET	SVC	9/12/2023	1957	RET ABN	UG-SERVICE
37740415	GRET	SVC	11/21/2020	1957	RET ABN	UG-SERVICE
36137570	GRET	SVC	4/21/2020	1957	RET ABN	UG-SERVICE
41442142	GRET	SVC	9/13/2023	1957	RET ABN	UG-SERVICE
39518727	GRET	SVC	12/10/2021	1957	RET ABN	UG-SERVICE
38881452	GRET	SVC	8/31/2021	1957	RET ABN	UG-SERVICE
39542672	GRET	SVC	12/15/2021	1957	RET ABN	UG-SERVICE
41669838	GRET	SVC	6/17/2023	1957	RET ABN	UG-SERVICE
36267558	GRET	SVC	3/24/2020	1957	RET ABN	UG-SERVICE
36387479	GRET	SVC	7/2/2020	1957	RET ABN	UG-SERVICE
41075020	GRET	SVC	12/21/2022	1957	RET ABN	UG-SERVICE
41068182	GRET	SVC	1/10/2023	1957	RET ABN	UG-SERVICE
41411755	GRET	SVC	4/2/2024	1957	RET ABN	UG-SERVICE
42176690	GRET	SVC	10/3/2023	1957	RET ABN	UG-SERVICE
36598691	GRET	SVC	7/25/2020	1957	RET ABN	UG-SERVICE
41424518	GRET	SVC	10/18/2023	1957	RET ABN	UG-SERVICE
41028795	GRET	SVC	12/6/2022	1957	RET ABN	UG-SERVICE
39806497	GRET	SVC	2/21/2022	1957	RET ABN	UG-SERVICE
41362916	GRET	SVC	3/13/2023	1957	RET ABN	UG-SERVICE
36118917	GRET	SVC	10/30/2020	1957	RET ABN	UG-SERVICE
41807889	GRET	SVC	6/27/2023	1957	RET ABN	UG-SERVICE
40990955	GRET	SVC	12/15/2022	1957	RET ABN	UG-SERVICE
36118832	GRET	SVC	10/14/2020	1957	RET ABN	UG-SERVICE
36102856	GRET	SVC	4/22/2020	1957	RET ABN	UG-SERVICE
41117720	GRET	SVC	1/10/2023	1957	RET ABN	UG-SERVICE
41423884	GRET	SVC	10/18/2023	1957	RET ABN	UG-SERVICE
38599595	GRET	SVC	6/9/2021	1957	RET ABN	UG-SERVICE
35837924	GRET	SVC	8/19/2020	1957	RET ABN	UG-SERVICE
40131343	GRET	SVC	5/17/2022	1957	RET ABN	UG-SERVICE
41442140	GRET	SVC	9/13/2023	1957	RET ABN	UG-SERVICE
36108624	GRET	SVC	4/23/2020	1957	RET ABN	UG-SERVICE
43303826	GRET	SVC	7/11/2024	1957	RET ABN	UG-SERVICE
40137963	GRET	SVC	5/19/2022	1957	RET ABN	UG-SERVICE
39606854	GRET	SVC	4/20/2021	1957	RET ABN	UG-SERVICE
40082004	GRET	SVC	8/24/2022	1957	RET ABN	UG-SERVICE
38568559	GRET	SVC	6/7/2021	1957	RET ABN	UG-SERVICE
41430105	GRET	SVC	9/12/2023	1957	RET ABN	UG-SERVICE
41969457	GRET	SVC	7/30/2024	1957	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41409318	GRET	SVC	4/2/2024	1957	RET ABN	UG-SERVICE
36170363	GRET	SVC	3/24/2020	1957	RET ABN	UG-SERVICE
36119061	GRET	SVC	10/30/2020	1957	RET ABN	UG-SERVICE
37639344	GRET	SVC	11/17/2020	1957	RET ABN	UG-SERVICE
41969454	GRET	SVC	7/30/2024	1957	RET ABN	UG-SERVICE
42898518	GRET	SVC	9/19/2024	1957	RET ABN	UG-SERVICE
36425569	GRET	SVC	5/12/2020	1957	RET ABN	UG-SERVICE
42137717	GRET	SVC	9/21/2023	1957	RET ABN	UG-SERVICE
35838041	GRET	SVC	8/19/2020	1957	RET ABN	UG-SERVICE
36580954	GRET	SVC	7/6/2020	1957	RET ABN	UG-SERVICE
40973890	GRET	SVC	1/24/2023	1957	RET ABN	UG-SERVICE
39578746	GRET	SVC	12/22/2021	1957	RET ABN	UG-SERVICE
38033879	GRET	SVC	1/21/2021	1957	RET ABN	UG-SERVICE
40865909	GRET	SVC	8/22/2023	1957	RET ABN	UG-SERVICE
42995221	GRET	SVC	7/2/2024	1957	RET ABN	UG-SERVICE
43945703	GRET	SVC	12/17/2024	1957	RET ABN	UG-SERVICE
41424355	GRET	SVC	4/2/2023	1957	RET ABN	UG-SERVICE
40583049	GRET	SVC	9/24/2022	1957	RET ABN	UG-SERVICE
41117391	GRET	SVC	1/12/2023	1957	RET ABN	UG-SERVICE
41691783	GRET	SVC	6/2/2023	1957	RET ABN	UG-SERVICE
37183757	GRET	SVC	8/23/2020	1957	RET ABN	UG-SERVICE
39665276	GRET	SVC	8/3/2022	1957	RET ABN	UG-SERVICE
43208433	GRET	SVC	6/25/2024	1957	RET ABN	UG-SERVICE
42247030	GRET	SVC	10/30/2023	1957	RET ABN	UG-SERVICE
41430214	GRET	SVC	9/19/2023	1957	RET ABN	UG-SERVICE
39830526	GRET	SVC	8/3/2022	1957	RET ABN	UG-SERVICE
41287030	GRET	SVC	3/17/2023	1957	RET ABN	UG-SERVICE
38541491	GRET	SVC	5/26/2021	1957	RET ABN	UG-SERVICE
42701509	GRET	SVC	2/14/2024	1957	RET ABN	UG-SERVICE
36121520	GRET	SVC	11/5/2020	1957	RET ABN	UG-SERVICE
37415381	GRET	SVC	10/28/2020	1957	RET ABN	UG-SERVICE
41068186	GRET	SVC	1/21/2023	1957	RET ABN	UG-SERVICE
36118826	GRET	SVC	10/14/2020	1957	RET ABN	UG-SERVICE
41088303	GRET	SVC	1/9/2023	1957	RET ABN	UG-SERVICE
38611656	GRET	SVC	6/10/2021	1957	RET ABN	UG-SERVICE
43621453	GRET	SVC	9/17/2024	1957	RET ABN	UG-SERVICE
43863443	GRET	SVC	11/23/2024	1957	RET ABN	UG-SERVICE
35939239	GRET	SVC	1/28/2020	1957	RET ABN	UG-SERVICE
41036611	GRET	SVC	12/13/2022	1957	RET ABN	UG-SERVICE
42336427	GRET	SVC	4/2/2024	1957	RET ABN	UG-SERVICE
36023387	GRET	SVC	2/17/2020	1957	RET ABN	UG-SERVICE
41430211	GRET	SVC	9/13/2023	1957	RET ABN	UG-SERVICE
41222696	GRET	SVC	2/2/2023	1957	RET ABN	UG-SERVICE
36121611	GRET	SVC	10/30/2020	1957	RET ABN	UG-SERVICE
41401747	GRET	SVC	3/15/2023	1957	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36228629	GRET	SVC	3/8/2021	1957	RET ABN	UG-SERVICE
36303557	GRET	SVC	5/6/2020	1957	RET ABN	UG-SERVICE
41707019	GRET	SVC	6/12/2023	1957	RET ABN	UG-SERVICE
41807579	GRET	SVC	6/28/2023	1957	RET ABN	UG-SERVICE
41409106	GRET	SVC	4/2/2024	1957	RET ABN	UG-SERVICE
41898750	GRET	SVC	7/24/2023	1957	RET ABN	UG-SERVICE
41063474	GRET	SVC	12/17/2022	1957	RET ABN	UG-SERVICE
41424263	GRET	SVC	10/18/2023	1957	RET ABN	UG-SERVICE
39423526	GRET	SVC	6/27/2022	1957	RET ABN	UG-SERVICE
42028594	GRET	SVC	8/24/2023	1957	RET ABN	UG-SERVICE
41513777	GRET	SVC	4/25/2023	1957	RET ABN	UG-SERVICE
41411416	GRET	SVC	11/2/2023	1957	RET ABN	UG-SERVICE
41083730	GRET	SVC	12/21/2022	1957	RET ABN	UG-SERVICE
38352975	GRET	SVC	2/14/2023	1958	RET ABN	UG-SERVICE
41085609	GRET	SVC	1/13/2023	1958	RET ABN	UG-SERVICE
38097172	GRET	SVC	9/2/2021	1958	RET ABN	UG-SERVICE
36245398	GRET	SVC	3/7/2020	1958	RET ABN	UG-SERVICE
37740543	GRET	SVC	11/25/2020	1958	RET ABN	UG-SERVICE
39366490	GRET	SVC	11/4/2021	1958	RET ABN	UG-SERVICE
41408227	GRET	SVC	4/2/2024	1958	RET ABN	UG-SERVICE
38352973	GRET	SVC	2/17/2023	1958	RET ABN	UG-SERVICE
40171770	GRET	SVC	5/17/2022	1958	RET ABN	UG-SERVICE
41411415	GRET	SVC	11/2/2023	1958	RET ABN	UG-SERVICE
41965726	GRET	SVC	8/3/2023	1958	RET ABN	UG-SERVICE
41617607	GRET	SVC	4/27/2023	1958	RET ABN	UG-SERVICE
36347721	GRET	SVC	6/29/2020	1958	RET ABN	UG-SERVICE
41423892	GRET	SVC	10/18/2023	1958	RET ABN	UG-SERVICE
38034501	GRET	SVC	12/6/2020	1958	RET ABN	UG-SERVICE
35887497	GRET	SVC	1/13/2020	1958	RET ABN	UG-SERVICE
36120267	GRET	SVC	10/30/2020	1958	RET ABN	UG-SERVICE
38357049	GRET	SVC	2/17/2023	1958	RET ABN	UG-SERVICE
35995645	GRET	SVC	2/10/2020	1958	RET ABN	UG-SERVICE
41423893	GRET	SVC	10/18/2023	1958	RET ABN	UG-SERVICE
42979658	GRET	SVC	4/26/2024	1958	RET ABN	UG-SERVICE
36106825	GRET	SVC	3/9/2020	1958	RET ABN	UG-SERVICE
41148325	GRET	SVC	1/7/2023	1958	RET ABN	UG-SERVICE
40035442	GRET	SVC	4/20/2022	1958	RET ABN	UG-SERVICE
38522091	GRET	SVC	5/21/2021	1958	RET ABN	UG-SERVICE
36868685	GRET	SVC	8/31/2020	1958	RET ABN	UG-SERVICE
41423894	GRET	SVC	10/18/2023	1958	RET ABN	UG-SERVICE
38474291	GRET	SVC	3/30/2021	1958	RET ABN	UG-SERVICE
42786964	GRET	SVC	3/4/2024	1958	RET ABN	UG-SERVICE
41424762	GRET	SVC	6/20/2023	1958	RET ABN	UG-SERVICE
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order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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42737790	GRET	SVC	2/19/2024	1958	RET ABN	UG-SERVICE
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38970342	GRET	SVC	12/9/2021	1958	RET ABN	UG-SERVICE
41441929	GRET	SVC	9/13/2023	1958	RET ABN	UG-SERVICE
38507101	GRET	SVC	5/3/2021	1958	RET ABN	UG-SERVICE
40460466	GRET	SVC	7/25/2022	1958	RET ABN	UG-SERVICE
38426008	GRET	SVC	4/28/2021	1958	RET ABN	UG-SERVICE
43752107	GRET	SVC	12/10/2024	1958	RET ABN	UG-SERVICE
40432962	GRET	SVC	7/22/2022	1958	RET ABN	UG-SERVICE
36105787	GRET	SVC	2/13/2020	1958	RET ABN	UG-SERVICE
43834420	GRET	SVC	11/18/2024	1958	RET ABN	UG-SERVICE
39493537	GRET	SVC	12/22/2021	1958	RET ABN	UG-SERVICE
38352458	GRET	SVC	6/10/2021	1958	RET ABN	UG-SERVICE
41284186	GRET	SVC	3/15/2023	1958	RET ABN	UG-SERVICE
42656588	GRET	SVC	12/19/2024	1958	RET ABN	UG-SERVICE
43620926	GRET	SVC	9/20/2024	1958	RET ABN	UG-SERVICE
41147849	GRET	SVC	1/9/2023	1958	RET ABN	UG-SERVICE
41051916	GRET	SVC	1/12/2023	1958	RET ABN	UG-SERVICE
35682119	GRET	SVC	1/9/2020	1958	RET ABN	UG-SERVICE
41052320	GRET	SVC	1/12/2023	1958	RET ABN	UG-SERVICE
36086679	GRET	SVC	2/27/2020	1958	RET ABN	UG-SERVICE
39382160	GRET	SVC	11/5/2021	1958	RET ABN	UG-SERVICE
41139506	GRET	SVC	1/9/2023	1958	RET ABN	UG-SERVICE
42847072	GRET	SVC	4/1/2024	1958	RET ABN	UG-SERVICE
43984868	GRET	SVC	12/12/2024	1958	RET ABN	UG-SERVICE
39831388	GRET	SVC	8/3/2022	1958	RET ABN	UG-SERVICE
36120268	GRET	SVC	10/30/2020	1958	RET ABN	UG-SERVICE
43623434	GRET	SVC	11/25/2024	1958	RET ABN	UG-SERVICE
38352968	GRET	SVC	2/14/2023	1958	RET ABN	UG-SERVICE
41411432	GRET	SVC	11/2/2023	1958	RET ABN	UG-SERVICE
39916054	GRET	SVC	5/2/2022	1958	RET ABN	UG-SERVICE
38111180	GRET	SVC	2/9/2021	1958	RET ABN	UG-SERVICE
38352977	GRET	SVC	2/17/2023	1958	RET ABN	UG-SERVICE
37887690	GRET	SVC	12/11/2020	1958	RET ABN	UG-SERVICE
39383979	GRET	SVC	11/9/2021	1958	RET ABN	UG-SERVICE
38352979	GRET	SVC	2/17/2023	1958	RET ABN	UG-SERVICE
36120487	GRET	SVC	10/30/2020	1958	RET ABN	UG-SERVICE
39806834	GRET	SVC	2/16/2022	1958	RET ABN	UG-SERVICE
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36166301	GRET	SVC	3/23/2020	1958	RET ABN	UG-SERVICE
39609259	GRET	SVC	4/27/2021	1958	RET ABN	UG-SERVICE
42915278	GRET	SVC	4/15/2024	1958	RET ABN	UG-SERVICE
36559263	GRET	SVC	6/4/2020	1958	RET ABN	UG-SERVICE
38352976	GRET	SVC	2/17/2023	1958	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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38097177	GRET	SVC	9/2/2021	1958	RET ABN	UG-SERVICE
37386989	GRET	SVC	11/25/2020	1958	RET ABN	UG-SERVICE
39831208	GRET	SVC	8/3/2022	1958	RET ABN	UG-SERVICE
39301096	GRET	SVC	10/20/2021	1958	RET ABN	UG-SERVICE
36658889	GRET	SVC	7/21/2020	1958	RET ABN	UG-SERVICE
38301288	GRET	SVC	5/5/2021	1958	RET ABN	UG-SERVICE
40870148	GRET	SVC	10/28/2022	1958	RET ABN	UG-SERVICE
40318186	GRET	SVC	6/20/2022	1958	RET ABN	UG-SERVICE
36570144	GRET	SVC	7/1/2020	1958	RET ABN	UG-SERVICE
38352972	GRET	SVC	2/17/2023	1958	RET ABN	UG-SERVICE
38089255	GRET	SVC	1/20/2021	1958	RET ABN	UG-SERVICE
40495220	GRET	SVC	7/23/2022	1958	RET ABN	UG-SERVICE
41424763	GRET	SVC	10/18/2023	1958	RET ABN	UG-SERVICE
42957326	GRET	SVC	9/19/2024	1958	RET ABN	UG-SERVICE
41441928	GRET	SVC	9/13/2023	1958	RET ABN	UG-SERVICE
39721554	GRET	SVC	1/28/2022	1958	RET ABN	UG-SERVICE
38357046	GRET	SVC	2/17/2023	1958	RET ABN	UG-SERVICE
41408474	GRET	SVC	4/2/2024	1958	RET ABN	UG-SERVICE
40399649	GRET	SVC	7/15/2022	1958	RET ABN	UG-SERVICE
36107160	GRET	SVC	4/22/2020	1958	RET ABN	UG-SERVICE
36122371	GRET	SVC	11/5/2020	1958	RET ABN	UG-SERVICE
39353523	GRET	SVC	2/15/2022	1958	RET ABN	UG-SERVICE
36149149	GRET	SVC	1/6/2021	1958	RET ABN	UG-SERVICE
43011963	GRET	SVC	4/30/2024	1958	RET ABN	UG-SERVICE
41411413	GRET	SVC	11/2/2023	1958	RET ABN	UG-SERVICE
38205412	GRET	SVC	3/16/2021	1958	RET ABN	UG-SERVICE
43353724	GRET	SVC	11/7/2024	1958	RET ABN	UG-SERVICE
38791176	GRET	SVC	8/2/2021	1958	RET ABN	UG-SERVICE
40492804	GRET	SVC	8/2/2022	1958	RET ABN	UG-SERVICE
41286908	GRET	SVC	3/17/2023	1958	RET ABN	UG-SERVICE
40036424	GRET	SVC	4/20/2022	1958	RET ABN	UG-SERVICE
35958597	GRET	SVC	2/20/2020	1958	RET ABN	UG-SERVICE
36992541	GRET	SVC	9/22/2020	1958	RET ABN	UG-SERVICE
41148327	GRET	SVC	1/7/2023	1958	RET ABN	UG-SERVICE
37948477	GRET	SVC	12/23/2020	1959	RET ABN	UG-SERVICE
41398905	GRET	SVC	3/24/2023	1959	RET ABN	UG-SERVICE
36121341	GRET	SVC	10/30/2020	1959	RET ABN	UG-SERVICE
38659865	GRET	SVC	6/24/2021	1959	RET ABN	UG-SERVICE
40487935	GRET	SVC	7/25/2022	1959	RET ABN	UG-SERVICE
42353965	GRET	SVC	11/14/2023	1959	RET ABN	UG-SERVICE
36893335	GRET	SVC	8/29/2020	1959	RET ABN	UG-SERVICE
39699185	GRET	SVC	1/18/2022	1959	RET ABN	UG-SERVICE
41411078	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
41411074	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43151637	GRET	SVC	7/15/2024	1959	RET ABN	UG-SERVICE
42208445	GRET	SVC	10/13/2023	1959	RET ABN	UG-SERVICE
41408519	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
40172804	GRET	SVC	5/16/2022	1959	RET ABN	UG-SERVICE
43274816	GRET	SVC	7/6/2024	1959	RET ABN	UG-SERVICE
39380921	GRET	SVC	10/21/2021	1959	RET ABN	UG-SERVICE
43377183	GRET	SVC	8/6/2024	1959	RET ABN	UG-SERVICE
37307282	GRET	SVC	11/5/2020	1959	RET REM	UG-SERVICE
37934432	GRET	SVC	12/21/2020	1959	RET ABN	UG-SERVICE
42452951	GRET	SVC	4/26/2024	1959	RET ABN	UG-SERVICE
42168657	GRET	SVC	10/2/2023	1959	RET ABN	UG-SERVICE
36298881	GRET	SVC	5/5/2020	1959	RET ABN	UG-SERVICE
36122368	GRET	SVC	10/30/2020	1959	RET ABN	UG-SERVICE
41409110	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
43346976	GRET	SVC	7/25/2024	1959	RET ABN	UG-SERVICE
41409109	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
41842797	GRET	SVC	7/8/2023	1959	RET ABN	UG-SERVICE
39780203	GRET	SVC	2/11/2022	1959	RET ABN	UG-SERVICE
41544813	GRET	SVC	12/11/2023	1959	RET ABN	UG-SERVICE
38352931	GRET	SVC	2/17/2023	1959	RET ABN	UG-SERVICE
36927908	GRET	SVC	9/17/2020	1959	RET ABN	UG-SERVICE
36121816	GRET	SVC	10/12/2020	1959	RET ABN	UG-SERVICE
37321680	GRET	SVC	12/1/2020	1959	RET ABN	UG-SERVICE
41411901	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
39845055	GRET	SVC	3/4/2022	1959	RET ABN	UG-SERVICE
42670034	GRET	SVC	2/9/2024	1959	RET ABN	UG-SERVICE
36101963	GRET	SVC	3/18/2020	1959	RET ABN	UG-SERVICE
41407232	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
41407210	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
39611979	GRET	SVC	5/27/2021	1959	RET ABN	UG-SERVICE
40858381	GRET	SVC	10/26/2022	1959	RET ABN	UG-SERVICE
41859889	GRET	SVC	8/11/2023	1959	RET ABN	UG-SERVICE
36035810	GRET	SVC	2/15/2020	1959	RET ABN	UG-SERVICE
40490110	GRET	SVC	5/23/2023	1959	RET ABN	UG-SERVICE
41288533	GRET	SVC	3/1/2023	1959	RET ABN	UG-SERVICE
39666420	GRET	SVC	11/18/2022	1959	RET ABN	UG-SERVICE
37249819	GRET	SVC	11/17/2020	1959	RET ABN	UG-SERVICE
38441389	GRET	SVC	1/6/2022	1959	RET ABN	UG-SERVICE
40338701	GRET	SVC	6/21/2022	1959	RET ABN	UG-SERVICE
41007816	GRET	SVC	12/8/2022	1959	RET ABN	UG-SERVICE
41408461	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
40478345	GRET	SVC	7/25/2022	1959	RET ABN	UG-SERVICE
38033756	GRET	SVC	1/22/2021	1959	RET ABN	UG-SERVICE
37019048	GRET	SVC	9/28/2020	1959	RET ABN	UG-SERVICE
42506338	GRET	SVC	1/4/2024	1959	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41273847	GRET	SVC	2/28/2023	1959	RET ABN	UG-SERVICE
36260061	GRET	SVC	3/18/2020	1959	RET ABN	UG-SERVICE
43154437	GRET	SVC	6/10/2024	1959	RET ABN	UG-SERVICE
36254921	GRET	SVC	10/25/2020	1959	RET ABN	UG-SERVICE
36120709	GRET	SVC	10/30/2020	1959	RET ABN	UG-SERVICE
43394312	GRET	SVC	9/19/2024	1959	RET ABN	UG-SERVICE
37869002	GRET	SVC	12/2/2020	1959	RET ABN	UG-SERVICE
42008802	GRET	SVC	8/16/2023	1959	RET ABN	UG-SERVICE
31040393	GRET	SVC	11/10/2022	1959	RET ABN	UG-SERVICE
36336551	GRET	SVC	5/8/2020	1959	RET ABN	UG-SERVICE
39367005	GRET	SVC	11/2/2021	1959	RET ABN	UG-SERVICE
39904815	GRET	SVC	3/24/2022	1959	RET ABN	UG-SERVICE
39745884	GRET	SVC	2/9/2022	1959	RET ABN	UG-SERVICE
42911783	GRET	SVC	4/13/2024	1959	RET ABN	UG-SERVICE
41318360	GRET	SVC	3/3/2023	1959	RET ABN	UG-SERVICE
41411279	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
36168654	GRET	SVC	3/23/2020	1959	RET ABN	UG-SERVICE
43318343	GRET	SVC	8/9/2024	1959	RET ABN	UG-SERVICE
41277882	GRET	SVC	2/13/2023	1959	RET ABN	UG-SERVICE
41407806	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
38594833	GRET	SVC	6/8/2021	1959	RET ABN	UG-SERVICE
41571592	GRET	SVC	5/1/2023	1959	RET ABN	UG-SERVICE
43614177	GRET	SVC	9/25/2024	1959	RET ABN	UG-SERVICE
36609185	GRET	SVC	7/22/2020	1959	RET ABN	UG-SERVICE
41407230	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
38964849	GRET	SVC	9/20/2021	1959	RET ABN	UG-SERVICE
39791766	GRET	SVC	10/5/2021	1959	RET ABN	UG-SERVICE
42752845	GRET	SVC	6/28/2024	1959	RET ABN	UG-SERVICE
41408225	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
43473548	GRET	SVC	8/15/2024	1959	RET ABN	UG-SERVICE
42316686	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
36121809	GRET	SVC	10/12/2020	1959	RET ABN	UG-SERVICE
41116695	GRET	SVC	2/2/2023	1959	RET ABN	UG-SERVICE
41573846	GRET	SVC	5/10/2023	1959	RET ABN	UG-SERVICE
36609164	GRET	SVC	7/22/2020	1959	RET ABN	UG-SERVICE
41411052	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
41560331	GRET	SVC	6/10/2024	1959	RET ABN	UG-SERVICE
38575530	GRET	SVC	6/7/2021	1959	RET ABN	UG-SERVICE
41146287	GRET	SVC	1/9/2023	1959	RET ABN	UG-SERVICE
40371078	GRET	SVC	7/6/2022	1959	RET ABN	UG-SERVICE
36121811	GRET	SVC	10/14/2020	1959	RET ABN	UG-SERVICE
40546486	GRET	SVC	8/17/2022	1959	RET ABN	UG-SERVICE
41185868	GRET	SVC	1/20/2023	1959	RET ABN	UG-SERVICE
43469668	GRET	SVC	8/21/2024	1959	RET ABN	UG-SERVICE
39169178	GRET	SVC	9/20/2021	1959	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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37985467	GRET	SVC	1/5/2021	1959	RET ABN	UG-SERVICE
38731096	GRET	SVC	5/24/2021	1959	RET ABN	UG-SERVICE
40561334	GRET	SVC	8/21/2022	1959	RET ABN	UG-SERVICE
36101523	GRET	SVC	4/24/2020	1959	RET ABN	UG-SERVICE
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37033025	GRET	SVC	10/6/2020	1959	RET ABN	UG-SERVICE
38503996	GRET	SVC	4/1/2021	1959	RET ABN	UG-SERVICE
42493055	GRET	SVC	12/18/2023	1959	RET ABN	UG-SERVICE
36120279	GRET	SVC	10/30/2020	1959	RET ABN	UG-SERVICE
36109951	GRET	SVC	4/22/2020	1959	RET ABN	UG-SERVICE
35926327	GRET	SVC	1/20/2020	1959	RET ABN	UG-SERVICE
40500730	GRET	SVC	8/25/2022	1959	RET ABN	UG-SERVICE
40659494	GRET	SVC	9/7/2022	1959	RET ABN	UG-SERVICE
39814853	GRET	SVC	3/7/2022	1959	RET ABN	UG-SERVICE
43775657	GRET	SVC	10/29/2024	1959	RET ABN	UG-SERVICE
38033758	GRET	SVC	1/22/2021	1959	RET ABN	UG-SERVICE
36102665	GRET	SVC	3/9/2020	1960	RET ABN	UG-SERVICE
41407614	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
41035823	GRET	SVC	12/8/2022	1960	RET ABN	UG-SERVICE
36342646	GRET	SVC	5/6/2020	1960	RET ABN	UG-SERVICE
41411769	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
39609135	GRET	SVC	4/26/2021	1960	RET ABN	UG-SERVICE
41411297	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
41529304	GRET	SVC	4/17/2023	1960	RET ABN	UG-SERVICE
40425796	GRET	SVC	7/15/2022	1960	RET ABN	UG-SERVICE
39424062	GRET	SVC	6/27/2022	1960	RET ABN	UG-SERVICE
41462844	GRET	SVC	4/17/2023	1960	RET ABN	UG-SERVICE
36241471	GRET	SVC	4/30/2020	1960	RET ABN	UG-SERVICE
42141049	GRET	SVC	8/7/2024	1960	RET ABN	UG-SERVICE
43386121	GRET	SVC	8/7/2024	1960	RET ABN	UG-SERVICE
43353802	GRET	SVC	11/6/2024	1960	RET ABN	UG-SERVICE
41407611	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
40608423	GRET	SVC	8/23/2022	1960	RET ABN	UG-SERVICE
41769886	GRET	SVC	7/14/2023	1960	RET ABN	UG-SERVICE
41411343	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
37834100	GRET	SVC	12/1/2020	1960	RET ABN	UG-SERVICE
37887893	GRET	SVC	12/7/2020	1960	RET ABN	UG-SERVICE
40139567	GRET	SVC	5/9/2022	1960	RET ABN	UG-SERVICE
41940414	GRET	SVC	7/31/2023	1960	RET ABN	UG-SERVICE
41411298	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
36342641	GRET	SVC	5/6/2020	1960	RET ABN	UG-SERVICE
39469482	GRET	SVC	11/29/2021	1960	RET ABN	UG-SERVICE
42518567	GRET	SVC	12/27/2023	1960	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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41441936	GRET	SVC	9/12/2023	1960	RET ABN	UG-SERVICE
36342398	GRET	SVC	5/6/2020	1960	RET ABN	UG-SERVICE
43353735	GRET	SVC	11/7/2024	1960	RET ABN	UG-SERVICE
40425794	GRET	SVC	7/15/2022	1960	RET ABN	UG-SERVICE
43710834	GRET	SVC	10/16/2024	1960	RET ABN	UG-SERVICE
42801581	GRET	SVC	3/11/2024	1960	RET ABN	UG-SERVICE
36112814	GRET	SVC	10/30/2020	1960	RET ABN	UG-SERVICE
39066318	GRET	SVC	9/1/2021	1960	RET ABN	UG-SERVICE
39077882	GRET	SVC	1/31/2022	1960	RET ABN	UG-SERVICE
36342644	GRET	SVC	5/6/2020	1960	RET ABN	UG-SERVICE
35997487	GRET	SVC	2/10/2020	1960	RET ABN	UG-SERVICE
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36112444	GRET	SVC	10/30/2020	1960	RET ABN	UG-SERVICE
42242910	GRET	SVC	10/12/2023	1960	RET ABN	UG-SERVICE
41407612	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
41407775	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
36769509	GRET	SVC	9/18/2020	1960	RET ABN	UG-SERVICE
42202957	GRET	SVC	10/19/2023	1960	RET ABN	UG-SERVICE
42828842	GRET	SVC	3/18/2024	1960	RET ABN	UG-SERVICE
39199772	GRET	SVC	10/11/2021	1960	RET ABN	UG-SERVICE
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41277651	GRET	SVC	2/13/2023	1960	RET ABN	UG-SERVICE
41051919	GRET	SVC	1/12/2023	1960	RET ABN	UG-SERVICE
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38480409	GRET	SVC	5/10/2021	1960	RET ABN	UG-SERVICE
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42021634	GRET	SVC	8/21/2023	1960	RET ABN	UG-SERVICE
38205080	GRET	SVC	3/13/2021	1960	RET ABN	UG-SERVICE
39950874	GRET	SVC	6/17/2022	1960	RET ABN	UG-SERVICE
39657141	GRET	SVC	6/28/2022	1960	RET ABN	UG-SERVICE
41185257	GRET	SVC	1/17/2023	1960	RET ABN	UG-SERVICE
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39543595	GRET	SVC	12/14/2021	1960	RET ABN	UG-SERVICE
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42115267	GRET	SVC	9/15/2023	1960	RET ABN	UG-SERVICE
40171166	GRET	SVC	9/23/2022	1960	RET ABN	UG-SERVICE
36124971	GRET	SVC	3/11/2020	1960	RET ABN	UG-SERVICE
40691314	GRET	SVC	9/13/2022	1960	RET ABN	UG-SERVICE
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41407882	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
36983777	GRET	SVC	9/23/2020	1960	RET ABN	UG-SERVICE
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42539919	GRET	SVC	1/5/2024	1960	RET ABN	UG-SERVICE
42028371	GRET	SVC	8/24/2023	1960	RET ABN	UG-SERVICE
41407610	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
41180788	GRET	SVC	1/4/2023	1960	RET ABN	UG-SERVICE
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38835873	GRET	SVC	8/6/2021	1960	RET ABN	UG-SERVICE
41503458	GRET	SVC	4/24/2023	1960	RET ABN	UG-SERVICE
36876164	GRET	SVC	4/19/2021	1960	RET ABN	UG-SERVICE
36363717	GRET	SVC	5/19/2020	1960	RET ABN	UG-SERVICE
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39657140	GRET	SVC	6/28/2022	1960	RET ABN	UG-SERVICE
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36495068	GRET	SVC	7/7/2020	1960	RET ABN	UG-SERVICE
41429979	GRET	SVC	9/13/2023	1960	RET ABN	UG-SERVICE
41411344	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
35988521	GRET	SVC	3/9/2020	1960	RET ABN	UG-SERVICE
41185580	GRET	SVC	1/20/2023	1960	RET ABN	UG-SERVICE
40751406	GRET	SVC	9/30/2022	1960	RET ABN	UG-SERVICE
37706889	GRET	SVC	11/20/2020	1960	RET ABN	UG-SERVICE
36589015	GRET	SVC	7/8/2020	1960	RET ABN	UG-SERVICE
38624477	GRET	SVC	7/29/2021	1960	RET ABN	UG-SERVICE
42969403	GRET	SVC	4/29/2024	1960	RET ABN	UG-SERVICE
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42069770	GRET	SVC	9/7/2023	1960	RET ABN	UG-SERVICE
36342640	GRET	SVC	5/6/2020	1960	RET ABN	UG-SERVICE
42888698	GRET	SVC	3/21/2024	1960	RET ABN	UG-SERVICE
40980863	GRET	SVC	11/23/2022	1960	RET ABN	UG-SERVICE
41183641	GRET	SVC	1/20/2023	1960	RET ABN	UG-SERVICE
36587660	GRET	SVC	6/9/2020	1960	RET ABN	UG-SERVICE
39230077	GRET	SVC	10/27/2021	1960	RET ABN	UG-SERVICE
38236492	GRET	SVC	3/16/2021	1960	RET ABN	UG-SERVICE
39319508	GRET	SVC	11/1/2021	1960	RET ABN	UG-SERVICE
40472862	GRET	SVC	7/26/2022	1960	RET ABN	UG-SERVICE
36068289	GRET	SVC	2/25/2020	1960	RET ABN	UG-SERVICE
43918276	GRET	SVC	12/10/2024	1960	RET ABN	UG-SERVICE
43700394	GRET	SVC	10/18/2024	1960	RET ABN	UG-SERVICE
40505994	GRET	SVC	8/5/2022	1960	RET ABN	UG-SERVICE
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37877948	GRET	SVC	11/30/2020	1960	RET ABN	UG-SERVICE
36056072	GRET	SVC	2/27/2020	1960	RET ABN	UG-SERVICE
40120512	GRET	SVC	5/3/2022	1960	RET ABN	UG-SERVICE
38064373	GRET	SVC	1/22/2021	1960	RET ABN	UG-SERVICE
36077747	GRET	SVC	3/2/2020	1960	RET ABN	UG-SERVICE
40782896	GRET	SVC	10/10/2022	1960	RET ABN	UG-SERVICE
43234773	GRET	SVC	7/11/2024	1960	RET ABN	UG-SERVICE
41243041	GRET	SVC	2/10/2023	1960	RET ABN	UG-SERVICE
36196171	GRET	SVC	6/25/2020	1960	RET ABN	UG-SERVICE
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36342397	GRET	SVC	5/6/2020	1960	RET ABN	UG-SERVICE
41441933	GRET	SVC	9/12/2023	1960	RET ABN	UG-SERVICE
41407885	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
40371452	GRET	SVC	6/29/2022	1960	RET ABN	UG-SERVICE
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32769562	GRET	SVC	7/8/2020	1960	RET ABN	UG-SERVICE
38324999	GRET	SVC	4/7/2021	1960	RET ABN	UG-SERVICE
39783713	GRET	SVC	2/11/2022	1960	RET ABN	UG-SERVICE
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41411345	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
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42670288	GRET	SVC	9/19/2024	1960	RET ABN	UG-SERVICE
41411299	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
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35960298	GRET	SVC	1/28/2020	1960	RET ABN	UG-SERVICE
40398607	GRET	SVC	7/15/2022	1960	RET ABN	UG-SERVICE
40265107	GRET	SVC	5/26/2022	1960	RET ABN	UG-SERVICE
37834104	GRET	SVC	12/11/2020	1960	RET ABN	UG-SERVICE
41407769	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
37529554	GRET	SVC	11/16/2020	1960	RET ABN	UG-SERVICE
41441934	GRET	SVC	9/12/2023	1960	RET ABN	UG-SERVICE
39654871	GRET	SVC	6/28/2022	1960	RET ABN	UG-SERVICE
37883994	GRET	SVC	12/8/2020	1960	RET ABN	UG-SERVICE
39379823	GRET	SVC	11/19/2021	1960	RET ABN	UG-SERVICE
42205146	GRET	SVC	10/11/2023	1960	RET ABN	UG-SERVICE
36779260	GRET	SVC	8/17/2020	1960	RET ABN	UG-SERVICE
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41411342	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
42299476	GRET	SVC	11/4/2023	1961	RET ABN	UG-SERVICE
40456658	GRET	SVC	7/20/2022	1961	RET ABN	UG-SERVICE
42548670	GRET	SVC	1/5/2024	1961	RET ABN	UG-SERVICE
38415912	GRET	SVC	4/27/2021	1961	RET ABN	UG-SERVICE
39618730	GRET	SVC	1/8/2022	1961	RET ABN	UG-SERVICE
36671619	GRET	SVC	8/21/2020	1961	RET ABN	UG-SERVICE
40230311	GRET	SVC	5/31/2022	1961	RET ABN	UG-SERVICE
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36120496	GRET	SVC	11/5/2020	1961	RET ABN	UG-SERVICE
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43918919	GRET	SVC	12/13/2024	1961	RET ABN	UG-SERVICE
39705919	GRET	SVC	1/18/2022	1961	RET ABN	UG-SERVICE
35960291	GRET	SVC	1/30/2020	1961	RET ABN	UG-SERVICE
40492793	GRET	SVC	7/23/2022	1961	RET ABN	UG-SERVICE
38125275	GRET	SVC	2/18/2021	1961	RET ABN	UG-SERVICE
40500736	GRET	SVC	8/31/2022	1961	RET ABN	UG-SERVICE
40634921	GRET	SVC	9/1/2022	1961	RET ABN	UG-SERVICE
37974006	GRET	SVC	12/23/2020	1961	RET ABN	UG-SERVICE
42185807	GRET	SVC	10/3/2023	1961	RET ABN	UG-SERVICE
43353732	GRET	SVC	11/6/2024	1961	RET ABN	UG-SERVICE
40216360	GRET	SVC	6/13/2022	1961	RET ABN	UG-SERVICE
42007332	GRET	SVC	8/15/2023	1961	RET ABN	UG-SERVICE
36469854	GRET	SVC	7/27/2020	1961	RET ABN	UG-SERVICE
38742158	GRET	SVC	7/12/2021	1961	RET ABN	UG-SERVICE
36893417	GRET	SVC	9/3/2020	1961	RET ABN	UG-SERVICE
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order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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38142517	GRET	SVC	2/10/2021	1961	RET ABN	UG-SERVICE
40353047	GRET	SVC	6/28/2022	1961	RET ABN	UG-SERVICE
35926372	GRET	SVC	2/13/2020	1961	RET ABN	UG-SERVICE
36977722	GRET	SVC	9/22/2020	1961	RET ABN	UG-SERVICE
40231367	GRET	SVC	6/15/2022	1961	RET ABN	UG-SERVICE
40612130	GRET	SVC	10/27/2022	1961	RET ABN	UG-SERVICE
41119588	GRET	SVC	1/6/2023	1961	RET ABN	UG-SERVICE
40330300	GRET	SVC	6/21/2022	1961	RET ABN	UG-SERVICE
42410988	GRET	SVC	11/27/2023	1961	RET ABN	UG-SERVICE
39680508	GRET	SVC	1/10/2022	1961	RET ABN	UG-SERVICE
42332980	GRET	SVC	11/3/2023	1961	RET ABN	UG-SERVICE
36164486	GRET	SVC	3/23/2020	1961	RET ABN	UG-SERVICE
41660045	GRET	SVC	5/22/2023	1961	RET ABN	UG-SERVICE
42024678	GRET	SVC	8/22/2023	1961	RET ABN	UG-SERVICE
39994343	GRET	SVC	4/19/2022	1961	RET ABN	UG-SERVICE
41411599	GRET	SVC	4/2/2024	1961	RET ABN	UG-SERVICE
43468927	GRET	SVC	8/26/2024	1961	RET ABN	UG-SERVICE
42284251	GRET	SVC	10/23/2023	1961	RET ABN	UG-SERVICE
35855538	GRET	SVC	1/7/2020	1961	RET ABN	UG-SERVICE
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38940899	GRET	SVC	8/16/2021	1961	RET ABN	UG-SERVICE
42687136	GRET	SVC	2/13/2024	1961	RET ABN	UG-SERVICE
43511838	GRET	SVC	9/4/2024	1961	RET ABN	UG-SERVICE
35856107	GRET	SVC	1/6/2020	1961	RET ABN	UG-SERVICE
39328380	GRET	SVC	10/18/2021	1961	RET ABN	UG-SERVICE
40645368	GRET	SVC	9/1/2022	1961	RET ABN	UG-SERVICE
39463485	GRET	SVC	11/26/2021	1961	RET ABN	UG-SERVICE
40500727	GRET	SVC	8/20/2022	1961	RET ABN	UG-SERVICE
43058302	GRET	SVC	5/14/2024	1961	RET ABN	UG-SERVICE
39209627	GRET	SVC	9/28/2021	1961	RET ABN	UG-SERVICE
41436801	GRET	SVC	3/30/2023	1961	RET ABN	UG-SERVICE
43290640	GRET	SVC	7/15/2024	1961	RET ABN	UG-SERVICE
42809628	GRET	SVC	3/11/2024	1961	RET ABN	UG-SERVICE
42137713	GRET	SVC	9/21/2023	1961	RET ABN	UG-SERVICE
35862608	GRET	SVC	1/7/2020	1961	RET ABN	UG-SERVICE
43056751	GRET	SVC	5/14/2024	1961	RET ABN	UG-SERVICE
39997913	GRET	SVC	4/18/2022	1961	RET ABN	UG-SERVICE
37925865	GRET	SVC	12/18/2020	1961	RET ABN	UG-SERVICE
36343658	GRET	SVC	5/18/2020	1961	RET ABN	UG-SERVICE
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36210724	GRET	SVC	5/7/2020	1961	RET ABN	UG-SERVICE
41320418	GRET	SVC	3/1/2023	1961	RET ABN	UG-SERVICE
43010772	GRET	SVC	5/9/2024	1961	RET ABN	UG-SERVICE
37048341	GRET	SVC	10/26/2020	1961	RET ABN	UG-SERVICE
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40359852	GRET	SVC	7/1/2022	1961	RET ABN	UG-SERVICE
39613400	GRET	SVC	12/28/2021	1961	RET ABN	UG-SERVICE
35963463	GRET	SVC	1/23/2020	1961	RET ABN	UG-SERVICE
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40561485	GRET	SVC	8/13/2022	1961	RET ABN	UG-SERVICE
42908244	GRET	SVC	4/13/2024	1961	RET ABN	UG-SERVICE
43480938	GRET	SVC	10/25/2024	1961	RET ABN	UG-SERVICE
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43486866	GRET	SVC	8/26/2024	1961	RET ABN	UG-SERVICE
38803009	GRET	SVC	6/12/2021	1961	RET ABN	UG-SERVICE
39863174	GRET	SVC	3/9/2022	1961	RET ABN	UG-SERVICE
42169433	GRET	SVC	10/2/2023	1961	RET ABN	UG-SERVICE
36102271	GRET	SVC	4/23/2020	1961	RET ABN	UG-SERVICE
40512943	GRET	SVC	8/17/2022	1961	RET ABN	UG-SERVICE
36433443	GRET	SVC	6/12/2020	1961	RET ABN	UG-SERVICE
43607619	GRET	SVC	10/8/2024	1961	RET ABN	UG-SERVICE
38239128	GRET	SVC	3/15/2021	1961	RET ABN	UG-SERVICE
36947759	GRET	SVC	9/15/2020	1961	RET ABN	UG-SERVICE
43235511	GRET	SVC	7/2/2024	1961	RET ABN	UG-SERVICE
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37081391	GRET	SVC	10/15/2020	1961	RET ABN	UG-SERVICE
38388082	GRET	SVC	4/20/2021	1961	RET ABN	UG-SERVICE
36019872	GRET	SVC	2/14/2020	1961	RET ABN	UG-SERVICE
40667985	GRET	SVC	8/30/2022	1961	RET ABN	UG-SERVICE
35960591	GRET	SVC	2/3/2020	1961	RET ABN	UG-SERVICE
37039874	GRET	SVC	11/6/2020	1961	RET ABN	UG-SERVICE
39759217	GRET	SVC	2/8/2022	1961	RET ABN	UG-SERVICE
41003931	GRET	SVC	11/28/2022	1961	RET ABN	UG-SERVICE
38624151	GRET	SVC	6/15/2021	1961	RET ABN	UG-SERVICE
42680515	GRET	SVC	2/12/2024	1961	RET ABN	UG-SERVICE
43930848	GRET	SVC	12/10/2024	1961	RET ABN	UG-SERVICE
36833518	GRET	SVC	9/2/2020	1961	RET ABN	UG-SERVICE
40463854	GRET	SVC	8/25/2022	1961	RET ABN	UG-SERVICE
36712387	GRET	SVC	8/12/2020	1961	RET ABN	UG-SERVICE

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43870606	GRET	SVC	11/23/2024	1961	RET ABN	UG-SERVICE
41287274	GRET	SVC	2/24/2023	1961	RET ABN	UG-SERVICE
38276274	GRET	SVC	3/25/2021	1961	RET ABN	UG-SERVICE
40416539	GRET	SVC	7/14/2022	1961	RET ABN	UG-SERVICE
36802711	GRET	SVC	9/21/2020	1961	RET ABN	UG-SERVICE
40644179	GRET	SVC	9/14/2022	1961	RET ABN	UG-SERVICE
42595957	GRET	SVC	1/25/2024	1961	RET ABN	UG-SERVICE
42177090	GRET	SVC	10/2/2023	1961	RET ABN	UG-SERVICE
42590284	GRET	SVC	1/29/2024	1961	RET ABN	UG-SERVICE
42246019	GRET	SVC	10/19/2023	1961	RET ABN	UG-SERVICE
42140976	GRET	SVC	10/5/2023	1961	RET ABN	UG-SERVICE
35960288	GRET	SVC	1/28/2020	1961	RET ABN	UG-SERVICE
40670805	GRET	SVC	9/15/2022	1961	RET ABN	UG-SERVICE
43304929	GRET	SVC	7/15/2024	1961	RET ABN	UG-SERVICE
42380961	GRET	SVC	12/2/2023	1961	RET ABN	UG-SERVICE
38595490	GRET	SVC	6/7/2021	1961	RET ABN	UG-SERVICE
39741942	GRET	SVC	1/31/2022	1961	RET ABN	UG-SERVICE
40612444	GRET	SVC	10/27/2022	1961	RET ABN	UG-SERVICE
36120497	GRET	SVC	11/5/2020	1961	RET ABN	UG-SERVICE
41063457	GRET	SVC	12/15/2022	1961	RET ABN	UG-SERVICE
41634521	GRET	SVC	5/16/2023	1961	RET ABN	UG-SERVICE
43445180	GRET	SVC	8/13/2024	1961	RET ABN	UG-SERVICE
37841630	GRET	SVC	11/30/2020	1961	RET ABN	UG-SERVICE
40701267	GRET	SVC	9/15/2022	1961	RET ABN	UG-SERVICE
42855076	GRET	SVC	3/21/2024	1961	RET ABN	UG-SERVICE
36587825	GRET	SVC	7/23/2020	1961	RET ABN	UG-SERVICE
41577209	GRET	SVC	5/1/2023	1961	RET ABN	UG-SERVICE
38934636	GRET	SVC	8/23/2021	1961	RET ABN	UG-SERVICE
38314468	GRET	SVC	4/6/2021	1961	RET ABN	UG-SERVICE
40498213	GRET	SVC	7/26/2022	1961	RET ABN	UG-SERVICE
43710050	GRET	SVC	10/16/2024	1961	RET ABN	UG-SERVICE
36137410	GRET	SVC	4/21/2020	1961	RET ABN	UG-SERVICE
43036780	GRET	SVC	5/9/2024	1961	RET ABN	UG-SERVICE
42860518	GRET	SVC	3/26/2024	1961	RET ABN	UG-SERVICE
39756199	GRET	SVC	2/10/2022	1961	RET ABN	UG-SERVICE
42409246	GRET	SVC	11/27/2023	1961	RET ABN	UG-SERVICE
43445182	GRET	SVC	8/16/2024	1961	RET ABN	UG-SERVICE
40224351	GRET	SVC	5/29/2022	1961	RET ABN	UG-SERVICE
42651562	GRET	SVC	2/1/2024	1961	RET ABN	UG-SERVICE
42166122	GRET	SVC	9/19/2023	1961	RET ABN	UG-SERVICE
38681627	GRET	SVC	6/28/2021	1961	RET ABN	UG-SERVICE
41436559	GRET	SVC	3/30/2023	1961	RET ABN	UG-SERVICE
36988225	GRET	SVC	9/24/2020	1961	RET ABN	UG-SERVICE
38441546	GRET	SVC	1/3/2022	1961	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42248566	GRET	SVC	10/18/2023	1961	RET ABN	UG-SERVICE
40316642	GRET	SVC	6/21/2022	1962	RET ABN	UG-SERVICE
43793521	GRET	SVC	11/6/2024	1962	RET ABN	UG-SERVICE
38441445	GRET	SVC	1/3/2022	1962	RET ABN	UG-SERVICE
42507088	GRET	SVC	1/25/2024	1962	RET ABN	UG-SERVICE
38607202	GRET	SVC	6/11/2021	1962	RET ABN	UG-SERVICE
42138327	GRET	SVC	9/25/2023	1962	RET ABN	UG-SERVICE
40162115	GRET	SVC	5/16/2022	1962	RET ABN	UG-SERVICE
36137880	GRET	SVC	4/20/2020	1962	RET ABN	UG-SERVICE
41775612	GRET	SVC	6/26/2023	1962	RET ABN	UG-SERVICE
40246933	GRET	SVC	6/1/2022	1962	RET ABN	UG-SERVICE
37900933	GRET	SVC	12/11/2020	1962	RET ABN	UG-SERVICE
40514002	GRET	SVC	8/5/2022	1962	RET ABN	UG-SERVICE
36122362	GRET	SVC	10/30/2020	1962	RET ABN	UG-SERVICE
42491328	GRET	SVC	12/19/2023	1962	RET ABN	UG-SERVICE
36419786	GRET	SVC	6/19/2020	1962	RET ABN	UG-SERVICE
38818719	GRET	SVC	7/21/2021	1962	RET ABN	UG-SERVICE
37023787	GRET	SVC	1/6/2021	1962	RET ABN	UG-SERVICE
41803574	GRET	SVC	6/30/2023	1962	RET ABN	UG-SERVICE
38122575	GRET	SVC	2/20/2021	1962	RET ABN	UG-SERVICE
38943041	GRET	SVC	8/17/2021	1962	RET ABN	UG-SERVICE
37948944	GRET	SVC	3/31/2021	1962	RET ABN	UG-SERVICE
43221438	GRET	SVC	7/3/2024	1962	RET ABN	UG-SERVICE
41106287	GRET	SVC	2/1/2023	1962	RET ABN	UG-SERVICE
42561425	GRET	SVC	1/11/2024	1962	RET ABN	UG-SERVICE
41614906	GRET	SVC	5/10/2023	1962	RET ABN	UG-SERVICE
40561481	GRET	SVC	8/18/2022	1962	RET ABN	UG-SERVICE
40545926	GRET	SVC	8/10/2022	1962	RET ABN	UG-SERVICE
43623488	GRET	SVC	12/4/2024	1962	RET ABN	UG-SERVICE
42043602	GRET	SVC	9/6/2023	1962	RET ABN	UG-SERVICE
36590133	GRET	SVC	9/30/2020	1962	RET ABN	UG-SERVICE
43448067	GRET	SVC	8/15/2024	1962	RET ABN	UG-SERVICE
40181796	GRET	SVC	5/16/2022	1962	RET ABN	UG-SERVICE
39445868	GRET	SVC	12/6/2021	1962	RET ABN	UG-SERVICE
42496456	GRET	SVC	12/21/2023	1962	RET ABN	UG-SERVICE
41018463	GRET	SVC	12/7/2022	1962	RET ABN	UG-SERVICE
40216739	GRET	SVC	6/27/2022	1962	RET ABN	UG-SERVICE
40472860	GRET	SVC	7/26/2022	1962	RET ABN	UG-SERVICE
37045167	GRET	SVC	10/7/2020	1962	RET ABN	UG-SERVICE
36240446	GRET	SVC	5/1/2020	1962	RET ABN	UG-SERVICE
41179267	GRET	SVC	1/18/2023	1962	RET ABN	UG-SERVICE
36141882	GRET	SVC	3/16/2020	1962	RET ABN	UG-SERVICE
40495499	GRET	SVC	8/14/2022	1962	RET ABN	UG-SERVICE
38531968	GRET	SVC	6/25/2021	1962	RET ABN	UG-SERVICE
41114164	GRET	SVC	12/30/2022	1962	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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36091006	GRET	SVC	4/30/2020	1962	RET ABN	UG-SERVICE
39448053	GRET	SVC	11/22/2021	1962	RET ABN	UG-SERVICE
41888789	GRET	SVC	7/19/2023	1962	RET ABN	UG-SERVICE
36760768	GRET	SVC	8/12/2020	1962	RET ABN	UG-SERVICE
41338340	GRET	SVC	3/20/2023	1962	RET ABN	UG-SERVICE
39152932	GRET	SVC	9/20/2021	1962	RET ABN	UG-SERVICE
36658261	GRET	SVC	7/20/2020	1962	RET ABN	UG-SERVICE
43975758	GRET	SVC	12/30/2024	1962	RET ABN	UG-SERVICE
38043536	GRET	SVC	1/21/2021	1962	RET ABN	UG-SERVICE
37025413	GRET	SVC	11/13/2020	1962	RET ABN	UG-SERVICE
41106293	GRET	SVC	1/4/2023	1962	RET ABN	UG-SERVICE
36103124	GRET	SVC	3/9/2020	1962	RET ABN	UG-SERVICE
43794870	GRET	SVC	11/12/2024	1962	RET ABN	UG-SERVICE
41573261	GRET	SVC	4/26/2023	1962	RET ABN	UG-SERVICE
40488535	GRET	SVC	7/27/2022	1962	RET ABN	UG-SERVICE
35985632	GRET	SVC	2/3/2020	1962	RET ABN	UG-SERVICE
41590197	GRET	SVC	4/19/2023	1962	RET ABN	UG-SERVICE
43957617	GRET	SVC	12/18/2024	1962	RET ABN	UG-SERVICE
44025728	GRET	SVC	12/18/2024	1962	RET ABN	UG-SERVICE
43108406	GRET	SVC	5/17/2024	1962	RET ABN	UG-SERVICE
42554645	GRET	SVC	1/10/2024	1962	RET ABN	UG-SERVICE
36540578	GRET	SVC	5/21/2020	1962	RET ABN	UG-SERVICE
36137856	GRET	SVC	4/20/2020	1962	RET ABN	UG-SERVICE
36106423	GRET	SVC	10/30/2020	1962	RET ABN	UG-SERVICE
37103006	GRET	SVC	10/23/2020	1962	RET ABN	UG-SERVICE
38097502	GRET	SVC	9/2/2021	1962	RET ABN	UG-SERVICE
36138115	GRET	SVC	4/21/2020	1962	RET ABN	UG-SERVICE
40924917	GRET	SVC	12/9/2022	1962	RET ABN	UG-SERVICE
38659705	GRET	SVC	6/22/2021	1962	RET ABN	UG-SERVICE
40545905	GRET	SVC	8/10/2022	1962	RET ABN	UG-SERVICE
43620583	GRET	SVC	9/19/2024	1962	RET ABN	UG-SERVICE
42180663	GRET	SVC	9/27/2023	1962	RET ABN	UG-SERVICE
36608884	GRET	SVC	7/13/2020	1962	RET ABN	UG-SERVICE
39459830	GRET	SVC	11/24/2021	1962	RET ABN	UG-SERVICE
37877296	GRET	SVC	12/7/2020	1962	RET ABN	UG-SERVICE
43763661	GRET	SVC	11/1/2024	1962	RET ABN	UG-SERVICE
42278781	GRET	SVC	11/1/2023	1962	RET ABN	UG-SERVICE
36818385	GRET	SVC	11/3/2020	1962	RET ABN	UG-SERVICE
38595701	GRET	SVC	6/9/2021	1962	RET ABN	UG-SERVICE
41429966	GRET	SVC	9/19/2023	1962	RET ABN	UG-SERVICE
41478971	GRET	SVC	4/14/2023	1962	RET ABN	UG-SERVICE
38211695	GRET	SVC	3/9/2021	1962	RET ABN	UG-SERVICE
40963269	GRET	SVC	12/20/2022	1962	RET ABN	UG-SERVICE
38571056	GRET	SVC	6/11/2021	1962	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38033745	GRET	SVC	1/22/2021	1962	RET ABN	UG-SERVICE
43656240	GRET	SVC	10/19/2024	1962	RET ABN	UG-SERVICE
41210969	GRET	SVC	12/11/2023	1962	RET ABN	UG-SERVICE
41065859	GRET	SVC	12/15/2022	1962	RET ABN	UG-SERVICE
42982497	GRET	SVC	4/29/2024	1962	RET ABN	UG-SERVICE
40217061	GRET	SVC	5/24/2022	1962	RET ABN	UG-SERVICE
39766939	GRET	SVC	2/8/2022	1962	RET ABN	UG-SERVICE
38396451	GRET	SVC	4/22/2021	1962	RET ABN	UG-SERVICE
37045188	GRET	SVC	10/9/2020	1962	RET ABN	UG-SERVICE
41330546	GRET	SVC	3/1/2023	1962	RET ABN	UG-SERVICE
38097223	GRET	SVC	9/2/2021	1962	RET ABN	UG-SERVICE
36787049	GRET	SVC	8/17/2020	1962	RET ABN	UG-SERVICE
41380228	GRET	SVC	3/14/2023	1962	RET ABN	UG-SERVICE
38185324	GRET	SVC	3/4/2021	1962	RET ABN	UG-SERVICE
43474116	GRET	SVC	8/22/2024	1962	RET ABN	UG-SERVICE
36093024	GRET	SVC	4/27/2020	1962	RET ABN	UG-SERVICE
39254233	GRET	SVC	10/8/2021	1962	RET ABN	UG-SERVICE
41105420	GRET	SVC	1/21/2023	1962	RET ABN	UG-SERVICE
36729952	GRET	SVC	8/4/2020	1962	RET ABN	UG-SERVICE
38976089	GRET	SVC	8/22/2021	1962	RET ABN	UG-SERVICE
37322812	GRET	SVC	11/10/2020	1962	RET ABN	UG-SERVICE
43596820	GRET	SVC	10/1/2024	1962	RET ABN	UG-SERVICE
40225209	GRET	SVC	6/21/2022	1962	RET ABN	UG-SERVICE
37096383	GRET	SVC	10/20/2020	1962	RET ABN	UG-SERVICE
41052707	GRET	SVC	1/12/2023	1962	RET ABN	UG-SERVICE
39252661	GRET	SVC	6/12/2021	1962	RET ABN	UG-SERVICE
39916059	GRET	SVC	4/25/2022	1962	RET ABN	UG-SERVICE
43245088	GRET	SVC	9/11/2024	1962	RET ABN	UG-SERVICE
41767405	GRET	SVC	6/20/2023	1962	RET ABN	UG-SERVICE
42943003	GRET	SVC	4/16/2024	1962	RET ABN	UG-SERVICE
41236473	GRET	SVC	2/7/2023	1962	RET ABN	UG-SERVICE
42428939	GRET	SVC	11/30/2023	1962	RET ABN	UG-SERVICE
40522780	GRET	SVC	8/5/2022	1962	RET ABN	UG-SERVICE
43092112	GRET	SVC	5/23/2024	1962	RET ABN	UG-SERVICE
36142485	GRET	SVC	3/18/2020	1962	RET ABN	UG-SERVICE
37883992	GRET	SVC	12/9/2020	1962	RET ABN	UG-SERVICE
41114177	GRET	SVC	12/30/2022	1962	RET ABN	UG-SERVICE
42137793	GRET	SVC	9/25/2023	1962	RET ABN	UG-SERVICE
36809613	GRET	SVC	8/23/2020	1962	RET ABN	UG-SERVICE
39064575	GRET	SVC	9/2/2021	1962	RET ABN	UG-SERVICE
36138116	GRET	SVC	4/20/2020	1962	RET ABN	UG-SERVICE
41083868	GRET	SVC	12/20/2022	1962	RET ABN	UG-SERVICE
38741233	GRET	SVC	7/12/2021	1962	RET ABN	UG-SERVICE
42465584	GRET	SVC	12/13/2023	1962	RET ABN	UG-SERVICE
38735429	GRET	SVC	8/24/2021	1962	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42344688	GRET	SVC	11/7/2023	1962	RET ABN	UG-SERVICE
37940639	GRET	SVC	1/5/2021	1962	RET ABN	UG-SERVICE
41316690	GRET	SVC	2/27/2023	1963	RET ABN	UG-SERVICE
38534366	GRET	SVC	5/24/2021	1963	RET ABN	UG-SERVICE
36045936	GRET	SVC	2/21/2020	1963	RET ABN	UG-SERVICE
39385318	GRET	SVC	3/28/2022	1963	RET ABN	UG-SERVICE
40912633	GRET	SVC	11/8/2022	1963	RET ABN	UG-SERVICE
42418419	GRET	SVC	11/27/2023	1963	RET ABN	UG-SERVICE
37593076	GRET	SVC	1/21/2021	1963	RET ABN	UG-SERVICE
42956869	GRET	SVC	9/19/2024	1963	RET ABN	UG-SERVICE
42834156	GRET	SVC	7/23/2024	1963	RET ABN	UG-SERVICE
40009604	GRET	SVC	4/19/2022	1963	RET ABN	UG-SERVICE
42681364	GRET	SVC	8/1/2024	1963	RET ABN	UG-SERVICE
42292950	GRET	SVC	11/1/2023	1963	RET ABN	UG-SERVICE
39925585	GRET	SVC	3/9/2022	1963	RET ABN	UG-SERVICE
41853019	GRET	SVC	7/12/2023	1963	RET ABN	UG-SERVICE
37953467	GRET	SVC	12/22/2020	1963	RET ABN	UG-SERVICE
42204578	GRET	SVC	10/9/2023	1963	RET ABN	UG-SERVICE
43524154	GRET	SVC	9/12/2024	1963	RET ABN	UG-SERVICE
42748898	GRET	SVC	2/22/2024	1963	RET ABN	UG-SERVICE
43353625	GRET	SVC	11/4/2024	1963	RET ABN	UG-SERVICE
43625813	GRET	SVC	9/30/2024	1963	RET ABN	UG-SERVICE
38441295	GRET	SVC	1/3/2022	1963	RET ABN	UG-SERVICE
43675965	GRET	SVC	10/10/2024	1963	RET ABN	UG-SERVICE
42333907	GRET	SVC	11/10/2023	1963	RET ABN	UG-SERVICE
41088832	GRET	SVC	1/6/2023	1963	RET ABN	UG-SERVICE
42196659	GRET	SVC	10/9/2023	1963	RET ABN	UG-SERVICE
43327968	GRET	SVC	7/15/2024	1963	RET ABN	UG-SERVICE
36101971	GRET	SVC	4/23/2020	1963	RET ABN	UG-SERVICE
41411276	GRET	SVC	4/2/2024	1963	RET ABN	UG-SERVICE
36918200	GRET	SVC	8/17/2020	1963	RET ABN	UG-SERVICE
38172940	GRET	SVC	2/26/2021	1963	RET ABN	UG-SERVICE
42487543	GRET	SVC	11/9/2023	1963	RET ABN	UG-SERVICE
38312531	GRET	SVC	10/5/2021	1963	RET ABN	UG-SERVICE
40883584	GRET	SVC	11/4/2022	1963	RET ABN	UG-SERVICE
40898581	GRET	SVC	11/2/2022	1963	RET ABN	UG-SERVICE
42938326	GRET	SVC	4/16/2024	1963	RET ABN	UG-SERVICE
41408968	GRET	SVC	4/2/2024	1963	RET ABN	UG-SERVICE
41085606	GRET	SVC	12/21/2022	1963	RET ABN	UG-SERVICE
41079133	GRET	SVC	12/20/2022	1963	RET ABN	UG-SERVICE
40608420	GRET	SVC	8/23/2022	1963	RET ABN	UG-SERVICE
41075030	GRET	SVC	12/29/2022	1963	RET ABN	UG-SERVICE
40443479	GRET	SVC	7/18/2022	1963	RET ABN	UG-SERVICE
40811065	GRET	SVC	10/13/2022	1963	RET ABN	UG-SERVICE
41075023	GRET	SVC	12/20/2022	1963	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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40497359	GRET	SVC	7/26/2022	1963	RET ABN	UG-SERVICE
41610030	GRET	SVC	5/8/2023	1963	RET ABN	UG-SERVICE
41298235	GRET	SVC	2/24/2023	1963	RET ABN	UG-SERVICE
41180405	GRET	SVC	1/25/2023	1963	RET ABN	UG-SERVICE
42653894	GRET	SVC	1/29/2024	1963	RET ABN	UG-SERVICE
38736867	GRET	SVC	7/12/2021	1963	RET ABN	UG-SERVICE
38699828	GRET	SVC	6/29/2021	1963	RET ABN	UG-SERVICE
41027616	GRET	SVC	12/14/2022	1963	RET ABN	UG-SERVICE
39879060	GRET	SVC	3/14/2022	1963	RET ABN	UG-SERVICE
43480991	GRET	SVC	11/20/2024	1963	RET ABN	UG-SERVICE
36751503	GRET	SVC	8/12/2020	1963	RET ABN	UG-SERVICE
36047648	GRET	SVC	2/21/2020	1963	RET ABN	UG-SERVICE
40607679	GRET	SVC	8/23/2022	1963	RET ABN	UG-SERVICE
41179264	GRET	SVC	1/23/2023	1963	RET ABN	UG-SERVICE
40315630	GRET	SVC	6/13/2022	1963	RET ABN	UG-SERVICE
36056425	GRET	SVC	2/24/2020	1963	RET ABN	UG-SERVICE
37932659	GRET	SVC	12/16/2020	1963	RET ABN	UG-SERVICE
43627921	GRET	SVC	9/28/2024	1963	RET ABN	UG-SERVICE
36254937	GRET	SVC	3/7/2020	1963	RET ABN	UG-SERVICE
32667123	GRET	SVC	11/1/2020	1963	RET ABN	UG-SERVICE
35996899	GRET	SVC	2/10/2020	1963	RET ABN	UG-SERVICE
37097501	GRET	SVC	12/9/2020	1963	RET ABN	UG-SERVICE
38579872	GRET	SVC	9/28/2021	1963	RET ABN	UG-SERVICE
43063031	GRET	SVC	5/14/2024	1963	RET ABN	UG-SERVICE
41408006	GRET	SVC	4/2/2024	1963	RET ABN	UG-SERVICE
41273853	GRET	SVC	2/15/2023	1963	RET ABN	UG-SERVICE
42565052	GRET	SVC	1/10/2024	1963	RET ABN	UG-SERVICE
41593695	GRET	SVC	5/31/2023	1963	RET ABN	UG-SERVICE
37045853	GRET	SVC	10/9/2020	1963	RET ABN	UG-SERVICE
38441299	GRET	SVC	1/3/2022	1963	RET ABN	UG-SERVICE
41411430	GRET	SVC	11/2/2023	1963	RET ABN	UG-SERVICE
42674645	GRET	SVC	2/6/2024	1963	RET ABN	UG-SERVICE
41414945	GRET	SVC	3/21/2023	1963	RET ABN	UG-SERVICE
37025410	GRET	SVC	10/16/2020	1963	RET ABN	UG-SERVICE
40895494	GRET	SVC	10/28/2022	1963	RET ABN	UG-SERVICE
43462069	GRET	SVC	10/7/2024	1963	RET ABN	UG-SERVICE
43100268	GRET	SVC	6/3/2024	1963	RET ABN	UG-SERVICE
41015447	GRET	SVC	12/16/2022	1963	RET ABN	UG-SERVICE
41330542	GRET	SVC	3/3/2023	1963	RET ABN	UG-SERVICE
37387646	GRET	SVC	11/9/2020	1963	RET ABN	UG-SERVICE
41194798	GRET	SVC	1/23/2023	1963	RET ABN	UG-SERVICE
41241964	GRET	SVC	3/1/2023	1963	RET ABN	UG-SERVICE
38726593	GRET	SVC	7/12/2021	1963	RET ABN	UG-SERVICE
39806444	GRET	SVC	3/1/2022	1963	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38702005	GRET	SVC	7/14/2021	1963	RET ABN	UG-SERVICE
38179599	GRET	SVC	3/3/2021	1963	RET ABN	UG-SERVICE
42972889	GRET	SVC	4/22/2024	1963	RET ABN	UG-SERVICE
40488325	GRET	SVC	7/27/2022	1963	RET ABN	UG-SERVICE
41074876	GRET	SVC	12/22/2022	1963	RET ABN	UG-SERVICE
38267218	GRET	SVC	3/22/2021	1963	RET ABN	UG-SERVICE
41411224	GRET	SVC	4/2/2024	1963	RET ABN	UG-SERVICE
41051914	GRET	SVC	1/12/2023	1963	RET ABN	UG-SERVICE
40440351	GRET	SVC	6/30/2022	1963	RET ABN	UG-SERVICE
42792743	GRET	SVC	7/2/2024	1963	RET ABN	UG-SERVICE
41069356	GRET	SVC	1/5/2023	1963	RET ABN	UG-SERVICE
41440482	GRET	SVC	3/27/2023	1963	RET ABN	UG-SERVICE
39545562	GRET	SVC	1/10/2022	1963	RET ABN	UG-SERVICE
37088508	GRET	SVC	10/20/2020	1963	RET ABN	UG-SERVICE
41052710	GRET	SVC	1/12/2023	1963	RET ABN	UG-SERVICE
36121609	GRET	SVC	10/30/2020	1963	RET ABN	UG-SERVICE
37934041	GRET	SVC	12/21/2020	1963	RET ABN	UG-SERVICE
38334678	GRET	SVC	4/7/2021	1963	RET ABN	UG-SERVICE
41969557	GRET	SVC	8/1/2024	1963	RET ABN	UG-SERVICE
38091187	GRET	SVC	2/19/2021	1963	RET ABN	UG-SERVICE
40802173	GRET	SVC	10/12/2022	1963	RET ABN	UG-SERVICE
38543965	GRET	SVC	5/25/2021	1963	RET ABN	UG-SERVICE
43189731	GRET	SVC	6/19/2024	1963	RET ABN	UG-SERVICE
41408065	GRET	SVC	4/2/2024	1963	RET ABN	UG-SERVICE
43480990	GRET	SVC	11/20/2024	1963	RET ABN	UG-SERVICE
42833355	GRET	SVC	7/22/2024	1963	RET ABN	UG-SERVICE
42910311	GRET	SVC	6/21/2024	1963	RET ABN	UG-SERVICE
42193964	GRET	SVC	10/10/2023	1963	RET ABN	UG-SERVICE
36740597	GRET	SVC	8/5/2020	1963	RET ABN	UG-SERVICE
41408005	GRET	SVC	4/2/2024	1963	RET ABN	UG-SERVICE
38441487	GRET	SVC	1/6/2022	1963	RET ABN	UG-SERVICE
42265960	GRET	SVC	10/26/2023	1963	RET ABN	UG-SERVICE
41411266	GRET	SVC	4/2/2024	1963	RET ABN	UG-SERVICE
41318581	GRET	SVC	3/2/2023	1963	RET ABN	UG-SERVICE
39478139	GRET	SVC	12/3/2021	1963	RET ABN	UG-SERVICE
36685507	GRET	SVC	7/27/2020	1963	RET ABN	UG-SERVICE
38756390	GRET	SVC	10/26/2021	1963	RET ABN	UG-SERVICE
36433567	GRET	SVC	6/10/2020	1963	RET ABN	UG-SERVICE
42297558	GRET	SVC	11/1/2023	1963	RET ABN	UG-SERVICE
41408974	GRET	SVC	4/2/2024	1963	RET ABN	UG-SERVICE
41104256	GRET	SVC	1/21/2023	1963	RET ABN	UG-SERVICE
40611928	GRET	SVC	8/21/2022	1963	RET ABN	UG-SERVICE
40775287	GRET	SVC	9/26/2022	1963	RET ABN	UG-SERVICE
41410852	GRET	SVC	4/2/2024	1963	RET ABN	UG-SERVICE
38906164	GRET	SVC	9/17/2021	1963	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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38934718	GRET	SVC	8/19/2021	1963	RET ABN	UG-SERVICE
39831656	GRET	SVC	8/3/2022	1963	RET ABN	UG-SERVICE
38593533	GRET	SVC	6/22/2021	1963	RET ABN	UG-SERVICE
43943431	GRET	SVC	12/18/2024	1963	RET ABN	UG-SERVICE
40561494	GRET	SVC	8/27/2022	1963	RET ABN	UG-SERVICE
42944585	GRET	SVC	4/9/2024	1963	RET ABN	UG-SERVICE
37088362	GRET	SVC	10/20/2020	1963	RET ABN	UG-SERVICE
37455519	GRET	SVC	11/23/2020	1963	RET ABN	UG-SERVICE
36014157	GRET	SVC	2/11/2020	1963	RET ABN	UG-SERVICE
42542521	GRET	SVC	4/30/2024	1963	RET ABN	UG-SERVICE
41411419	GRET	SVC	11/2/2023	1963	RET ABN	UG-SERVICE
36152267	GRET	SVC	3/16/2020	1963	RET ABN	UG-SERVICE
43559752	GRET	SVC	10/4/2024	1963	RET ABN	UG-SERVICE
42649991	GRET	SVC	2/1/2024	1963	RET ABN	UG-SERVICE
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41410851	GRET	SVC	4/2/2024	1963	RET ABN	UG-SERVICE
41817666	GRET	SVC	6/29/2023	1963	RET ABN	UG-SERVICE
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41321959	GRET	SVC	3/9/2023	1963	RET ABN	UG-SERVICE
39864036	GRET	SVC	3/9/2022	1963	RET ABN	UG-SERVICE
41946657	GRET	SVC	8/8/2023	1963	RET ABN	UG-SERVICE
41825248	GRET	SVC	7/5/2023	1963	RET ABN	UG-SERVICE
36138460	GRET	SVC	3/19/2020	1963	RET ABN	UG-SERVICE
43606797	GRET	SVC	11/15/2024	1963	RET ABN	UG-SERVICE
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37892183	GRET	SVC	12/10/2020	1963	RET ABN	UG-SERVICE
38441298	GRET	SVC	1/6/2022	1963	RET ABN	UG-SERVICE
43886024	GRET	SVC	11/25/2024	1963	RET ABN	UG-SERVICE
42197020	GRET	SVC	10/9/2023	1963	RET ABN	UG-SERVICE
39543012	GRET	SVC	12/16/2021	1963	RET ABN	UG-SERVICE
38441289	GRET	SVC	1/6/2022	1963	RET ABN	UG-SERVICE
41408064	GRET	SVC	4/2/2024	1963	RET ABN	UG-SERVICE
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37082696	GRET	SVC	10/15/2020	1963	RET ABN	UG-SERVICE
40066513	GRET	SVC	3/31/2022	1963	RET ABN	UG-SERVICE
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37084631	GRET	SVC	10/15/2020	1963	RET ABN	UG-SERVICE
42956323	GRET	SVC	9/19/2024	1963	RET ABN	UG-SERVICE
36153320	GRET	SVC	3/19/2020	1963	RET ABN	UG-SERVICE
42314563	GRET	SVC	11/7/2023	1963	RET ABN	UG-SERVICE
36137314	GRET	SVC	4/20/2020	1963	RET ABN	UG-SERVICE
39935401	GRET	SVC	6/20/2022	1963	RET ABN	UG-SERVICE
40363435	GRET	SVC	6/28/2022	1963	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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36387252	GRET	SVC	6/1/2020	1963	RET ABN	UG-SERVICE
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40432964	GRET	SVC	7/14/2022	1963	RET ABN	UG-SERVICE
43623796	GRET	SVC	9/27/2024	1963	RET ABN	UG-SERVICE
43624005	GRET	SVC	10/1/2024	1963	RET ABN	UG-SERVICE
41052706	GRET	SVC	1/12/2023	1963	RET ABN	UG-SERVICE
43444205	GRET	SVC	8/15/2024	1963	RET ABN	UG-SERVICE
41052709	GRET	SVC	1/12/2023	1963	RET ABN	UG-SERVICE
38959418	GRET	SVC	8/17/2021	1963	RET ABN	UG-SERVICE
40723258	GRET	SVC	10/19/2022	1964	RET ABN	UG-SERVICE
40675411	GRET	SVC	9/15/2022	1964	RET ABN	UG-SERVICE
36110467	GRET	SVC	4/20/2020	1964	RET ABN	UG-SERVICE
36753394	GRET	SVC	4/7/2022	1964	RET ABN	UG-SERVICE
43086207	GRET	SVC	5/17/2024	1964	RET ABN	UG-SERVICE
36081780	GRET	SVC	3/4/2020	1964	RET ABN	UG-SERVICE
39923819	GRET	SVC	3/24/2022	1964	RET ABN	UG-SERVICE
37932977	GRET	SVC	12/17/2020	1964	RET ABN	UG-SERVICE
42833352	GRET	SVC	7/23/2024	1964	RET ABN	UG-SERVICE
38033818	GRET	SVC	1/22/2021	1964	RET ABN	UG-SERVICE
36136180	GRET	SVC	4/23/2020	1964	RET ABN	UG-SERVICE
36121614	GRET	SVC	10/12/2020	1964	RET ABN	UG-SERVICE
41318155	GRET	SVC	3/3/2023	1964	RET ABN	UG-SERVICE
36138305	GRET	SVC	4/20/2020	1964	RET ABN	UG-SERVICE
37917270	GRET	SVC	12/15/2020	1964	RET ABN	UG-SERVICE
36751246	GRET	SVC	8/19/2020	1964	RET ABN	UG-SERVICE
38232314	GRET	SVC	3/16/2021	1964	RET ABN	UG-SERVICE
32667129	GRET	SVC	9/30/2020	1964	RET ABN	UG-SERVICE
43624720	GRET	SVC	9/27/2024	1964	RET ABN	UG-SERVICE
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41079886	GRET	SVC	4/5/2024	1964	RET ABN	UG-SERVICE
39905417	GRET	SVC	1/9/2023	1964	RET ABN	UG-SERVICE
36137779	GRET	SVC	4/21/2020	1964	RET ABN	UG-SERVICE
41911378	GRET	SVC	7/28/2023	1964	RET ABN	UG-SERVICE
39955662	GRET	SVC	5/18/2022	1964	RET ABN	UG-SERVICE
38312803	GRET	SVC	4/7/2021	1964	RET ABN	UG-SERVICE
39288068	GRET	SVC	10/10/2021	1964	RET ABN	UG-SERVICE
39928987	GRET	SVC	3/22/2022	1964	RET ABN	UG-SERVICE
38489303	GRET	SVC	4/1/2021	1964	RET ABN	UG-SERVICE
42140813	GRET	SVC	9/19/2023	1964	RET ABN	UG-SERVICE
36137882	GRET	SVC	4/22/2020	1964	RET ABN	UG-SERVICE
40654853	GRET	SVC	9/7/2022	1964	RET ABN	UG-SERVICE
39950426	GRET	SVC	3/30/2022	1964	RET ABN	UG-SERVICE
41790202	GRET	SVC	6/28/2023	1964	RET ABN	UG-SERVICE
39875446	GRET	SVC	3/9/2022	1964	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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40315825	GRET	SVC	6/20/2022	1964	RET ABN	UG-SERVICE
41904015	GRET	SVC	7/25/2023	1964	RET ABN	UG-SERVICE
38543492	GRET	SVC	10/20/2021	1964	RET ABN	UG-SERVICE
39125879	GRET	SVC	9/13/2021	1964	RET ABN	UG-SERVICE
39291302	GRET	SVC	10/13/2021	1964	RET ABN	UG-SERVICE
41411646	GRET	SVC	4/2/2024	1964	RET ABN	UG-SERVICE
39830419	GRET	SVC	8/3/2022	1964	RET ABN	UG-SERVICE
41750843	GRET	SVC	6/12/2023	1964	RET ABN	UG-SERVICE
41024535	GRET	SVC	4/4/2023	1964	RET ABN	UG-SERVICE
42620386	GRET	SVC	1/25/2024	1964	RET ABN	UG-SERVICE
39666744	GRET	SVC	11/18/2022	1964	RET ABN	UG-SERVICE
43714036	GRET	SVC	11/12/2024	1964	RET ABN	UG-SERVICE
40517068	GRET	SVC	8/6/2022	1964	RET ABN	UG-SERVICE
36321219	GRET	SVC	7/6/2020	1964	RET ABN	UG-SERVICE
40030349	GRET	SVC	4/20/2022	1964	RET ABN	UG-SERVICE
41541192	GRET	SVC	5/22/2023	1964	RET ABN	UG-SERVICE
39450179	GRET	SVC	11/22/2021	1964	RET ABN	UG-SERVICE
38400028	GRET	SVC	4/21/2021	1964	RET ABN	UG-SERVICE
39804198	GRET	SVC	2/15/2022	1964	RET ABN	UG-SERVICE
38033750	GRET	SVC	1/22/2021	1964	RET ABN	UG-SERVICE
36739208	GRET	SVC	8/3/2020	1964	RET ABN	UG-SERVICE
41877225	GRET	SVC	7/14/2023	1964	RET ABN	UG-SERVICE
42224958	GRET	SVC	7/22/2024	1964	RET ABN	UG-SERVICE
39380912	GRET	SVC	11/11/2021	1964	RET ABN	UG-SERVICE
43612806	GRET	SVC	11/18/2024	1964	RET ABN	UG-SERVICE
38426940	GRET	SVC	3/22/2021	1964	RET ABN	UG-SERVICE
35882772	GRET	SVC	1/13/2020	1964	RET ABN	UG-SERVICE
39224591	GRET	SVC	9/29/2021	1964	RET ABN	UG-SERVICE
36135880	GRET	SVC	4/21/2020	1964	RET ABN	UG-SERVICE
36672270	GRET	SVC	9/28/2020	1964	RET ABN	UG-SERVICE
40727980	GRET	SVC	9/20/2022	1964	RET ABN	UG-SERVICE
36106819	GRET	SVC	10/12/2020	1964	RET ABN	UG-SERVICE
39496778	GRET	SVC	12/1/2021	1964	RET ABN	UG-SERVICE
42587967	GRET	SVC	8/1/2024	1964	RET ABN	UG-SERVICE
42813703	GRET	SVC	3/8/2024	1964	RET ABN	UG-SERVICE
39078774	GRET	SVC	9/14/2021	1964	RET ABN	UG-SERVICE
42057080	GRET	SVC	10/30/2023	1964	RET ABN	UG-SERVICE
40182832	GRET	SVC	6/7/2022	1964	RET ABN	UG-SERVICE
42586642	GRET	SVC	2/8/2024	1964	RET ABN	UG-SERVICE
36638130	GRET	SVC	7/20/2020	1964	RET ABN	UG-SERVICE
36214903	GRET	SVC	4/28/2020	1964	RET ABN	UG-SERVICE
36259645	GRET	SVC	4/22/2020	1964	RET ABN	UG-SERVICE
42566813	GRET	SVC	1/16/2024	1964	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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36821064	GRET	SVC	11/12/2020	1964	RET ABN	UG-SERVICE
42870885	GRET	SVC	5/20/2024	1964	RET ABN	UG-SERVICE
36425578	GRET	SVC	5/14/2020	1964	RET ABN	UG-SERVICE
40513282	GRET	SVC	8/2/2022	1964	RET ABN	UG-SERVICE
38353013	GRET	SVC	2/14/2023	1964	RET ABN	UG-SERVICE
41407665	GRET	SVC	4/2/2024	1964	RET ABN	UG-SERVICE
41969660	GRET	SVC	8/1/2024	1964	RET ABN	UG-SERVICE
38487654	GRET	SVC	5/18/2021	1964	RET ABN	UG-SERVICE
38169140	GRET	SVC	3/9/2021	1964	RET ABN	UG-SERVICE
39304392	GRET	SVC	10/20/2021	1964	RET ABN	UG-SERVICE
41497750	GRET	SVC	5/3/2023	1964	RET ABN	UG-SERVICE
37357286	GRET	SVC	11/10/2020	1964	RET ABN	UG-SERVICE
43643658	GRET	SVC	10/7/2024	1964	RET ABN	UG-SERVICE
37082530	GRET	SVC	10/15/2020	1964	RET ABN	UG-SERVICE
40578228	GRET	SVC	8/26/2022	1964	RET ABN	UG-SERVICE
43229385	GRET	SVC	6/28/2024	1964	RET ABN	UG-SERVICE
40860481	GRET	SVC	10/28/2022	1964	RET ABN	UG-SERVICE
40865919	GRET	SVC	8/22/2023	1964	RET ABN	UG-SERVICE
42068574	GRET	SVC	9/6/2023	1964	RET ABN	UG-SERVICE
43650235	GRET	SVC	10/4/2024	1964	RET ABN	UG-SERVICE
41969652	GRET	SVC	8/1/2024	1964	RET ABN	UG-SERVICE
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39935384	GRET	SVC	5/14/2022	1964	RET ABN	UG-SERVICE
36313897	GRET	SVC	6/8/2020	1964	RET ABN	UG-SERVICE
38352839	GRET	SVC	5/5/2021	1964	RET ABN	UG-SERVICE
40827499	GRET	SVC	11/2/2022	1964	RET ABN	UG-SERVICE
41114168	GRET	SVC	1/12/2023	1964	RET ABN	UG-SERVICE
43715920	GRET	SVC	10/24/2024	1964	RET ABN	UG-SERVICE
41829854	GRET	SVC	7/13/2023	1964	RET ABN	UG-SERVICE
41247067	GRET	SVC	2/8/2023	1964	RET ABN	UG-SERVICE
36766246	GRET	SVC	8/11/2020	1964	RET ABN	UG-SERVICE
42892210	GRET	SVC	4/30/2024	1964	RET ABN	UG-SERVICE
38474292	GRET	SVC	3/30/2021	1964	RET ABN	UG-SERVICE
43244751	GRET	SVC	12/17/2024	1964	RET ABN	UG-SERVICE
43942523	GRET	SVC	12/17/2024	1964	RET ABN	UG-SERVICE
41821731	GRET	SVC	7/3/2023	1964	RET ABN	UG-SERVICE
42344673	GRET	SVC	11/8/2023	1964	RET ABN	UG-SERVICE
41114059	GRET	SVC	1/4/2023	1964	RET ABN	UG-SERVICE
38697774	GRET	SVC	7/6/2021	1964	RET ABN	UG-SERVICE
40561330	GRET	SVC	8/27/2022	1964	RET ABN	UG-SERVICE
42897389	GRET	SVC	9/11/2024	1964	RET ABN	UG-SERVICE
37142034	GRET	SVC	10/31/2020	1964	RET ABN	UG-SERVICE
41194402	GRET	SVC	1/23/2023	1964	RET ABN	UG-SERVICE
42122263	GRET	SVC	9/14/2023	1964	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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39657982	GRET	SVC	2/18/2022	1964	RET ABN	UG-SERVICE
41262153	GRET	SVC	3/20/2023	1964	RET ABN	UG-SERVICE
40394666	GRET	SVC	7/6/2022	1964	RET ABN	UG-SERVICE
37993927	GRET	SVC	1/11/2021	1964	RET ABN	UG-SERVICE
38390547	GRET	SVC	4/20/2021	1964	RET ABN	UG-SERVICE
43952060	GRET	SVC	12/17/2024	1964	RET ABN	UG-SERVICE
36122502	GRET	SVC	10/30/2020	1964	RET ABN	UG-SERVICE
42952137	GRET	SVC	4/20/2024	1964	RET ABN	UG-SERVICE
39666586	GRET	SVC	1/6/2022	1964	RET ABN	UG-SERVICE
41082589	GRET	SVC	12/21/2022	1964	RET ABN	UG-SERVICE
43379779	GRET	SVC	8/1/2024	1964	RET ABN	UG-SERVICE
41472351	GRET	SVC	5/5/2023	1964	RET ABN	UG-SERVICE
38510812	GRET	SVC	5/17/2021	1964	RET ABN	UG-SERVICE
41222710	GRET	SVC	5/8/2023	1964	RET ABN	UG-SERVICE
40449448	GRET	SVC	7/18/2022	1964	RET ABN	UG-SERVICE
40197873	GRET	SVC	6/6/2022	1964	RET ABN	UG-SERVICE
38109700	GRET	SVC	2/10/2021	1964	RET ABN	UG-SERVICE
36606201	GRET	SVC	7/9/2020	1964	RET ABN	UG-SERVICE
40208810	GRET	SVC	5/26/2022	1964	RET ABN	UG-SERVICE
41223591	GRET	SVC	2/3/2023	1964	RET ABN	UG-SERVICE
38141922	GRET	SVC	2/16/2021	1964	RET ABN	UG-SERVICE
41018644	GRET	SVC	12/8/2022	1964	RET ABN	UG-SERVICE
41411666	GRET	SVC	4/2/2024	1964	RET ABN	UG-SERVICE
38263831	GRET	SVC	3/22/2021	1964	RET ABN	UG-SERVICE
37039775	GRET	SVC	10/5/2020	1964	RET ABN	UG-SERVICE
41830199	GRET	SVC	8/10/2023	1964	RET ABN	UG-SERVICE
41556176	GRET	SVC	4/24/2023	1964	RET ABN	UG-SERVICE
40127065	GRET	SVC	5/5/2022	1964	RET ABN	UG-SERVICE
36366994	GRET	SVC	5/26/2020	1964	RET ABN	UG-SERVICE
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36041230	GRET	SVC	2/19/2020	1964	RET ABN	UG-SERVICE
41424028	GRET	SVC	10/18/2023	1964	RET ABN	UG-SERVICE
36136100	GRET	SVC	4/23/2020	1964	RET ABN	UG-SERVICE
42833920	GRET	SVC	7/22/2024	1964	RET ABN	UG-SERVICE
37014743	GRET	SVC	10/2/2020	1964	RET ABN	UG-SERVICE
36147555	GRET	SVC	1/6/2021	1964	RET ABN	UG-SERVICE
36135912	GRET	SVC	4/23/2020	1964	RET ABN	UG-SERVICE
39431224	GRET	SVC	11/15/2021	1964	RET ABN	UG-SERVICE
36152340	GRET	SVC	3/19/2020	1964	RET ABN	UG-SERVICE
36881990	GRET	SVC	8/30/2020	1964	RET ABN	UG-SERVICE
36906875	GRET	SVC	9/9/2020	1964	RET ABN	UG-SERVICE
36118901	GRET	SVC	10/12/2020	1964	RET ABN	UG-SERVICE
41802972	GRET	SVC	6/26/2023	1964	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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39081585	GRET	SVC	9/8/2021	1964	RET ABN	UG-SERVICE
37122072	GRET	SVC	10/30/2020	1964	RET ABN	UG-SERVICE
38234185	GRET	SVC	8/24/2021	1964	RET ABN	UG-SERVICE
36107011	GRET	SVC	4/27/2020	1964	RET ABN	UG-SERVICE
38569061	GRET	SVC	6/9/2021	1964	RET ABN	UG-SERVICE
36777009	GRET	SVC	8/13/2020	1964	RET ABN	UG-SERVICE
35863545	GRET	SVC	1/23/2020	1964	RET ABN	UG-SERVICE
36102844	GRET	SVC	4/21/2020	1964	RET ABN	UG-SERVICE
40498177	GRET	SVC	9/16/2022	1964	RET ABN	UG-SERVICE
43901494	GRET	SVC	11/19/2024	1965	RET ABN	UG-SERVICE
42427178	GRET	SVC	9/19/2024	1965	RET ABN	UG-SERVICE
39211546	GRET	SVC	9/28/2021	1965	RET ABN	UG-SERVICE
36102274	GRET	SVC	4/23/2020	1965	RET ABN	UG-SERVICE
39666604	GRET	SVC	11/18/2022	1965	RET ABN	UG-SERVICE
36732666	GRET	SVC	7/30/2020	1965	RET ABN	UG-SERVICE
42224937	GRET	SVC	10/16/2023	1965	RET ABN	UG-SERVICE
42455479	GRET	SVC	12/12/2023	1965	RET ABN	UG-SERVICE
36867895	GRET	SVC	10/11/2020	1965	RET ABN	UG-SERVICE
39721546	GRET	SVC	1/24/2022	1965	RET ABN	UG-SERVICE
38239042	GRET	SVC	3/15/2021	1965	RET ABN	UG-SERVICE
36122366	GRET	SVC	10/30/2020	1965	RET ABN	UG-SERVICE
38057493	GRET	SVC	1/26/2021	1965	RET ABN	UG-SERVICE
38051591	GRET	SVC	1/25/2021	1965	RET ABN	UG-SERVICE
36136110	GRET	SVC	4/21/2020	1965	RET ABN	UG-SERVICE
41106895	GRET	SVC	1/4/2023	1965	RET ABN	UG-SERVICE
41321357	GRET	SVC	3/16/2023	1965	RET ABN	UG-SERVICE
42427221	GRET	SVC	11/20/2023	1965	RET ABN	UG-SERVICE
36103000	GRET	SVC	4/22/2020	1965	RET ABN	UG-SERVICE
37643324	GRET	SVC	11/17/2020	1965	RET ABN	UG-SERVICE
42899874	GRET	SVC	4/9/2024	1965	RET ABN	UG-SERVICE
41140336	GRET	SVC	1/6/2023	1965	RET ABN	UG-SERVICE
42427222	GRET	SVC	11/20/2023	1965	RET ABN	UG-SERVICE
43124066	GRET	SVC	6/3/2024	1965	RET ABN	UG-SERVICE
39858317	GRET	SVC	3/9/2022	1965	RET ABN	UG-SERVICE
42177398	GRET	SVC	10/3/2023	1965	RET ABN	UG-SERVICE
39666609	GRET	SVC	11/18/2022	1965	RET ABN	UG-SERVICE
43650230	GRET	SVC	10/10/2024	1965	RET ABN	UG-SERVICE
41083726	GRET	SVC	12/21/2022	1965	RET ABN	UG-SERVICE
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38512595	GRET	SVC	5/20/2021	1965	RET ABN	UG-SERVICE
38110997	GRET	SVC	2/11/2021	1965	RET ABN	UG-SERVICE
42196724	GRET	SVC	10/9/2023	1965	RET ABN	UG-SERVICE
33904524	GRET	SVC	7/22/2020	1965	RET ABN	UG-SERVICE
39423499	GRET	SVC	6/27/2022	1965	RET ABN	UG-SERVICE

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41398909	GRET	SVC	3/14/2023	1965	RET ABN	UG-SERVICE
36085786	GRET	SVC	2/27/2020	1965	RET ABN	UG-SERVICE
40558512	GRET	SVC	8/20/2022	1965	RET ABN	UG-SERVICE
41277890	GRET	SVC	3/1/2023	1965	RET ABN	UG-SERVICE
41450121	GRET	SVC	3/30/2023	1965	RET ABN	UG-SERVICE
38184601	GRET	SVC	3/12/2021	1965	RET ABN	UG-SERVICE
39791342	GRET	SVC	11/5/2021	1965	RET ABN	UG-SERVICE
42958049	GRET	SVC	9/19/2024	1965	RET ABN	UG-SERVICE
38536854	GRET	SVC	6/30/2021	1965	RET ABN	UG-SERVICE
36118404	GRET	SVC	3/11/2020	1965	RET ABN	UG-SERVICE
38658886	GRET	SVC	6/24/2021	1965	RET ABN	UG-SERVICE
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39931524	GRET	SVC	4/28/2022	1965	RET ABN	UG-SERVICE
42165247	GRET	SVC	10/10/2023	1965	RET ABN	UG-SERVICE
39337452	GRET	SVC	10/28/2021	1965	RET ABN	UG-SERVICE
41411663	GRET	SVC	4/2/2024	1965	RET ABN	UG-SERVICE
38912991	GRET	SVC	8/11/2021	1965	RET ABN	UG-SERVICE
41423576	GRET	SVC	10/18/2023	1965	RET ABN	UG-SERVICE
39935323	GRET	SVC	5/2/2022	1965	RET ABN	UG-SERVICE
42509259	GRET	SVC	7/31/2024	1965	RET ABN	UG-SERVICE
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36961508	GRET	SVC	9/21/2020	1965	RET ABN	UG-SERVICE
38792416	GRET	SVC	7/20/2021	1965	RET ABN	UG-SERVICE
37529540	GRET	SVC	11/16/2020	1965	RET ABN	UG-SERVICE
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42427119	GRET	SVC	9/19/2024	1965	RET ABN	UG-SERVICE
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39464875	GRET	SVC	12/12/2021	1965	RET ABN	UG-SERVICE
39484726	GRET	SVC	10/22/2021	1965	RET ABN	UG-SERVICE
36040145	GRET	SVC	2/4/2020	1965	RET ABN	UG-SERVICE
43365686	GRET	SVC	12/3/2024	1965	RET ABN	UG-SERVICE
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42182890	GRET	SVC	10/3/2023	1965	RET ABN	UG-SERVICE
42958176	GRET	SVC	4/22/2024	1965	RET ABN	UG-SERVICE
38169073	GRET	SVC	2/25/2021	1965	RET ABN	UG-SERVICE
41423889	GRET	SVC	10/18/2023	1965	RET ABN	UG-SERVICE
38571832	GRET	SVC	6/3/2021	1965	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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42144500	GRET	SVC	9/26/2023	1965	RET ABN	UG-SERVICE
41330853	GRET	SVC	3/9/2023	1965	RET ABN	UG-SERVICE
39666603	GRET	SVC	11/18/2022	1965	RET ABN	UG-SERVICE
39581411	GRET	SVC	12/20/2021	1965	RET ABN	UG-SERVICE
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39935336	GRET	SVC	6/21/2022	1965	RET ABN	UG-SERVICE
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42957223	GRET	SVC	9/19/2024	1965	RET ABN	UG-SERVICE
39341152	GRET	SVC	10/26/2021	1965	RET ABN	UG-SERVICE
39666608	GRET	SVC	11/18/2022	1965	RET ABN	UG-SERVICE
39725976	GRET	SVC	1/26/2022	1965	RET ABN	UG-SERVICE
39739149	GRET	SVC	1/31/2022	1965	RET ABN	UG-SERVICE
36885289	GRET	SVC	10/14/2020	1965	RET ABN	UG-SERVICE
40370330	GRET	SVC	7/6/2022	1965	RET ABN	UG-SERVICE
38040097	GRET	SVC	1/28/2021	1965	RET ABN	UG-SERVICE
41237590	GRET	SVC	2/6/2023	1965	RET ABN	UG-SERVICE
36102857	GRET	SVC	4/22/2020	1965	RET ABN	UG-SERVICE
43183971	GRET	SVC	6/18/2024	1965	RET ABN	UG-SERVICE
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43623541	GRET	SVC	12/16/2024	1965	RET ABN	UG-SERVICE
38014261	GRET	SVC	1/11/2021	1965	RET ABN	UG-SERVICE
38311563	GRET	SVC	4/5/2021	1965	RET ABN	UG-SERVICE
42487348	GRET	SVC	7/18/2024	1965	RET ABN	UG-SERVICE
39519787	GRET	SVC	12/12/2021	1965	RET ABN	UG-SERVICE
42008727	GRET	SVC	8/14/2023	1965	RET ABN	UG-SERVICE
42207966	GRET	SVC	7/18/2024	1965	RET ABN	UG-SERVICE
41807608	GRET	SVC	6/27/2023	1965	RET ABN	UG-SERVICE
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36636735	GRET	SVC	7/16/2020	1965	RET ABN	UG-SERVICE
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39666605	GRET	SVC	11/18/2022	1965	RET ABN	UG-SERVICE
40726492	GRET	SVC	9/23/2022	1965	RET ABN	UG-SERVICE
36136185	GRET	SVC	4/28/2020	1965	RET ABN	UG-SERVICE
42957943	GRET	SVC	9/19/2024	1965	RET ABN	UG-SERVICE
39423535	GRET	SVC	6/27/2022	1965	RET ABN	UG-SERVICE
43423330	GRET	SVC	9/11/2024	1965	RET ABN	UG-SERVICE
42812485	GRET	SVC	3/12/2024	1965	RET ABN	UG-SERVICE
36122121	GRET	SVC	10/14/2020	1965	RET ABN	UG-SERVICE
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38712739	GRET	SVC	7/2/2021	1965	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41274141	GRET	SVC	2/15/2023	1965	RET ABN	UG-SERVICE
41427598	GRET	SVC	4/14/2023	1965	RET ABN	UG-SERVICE
36743332	GRET	SVC	8/21/2020	1965	RET ABN	UG-SERVICE
42202951	GRET	SVC	10/9/2023	1965	RET ABN	UG-SERVICE
36829577	GRET	SVC	8/26/2020	1965	RET ABN	UG-SERVICE
42409061	GRET	SVC	11/22/2023	1965	RET ABN	UG-SERVICE
39666601	GRET	SVC	11/18/2022	1965	RET ABN	UG-SERVICE
42473588	GRET	SVC	12/12/2023	1965	RET ABN	UG-SERVICE
41211356	GRET	SVC	12/11/2023	1965	RET ABN	UG-SERVICE
39423741	GRET	SVC	6/27/2022	1965	RET ABN	UG-SERVICE
41989714	GRET	SVC	8/18/2023	1965	RET ABN	UG-SERVICE
37900138	GRET	SVC	12/11/2020	1965	RET ABN	UG-SERVICE
42363567	GRET	SVC	11/28/2023	1965	RET ABN	UG-SERVICE
41472419	GRET	SVC	10/6/2023	1965	RET ABN	UG-SERVICE
36878133	GRET	SVC	9/1/2020	1965	RET ABN	UG-SERVICE
39928912	GRET	SVC	4/12/2022	1965	RET ABN	UG-SERVICE
42522466	GRET	SVC	12/28/2023	1965	RET ABN	UG-SERVICE
39952104	GRET	SVC	5/13/2022	1965	RET ABN	UG-SERVICE
36228453	GRET	SVC	4/22/2020	1965	RET ABN	UG-SERVICE
36795121	GRET	SVC	8/18/2020	1965	RET ABN	UG-SERVICE
36670564	GRET	SVC	7/22/2020	1965	RET ABN	UG-SERVICE
40359182	GRET	SVC	6/30/2022	1965	RET ABN	UG-SERVICE
43365684	GRET	SVC	11/20/2024	1965	RET ABN	UG-SERVICE
38577087	GRET	SVC	6/7/2021	1965	RET ABN	UG-SERVICE
42029486	GRET	SVC	8/24/2023	1965	RET ABN	UG-SERVICE
39666671	GRET	SVC	11/18/2022	1965	RET ABN	UG-SERVICE
43245060	GRET	SVC	9/19/2024	1965	RET ABN	UG-SERVICE
36260068	GRET	SVC	3/19/2020	1965	RET ABN	UG-SERVICE
41411649	GRET	SVC	4/2/2024	1965	RET ABN	UG-SERVICE
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40420598	GRET	SVC	7/22/2022	1965	RET ABN	UG-SERVICE
39725934	GRET	SVC	1/26/2022	1965	RET ABN	UG-SERVICE
36473508	GRET	SVC	6/22/2020	1965	RET ABN	UG-SERVICE
38740519	GRET	SVC	7/12/2021	1965	RET ABN	UG-SERVICE
39666494	GRET	SVC	11/18/2022	1965	RET ABN	UG-SERVICE
39220431	GRET	SVC	9/29/2021	1965	RET ABN	UG-SERVICE
41534819	GRET	SVC	4/18/2023	1965	RET ABN	UG-SERVICE
43881519	GRET	SVC	11/13/2024	1965	RET ABN	UG-SERVICE
39858318	GRET	SVC	3/9/2022	1965	RET ABN	UG-SERVICE
43766464	GRET	SVC	10/29/2024	1965	RET ABN	UG-SERVICE
40103536	GRET	SVC	4/27/2022	1965	RET ABN	UG-SERVICE
41088830	GRET	SVC	1/31/2023	1965	RET ABN	UG-SERVICE
39666493	GRET	SVC	11/18/2022	1965	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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43423334	GRET	SVC	9/11/2024	1965	RET ABN	UG-SERVICE
39536549	GRET	SVC	12/13/2021	1965	RET ABN	UG-SERVICE
39395625	GRET	SVC	11/7/2021	1965	RET ABN	UG-SERVICE
41505539	GRET	SVC	4/12/2023	1965	RET ABN	UG-SERVICE
39656535	GRET	SVC	3/1/2022	1965	RET ABN	UG-SERVICE
37707219	GRET	SVC	12/8/2020	1965	RET ABN	UG-SERVICE
41423577	GRET	SVC	10/18/2023	1965	RET ABN	UG-SERVICE
41830302	GRET	SVC	8/11/2023	1965	RET ABN	UG-SERVICE
42363564	GRET	SVC	11/28/2023	1965	RET ABN	UG-SERVICE
42427223	GRET	SVC	11/20/2023	1965	RET ABN	UG-SERVICE
36122373	GRET	SVC	10/14/2020	1965	RET ABN	UG-SERVICE
37045733	GRET	SVC	10/14/2020	1965	RET ABN	UG-SERVICE
39666498	GRET	SVC	11/18/2022	1965	RET ABN	UG-SERVICE
42957392	GRET	SVC	9/19/2024	1965	RET ABN	UG-SERVICE
39661046	GRET	SVC	1/28/2022	1965	RET ABN	UG-SERVICE
42337726	GRET	SVC	1/26/2024	1965	RET ABN	UG-SERVICE
42833356	GRET	SVC	7/22/2024	1965	RET ABN	UG-SERVICE
39935372	GRET	SVC	5/14/2022	1965	RET ABN	UG-SERVICE
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40979415	GRET	SVC	11/28/2022	1965	RET ABN	UG-SERVICE
39225182	GRET	SVC	10/8/2021	1965	RET ABN	UG-SERVICE
41742291	GRET	SVC	7/25/2023	1965	RET ABN	UG-SERVICE
38496924	GRET	SVC	4/2/2021	1965	RET ABN	UG-SERVICE
42958101	GRET	SVC	9/19/2024	1965	RET ABN	UG-SERVICE
38617543	GRET	SVC	6/13/2021	1965	RET ABN	UG-SERVICE
37706318	GRET	SVC	11/20/2020	1965	RET ABN	UG-SERVICE
43646437	GRET	SVC	10/2/2024	1965	RET ABN	UG-SERVICE
42363560	GRET	SVC	11/28/2023	1965	RET ABN	UG-SERVICE
42957329	GRET	SVC	9/19/2024	1965	RET ABN	UG-SERVICE
36260066	GRET	SVC	3/19/2020	1965	RET ABN	UG-SERVICE
39654865	GRET	SVC	6/28/2022	1965	RET ABN	UG-SERVICE
42270107	GRET	SVC	11/2/2023	1965	RET ABN	UG-SERVICE
37978600	GRET	SVC	1/6/2021	1965	RET ABN	UG-SERVICE
37983192	GRET	SVC	1/6/2021	1965	RET ABN	UG-SERVICE
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39725954	GRET	SVC	1/26/2022	1965	RET ABN	UG-SERVICE
39666661	GRET	SVC	11/18/2022	1965	RET ABN	UG-SERVICE
40283204	GRET	SVC	6/7/2022	1965	RET ABN	UG-SERVICE
36080248	GRET	SVC	3/3/2020	1965	RET ABN	UG-SERVICE
38638023	GRET	SVC	6/16/2021	1965	RET ABN	UG-SERVICE
41052708	GRET	SVC	1/12/2023	1965	RET ABN	UG-SERVICE
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36152601	GRET	SVC	3/10/2020	1965	RET ABN	UG-SERVICE

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36838877	GRET	SVC	9/1/2020	1966	RET ABN	UG-SERVICE
42376902	GRET	SVC	11/22/2023	1966	RET ABN	UG-SERVICE
40978938	GRET	SVC	12/2/2022	1966	RET ABN	UG-SERVICE
38918860	GRET	SVC	8/17/2021	1966	RET ABN	UG-SERVICE
41204072	GRET	SVC	1/24/2023	1966	RET ABN	UG-SERVICE
41224415	GRET	SVC	2/3/2023	1966	RET REM	UG-SERVICE
41442094	GRET	SVC	3/28/2024	1966	RET ABN	UG-SERVICE
42870398	GRET	SVC	6/5/2024	1966	RET ABN	UG-SERVICE
40527282	GRET	SVC	8/8/2022	1966	RET ABN	UG-SERVICE
36330662	GRET	SVC	5/21/2020	1966	RET ABN	UG-SERVICE
40654496	GRET	SVC	9/6/2022	1966	RET ABN	UG-SERVICE
41273674	GRET	SVC	3/13/2023	1966	RET ABN	UG-SERVICE
36485524	GRET	SVC	6/23/2020	1966	RET ABN	UG-SERVICE
43330049	GRET	SVC	7/18/2024	1966	RET ABN	UG-SERVICE
36120845	GRET	SVC	10/12/2020	1966	RET ABN	UG-SERVICE
43423331	GRET	SVC	10/1/2024	1966	RET ABN	UG-SERVICE
37052009	GRET	SVC	10/12/2020	1966	RET ABN	UG-SERVICE
42273032	GRET	SVC	11/3/2023	1966	RET ABN	UG-SERVICE
40230897	GRET	SVC	5/31/2022	1966	RET ABN	UG-SERVICE
38909909	GRET	SVC	8/7/2021	1966	RET ABN	UG-SERVICE
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41111500	GRET	SVC	1/4/2023	1966	RET ABN	UG-SERVICE
42388694	GRET	SVC	12/6/2023	1966	RET ABN	UG-SERVICE
41407590	GRET	SVC	4/2/2024	1966	RET ABN	UG-SERVICE
37866261	GRET	SVC	11/21/2020	1966	RET ABN	UG-SERVICE
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38992456	GRET	SVC	8/31/2021	1966	RET ABN	UG-SERVICE
41052711	GRET	SVC	1/12/2023	1966	RET ABN	UG-SERVICE
36951629	GRET	SVC	9/24/2020	1966	RET ABN	UG-SERVICE
40128247	GRET	SVC	7/6/2022	1966	RET ABN	UG-SERVICE
42910237	GRET	SVC	4/9/2024	1966	RET ABN	UG-SERVICE
41830303	GRET	SVC	8/11/2023	1966	RET ABN	UG-SERVICE
36157802	GRET	SVC	3/24/2020	1966	RET ABN	UG-SERVICE
42282770	GRET	SVC	10/24/2023	1966	RET ABN	UG-SERVICE
39725755	GRET	SVC	1/26/2022	1966	RET ABN	UG-SERVICE
39116215	GRET	SVC	9/13/2021	1966	RET ABN	UG-SERVICE
38391849	GRET	SVC	4/23/2021	1966	RET ABN	UG-SERVICE
37638488	GRET	SVC	11/17/2020	1966	RET ABN	UG-SERVICE
42580401	GRET	SVC	1/22/2024	1966	RET ABN	UG-SERVICE
36711652	GRET	SVC	8/5/2020	1966	RET ABN	UG-SERVICE
36058177	GRET	SVC	2/24/2020	1966	RET ABN	UG-SERVICE
43903742	GRET	SVC	11/20/2024	1966	RET ABN	UG-SERVICE

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43252353	GRET	SVC	6/27/2024	1966	RET ABN	UG-SERVICE
41273672	GRET	SVC	2/15/2023	1966	RET ABN	UG-SERVICE
43446242	GRET	SVC	8/15/2024	1966	RET ABN	UG-SERVICE
42320774	GRET	SVC	11/6/2023	1966	RET ABN	UG-SERVICE
38356365	GRET	SVC	4/23/2021	1966	RET ABN	UG-SERVICE
41407589	GRET	SVC	4/2/2024	1966	RET ABN	UG-SERVICE
42276565	GRET	SVC	10/30/2023	1966	RET ABN	UG-SERVICE
39423750	GRET	SVC	6/27/2022	1966	RET ABN	UG-SERVICE
43523502	GRET	SVC	9/11/2024	1966	RET ABN	UG-SERVICE
36107792	GRET	SVC	4/24/2020	1966	RET ABN	UG-SERVICE
41388767	GRET	SVC	3/16/2023	1966	RET ABN	UG-SERVICE
43257608	GRET	SVC	7/2/2024	1966	RET ABN	UG-SERVICE
36915301	GRET	SVC	9/10/2020	1966	RET ABN	UG-SERVICE
36247036	GRET	SVC	4/3/2020	1966	RET ABN	UG-SERVICE
38401486	GRET	SVC	8/31/2021	1966	RET ABN	UG-SERVICE
43245032	GRET	SVC	9/19/2024	1966	RET ABN	UG-SERVICE
41407584	GRET	SVC	4/2/2024	1966	RET ABN	UG-SERVICE
39935350	GRET	SVC	5/14/2022	1966	RET ABN	UG-SERVICE
39831381	GRET	SVC	8/3/2022	1966	RET ABN	UG-SERVICE
40991241	GRET	SVC	12/3/2022	1966	RET ABN	UG-SERVICE
41349222	GRET	SVC	4/17/2023	1966	RET ABN	UG-SERVICE
40979006	GRET	SVC	12/2/2022	1966	RET ABN	UG-SERVICE
42956945	GRET	SVC	9/19/2024	1966	RET ABN	UG-SERVICE
36145871	GRET	SVC	3/17/2020	1966	RET ABN	UG-SERVICE
39513499	GRET	SVC	12/6/2021	1966	RET ABN	UG-SERVICE
40498178	GRET	SVC	8/17/2022	1966	RET ABN	UG-SERVICE
36122126	GRET	SVC	10/30/2020	1966	RET ABN	UG-SERVICE
36136193	GRET	SVC	4/20/2020	1966	RET ABN	UG-SERVICE
39153977	GRET	SVC	8/2/2021	1966	RET ABN	UG-SERVICE
36109957	GRET	SVC	4/22/2020	1966	RET ABN	UG-SERVICE
43522786	GRET	SVC	9/3/2024	1966	RET ABN	UG-SERVICE
36183828	GRET	SVC	3/30/2020	1966	RET ABN	UG-SERVICE
43256912	GRET	SVC	7/17/2024	1966	RET ABN	UG-SERVICE
36751428	GRET	SVC	10/5/2020	1966	RET ABN	UG-SERVICE
41062433	GRET	SVC	12/14/2022	1966	RET ABN	UG-SERVICE
38912078	GRET	SVC	11/4/2021	1966	RET ABN	UG-SERVICE
43245040	GRET	SVC	9/19/2024	1966	RET ABN	UG-SERVICE
38741028	GRET	SVC	7/28/2021	1966	RET ABN	UG-SERVICE
39353378	GRET	SVC	11/1/2021	1966	RET ABN	UG-SERVICE
43481242	GRET	SVC	10/25/2024	1966	RET ABN	UG-SERVICE
38378981	GRET	SVC	6/28/2021	1966	RET ABN	UG-SERVICE
36107163	GRET	SVC	4/23/2020	1966	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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38305182	GRET	SVC	4/5/2021	1966	RET ABN	UG-SERVICE
36122125	GRET	SVC	10/30/2020	1966	RET ABN	UG-SERVICE
39319507	GRET	SVC	10/20/2021	1966	RET ABN	UG-SERVICE
40332412	GRET	SVC	6/28/2022	1966	RET ABN	UG-SERVICE
40284142	GRET	SVC	6/13/2022	1966	RET ABN	UG-SERVICE
40500613	GRET	SVC	8/20/2022	1966	RET ABN	UG-SERVICE
41408288	GRET	SVC	4/2/2024	1966	RET ABN	UG-SERVICE
41407875	GRET	SVC	4/6/2023	1966	RET ABN	UG-SERVICE
37047386	GRET	SVC	4/15/2021	1966	RET ABN	UG-SERVICE
38564394	GRET	SVC	6/21/2021	1966	RET ABN	UG-SERVICE
42898274	GRET	SVC	4/8/2024	1966	RET ABN	UG-SERVICE
36177521	GRET	SVC	2/14/2020	1966	RET ABN	UG-SERVICE
38416170	GRET	SVC	4/27/2021	1966	RET ABN	UG-SERVICE
43171328	GRET	SVC	6/11/2024	1966	RET ABN	UG-SERVICE
39875729	GRET	SVC	5/18/2022	1966	RET ABN	UG-SERVICE
43245044	GRET	SVC	9/11/2024	1966	RET ABN	UG-SERVICE
43245049	GRET	SVC	9/11/2024	1966	RET ABN	UG-SERVICE
40654907	GRET	SVC	9/4/2022	1966	RET ABN	UG-SERVICE
43529749	GRET	SVC	10/21/2024	1966	RET ABN	UG-SERVICE
36797243	GRET	SVC	8/17/2020	1966	RET ABN	UG-SERVICE
40717084	GRET	SVC	9/20/2022	1966	RET ABN	UG-SERVICE
43245048	GRET	SVC	9/11/2024	1966	RET ABN	UG-SERVICE
41179359	GRET	SVC	1/20/2023	1966	RET ABN	UG-SERVICE
36406483	GRET	SVC	6/22/2020	1966	RET ABN	UG-SERVICE
43005042	GRET	SVC	9/19/2024	1966	RET ABN	UG-SERVICE
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42549484	GRET	SVC	1/4/2024	1966	RET ABN	UG-SERVICE
41407592	GRET	SVC	4/2/2024	1966	RET ABN	UG-SERVICE
42046170	GRET	SVC	8/28/2023	1966	RET ABN	UG-SERVICE
39231670	GRET	SVC	9/30/2021	1966	RET ABN	UG-SERVICE
38407207	GRET	SVC	3/19/2021	1966	RET ABN	UG-SERVICE
40798417	GRET	SVC	10/10/2022	1966	RET ABN	UG-SERVICE
36107783	GRET	SVC	4/24/2020	1966	RET ABN	UG-SERVICE
39324017	GRET	SVC	10/19/2021	1966	RET ABN	UG-SERVICE
41472721	GRET	SVC	7/12/2023	1966	RET ABN	UG-SERVICE
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43318163	GRET	SVC	8/5/2024	1966	RET ABN	UG-SERVICE
39831374	GRET	SVC	8/3/2022	1966	RET ABN	UG-SERVICE
40798329	GRET	SVC	10/10/2022	1966	RET ABN	UG-SERVICE
43229977	GRET	SVC	6/25/2024	1966	RET ABN	UG-SERVICE
39192329	GRET	SVC	9/30/2021	1966	RET ABN	UG-SERVICE
41697290	GRET	SVC	4/21/2023	1966	RET ABN	UG-SERVICE

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39423859	GRET	SVC	6/27/2022	1966	RET ABN	UG-SERVICE
41124022	GRET	SVC	1/4/2023	1966	RET ABN	UG-SERVICE
42957221	GRET	SVC	9/19/2024	1966	RET ABN	UG-SERVICE
38844638	GRET	SVC	7/27/2021	1966	RET ABN	UG-SERVICE
38470298	GRET	SVC	3/29/2021	1966	RET ABN	UG-SERVICE
36107790	GRET	SVC	4/24/2020	1966	RET ABN	UG-SERVICE
43423332	GRET	SVC	10/1/2024	1966	RET ABN	UG-SERVICE
39614518	GRET	SVC	12/29/2021	1966	RET ABN	UG-SERVICE
42885139	GRET	SVC	4/5/2024	1966	RET ABN	UG-SERVICE
38390575	GRET	SVC	4/20/2021	1966	RET ABN	UG-SERVICE
38443004	GRET	SVC	5/4/2021	1966	RET ABN	UG-SERVICE
40806281	GRET	SVC	10/13/2022	1966	RET ABN	UG-SERVICE
36107788	GRET	SVC	4/24/2020	1966	RET ABN	UG-SERVICE
41407548	GRET	SVC	4/2/2024	1966	RET ABN	UG-SERVICE
40493050	GRET	SVC	7/26/2022	1966	RET ABN	UG-SERVICE
37110282	GRET	SVC	10/21/2020	1966	RET ABN	UG-SERVICE
42678874	GRET	SVC	2/6/2024	1966	RET ABN	UG-SERVICE
36287104	GRET	SVC	5/5/2020	1966	RET ABN	UG-SERVICE
43330681	GRET	SVC	8/13/2024	1966	RET ABN	UG-SERVICE
38936703	GRET	SVC	8/4/2021	1966	RET ABN	UG-SERVICE
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36201750	GRET	SVC	4/20/2020	1966	RET ABN	UG-SERVICE
36599915	GRET	SVC	7/2/2020	1966	RET ABN	UG-SERVICE
38492277	GRET	SVC	5/13/2021	1966	RET ABN	UG-SERVICE
36980369	GRET	SVC	9/23/2020	1966	RET ABN	UG-SERVICE
40484247	GRET	SVC	7/26/2022	1966	RET ABN	UG-SERVICE
36695968	GRET	SVC	9/17/2020	1966	RET ABN	UG-SERVICE
36109251	GRET	SVC	3/10/2020	1966	RET ABN	UG-SERVICE
43245033	GRET	SVC	9/19/2024	1966	RET ABN	UG-SERVICE
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38474293	GRET	SVC	3/30/2021	1966	RET ABN	UG-SERVICE
43408117	GRET	SVC	8/13/2024	1966	RET ABN	UG-SERVICE
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42225324	GRET	SVC	6/14/2024	1966	RET ABN	UG-SERVICE
41441932	GRET	SVC	9/12/2023	1966	RET ABN	UG-SERVICE
42165916	GRET	SVC	9/19/2023	1966	RET ABN	UG-SERVICE
40396182	GRET	SVC	7/7/2022	1966	RET ABN	UG-SERVICE
43719270	GRET	SVC	10/21/2024	1966	RET ABN	UG-SERVICE
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41001867	GRET	SVC	11/28/2022	1966	RET ABN	UG-SERVICE
41035829	GRET	SVC	12/8/2022	1966	RET ABN	UG-SERVICE
39819175	GRET	SVC	3/3/2022	1966	RET ABN	UG-SERVICE
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order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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43366073	GRET	SVC	12/19/2024	1966	RET ABN	UG-SERVICE
39868516	GRET	SVC	3/9/2022	1966	RET ABN	UG-SERVICE
38067134	GRET	SVC	1/27/2021	1966	RET ABN	UG-SERVICE
42943660	GRET	SVC	7/17/2024	1966	RET ABN	UG-SERVICE
32785206	GRET	SVC	3/5/2020	1966	RET ABN	UG-SERVICE
36881998	GRET	SVC	9/2/2020	1966	RET ABN	UG-SERVICE
43401010	GRET	SVC	8/12/2024	1966	RET ABN	UG-SERVICE
37958746	GRET	SVC	12/29/2020	1966	RET ABN	UG-SERVICE
42327270	GRET	SVC	11/6/2023	1966	RET ABN	UG-SERVICE
42517348	GRET	SVC	12/28/2023	1966	RET ABN	UG-SERVICE
36137641	GRET	SVC	4/20/2020	1966	RET ABN	UG-SERVICE
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42844721	GRET	SVC	3/6/2024	1966	RET ABN	UG-SERVICE
39831379	GRET	SVC	8/3/2022	1966	RET ABN	UG-SERVICE
36734672	GRET	SVC	8/3/2020	1966	RET ABN	UG-SERVICE
36137138	GRET	SVC	4/21/2020	1966	RET ABN	UG-SERVICE
41411141	GRET	SVC	4/2/2024	1966	RET ABN	UG-SERVICE
38470224	GRET	SVC	5/11/2021	1966	RET ABN	UG-SERVICE
41020776	GRET	SVC	12/14/2022	1966	RET ABN	UG-SERVICE
41213128	GRET	SVC	1/30/2023	1966	RET ABN	UG-SERVICE
42956943	GRET	SVC	9/19/2024	1966	RET ABN	UG-SERVICE
40187487	GRET	SVC	5/18/2022	1966	RET ABN	UG-SERVICE
36349695	GRET	SVC	5/20/2020	1966	RET ABN	UG-SERVICE
37927124	GRET	SVC	12/15/2020	1966	RET ABN	UG-SERVICE
41913456	GRET	SVC	7/26/2023	1966	RET ABN	UG-SERVICE
43869730	GRET	SVC	11/26/2024	1966	RET ABN	UG-SERVICE
40050122	GRET	SVC	4/26/2022	1966	RET ABN	UG-SERVICE
36596780	GRET	SVC	7/9/2020	1966	RET ABN	UG-SERVICE
40976897	GRET	SVC	11/23/2022	1966	RET ABN	UG-SERVICE
39168281	GRET	SVC	9/22/2021	1966	RET ABN	UG-SERVICE
39814288	GRET	SVC	2/21/2022	1966	RET ABN	UG-SERVICE
41564104	GRET	SVC	4/24/2023	1966	RET ABN	UG-SERVICE
38379345	GRET	SVC	6/26/2021	1966	RET ABN	UG-SERVICE
36150722	GRET	SVC	3/23/2020	1967	RET ABN	UG-SERVICE
42605867	GRET	SVC	1/18/2024	1967	RET ABN	UG-SERVICE
41411749	GRET	SVC	4/2/2024	1967	RET ABN	UG-SERVICE
41898045	GRET	SVC	9/15/2023	1967	RET ABN	UG-SERVICE
38088945	GRET	SVC	2/3/2021	1967	RET ABN	UG-SERVICE
43593171	GRET	SVC	9/23/2024	1967	RET ABN	UG-SERVICE
39126411	GRET	SVC	9/13/2021	1967	RET ABN	UG-SERVICE
38713600	GRET	SVC	7/15/2021	1967	RET ABN	UG-SERVICE
36107419	GRET	SVC	3/9/2020	1967	RET ABN	UG-SERVICE
38804672	GRET	SVC	8/2/2021	1967	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38441366	GRET	SVC	1/6/2022	1967	RET ABN	UG-SERVICE
41402745	GRET	SVC	11/2/2023	1967	RET ABN	UG-SERVICE
43010129	GRET	SVC	5/9/2024	1967	RET ABN	UG-SERVICE
36880787	GRET	SVC	9/3/2020	1967	RET ABN	UG-SERVICE
40662648	GRET	SVC	9/16/2022	1967	RET ABN	UG-SERVICE
39665818	GRET	SVC	8/3/2022	1967	RET ABN	UG-SERVICE
41572254	GRET	SVC	5/1/2023	1967	RET ABN	UG-SERVICE
41679178	GRET	SVC	6/18/2023	1967	RET ABN	UG-SERVICE
42385646	GRET	SVC	11/18/2023	1967	RET ABN	UG-SERVICE
40469555	GRET	SVC	7/26/2022	1967	RET ABN	UG-SERVICE
36078166	GRET	SVC	3/2/2020	1967	RET ABN	UG-SERVICE
41324411	GRET	SVC	3/1/2023	1967	RET ABN	UG-SERVICE
40691857	GRET	SVC	9/16/2022	1967	RET ABN	UG-SERVICE
36122365	GRET	SVC	11/5/2020	1967	RET ABN	UG-SERVICE
41407817	GRET	SVC	4/2/2024	1967	RET ABN	UG-SERVICE
38206545	GRET	SVC	3/19/2021	1967	RET ABN	UG-SERVICE
41144028	GRET	SVC	1/11/2023	1967	RET ABN	UG-SERVICE
39998576	GRET	SVC	4/12/2022	1967	RET ABN	UG-SERVICE
43318491	GRET	SVC	8/9/2024	1967	RET ABN	UG-SERVICE
40496050	GRET	SVC	7/23/2022	1967	RET ABN	UG-SERVICE
41297878	GRET	SVC	2/21/2023	1967	RET ABN	UG-SERVICE
41307330	GRET	SVC	3/29/2023	1967	RET ABN	UG-SERVICE
40973101	GRET	SVC	12/12/2022	1967	RET ABN	UG-SERVICE
39665098	GRET	SVC	1/5/2022	1967	RET ABN	UG-SERVICE
36672714	GRET	SVC	7/18/2020	1967	RET ABN	UG-SERVICE
38541493	GRET	SVC	6/5/2021	1967	RET ABN	UG-SERVICE
40471339	GRET	SVC	7/23/2022	1967	RET ABN	UG-SERVICE
39971688	GRET	SVC	4/7/2022	1967	RET ABN	UG-SERVICE
39971299	GRET	SVC	4/18/2022	1967	RET ABN	UG-SERVICE
41534176	GRET	SVC	4/27/2023	1967	RET ABN	UG-SERVICE
39914955	GRET	SVC	3/31/2022	1967	RET ABN	UG-SERVICE
42161243	GRET	SVC	10/2/2023	1967	RET ABN	UG-SERVICE
39520336	GRET	SVC	12/10/2021	1967	RET ABN	UG-SERVICE
39576513	GRET	SVC	12/27/2021	1967	RET ABN	UG-SERVICE
38910763	GRET	SVC	8/16/2021	1967	RET ABN	UG-SERVICE
36422233	GRET	SVC	6/26/2020	1967	RET ABN	UG-SERVICE
43084020	GRET	SVC	7/30/2024	1967	RET ABN	UG-SERVICE
37525669	GRET	SVC	11/9/2020	1967	RET ABN	UG-SERVICE
42750555	GRET	SVC	2/20/2024	1967	RET ABN	UG-SERVICE
40091166	GRET	SVC	5/2/2022	1967	RET ABN	UG-SERVICE
41323426	GRET	SVC	2/28/2023	1967	RET ABN	UG-SERVICE
42925448	GRET	SVC	4/16/2024	1967	RET ABN	UG-SERVICE
41052705	GRET	SVC	1/12/2023	1967	RET ABN	UG-SERVICE
43869026	GRET	SVC	11/25/2024	1967	RET ABN	UG-SERVICE
36345887	GRET	SVC	5/13/2020	1967	RET ABN	UG-SERVICE

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38896259	GRET	SVC	8/16/2021	1967	RET ABN	UG-SERVICE
41143510	GRET	SVC	7/31/2023	1967	RET ABN	UG-SERVICE
42023624	GRET	SVC	8/22/2023	1967	RET ABN	UG-SERVICE
43134071	GRET	SVC	6/8/2024	1967	RET ABN	UG-SERVICE
40685461	GRET	SVC	9/24/2022	1967	RET ABN	UG-SERVICE
43596416	GRET	SVC	9/18/2024	1967	RET ABN	UG-SERVICE
41719026	GRET	SVC	6/6/2023	1967	RET ABN	UG-SERVICE
41194829	GRET	SVC	1/22/2023	1967	RET ABN	UG-SERVICE
43919197	GRET	SVC	12/23/2024	1967	RET ABN	UG-SERVICE
40425791	GRET	SVC	7/11/2022	1967	RET ABN	UG-SERVICE
42205157	GRET	SVC	10/13/2023	1967	RET ABN	UG-SERVICE
36715856	GRET	SVC	9/30/2020	1967	RET ABN	UG-SERVICE
41407487	GRET	SVC	4/2/2024	1967	RET ABN	UG-SERVICE
38265300	GRET	SVC	3/24/2021	1967	RET ABN	UG-SERVICE
43476336	GRET	SVC	8/15/2024	1967	RET ABN	UG-SERVICE
43892478	GRET	SVC	12/6/2024	1967	RET ABN	UG-SERVICE
41318153	GRET	SVC	3/2/2023	1967	RET ABN	UG-SERVICE
41052704	GRET	SVC	1/12/2023	1967	RET ABN	UG-SERVICE
39437495	GRET	SVC	11/19/2021	1967	RET ABN	UG-SERVICE
37415212	GRET	SVC	11/11/2020	1967	RET ABN	UG-SERVICE
36142352	GRET	SVC	3/17/2020	1967	RET ABN	UG-SERVICE
38012930	GRET	SVC	1/13/2021	1967	RET ABN	UG-SERVICE
43343955	GRET	SVC	7/30/2024	1967	RET ABN	UG-SERVICE
41194824	GRET	SVC	1/21/2023	1967	RET ABN	UG-SERVICE
40962280	GRET	SVC	11/21/2022	1967	RET ABN	UG-SERVICE
39331817	GRET	SVC	10/23/2021	1967	RET ABN	UG-SERVICE
41728314	GRET	SVC	6/12/2023	1967	RET ABN	UG-SERVICE
38479658	GRET	SVC	5/12/2021	1967	RET ABN	UG-SERVICE
41101695	GRET	SVC	12/29/2022	1967	RET ABN	UG-SERVICE
43477194	GRET	SVC	8/20/2024	1967	RET ABN	UG-SERVICE
39935367	GRET	SVC	6/27/2022	1967	RET ABN	UG-SERVICE
39503379	GRET	SVC	12/14/2021	1967	RET ABN	UG-SERVICE
42336409	GRET	SVC	7/18/2024	1967	RET ABN	UG-SERVICE
40636489	GRET	SVC	8/29/2022	1967	RET ABN	UG-SERVICE
39621712	GRET	SVC	1/3/2022	1967	RET ABN	UG-SERVICE
38217713	GRET	SVC	3/11/2021	1967	RET ABN	UG-SERVICE
42953077	GRET	SVC	4/18/2024	1967	RET ABN	UG-SERVICE
36102276	GRET	SVC	4/23/2020	1967	RET ABN	UG-SERVICE
43063958	GRET	SVC	5/13/2024	1967	RET ABN	UG-SERVICE
38955711	GRET	SVC	8/24/2021	1967	RET ABN	UG-SERVICE
40522528	GRET	SVC	8/4/2022	1967	RET ABN	UG-SERVICE
36240479	GRET	SVC	6/1/2020	1967	RET ABN	UG-SERVICE
36095277	GRET	SVC	3/6/2020	1967	RET ABN	UG-SERVICE
37896726	GRET	SVC	12/9/2020	1967	RET ABN	UG-SERVICE
37867316	GRET	SVC	12/3/2020	1967	RET ABN	UG-SERVICE

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43289879	GRET	SVC	7/12/2024	1967	RET ABN	UG-SERVICE
39831011	GRET	SVC	7/27/2020	1967	RET ABN	UG-SERVICE
43236421	GRET	SVC	6/28/2024	1967	RET ABN	UG-SERVICE
40771417	GRET	SVC	10/4/2022	1967	RET ABN	UG-SERVICE
36153162	GRET	SVC	8/17/2020	1967	RET ABN	UG-SERVICE
41409258	GRET	SVC	4/2/2024	1967	RET ABN	UG-SERVICE
43795188	GRET	SVC	11/8/2024	1967	RET ABN	UG-SERVICE
40478176	GRET	SVC	7/27/2022	1967	RET ABN	UG-SERVICE
38571058	GRET	SVC	6/11/2021	1967	RET ABN	UG-SERVICE
37035951	GRET	SVC	10/8/2020	1967	RET ABN	UG-SERVICE
40237837	GRET	SVC	6/1/2022	1967	RET ABN	UG-SERVICE
40729723	GRET	SVC	9/27/2022	1967	RET ABN	UG-SERVICE
42487579	GRET	SVC	7/18/2024	1967	RET ABN	UG-SERVICE
42534645	GRET	SVC	1/8/2024	1967	RET ABN	UG-SERVICE
43746369	GRET	SVC	10/28/2024	1967	RET ABN	UG-SERVICE
42097609	GRET	SVC	11/27/2023	1967	RET ABN	UG-SERVICE
36927420	GRET	SVC	9/16/2020	1967	RET ABN	UG-SERVICE
42145313	GRET	SVC	9/8/2023	1967	RET ABN	UG-SERVICE
40976611	GRET	SVC	11/23/2022	1967	RET ABN	UG-SERVICE
42995767	GRET	SVC	4/29/2024	1967	RET ABN	UG-SERVICE
39388230	GRET	SVC	11/4/2021	1967	RET ABN	UG-SERVICE
39371727	GRET	SVC	11/2/2021	1967	RET ABN	UG-SERVICE
38150614	GRET	SVC	2/22/2021	1967	RET ABN	UG-SERVICE
41577519	GRET	SVC	5/3/2023	1967	RET ABN	UG-SERVICE
41035391	GRET	SVC	12/15/2022	1967	RET ABN	UG-SERVICE
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43177756	GRET	SVC	6/13/2024	1967	RET ABN	UG-SERVICE
41057844	GRET	SVC	12/14/2022	1967	RET ABN	UG-SERVICE
41411190	GRET	SVC	4/2/2024	1967	RET ABN	UG-SERVICE
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42813116	GRET	SVC	3/11/2024	1967	RET ABN	UG-SERVICE
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41407486	GRET	SVC	4/2/2024	1967	RET ABN	UG-SERVICE
39498221	GRET	SVC	12/10/2021	1967	RET ABN	UG-SERVICE
41404770	GRET	SVC	3/29/2023	1967	RET ABN	UG-SERVICE
41410858	GRET	SVC	4/2/2024	1967	RET ABN	UG-SERVICE
43610002	GRET	SVC	10/16/2024	1967	RET ABN	UG-SERVICE
41321851	GRET	SVC	3/9/2023	1967	RET ABN	UG-SERVICE
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39424071	GRET	SVC	6/27/2022	1967	RET ABN	UG-SERVICE
41424037	GRET	SVC	10/18/2023	1967	RET ABN	UG-SERVICE
37146547	GRET	SVC	12/7/2020	1967	RET ABN	UG-SERVICE
43403341	GRET	SVC	8/12/2024	1967	RET ABN	UG-SERVICE
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36146773	GRET	SVC	3/14/2020	1967	RET ABN	UG-SERVICE
37415099	GRET	SVC	11/11/2020	1967	RET ABN	UG-SERVICE
39666485	GRET	SVC	11/18/2022	1967	RET ABN	UG-SERVICE
43854347	GRET	SVC	11/22/2024	1967	RET ABN	UG-SERVICE
39666047	GRET	SVC	8/3/2022	1967	RET ABN	UG-SERVICE
35928748	GRET	SVC	1/21/2020	1967	RET ABN	UG-SERVICE
41411425	GRET	SVC	11/2/2023	1967	RET ABN	UG-SERVICE
38076254	GRET	SVC	2/16/2021	1967	RET ABN	UG-SERVICE
36203943	GRET	SVC	4/22/2020	1967	RET ABN	UG-SERVICE
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38486936	GRET	SVC	5/13/2021	1967	RET ABN	UG-SERVICE
36931800	GRET	SVC	9/15/2020	1967	RET ABN	UG-SERVICE
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41409111	GRET	SVC	4/2/2024	1967	RET ABN	UG-SERVICE
41327517	GRET	SVC	2/15/2023	1967	RET ABN	UG-SERVICE
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42894876	GRET	SVC	11/19/2024	1967	RET ABN	UG-SERVICE
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38660377	GRET	SVC	6/24/2021	1967	RET ABN	UG-SERVICE
36214579	GRET	SVC	4/30/2020	1967	RET ABN	UG-SERVICE
41330184	GRET	SVC	3/1/2023	1967	RET ABN	UG-SERVICE
43642438	GRET	SVC	10/4/2024	1967	RET ABN	UG-SERVICE
40537458	GRET	SVC	8/10/2022	1967	RET ABN	UG-SERVICE
38242131	GRET	SVC	3/16/2021	1967	RET ABN	UG-SERVICE
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36278024	GRET	SVC	6/11/2020	1967	RET ABN	UG-SERVICE
41903924	GRET	SVC	11/3/2023	1967	RET ABN	UG-SERVICE
36750482	GRET	SVC	9/14/2020	1967	RET ABN	UG-SERVICE
39831378	GRET	SVC	8/3/2022	1967	RET ABN	UG-SERVICE

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36022114	GRET	SVC	2/18/2020	1967	RET ABN	UG-SERVICE
36342128	GRET	SVC	12/23/2020	1967	RET ABN	UG-SERVICE
36269698	GRET	SVC	4/27/2020	1967	RET ABN	UG-SERVICE
36304097	GRET	SVC	4/23/2020	1967	RET ABN	UG-SERVICE
42124244	GRET	SVC	9/19/2023	1967	RET ABN	UG-SERVICE
43757513	GRET	SVC	10/28/2024	1967	RET ABN	UG-SERVICE
40231470	GRET	SVC	5/31/2022	1967	RET ABN	UG-SERVICE
40524324	GRET	SVC	8/3/2022	1967	RET ABN	UG-SERVICE
36817871	GRET	SVC	9/2/2020	1967	RET ABN	UG-SERVICE
39370519	GRET	SVC	11/1/2021	1967	RET ABN	UG-SERVICE
37030982	GRET	SVC	10/9/2020	1967	RET ABN	UG-SERVICE
41675753	GRET	SVC	5/31/2023	1967	RET ABN	UG-SERVICE
41594980	GRET	SVC	5/2/2023	1967	RET ABN	UG-SERVICE
38052185	GRET	SVC	1/27/2021	1967	RET ABN	UG-SERVICE
43628685	GRET	SVC	9/30/2024	1967	RET ABN	UG-SERVICE
43112167	GRET	SVC	5/29/2024	1967	RET ABN	UG-SERVICE
42405621	GRET	SVC	11/22/2023	1967	RET ABN	UG-SERVICE
40536285	GRET	SVC	8/18/2022	1967	RET ABN	UG-SERVICE
41052712	GRET	SVC	1/12/2023	1967	RET ABN	UG-SERVICE
36138366	GRET	SVC	4/23/2020	1967	RET ABN	UG-SERVICE
36091940	GRET	SVC	10/30/2020	1967	RET ABN	UG-SERVICE
41411775	GRET	SVC	4/2/2024	1967	RET ABN	UG-SERVICE
41083734	GRET	SVC	12/22/2022	1967	RET ABN	UG-SERVICE
41306994	GRET	SVC	2/20/2023	1967	RET ABN	UG-SERVICE
41084268	GRET	SVC	1/11/2023	1967	RET ABN	UG-SERVICE
42216807	GRET	SVC	12/6/2023	1968	RET ABN	UG-SERVICE
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39831465	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
42036340	GRET	SVC	9/11/2023	1968	RET ABN	UG-SERVICE
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36121681	GRET	SVC	10/12/2020	1968	RET ABN	UG-SERVICE
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42542323	GRET	SVC	1/25/2024	1968	RET ABN	UG-SERVICE
41920619	GRET	SVC	7/31/2023	1968	RET ABN	UG-SERVICE
40395535	GRET	SVC	7/6/2022	1968	RET ABN	UG-SERVICE
40301513	GRET	SVC	6/16/2022	1968	RET ABN	UG-SERVICE
36951735	GRET	SVC	9/17/2020	1968	RET ABN	UG-SERVICE
40203722	GRET	SVC	5/23/2022	1968	RET ABN	UG-SERVICE
42216801	GRET	SVC	12/5/2023	1968	RET ABN	UG-SERVICE
43632098	GRET	SVC	10/4/2024	1968	RET ABN	UG-SERVICE
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order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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43364874	GRET	SVC	12/2/2024	1968	RET ABN	UG-SERVICE
40237978	GRET	SVC	6/2/2022	1968	RET ABN	UG-SERVICE
43365795	GRET	SVC	10/30/2024	1968	RET ABN	UG-SERVICE
38373630	GRET	SVC	4/14/2021	1968	RET ABN	UG-SERVICE
42520394	GRET	SVC	1/25/2024	1968	RET ABN	UG-SERVICE
38589148	GRET	SVC	10/5/2021	1968	RET ABN	UG-SERVICE
43610586	GRET	SVC	11/21/2024	1968	RET ABN	UG-SERVICE
33866282	GRET	SVC	10/16/2021	1968	RET ABN	UG-SERVICE
36611386	GRET	SVC	7/16/2020	1968	RET ABN	UG-SERVICE
36122580	GRET	SVC	10/30/2020	1968	RET ABN	UG-SERVICE
41697783	GRET	SVC	6/2/2023	1968	RET ABN	UG-SERVICE
42841037	GRET	SVC	3/19/2024	1968	RET ABN	UG-SERVICE
39935477	GRET	SVC	6/24/2022	1968	RET ABN	UG-SERVICE
39995703	GRET	SVC	4/14/2022	1968	RET ABN	UG-SERVICE
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43481195	GRET	SVC	10/23/2024	1968	RET ABN	UG-SERVICE
37149310	GRET	SVC	10/31/2020	1968	RET ABN	UG-SERVICE
41429991	GRET	SVC	9/12/2023	1968	RET ABN	UG-SERVICE
39554486	GRET	SVC	12/23/2021	1968	RET ABN	UG-SERVICE
39665944	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
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38658043	GRET	SVC	7/8/2021	1968	RET ABN	UG-SERVICE
38594108	GRET	SVC	9/9/2021	1968	RET ABN	UG-SERVICE
39374095	GRET	SVC	11/2/2021	1968	RET ABN	UG-SERVICE
43610588	GRET	SVC	12/11/2024	1968	RET ABN	UG-SERVICE
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36613098	GRET	SVC	7/11/2020	1968	RET ABN	UG-SERVICE
42450330	GRET	SVC	12/2/2023	1968	RET ABN	UG-SERVICE
41318143	GRET	SVC	3/2/2023	1968	RET ABN	UG-SERVICE
42427950	GRET	SVC	11/30/2023	1968	RET ABN	UG-SERVICE
36107003	GRET	SVC	4/24/2020	1968	RET ABN	UG-SERVICE
38608782	GRET	SVC	12/23/2021	1968	RET ABN	UG-SERVICE
39423116	GRET	SVC	6/27/2022	1968	RET ABN	UG-SERVICE
42564472	GRET	SVC	1/10/2024	1968	RET ABN	UG-SERVICE
36396246	GRET	SVC	6/2/2020	1968	RET ABN	UG-SERVICE
36613097	GRET	SVC	7/11/2020	1968	RET ABN	UG-SERVICE
42622530	GRET	SVC	2/12/2024	1968	RET ABN	UG-SERVICE
41088836	GRET	SVC	1/13/2023	1968	RET ABN	UG-SERVICE
36345899	GRET	SVC	5/20/2020	1968	RET ABN	UG-SERVICE
42774105	GRET	SVC	2/26/2024	1968	RET ABN	UG-SERVICE
38588933	GRET	SVC	9/29/2021	1968	RET ABN	UG-SERVICE
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36062451	GRET	SVC	2/26/2020	1968	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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42833341	GRET	SVC	7/22/2024	1968	RET ABN	UG-SERVICE
41411827	GRET	SVC	4/2/2024	1968	RET ABN	UG-SERVICE
43586515	GRET	SVC	9/9/2024	1968	RET ABN	UG-SERVICE
38589321	GRET	SVC	8/3/2021	1968	RET ABN	UG-SERVICE
41572927	GRET	SVC	6/10/2024	1968	RET ABN	UG-SERVICE
38642560	GRET	SVC	6/29/2021	1968	RET ABN	UG-SERVICE
37811156	GRET	SVC	12/4/2020	1968	RET ABN	UG-SERVICE
43524136	GRET	SVC	10/15/2024	1968	RET ABN	UG-SERVICE
39665953	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
36749021	GRET	SVC	8/17/2020	1968	RET ABN	UG-SERVICE
36613382	GRET	SVC	7/10/2020	1968	RET ABN	UG-SERVICE
39666145	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
42575791	GRET	SVC	1/13/2024	1968	RET ABN	UG-SERVICE
36241112	GRET	SVC	5/5/2020	1968	RET ABN	UG-SERVICE
41969542	GRET	SVC	8/1/2024	1968	RET ABN	UG-SERVICE
40126087	GRET	SVC	5/5/2022	1968	RET ABN	UG-SERVICE
40985080	GRET	SVC	11/14/2022	1968	RET ABN	UG-SERVICE
42050868	GRET	SVC	8/30/2023	1968	RET ABN	UG-SERVICE
39666056	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
36137881	GRET	SVC	4/22/2020	1968	RET ABN	UG-SERVICE
40802552	GRET	SVC	10/6/2022	1968	RET ABN	UG-SERVICE
43623499	GRET	SVC	12/3/2024	1968	RET ABN	UG-SERVICE
41922423	GRET	SVC	7/31/2023	1968	RET ABN	UG-SERVICE
41817953	GRET	SVC	6/26/2023	1968	RET ABN	UG-SERVICE
36613084	GRET	SVC	7/14/2020	1968	RET ABN	UG-SERVICE
42336406	GRET	SVC	7/18/2024	1968	RET ABN	UG-SERVICE
42833094	GRET	SVC	7/22/2024	1968	RET ABN	UG-SERVICE
43481193	GRET	SVC	10/22/2024	1968	RET ABN	UG-SERVICE
43493942	GRET	SVC	8/29/2024	1968	RET ABN	UG-SERVICE
39665954	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
36486231	GRET	SVC	6/25/2020	1968	RET ABN	UG-SERVICE
39666099	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
38991541	GRET	SVC	8/22/2021	1968	RET ABN	UG-SERVICE
40615036	GRET	SVC	8/22/2022	1968	RET ABN	UG-SERVICE
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40114951	GRET	SVC	5/4/2022	1968	RET ABN	UG-SERVICE
36612857	GRET	SVC	7/14/2020	1968	RET ABN	UG-SERVICE
39831563	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
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order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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38479663	GRET	SVC	5/12/2021	1968	RET ABN	UG-SERVICE
36966510	GRET	SVC	9/22/2020	1968	RET ABN	UG-SERVICE
36544029	GRET	SVC	7/26/2020	1968	RET ABN	UG-SERVICE
36893331	GRET	SVC	9/14/2020	1968	RET ABN	UG-SERVICE
43581817	GRET	SVC	9/19/2024	1968	RET ABN	UG-SERVICE
39666045	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
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39543432	GRET	SVC	12/14/2021	1968	RET ABN	UG-SERVICE
41913822	GRET	SVC	7/31/2023	1968	RET ABN	UG-SERVICE
41654468	GRET	SVC	5/18/2023	1968	RET ABN	UG-SERVICE
40577998	GRET	SVC	8/15/2022	1968	RET ABN	UG-SERVICE
40538368	GRET	SVC	8/12/2022	1968	RET ABN	UG-SERVICE
43365687	GRET	SVC	12/3/2024	1968	RET ABN	UG-SERVICE
42219601	GRET	SVC	10/11/2023	1968	RET ABN	UG-SERVICE
39417345	GRET	SVC	11/15/2021	1968	RET ABN	UG-SERVICE
41165474	GRET	SVC	1/17/2023	1968	RET ABN	UG-SERVICE
37943019	GRET	SVC	12/23/2020	1968	RET ABN	UG-SERVICE
41180518	GRET	SVC	1/20/2023	1968	RET ABN	UG-SERVICE
39666040	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
41969499	GRET	SVC	8/1/2024	1968	RET ABN	UG-SERVICE
41807875	GRET	SVC	6/27/2023	1968	RET ABN	UG-SERVICE
37741359	GRET	SVC	11/25/2020	1968	RET ABN	UG-SERVICE
43543033	GRET	SVC	10/4/2024	1968	RET ABN	UG-SERVICE
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42670281	GRET	SVC	9/19/2024	1968	RET ABN	UG-SERVICE
43443557	GRET	SVC	8/19/2024	1968	RET ABN	UG-SERVICE
41834506	GRET	SVC	7/21/2023	1968	RET ABN	UG-SERVICE
39665941	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
41469768	GRET	SVC	4/5/2023	1968	RET ABN	UG-SERVICE
36113086	GRET	SVC	10/12/2020	1968	RET ABN	UG-SERVICE
38512266	GRET	SVC	5/20/2021	1968	RET ABN	UG-SERVICE
42803974	GRET	SVC	3/15/2024	1968	RET ABN	UG-SERVICE
39665943	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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41844783	GRET	SVC	7/24/2023	1968	RET ABN	UG-SERVICE
39831467	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
38213089	GRET	SVC	3/11/2021	1968	RET ABN	UG-SERVICE
41316670	GRET	SVC	3/6/2023	1968	RET ABN	UG-SERVICE
42833351	GRET	SVC	7/23/2024	1968	RET ABN	UG-SERVICE
37994208	GRET	SVC	1/11/2021	1968	RET ABN	UG-SERVICE
38819878	GRET	SVC	8/2/2021	1968	RET ABN	UG-SERVICE
38732091	GRET	SVC	7/7/2021	1968	RET ABN	UG-SERVICE
41318463	GRET	SVC	3/6/2023	1968	RET ABN	UG-SERVICE
43749346	GRET	SVC	10/28/2024	1968	RET ABN	UG-SERVICE
38284395	GRET	SVC	3/29/2021	1968	RET ABN	UG-SERVICE
36119808	GRET	SVC	10/30/2020	1968	RET ABN	UG-SERVICE
39524063	GRET	SVC	12/11/2021	1968	RET ABN	UG-SERVICE
41452960	GRET	SVC	10/25/2023	1968	RET ABN	UG-SERVICE
40604652	GRET	SVC	8/24/2022	1968	RET ABN	UG-SERVICE
36122582	GRET	SVC	10/30/2020	1968	RET ABN	UG-SERVICE
43547204	GRET	SVC	9/11/2024	1968	RET ABN	UG-SERVICE
41429992	GRET	SVC	9/13/2023	1968	RET ABN	UG-SERVICE
42027511	GRET	SVC	8/28/2023	1968	RET ABN	UG-SERVICE
38593808	GRET	SVC	8/18/2021	1968	RET ABN	UG-SERVICE
39665723	GRET	SVC	1/5/2022	1968	RET ABN	UG-SERVICE
38353012	GRET	SVC	2/17/2023	1968	RET ABN	UG-SERVICE
43489848	GRET	SVC	8/26/2024	1968	RET ABN	UG-SERVICE
40189505	GRET	SVC	5/27/2022	1968	RET ABN	UG-SERVICE
36172660	GRET	SVC	2/12/2020	1968	RET ABN	UG-SERVICE
36119903	GRET	SVC	10/30/2020	1968	RET ABN	UG-SERVICE
43648966	GRET	SVC	12/5/2024	1968	RET ABN	UG-SERVICE
36613099	GRET	SVC	7/10/2020	1968	RET ABN	UG-SERVICE
41353367	GRET	SVC	3/9/2023	1968	RET ABN	UG-SERVICE
43675735	GRET	SVC	10/16/2024	1968	RET ABN	UG-SERVICE
36107018	GRET	SVC	4/22/2020	1968	RET ABN	UG-SERVICE
41572958	GRET	SVC	5/1/2023	1968	RET ABN	UG-SERVICE
42551425	GRET	SVC	1/9/2024	1968	RET ABN	UG-SERVICE
39292643	GRET	SVC	10/15/2021	1968	RET ABN	UG-SERVICE
41965714	GRET	SVC	8/7/2023	1968	RET ABN	UG-SERVICE
41965641	GRET	SVC	7/26/2023	1968	RET ABN	UG-SERVICE
36613394	GRET	SVC	7/10/2020	1968	RET ABN	UG-SERVICE
43677914	GRET	SVC	10/18/2024	1968	RET ABN	UG-SERVICE
39666080	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
43644025	GRET	SVC	10/1/2024	1968	RET ABN	UG-SERVICE
41485246	GRET	SVC	3/24/2023	1968	RET ABN	UG-SERVICE
40948343	GRET	SVC	11/21/2022	1968	RET ABN	UG-SERVICE
38793786	GRET	SVC	7/20/2021	1968	RET ABN	UG-SERVICE
39424066	GRET	SVC	6/27/2022	1968	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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39830446	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
36613389	GRET	SVC	7/8/2020	1968	RET ABN	UG-SERVICE
42135353	GRET	SVC	9/6/2023	1968	RET ABN	UG-SERVICE
38593157	GRET	SVC	10/26/2021	1968	RET ABN	UG-SERVICE
43484868	GRET	SVC	8/26/2024	1968	RET ABN	UG-SERVICE
38677200	GRET	SVC	6/24/2021	1968	RET ABN	UG-SERVICE
43223748	GRET	SVC	6/13/2024	1968	RET ABN	UG-SERVICE
38268742	GRET	SVC	10/20/2021	1968	RET ABN	UG-SERVICE
43141082	GRET	SVC	6/5/2024	1968	RET ABN	UG-SERVICE
38589154	GRET	SVC	10/27/2021	1968	RET ABN	UG-SERVICE
36649706	GRET	SVC	7/20/2020	1968	RET ABN	UG-SERVICE
43503585	GRET	SVC	8/28/2024	1968	RET ABN	UG-SERVICE
42216808	GRET	SVC	12/6/2023	1968	RET ABN	UG-SERVICE
38720230	GRET	SVC	7/16/2021	1968	RET ABN	UG-SERVICE
41407558	GRET	SVC	4/2/2024	1968	RET ABN	UG-SERVICE
39666042	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
41699621	GRET	SVC	6/1/2023	1968	RET ABN	UG-SERVICE
43732057	GRET	SVC	12/11/2024	1968	RET ABN	UG-SERVICE
36419429	GRET	SVC	6/8/2020	1968	RET ABN	UG-SERVICE
43490540	GRET	SVC	8/22/2024	1968	RET ABN	UG-SERVICE
40830319	GRET	SVC	9/8/2022	1968	RET ABN	UG-SERVICE
39423202	GRET	SVC	11/8/2021	1968	RET ABN	UG-SERVICE
43028509	GRET	SVC	8/1/2024	1968	RET ABN	UG-SERVICE
42136772	GRET	SVC	9/20/2023	1968	RET ABN	UG-SERVICE
39376581	GRET	SVC	3/22/2022	1968	RET ABN	UG-SERVICE
38417926	GRET	SVC	5/11/2021	1968	RET ABN	UG-SERVICE
38593804	GRET	SVC	10/7/2021	1968	RET ABN	UG-SERVICE
41245804	GRET	SVC	2/10/2023	1968	RET ABN	UG-SERVICE
41819913	GRET	SVC	7/3/2023	1968	RET ABN	UG-SERVICE
39863321	GRET	SVC	1/25/2022	1968	RET ABN	UG-SERVICE
41472415	GRET	SVC	9/1/2023	1968	RET ABN	UG-SERVICE
39508225	GRET	SVC	11/21/2021	1968	RET ABN	UG-SERVICE
39619116	GRET	SVC	1/3/2022	1968	RET ABN	UG-SERVICE
39921034	GRET	SVC	3/21/2022	1968	RET ABN	UG-SERVICE
38589200	GRET	SVC	10/1/2021	1968	RET ABN	UG-SERVICE
38589159	GRET	SVC	9/9/2021	1968	RET ABN	UG-SERVICE
39423746	GRET	SVC	6/27/2022	1968	RET ABN	UG-SERVICE
41273846	GRET	SVC	2/14/2023	1968	RET ABN	UG-SERVICE
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36673187	GRET	SVC	7/20/2020	1968	RET ABN	UG-SERVICE
38608389	GRET	SVC	8/9/2021	1968	RET ABN	UG-SERVICE
39956345	GRET	SVC	4/11/2022	1968	RET ABN	UG-SERVICE
39554487	GRET	SVC	12/23/2021	1968	RET ABN	UG-SERVICE
36121008	GRET	SVC	10/30/2020	1968	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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39554489	GRET	SVC	12/23/2021	1968	RET ABN	UG-SERVICE
43837910	GRET	SVC	11/21/2024	1968	RET ABN	UG-SERVICE
39532682	GRET	SVC	12/13/2021	1968	RET ABN	UG-SERVICE
39665940	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
40207181	GRET	SVC	6/2/2022	1968	RET ABN	UG-SERVICE
43179538	GRET	SVC	5/30/2024	1968	RET ABN	UG-SERVICE
39666051	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
36157809	GRET	SVC	3/24/2020	1968	RET ABN	UG-SERVICE
39666059	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
36485742	GRET	SVC	6/24/2020	1968	RET ABN	UG-SERVICE
42419710	GRET	SVC	12/6/2023	1968	RET ABN	UG-SERVICE
38589146	GRET	SVC	10/5/2021	1968	RET ABN	UG-SERVICE
41454523	GRET	SVC	2/20/2023	1968	RET ABN	UG-SERVICE
40768323	GRET	SVC	11/1/2022	1968	RET ABN	UG-SERVICE
39740639	GRET	SVC	2/14/2022	1968	RET ABN	UG-SERVICE
40707705	GRET	SVC	9/24/2022	1968	RET ABN	UG-SERVICE
40738247	GRET	SVC	9/28/2022	1968	RET ABN	UG-SERVICE
39665950	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
39809494	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
36119904	GRET	SVC	10/30/2020	1968	RET ABN	UG-SERVICE
36153651	GRET	SVC	7/15/2020	1968	RET ABN	UG-SERVICE
36367966	GRET	SVC	5/27/2020	1968	RET ABN	UG-SERVICE
38655449	GRET	SVC	6/24/2021	1968	RET ABN	UG-SERVICE
36120704	GRET	SVC	10/30/2020	1968	RET ABN	UG-SERVICE
39666057	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
41082945	GRET	SVC	12/21/2022	1968	RET ABN	UG-SERVICE
40724354	GRET	SVC	9/21/2022	1968	RET ABN	UG-SERVICE
41760939	GRET	SVC	6/24/2023	1968	RET ABN	UG-SERVICE
41411143	GRET	SVC	4/2/2024	1968	RET ABN	UG-SERVICE
42812054	GRET	SVC	3/26/2024	1968	RET ABN	UG-SERVICE
38589317	GRET	SVC	11/2/2021	1968	RET ABN	UG-SERVICE
42247377	GRET	SVC	10/16/2023	1968	RET ABN	UG-SERVICE
36609968	GRET	SVC	7/8/2020	1968	RET ABN	UG-SERVICE
43366068	GRET	SVC	10/29/2024	1968	RET ABN	UG-SERVICE
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40868725	GRET	SVC	10/27/2022	1968	RET ABN	UG-SERVICE
43616973	GRET	SVC	10/14/2024	1968	RET ABN	UG-SERVICE
36750113	GRET	SVC	8/17/2020	1968	RET ABN	UG-SERVICE
38676978	GRET	SVC	6/20/2021	1968	RET ABN	UG-SERVICE
38593811	GRET	SVC	8/19/2021	1968	RET ABN	UG-SERVICE
39424072	GRET	SVC	6/27/2022	1968	RET ABN	UG-SERVICE
42498209	GRET	SVC	12/20/2023	1968	RET ABN	UG-SERVICE
36108032	GRET	SVC	3/10/2020	1968	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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43362654	GRET	SVC	8/9/2024	1968	RET ABN	UG-SERVICE
41424185	GRET	SVC	10/18/2023	1968	RET ABN	UG-SERVICE
41779584	GRET	SVC	6/23/2023	1968	RET ABN	UG-SERVICE
38593156	GRET	SVC	11/3/2021	1968	RET ABN	UG-SERVICE
39346037	GRET	SVC	11/2/2021	1969	RET ABN	UG-SERVICE
42135426	GRET	SVC	9/21/2023	1969	RET ABN	UG-SERVICE
38987685	GRET	SVC	8/24/2021	1969	RET ABN	UG-SERVICE
43318346	GRET	SVC	7/17/2024	1969	RET ABN	UG-SERVICE
40526784	GRET	SVC	8/9/2022	1969	RET ABN	UG-SERVICE
39665666	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
43760796	GRET	SVC	10/29/2024	1969	RET ABN	UG-SERVICE
39657778	GRET	SVC	2/9/2022	1969	RET ABN	UG-SERVICE
42216598	GRET	SVC	12/5/2023	1969	RET ABN	UG-SERVICE
38379359	GRET	SVC	8/2/2021	1969	RET ABN	UG-SERVICE
38200599	GRET	SVC	3/12/2021	1969	RET ABN	UG-SERVICE
36885293	GRET	SVC	10/15/2020	1969	RET ABN	UG-SERVICE
39665271	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
36396224	GRET	SVC	6/3/2020	1969	RET ABN	UG-SERVICE
36314386	GRET	SVC	5/11/2020	1969	RET ABN	UG-SERVICE
36867931	GRET	SVC	8/31/2020	1969	RET ABN	UG-SERVICE
35934605	GRET	SVC	1/10/2020	1969	RET ABN	UG-SERVICE
39830404	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
43477846	GRET	SVC	9/5/2024	1969	RET ABN	UG-SERVICE
42014810	GRET	SVC	8/21/2023	1969	RET ABN	UG-SERVICE
41303790	GRET	SVC	2/23/2023	1969	RET ABN	UG-SERVICE
42834157	GRET	SVC	8/12/2024	1969	RET ABN	UG-SERVICE
39831568	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
43610471	GRET	SVC	9/23/2024	1969	RET ABN	UG-SERVICE
40354414	GRET	SVC	6/25/2022	1969	RET ABN	UG-SERVICE
39830441	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
37122616	GRET	SVC	10/28/2020	1969	RET ABN	UG-SERVICE
38394494	GRET	SVC	5/10/2021	1969	RET ABN	UG-SERVICE
40561834	GRET	SVC	8/10/2022	1969	RET ABN	UG-SERVICE
41242617	GRET	SVC	3/24/2023	1969	RET ABN	UG-SERVICE
42833774	GRET	SVC	7/22/2024	1969	RET ABN	UG-SERVICE
41408295	GRET	SVC	4/2/2024	1969	RET ABN	UG-SERVICE
39421588	GRET	SVC	11/7/2021	1969	RET ABN	UG-SERVICE
38967762	GRET	SVC	9/1/2021	1969	RET ABN	UG-SERVICE
38942478	GRET	SVC	8/22/2021	1969	RET ABN	UG-SERVICE
39041591	GRET	SVC	8/31/2021	1969	RET ABN	UG-SERVICE
42666380	GRET	SVC	2/16/2024	1969	RET ABN	UG-SERVICE
39522259	GRET	SVC	12/13/2021	1969	RET ABN	UG-SERVICE
43320398	GRET	SVC	7/18/2024	1969	RET ABN	UG-SERVICE
39389661	GRET	SVC	11/23/2021	1969	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42386658	GRET	SVC	11/20/2023	1969	RET ABN	UG-SERVICE
43904972	GRET	SVC	12/9/2024	1969	RET ABN	UG-SERVICE
39741134	GRET	SVC	2/7/2022	1969	RET ABN	UG-SERVICE
40359859	GRET	SVC	6/29/2022	1969	RET ABN	UG-SERVICE
41194178	GRET	SVC	1/27/2023	1969	RET ABN	UG-SERVICE
38392184	GRET	SVC	4/19/2021	1969	RET ABN	UG-SERVICE
36260064	GRET	SVC	3/18/2020	1969	RET ABN	UG-SERVICE
38746118	GRET	SVC	7/12/2021	1969	RET ABN	UG-SERVICE
43116179	GRET	SVC	5/29/2024	1969	RET ABN	UG-SERVICE
41436457	GRET	SVC	3/30/2023	1969	RET ABN	UG-SERVICE
41323230	GRET	SVC	3/20/2023	1969	RET ABN	UG-SERVICE
41214310	GRET	SVC	1/31/2023	1969	RET ABN	UG-SERVICE
40744383	GRET	SVC	9/28/2022	1969	RET ABN	UG-SERVICE
38738847	GRET	SVC	7/12/2021	1969	RET ABN	UG-SERVICE
43064607	GRET	SVC	5/16/2024	1969	RET ABN	UG-SERVICE
39437430	GRET	SVC	11/18/2021	1969	RET ABN	UG-SERVICE
36704920	GRET	SVC	8/18/2020	1969	RET ABN	UG-SERVICE
43324306	GRET	SVC	10/18/2024	1969	RET ABN	UG-SERVICE
41914102	GRET	SVC	7/27/2023	1969	RET ABN	UG-SERVICE
37387655	GRET	SVC	11/9/2020	1969	RET ABN	UG-SERVICE
36396462	GRET	SVC	6/3/2020	1969	RET ABN	UG-SERVICE
41053076	GRET	SVC	12/15/2022	1969	RET ABN	UG-SERVICE
43258991	GRET	SVC	9/19/2024	1969	RET ABN	UG-SERVICE
39830405	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
40280048	GRET	SVC	4/27/2023	1969	RET ABN	UG-SERVICE
39665672	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
39830413	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
36591056	GRET	SVC	7/7/2020	1969	RET ABN	UG-SERVICE
36135786	GRET	SVC	4/21/2020	1969	RET ABN	UG-SERVICE
39665667	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
39350621	GRET	SVC	12/3/2021	1969	RET ABN	UG-SERVICE
39665270	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
36002346	GRET	SVC	2/11/2020	1969	RET ABN	UG-SERVICE
43013320	GRET	SVC	5/6/2024	1969	RET ABN	UG-SERVICE
40980504	GRET	SVC	11/23/2022	1969	RET ABN	UG-SERVICE
39247280	GRET	SVC	10/22/2021	1969	RET ABN	UG-SERVICE
39830440	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
35882477	GRET	SVC	1/13/2020	1969	RET ABN	UG-SERVICE
39757031	GRET	SVC	6/17/2021	1969	RET ABN	UG-SERVICE
42389810	GRET	SVC	11/20/2023	1969	RET ABN	UG-SERVICE
39665668	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
39830458	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
42564737	GRET	SVC	1/10/2024	1969	RET ABN	UG-SERVICE
43461018	GRET	SVC	8/21/2024	1969	RET ABN	UG-SERVICE
41348969	GRET	SVC	3/8/2023	1969	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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35925105	GRET	SVC	1/18/2020	1969	RET ABN	UG-SERVICE
42216812	GRET	SVC	12/6/2023	1969	RET ABN	UG-SERVICE
39274159	GRET	SVC	10/12/2021	1969	RET ABN	UG-SERVICE
40933264	GRET	SVC	11/16/2022	1969	RET ABN	UG-SERVICE
42216814	GRET	SVC	12/6/2023	1969	RET ABN	UG-SERVICE
41065454	GRET	SVC	12/13/2022	1969	RET ABN	UG-SERVICE
38314467	GRET	SVC	4/5/2021	1969	RET ABN	UG-SERVICE
36121688	GRET	SVC	10/12/2020	1969	RET ABN	UG-SERVICE
36314075	GRET	SVC	5/7/2020	1969	RET ABN	UG-SERVICE
38267999	GRET	SVC	3/20/2021	1969	RET ABN	UG-SERVICE
39654867	GRET	SVC	6/28/2022	1969	RET ABN	UG-SERVICE
42744009	GRET	SVC	2/21/2024	1969	RET ABN	UG-SERVICE
42165831	GRET	SVC	10/11/2023	1969	RET ABN	UG-SERVICE
43614043	GRET	SVC	9/23/2024	1969	RET ABN	UG-SERVICE
38413340	GRET	SVC	5/6/2021	1969	RET ABN	UG-SERVICE
36876148	GRET	SVC	9/2/2020	1969	RET ABN	UG-SERVICE
36106836	GRET	SVC	4/24/2020	1969	RET ABN	UG-SERVICE
42433001	GRET	SVC	12/6/2023	1969	RET ABN	UG-SERVICE
40469915	GRET	SVC	7/20/2022	1969	RET ABN	UG-SERVICE
39665811	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
43610593	GRET	SVC	11/21/2024	1969	RET ABN	UG-SERVICE
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36370503	GRET	SVC	5/28/2020	1969	RET ABN	UG-SERVICE
39571086	GRET	SVC	12/17/2021	1969	RET ABN	UG-SERVICE
40609436	GRET	SVC	8/24/2022	1969	RET ABN	UG-SERVICE
38607906	GRET	SVC	12/23/2021	1969	RET ABN	UG-SERVICE
38896185	GRET	SVC	8/3/2021	1969	RET ABN	UG-SERVICE
40619595	GRET	SVC	8/22/2022	1969	RET ABN	UG-SERVICE
43344390	GRET	SVC	7/23/2024	1969	RET ABN	UG-SERVICE
35936783	GRET	SVC	1/23/2020	1969	RET ABN	UG-SERVICE
41786378	GRET	SVC	6/19/2023	1969	RET ABN	UG-SERVICE
40616868	GRET	SVC	9/10/2022	1969	RET ABN	UG-SERVICE
42833096	GRET	SVC	7/22/2024	1969	RET ABN	UG-SERVICE
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41068027	GRET	SVC	12/15/2022	1969	RET ABN	UG-SERVICE
39703967	GRET	SVC	1/18/2022	1969	RET ABN	UG-SERVICE
39665277	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
38435783	GRET	SVC	5/4/2021	1969	RET ABN	UG-SERVICE
42216815	GRET	SVC	12/7/2023	1969	RET ABN	UG-SERVICE
42249677	GRET	SVC	12/20/2023	1969	RET ABN	UG-SERVICE
39983346	GRET	SVC	4/11/2022	1969	RET ABN	UG-SERVICE
39423637	GRET	SVC	11/15/2021	1969	RET ABN	UG-SERVICE
36122438	GRET	SVC	10/14/2020	1969	RET ABN	UG-SERVICE
37641860	GRET	SVC	11/19/2020	1969	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40472616	GRET	SVC	9/15/2022	1969	RET ABN	UG-SERVICE
39665814	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
41853474	GRET	SVC	7/12/2023	1969	RET ABN	UG-SERVICE
36106830	GRET	SVC	4/21/2020	1969	RET ABN	UG-SERVICE
39303367	GRET	SVC	10/19/2021	1969	RET ABN	UG-SERVICE
38194547	GRET	SVC	3/12/2021	1969	RET ABN	UG-SERVICE
42122256	GRET	SVC	9/18/2023	1969	RET ABN	UG-SERVICE
41844253	GRET	SVC	7/11/2023	1969	RET ABN	UG-SERVICE
41188318	GRET	SVC	1/24/2023	1969	RET ABN	UG-SERVICE
39665800	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
35678083	GRET	SVC	1/23/2020	1969	RET ABN	UG-SERVICE
40558767	GRET	SVC	8/10/2022	1969	RET ABN	UG-SERVICE
36751465	GRET	SVC	8/13/2020	1969	RET ABN	UG-SERVICE
41411153	GRET	SVC	4/2/2024	1969	RET ABN	UG-SERVICE
39691660	GRET	SVC	1/15/2022	1969	RET ABN	UG-SERVICE
37065553	GRET	SVC	10/20/2020	1969	RET ABN	UG-SERVICE
41896886	GRET	SVC	7/30/2023	1969	RET ABN	UG-SERVICE
38593802	GRET	SVC	8/31/2021	1969	RET ABN	UG-SERVICE
39665673	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
41245576	GRET	SVC	2/10/2023	1969	RET ABN	UG-SERVICE
39830451	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
37387501	GRET	SVC	11/5/2020	1969	RET ABN	UG-SERVICE
43365680	GRET	SVC	10/30/2024	1969	RET ABN	UG-SERVICE
43448533	GRET	SVC	8/19/2024	1969	RET ABN	UG-SERVICE
42600180	GRET	SVC	1/26/2024	1969	RET ABN	UG-SERVICE
37098911	GRET	SVC	10/29/2020	1969	RET ABN	UG-SERVICE
36885292	GRET	SVC	10/15/2020	1969	RET ABN	UG-SERVICE
36121359	GRET	SVC	10/16/2020	1969	RET ABN	UG-SERVICE
41411045	GRET	SVC	4/2/2024	1969	RET ABN	UG-SERVICE
39830449	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
41409244	GRET	SVC	4/2/2024	1969	RET ABN	UG-SERVICE
40498170	GRET	SVC	7/25/2022	1969	RET ABN	UG-SERVICE
38795282	GRET	SVC	7/1/2021	1969	RET ABN	UG-SERVICE
39830402	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
43365682	GRET	SVC	12/19/2024	1969	RET ABN	UG-SERVICE
42331726	GRET	SVC	11/6/2023	1969	RET ABN	UG-SERVICE
39831365	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
40324802	GRET	SVC	6/21/2022	1969	RET ABN	UG-SERVICE
35968036	GRET	SVC	2/25/2020	1969	RET ABN	UG-SERVICE
36121692	GRET	SVC	10/12/2020	1969	RET ABN	UG-SERVICE
41497333	GRET	SVC	4/24/2023	1969	RET ABN	UG-SERVICE
39665815	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
41141851	GRET	SVC	1/9/2023	1969	RET ABN	UG-SERVICE
39250840	GRET	SVC	10/11/2021	1969	RET ABN	UG-SERVICE
43493320	GRET	SVC	12/19/2024	1969	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36647011	GRET	SVC	7/13/2020	1969	RET ABN	UG-SERVICE
41436454	GRET	SVC	4/30/2023	1969	RET ABN	UG-SERVICE
39903460	GRET	SVC	3/29/2022	1969	RET ABN	UG-SERVICE
42314951	GRET	SVC	11/20/2023	1969	RET ABN	UG-SERVICE
42297446	GRET	SVC	11/1/2023	1969	RET ABN	UG-SERVICE
36396472	GRET	SVC	6/3/2020	1969	RET ABN	UG-SERVICE
39830352	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
36666324	GRET	SVC	7/22/2020	1969	RET ABN	UG-SERVICE
42984750	GRET	SVC	4/22/2024	1969	RET ABN	UG-SERVICE
38322242	GRET	SVC	12/21/2021	1969	RET ABN	UG-SERVICE
39771827	GRET	SVC	2/8/2022	1969	RET ABN	UG-SERVICE
39665805	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
40671208	GRET	SVC	9/17/2022	1969	RET ABN	UG-SERVICE
39830448	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
41223154	GRET	SVC	1/30/2023	1969	RET ABN	UG-SERVICE
41969489	GRET	SVC	7/31/2024	1969	RET ABN	UG-SERVICE
36485659	GRET	SVC	6/23/2020	1969	RET ABN	UG-SERVICE
40987260	GRET	SVC	11/29/2022	1969	RET ABN	UG-SERVICE
40478413	GRET	SVC	7/26/2022	1969	RET ABN	UG-SERVICE
40910571	GRET	SVC	11/8/2022	1969	RET ABN	UG-SERVICE
41230526	GRET	SVC	2/2/2023	1969	RET ABN	UG-SERVICE
41752183	GRET	SVC	6/13/2023	1969	RET ABN	UG-SERVICE
40234274	GRET	SVC	5/31/2022	1969	RET ABN	UG-SERVICE
42784509	GRET	SVC	4/16/2024	1969	RET ABN	UG-SERVICE
42404814	GRET	SVC	12/12/2023	1969	RET ABN	UG-SERVICE
36989293	GRET	SVC	8/11/2020	1969	RET ABN	UG-SERVICE
38875278	GRET	SVC	1/3/2022	1969	RET ABN	UG-SERVICE
36235878	GRET	SVC	12/16/2020	1969	RET ABN	UG-SERVICE
41436452	GRET	SVC	3/31/2023	1969	RET ABN	UG-SERVICE
38677037	GRET	SVC	7/7/2021	1969	RET ABN	UG-SERVICE
43323971	GRET	SVC	7/22/2024	1969	RET ABN	UG-SERVICE
37597540	GRET	SVC	11/17/2020	1969	RET ABN	UG-SERVICE
41968714	GRET	SVC	8/7/2023	1969	RET ABN	UG-SERVICE
38670221	GRET	SVC	6/23/2021	1969	RET ABN	UG-SERVICE
40111686	GRET	SVC	5/4/2022	1969	RET ABN	UG-SERVICE
38257099	GRET	SVC	3/22/2021	1969	RET ABN	UG-SERVICE
39935328	GRET	SVC	5/2/2022	1969	RET ABN	UG-SERVICE
41288083	GRET	SVC	3/17/2023	1969	RET ABN	UG-SERVICE
39830346	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
38524218	GRET	SVC	6/15/2021	1969	RET ABN	UG-SERVICE
43203572	GRET	SVC	6/18/2024	1969	RET ABN	UG-SERVICE
36030739	GRET	SVC	2/14/2020	1969	RET ABN	UG-SERVICE
42216803	GRET	SVC	12/6/2023	1969	RET ABN	UG-SERVICE
36751436	GRET	SVC	10/5/2020	1969	RET ABN	UG-SERVICE
35876804	GRET	SVC	1/8/2020	1969	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38256808	GRET	SVC	4/1/2021	1969	RET ABN	UG-SERVICE
43274525	GRET	SVC	7/13/2024	1969	RET ABN	UG-SERVICE
36460197	GRET	SVC	6/18/2020	1969	RET ABN	UG-SERVICE
36670730	GRET	SVC	7/29/2020	1969	RET ABN	UG-SERVICE
42879026	GRET	SVC	4/2/2024	1969	RET ABN	UG-SERVICE
40500724	GRET	SVC	9/14/2022	1970	RET ABN	UG-SERVICE
41119748	GRET	SVC	1/3/2023	1970	RET ABN	UG-SERVICE
36183154	GRET	SVC	4/21/2020	1970	RET ABN	UG-SERVICE
39873582	GRET	SVC	3/14/2022	1970	RET ABN	UG-SERVICE
41401742	GRET	SVC	3/14/2023	1970	RET ABN	UG-SERVICE
43892423	GRET	SVC	12/3/2024	1970	RET ABN	UG-SERVICE
43799633	GRET	SVC	11/20/2024	1970	RET ABN	UG-SERVICE
39680096	GRET	SVC	1/12/2022	1970	RET ABN	UG-SERVICE
39450194	GRET	SVC	12/9/2021	1970	RET ABN	UG-SERVICE
41052713	GRET	SVC	1/12/2023	1970	RET ABN	UG-SERVICE
36350272	GRET	SVC	5/15/2020	1970	RET ABN	UG-SERVICE
40179803	GRET	SVC	5/18/2022	1970	RET ABN	UG-SERVICE
36283385	GRET	SVC	6/15/2020	1970	RET ABN	UG-SERVICE
39831475	GRET	SVC	8/3/2022	1970	RET ABN	UG-SERVICE
41075028	GRET	SVC	12/30/2022	1970	RET ABN	UG-SERVICE
42423918	GRET	SVC	11/28/2023	1970	RET ABN	UG-SERVICE
43353627	GRET	SVC	11/7/2024	1970	RET ABN	UG-SERVICE
41317159	GRET	SVC	3/4/2023	1970	RET ABN	UG-SERVICE
38441542	GRET	SVC	1/3/2022	1970	RET ABN	UG-SERVICE
36163049	GRET	SVC	3/24/2020	1970	RET ABN	UG-SERVICE
36118828	GRET	SVC	10/14/2020	1970	RET ABN	UG-SERVICE
41818696	GRET	SVC	7/22/2023	1970	RET ABN	UG-SERVICE
40963335	GRET	SVC	12/12/2022	1970	RET ABN	UG-SERVICE
36090177	GRET	SVC	3/6/2020	1970	RET ABN	UG-SERVICE
36057532	GRET	SVC	2/21/2020	1970	RET ABN	UG-SERVICE
43203666	GRET	SVC	6/19/2024	1970	RET ABN	UG-SERVICE
41659816	GRET	SVC	5/23/2023	1970	RET ABN	UG-SERVICE
41870478	GRET	SVC	7/18/2023	1970	RET ABN	UG-SERVICE
41052714	GRET	SVC	1/12/2023	1970	RET ABN	UG-SERVICE
39666317	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
36122378	GRET	SVC	10/14/2020	1970	RET ABN	UG-SERVICE
37055416	GRET	SVC	11/4/2020	1970	RET ABN	UG-SERVICE
42234544	GRET	SVC	10/17/2023	1970	RET ABN	UG-SERVICE
37324160	GRET	SVC	11/9/2020	1970	RET ABN	UG-SERVICE
43412674	GRET	SVC	8/14/2024	1970	RET ABN	UG-SERVICE
41473584	GRET	SVC	4/19/2023	1970	RET ABN	UG-SERVICE
40780609	GRET	SVC	10/13/2022	1970	RET ABN	UG-SERVICE
41882464	GRET	SVC	6/23/2023	1970	RET ABN	UG-SERVICE
36121770	GRET	SVC	10/12/2020	1970	RET ABN	UG-SERVICE
41330345	GRET	SVC	3/2/2023	1970	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42489092	GRET	SVC	12/18/2023	1970	RET ABN	UG-SERVICE
36283384	GRET	SVC	6/15/2020	1970	RET ABN	UG-SERVICE
36121348	GRET	SVC	11/5/2020	1970	RET ABN	UG-SERVICE
39716936	GRET	SVC	1/6/2022	1970	RET ABN	UG-SERVICE
43525078	GRET	SVC	10/15/2024	1970	RET ABN	UG-SERVICE
36283388	GRET	SVC	6/15/2020	1970	RET ABN	UG-SERVICE
40332367	GRET	SVC	6/22/2022	1970	RET ABN	UG-SERVICE
36702203	GRET	SVC	7/29/2020	1970	RET ABN	UG-SERVICE
40658153	GRET	SVC	9/14/2022	1970	RET ABN	UG-SERVICE
43807180	GRET	SVC	11/22/2024	1970	RET ABN	UG-SERVICE
40639350	GRET	SVC	8/31/2022	1970	RET ABN	UG-SERVICE
39550691	GRET	SVC	12/20/2021	1970	RET ABN	UG-SERVICE
39666400	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
41803298	GRET	SVC	6/26/2023	1970	RET ABN	UG-SERVICE
36282716	GRET	SVC	6/23/2020	1970	RET ABN	UG-SERVICE
39666404	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
36110443	GRET	SVC	3/9/2020	1970	RET ABN	UG-SERVICE
41229864	GRET	SVC	2/1/2023	1970	RET ABN	UG-SERVICE
39434287	GRET	SVC	11/19/2021	1970	RET ABN	UG-SERVICE
39666421	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
36122422	GRET	SVC	10/14/2020	1970	RET ABN	UG-SERVICE
43480939	GRET	SVC	10/25/2024	1970	RET ABN	UG-SERVICE
39666438	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
41279866	GRET	SVC	2/16/2023	1970	RET ABN	UG-SERVICE
38539150	GRET	SVC	6/28/2021	1970	RET ABN	UG-SERVICE
38608929	GRET	SVC	12/23/2021	1970	RET ABN	UG-SERVICE
43676679	GRET	SVC	10/15/2024	1970	RET ABN	UG-SERVICE
41916578	GRET	SVC	7/25/2023	1970	RET ABN	UG-SERVICE
37104386	GRET	SVC	10/26/2020	1970	RET ABN	UG-SERVICE
39666240	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
39666425	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
38772860	GRET	SVC	7/30/2021	1970	RET ABN	UG-SERVICE
39831477	GRET	SVC	8/3/2022	1970	RET ABN	UG-SERVICE
38407515	GRET	SVC	4/26/2021	1970	RET ABN	UG-SERVICE
43347408	GRET	SVC	7/24/2024	1970	RET ABN	UG-SERVICE
43789058	GRET	SVC	12/14/2024	1970	RET ABN	UG-SERVICE
42386287	GRET	SVC	11/14/2023	1970	RET ABN	UG-SERVICE
39809487	GRET	SVC	8/3/2022	1970	RET ABN	UG-SERVICE
40490995	GRET	SVC	7/29/2022	1970	RET ABN	UG-SERVICE
41408062	GRET	SVC	4/2/2024	1970	RET ABN	UG-SERVICE
36701300	GRET	SVC	7/30/2020	1970	RET ABN	UG-SERVICE
39424068	GRET	SVC	6/27/2022	1970	RET ABN	UG-SERVICE
40749589	GRET	SVC	5/13/2024	1970	RET ABN	UG-SERVICE
36142348	GRET	SVC	3/17/2020	1970	RET ABN	UG-SERVICE
38537594	GRET	SVC	4/13/2021	1970	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
35918148	GRET	SVC	1/20/2020	1970	RET ABN	UG-SERVICE
42378966	GRET	SVC	11/14/2023	1970	RET ABN	UG-SERVICE
39892775	GRET	SVC	6/2/2022	1970	RET ABN	UG-SERVICE
38107943	GRET	SVC	2/24/2021	1970	RET ABN	UG-SERVICE
40118767	GRET	SVC	5/9/2022	1970	RET ABN	UG-SERVICE
43151327	GRET	SVC	9/19/2024	1970	RET ABN	UG-SERVICE
40806481	GRET	SVC	10/10/2022	1970	RET ABN	UG-SERVICE
37957641	GRET	SVC	2/18/2021	1970	RET ABN	UG-SERVICE
42412181	GRET	SVC	11/20/2023	1970	RET ABN	UG-SERVICE
36283383	GRET	SVC	6/15/2020	1970	RET ABN	UG-SERVICE
42759492	GRET	SVC	2/27/2024	1970	RET ABN	UG-SERVICE
42833938	GRET	SVC	7/23/2024	1970	RET ABN	UG-SERVICE
42833934	GRET	SVC	7/23/2024	1970	RET ABN	UG-SERVICE
40808302	GRET	SVC	11/11/2022	1970	RET ABN	UG-SERVICE
38676767	GRET	SVC	8/2/2021	1970	RET ABN	UG-SERVICE
42487684	GRET	SVC	7/18/2024	1970	RET ABN	UG-SERVICE
42834145	GRET	SVC	8/5/2024	1970	RET ABN	UG-SERVICE
39935386	GRET	SVC	5/14/2022	1970	RET ABN	UG-SERVICE
36122434	GRET	SVC	10/14/2020	1970	RET ABN	UG-SERVICE
41407613	GRET	SVC	4/2/2024	1970	RET ABN	UG-SERVICE
41291591	GRET	SVC	2/20/2023	1970	RET ABN	UG-SERVICE
43280667	GRET	SVC	12/3/2024	1970	RET ABN	UG-SERVICE
43640980	GRET	SVC	10/1/2024	1970	RET ABN	UG-SERVICE
40318264	GRET	SVC	6/22/2022	1970	RET ABN	UG-SERVICE
43506838	GRET	SVC	9/27/2024	1970	RET ABN	UG-SERVICE
36701074	GRET	SVC	7/29/2020	1970	RET ABN	UG-SERVICE
38912205	GRET	SVC	7/7/2022	1970	RET ABN	UG-SERVICE
43705149	GRET	SVC	10/16/2024	1970	RET ABN	UG-SERVICE
41837155	GRET	SVC	7/7/2023	1970	RET ABN	UG-SERVICE
43649294	GRET	SVC	12/4/2024	1970	RET ABN	UG-SERVICE
42073738	GRET	SVC	9/29/2023	1970	RET ABN	UG-SERVICE
39666740	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
39666402	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
38545124	GRET	SVC	5/25/2021	1970	RET ABN	UG-SERVICE
39666481	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
43649292	GRET	SVC	12/5/2024	1970	RET ABN	UG-SERVICE
36122421	GRET	SVC	10/14/2020	1970	RET ABN	UG-SERVICE
42791899	GRET	SVC	3/5/2024	1970	RET ABN	UG-SERVICE
42956336	GRET	SVC	9/19/2024	1970	RET ABN	UG-SERVICE
39666439	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
40747501	GRET	SVC	9/28/2022	1970	RET ABN	UG-SERVICE
42487781	GRET	SVC	7/18/2024	1970	RET ABN	UG-SERVICE
36283387	GRET	SVC	6/15/2020	1970	RET ABN	UG-SERVICE
42381320	GRET	SVC	11/15/2023	1970	RET ABN	UG-SERVICE
36283382	GRET	SVC	6/15/2020	1970	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36122379	GRET	SVC	4/30/2020	1970	RET ABN	UG-SERVICE
39423524	GRET	SVC	6/27/2022	1970	RET ABN	UG-SERVICE
40947077	GRET	SVC	11/25/2022	1970	RET ABN	UG-SERVICE
36085532	GRET	SVC	3/4/2020	1970	RET ABN	UG-SERVICE
42824972	GRET	SVC	3/12/2024	1970	RET ABN	UG-SERVICE
42514799	GRET	SVC	12/15/2023	1970	RET ABN	UG-SERVICE
40811497	GRET	SVC	3/8/2023	1970	RET ABN	UG-SERVICE
43481199	GRET	SVC	10/24/2024	1970	RET ABN	UG-SERVICE
35960294	GRET	SVC	1/29/2020	1970	RET ABN	UG-SERVICE
42760335	GRET	SVC	7/30/2024	1970	RET ABN	UG-SERVICE
40556773	GRET	SVC	8/12/2022	1970	RET ABN	UG-SERVICE
40977040	GRET	SVC	11/28/2022	1970	RET ABN	UG-SERVICE
39831652	GRET	SVC	8/3/2022	1970	RET ABN	UG-SERVICE
41298680	GRET	SVC	2/21/2023	1970	RET ABN	UG-SERVICE
43650227	GRET	SVC	12/9/2024	1970	RET ABN	UG-SERVICE
40770432	GRET	SVC	9/29/2022	1970	RET ABN	UG-SERVICE
41296147	GRET	SVC	2/20/2023	1970	RET ABN	UG-SERVICE
41401435	GRET	SVC	3/24/2023	1970	RET ABN	UG-SERVICE
39666423	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
36391042	GRET	SVC	6/4/2020	1970	RET ABN	UG-SERVICE
40780612	GRET	SVC	10/10/2022	1970	RET ABN	UG-SERVICE
39831645	GRET	SVC	8/3/2022	1970	RET ABN	UG-SERVICE
41911980	GRET	SVC	8/1/2023	1970	RET ABN	UG-SERVICE
42494200	GRET	SVC	8/1/2024	1970	RET ABN	UG-SERVICE
40655699	GRET	SVC	8/31/2022	1970	RET ABN	UG-SERVICE
43648971	GRET	SVC	12/6/2024	1970	RET ABN	UG-SERVICE
41838366	GRET	SVC	7/7/2023	1970	RET ABN	UG-SERVICE
39831575	GRET	SVC	8/3/2022	1970	RET ABN	UG-SERVICE
36136190	GRET	SVC	4/23/2020	1970	RET ABN	UG-SERVICE
40338237	GRET	SVC	6/21/2022	1970	RET ABN	UG-SERVICE
43578156	GRET	SVC	9/17/2024	1970	RET ABN	UG-SERVICE
36077428	GRET	SVC	3/2/2020	1970	RET ABN	UG-SERVICE
38106693	GRET	SVC	2/10/2021	1970	RET ABN	UG-SERVICE
36992559	GRET	SVC	9/30/2020	1970	RET ABN	UG-SERVICE
36704451	GRET	SVC	7/30/2020	1970	RET ABN	UG-SERVICE
39423215	GRET	SVC	6/27/2022	1970	RET ABN	UG-SERVICE
38692662	GRET	SVC	7/2/2021	1970	RET ABN	UG-SERVICE
39649243	GRET	SVC	2/15/2022	1970	RET ABN	UG-SERVICE
39654870	GRET	SVC	6/28/2022	1970	RET ABN	UG-SERVICE
40231463	GRET	SVC	5/31/2022	1970	RET ABN	UG-SERVICE
40358943	GRET	SVC	6/28/2022	1970	RET ABN	UG-SERVICE
37741510	GRET	SVC	11/24/2020	1970	RET ABN	UG-SERVICE
40359856	GRET	SVC	6/28/2022	1970	RET ABN	UG-SERVICE
42321636	GRET	SVC	11/6/2023	1970	RET ABN	UG-SERVICE
36110213	GRET	SVC	10/12/2020	1970	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38966217	GRET	SVC	8/30/2021	1970	RET ABN	UG-SERVICE
38051914	GRET	SVC	1/25/2021	1970	RET ABN	UG-SERVICE
37098508	GRET	SVC	10/19/2020	1970	RET ABN	UG-SERVICE
42833937	GRET	SVC	7/23/2024	1970	RET ABN	UG-SERVICE
43365688	GRET	SVC	10/21/2024	1970	RET ABN	UG-SERVICE
42029728	GRET	SVC	8/25/2023	1970	RET ABN	UG-SERVICE
39666422	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
39666426	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
35846431	GRET	SVC	1/2/2020	1970	RET ABN	UG-SERVICE
39880056	GRET	SVC	3/14/2022	1970	RET ABN	UG-SERVICE
38110647	GRET	SVC	2/25/2021	1970	RET ABN	UG-SERVICE
43648976	GRET	SVC	12/5/2024	1970	RET ABN	UG-SERVICE
41411154	GRET	SVC	4/2/2024	1970	RET ABN	UG-SERVICE
36108480	GRET	SVC	10/12/2020	1970	RET ABN	UG-SERVICE
42487682	GRET	SVC	7/18/2024	1970	RET ABN	UG-SERVICE
41067833	GRET	SVC	12/22/2022	1970	RET ABN	UG-SERVICE
40205533	GRET	SVC	6/11/2022	1970	RET ABN	UG-SERVICE
39666427	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
39424069	GRET	SVC	6/27/2022	1970	RET ABN	UG-SERVICE
37011547	GRET	SVC	10/1/2020	1970	RET ABN	UG-SERVICE
41401740	GRET	SVC	3/14/2023	1970	RET ABN	UG-SERVICE
40273945	GRET	SVC	6/8/2022	1970	RET ABN	UG-SERVICE
38537392	GRET	SVC	5/27/2021	1970	RET ABN	UG-SERVICE
36877039	GRET	SVC	8/25/2020	1970	RET ABN	UG-SERVICE
35970045	GRET	SVC	2/3/2020	1970	RET ABN	UG-SERVICE
42956846	GRET	SVC	7/18/2024	1970	RET ABN	UG-SERVICE
41401961	GRET	SVC	3/9/2023	1970	RET ABN	UG-SERVICE
40356392	GRET	SVC	6/27/2022	1970	RET ABN	UG-SERVICE
42469443	GRET	SVC	12/12/2023	1970	RET ABN	UG-SERVICE
39666431	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
36252638	GRET	SVC	5/1/2020	1970	RET ABN	UG-SERVICE
43649298	GRET	SVC	12/6/2024	1970	RET ABN	UG-SERVICE
41279146	GRET	SVC	3/24/2023	1971	RET ABN	UG-SERVICE
39079965	GRET	SVC	9/2/2021	1971	RET ABN	UG-SERVICE
39819166	GRET	SVC	2/28/2022	1971	RET ABN	UG-SERVICE
42002925	GRET	SVC	8/15/2023	1971	RET ABN	UG-SERVICE
38441323	GRET	SVC	1/3/2022	1971	RET ABN	UG-SERVICE
38356367	GRET	SVC	4/15/2021	1971	RET ABN	UG-SERVICE
42956324	GRET	SVC	9/19/2024	1971	RET ABN	UG-SERVICE
39920971	GRET	SVC	4/5/2022	1971	RET ABN	UG-SERVICE
35856442	GRET	SVC	1/9/2020	1971	RET ABN	UG-SERVICE
43904906	GRET	SVC	12/4/2024	1971	RET ABN	UG-SERVICE
36711290	GRET	SVC	7/28/2020	1971	RET ABN	UG-SERVICE
41222691	GRET	SVC	1/20/2023	1971	RET ABN	UG-SERVICE
43151329	GRET	SVC	9/19/2024	1971	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41450269	GRET	SVC	4/10/2023	1971	RET ABN	UG-SERVICE
41411223	GRET	SVC	4/2/2024	1971	RET ABN	UG-SERVICE
39090216	GRET	SVC	9/8/2021	1971	RET ABN	UG-SERVICE
42902428	GRET	SVC	4/10/2024	1971	RET ABN	UG-SERVICE
41083627	GRET	SVC	2/13/2023	1971	RET ABN	UG-SERVICE
41775070	GRET	SVC	6/27/2023	1971	RET ABN	UG-SERVICE
37425042	GRET	SVC	11/11/2020	1971	RET ABN	UG-SERVICE
41411189	GRET	SVC	4/2/2024	1971	RET ABN	UG-SERVICE
36319078	GRET	SVC	4/27/2020	1971	RET ABN	UG-SERVICE
42534170	GRET	SVC	1/2/2024	1971	RET ABN	UG-SERVICE
41436886	GRET	SVC	3/27/2023	1971	RET ABN	UG-SERVICE
42448121	GRET	SVC	12/4/2023	1971	RET ABN	UG-SERVICE
41591360	GRET	SVC	5/2/2023	1971	RET ABN	UG-SERVICE
42327602	GRET	SVC	12/7/2023	1971	RET ABN	UG-SERVICE
36035401	GRET	SVC	2/17/2020	1971	RET ABN	UG-SERVICE
42320646	GRET	SVC	11/7/2023	1971	RET ABN	UG-SERVICE
38457555	GRET	SVC	5/7/2021	1971	RET ABN	UG-SERVICE
43267508	GRET	SVC	7/18/2024	1971	RET ABN	UG-SERVICE
41429913	GRET	SVC	3/21/2023	1971	RET ABN	UG-SERVICE
38097220	GRET	SVC	9/2/2021	1971	RET ABN	UG-SERVICE
41244030	GRET	SVC	3/20/2023	1971	RET ABN	UG-SERVICE
41029976	GRET	SVC	1/21/2023	1971	RET ABN	UG-SERVICE
41807843	GRET	SVC	6/26/2023	1971	RET ABN	UG-SERVICE
43364879	GRET	SVC	12/17/2024	1971	RET ABN	UG-SERVICE
41179619	GRET	SVC	1/18/2023	1971	RET ABN	UG-SERVICE
40938774	GRET	SVC	10/5/2022	1971	RET ABN	UG-SERVICE
36122498	GRET	SVC	10/30/2020	1971	RET ABN	UG-SERVICE
41411226	GRET	SVC	4/2/2024	1971	RET ABN	UG-SERVICE
39078482	GRET	SVC	9/7/2021	1971	RET ABN	UG-SERVICE
38252169	GRET	SVC	3/18/2021	1971	RET ABN	UG-SERVICE
41411427	GRET	SVC	11/2/2023	1971	RET ABN	UG-SERVICE
43480497	GRET	SVC	9/14/2024	1971	RET ABN	UG-SERVICE
42132870	GRET	SVC	9/20/2023	1971	RET ABN	UG-SERVICE
40618057	GRET	SVC	8/24/2022	1971	RET ABN	UG-SERVICE
38507684	GRET	SVC	5/18/2021	1971	RET ABN	UG-SERVICE
42314997	GRET	SVC	11/6/2023	1971	RET ABN	UG-SERVICE
36939018	GRET	SVC	9/22/2020	1971	RET ABN	UG-SERVICE
39312873	GRET	SVC	10/9/2021	1971	RET ABN	UG-SERVICE
43325228	GRET	SVC	7/16/2024	1971	RET ABN	UG-SERVICE
42328017	GRET	SVC	12/8/2023	1971	RET ABN	UG-SERVICE
43591096	GRET	SVC	9/16/2024	1971	RET ABN	UG-SERVICE
43506889	GRET	SVC	10/11/2024	1971	RET ABN	UG-SERVICE
37982149	GRET	SVC	1/6/2021	1971	RET ABN	UG-SERVICE
42192947	GRET	SVC	10/6/2023	1971	RET ABN	UG-SERVICE
39574845	GRET	SVC	12/22/2021	1971	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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38014263	GRET	SVC	1/14/2021	1971	RET ABN	UG-SERVICE
36105786	GRET	SVC	2/10/2020	1971	RET ABN	UG-SERVICE
41785520	GRET	SVC	6/19/2023	1971	RET ABN	UG-SERVICE
36710986	GRET	SVC	8/3/2020	1971	RET ABN	UG-SERVICE
39405134	GRET	SVC	12/7/2021	1971	RET ABN	UG-SERVICE
41870461	GRET	SVC	7/8/2023	1971	RET ABN	UG-SERVICE
38521824	GRET	SVC	5/20/2021	1971	RET ABN	UG-SERVICE
37025090	GRET	SVC	8/21/2020	1971	RET ABN	UG-SERVICE
35767016	GRET	SVC	1/8/2020	1971	RET ABN	UG-SERVICE
36120705	GRET	SVC	11/5/2020	1971	RET ABN	UG-SERVICE
39535924	GRET	SVC	12/14/2021	1971	RET ABN	UG-SERVICE
36255035	GRET	SVC	5/5/2020	1971	RET ABN	UG-SERVICE
43168069	GRET	SVC	6/28/2024	1971	RET ABN	UG-SERVICE
41741982	GRET	SVC	6/14/2023	1971	RET ABN	UG-SERVICE
41860747	GRET	SVC	8/16/2023	1971	RET ABN	UG-SERVICE
40521713	GRET	SVC	8/23/2022	1971	RET ABN	UG-SERVICE
40129808	GRET	SVC	5/10/2022	1971	RET ABN	UG-SERVICE
38547807	GRET	SVC	5/27/2021	1971	RET ABN	UG-SERVICE
43344403	GRET	SVC	7/23/2024	1971	RET ABN	UG-SERVICE
38260421	GRET	SVC	12/14/2021	1971	RET ABN	UG-SERVICE
41242161	GRET	SVC	2/24/2023	1971	RET ABN	UG-SERVICE
43584359	GRET	SVC	9/25/2024	1971	RET ABN	UG-SERVICE
36795096	GRET	SVC	9/1/2020	1971	RET ABN	UG-SERVICE
39990979	GRET	SVC	4/8/2022	1971	RET ABN	UG-SERVICE
39759178	GRET	SVC	8/16/2021	1971	RET ABN	UG-SERVICE
41009755	GRET	SVC	12/1/2022	1971	RET ABN	UG-SERVICE
43399718	GRET	SVC	8/9/2024	1971	RET ABN	UG-SERVICE
43347538	GRET	SVC	7/22/2024	1971	RET ABN	UG-SERVICE
42438487	GRET	SVC	12/5/2023	1971	RET ABN	UG-SERVICE
40251452	GRET	SVC	7/19/2022	1971	RET ABN	UG-SERVICE
37948598	GRET	SVC	12/22/2020	1971	RET ABN	UG-SERVICE
41317537	GRET	SVC	3/3/2023	1971	RET ABN	UG-SERVICE
41083628	GRET	SVC	1/11/2023	1971	RET ABN	UG-SERVICE
39223946	GRET	SVC	9/29/2021	1971	RET ABN	UG-SERVICE
37094270	GRET	SVC	10/30/2020	1971	RET ABN	UG-SERVICE
40249263	GRET	SVC	6/6/2022	1971	RET ABN	UG-SERVICE
35967994	GRET	SVC	2/28/2020	1971	RET ABN	UG-SERVICE
42670286	GRET	SVC	9/19/2024	1971	RET ABN	UG-SERVICE
39786506	GRET	SVC	2/14/2022	1971	RET ABN	UG-SERVICE
36259917	GRET	SVC	4/16/2020	1971	RET ABN	UG-SERVICE
38094297	GRET	SVC	2/8/2021	1971	RET ABN	UG-SERVICE
38441371	GRET	SVC	1/6/2022	1971	RET ABN	UG-SERVICE
41411664	GRET	SVC	4/2/2024	1971	RET ABN	UG-SERVICE
40341445	GRET	SVC	6/24/2022	1971	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43464130	GRET	SVC	8/20/2024	1971	RET ABN	UG-SERVICE
42437069	GRET	SVC	11/29/2023	1971	RET ABN	UG-SERVICE
36918266	GRET	SVC	9/14/2020	1971	RET ABN	UG-SERVICE
36592936	GRET	SVC	7/8/2020	1971	RET ABN	UG-SERVICE
39922193	GRET	SVC	3/24/2022	1971	RET ABN	UG-SERVICE
43364925	GRET	SVC	10/18/2024	1971	RET ABN	UG-SERVICE
42589542	GRET	SVC	1/24/2024	1971	RET ABN	UG-SERVICE
43480931	GRET	SVC	9/14/2024	1971	RET ABN	UG-SERVICE
38609629	GRET	SVC	6/9/2021	1971	RET ABN	UG-SERVICE
36283571	GRET	SVC	4/30/2020	1971	RET ABN	UG-SERVICE
40624086	GRET	SVC	8/30/2022	1971	RET ABN	UG-SERVICE
36709410	GRET	SVC	7/28/2020	1971	RET ABN	UG-SERVICE
43565122	GRET	SVC	9/9/2024	1971	RET ABN	UG-SERVICE
42330509	GRET	SVC	11/6/2023	1971	RET ABN	UG-SERVICE
36248250	GRET	SVC	5/6/2020	1971	RET ABN	UG-SERVICE
41584265	GRET	SVC	5/1/2023	1971	RET ABN	UG-SERVICE
38042126	GRET	SVC	1/22/2021	1971	RET ABN	UG-SERVICE
40341396	GRET	SVC	6/24/2022	1971	RET ABN	UG-SERVICE
37994124	GRET	SVC	1/11/2021	1971	RET ABN	UG-SERVICE
43480499	GRET	SVC	9/14/2024	1971	RET ABN	UG-SERVICE
36314805	GRET	SVC	5/8/2020	1971	RET ABN	UG-SERVICE
41411267	GRET	SVC	4/2/2024	1971	RET ABN	UG-SERVICE
40737724	GRET	SVC	9/27/2022	1971	RET ABN	UG-SERVICE
42138574	GRET	SVC	9/19/2023	1971	RET ABN	UG-SERVICE
40675869	GRET	SVC	9/13/2022	1971	RET ABN	UG-SERVICE
38707309	GRET	SVC	8/9/2021	1971	RET ABN	UG-SERVICE
42014187	GRET	SVC	8/21/2023	1971	RET ABN	UG-SERVICE
40917638	GRET	SVC	11/16/2022	1971	RET ABN	UG-SERVICE
43460131	GRET	SVC	8/27/2024	1971	RET ABN	UG-SERVICE
40700097	GRET	SVC	9/14/2022	1972	RET ABN	UG-SERVICE
41414154	GRET	SVC	3/20/2023	1972	RET ABN	UG-SERVICE
42514066	GRET	SVC	12/26/2023	1972	RET ABN	UG-SERVICE
43480932	GRET	SVC	9/14/2024	1972	RET ABN	UG-SERVICE
41918341	GRET	SVC	8/16/2023	1972	RET ABN	UG-SERVICE
41182817	GRET	SVC	3/1/2023	1972	RET ABN	UG-SERVICE
41139253	GRET	SVC	1/27/2023	1972	RET ABN	UG-SERVICE
40273700	GRET	SVC	6/9/2022	1972	RET ABN	UG-SERVICE
39475344	GRET	SVC	11/29/2021	1972	RET ABN	UG-SERVICE
42956850	GRET	SVC	7/18/2024	1972	RET ABN	UG-SERVICE
37898340	GRET	SVC	12/7/2020	1972	RET ABN	UG-SERVICE
40462865	GRET	SVC	7/14/2022	1972	RET ABN	UG-SERVICE
41402221	GRET	SVC	3/15/2023	1972	RET ABN	UG-SERVICE
43081215	GRET	SVC	5/17/2024	1972	RET ABN	UG-SERVICE
40991106	GRET	SVC	11/21/2022	1972	RET ABN	UG-SERVICE
43554625	GRET	SVC	9/13/2024	1972	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
35993848	GRET	SVC	6/16/2020	1972	RET ABN	UG-SERVICE
41429935	GRET	SVC	9/19/2023	1972	RET ABN	UG-SERVICE
36194997	GRET	SVC	4/28/2020	1972	RET ABN	UG-SERVICE
43699979	GRET	SVC	10/15/2024	1972	RET ABN	UG-SERVICE
37914376	GRET	SVC	12/6/2020	1972	RET ABN	UG-SERVICE
41411410	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
42438334	GRET	SVC	12/5/2023	1972	RET ABN	UG-SERVICE
42520328	GRET	SVC	12/18/2023	1972	RET ABN	UG-SERVICE
41407880	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
41242165	GRET	SVC	3/2/2023	1972	RET ABN	UG-SERVICE
38960829	GRET	SVC	8/24/2021	1972	RET ABN	UG-SERVICE
40325248	GRET	SVC	7/13/2022	1972	RET ABN	UG-SERVICE
42122080	GRET	SVC	9/16/2023	1972	RET ABN	UG-SERVICE
36164807	GRET	SVC	3/23/2020	1972	RET ABN	UG-SERVICE
42156649	GRET	SVC	9/26/2023	1972	RET ABN	UG-SERVICE
41430060	GRET	SVC	9/12/2023	1972	RET ABN	UG-SERVICE
41430069	GRET	SVC	9/13/2023	1972	RET ABN	UG-SERVICE
39849156	GRET	SVC	2/28/2022	1972	RET ABN	UG-SERVICE
40881642	GRET	SVC	11/1/2022	1972	RET ABN	UG-SERVICE
41407390	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
40896029	GRET	SVC	11/10/2022	1972	RET ABN	UG-SERVICE
36695038	GRET	SVC	8/5/2020	1972	RET ABN	UG-SERVICE
43679955	GRET	SVC	11/1/2024	1972	RET ABN	UG-SERVICE
42487785	GRET	SVC	7/31/2024	1972	RET ABN	UG-SERVICE
41402232	GRET	SVC	3/15/2023	1972	RET ABN	UG-SERVICE
42435907	GRET	SVC	9/19/2024	1972	RET ABN	UG-SERVICE
38363161	GRET	SVC	4/19/2021	1972	RET ABN	UG-SERVICE
42405710	GRET	SVC	12/8/2023	1972	RET ABN	UG-SERVICE
41214288	GRET	SVC	12/11/2023	1972	RET ABN	UG-SERVICE
40492259	GRET	SVC	8/14/2022	1972	RET ABN	UG-SERVICE
41411281	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
42214614	GRET	SVC	10/11/2023	1972	RET ABN	UG-SERVICE
38909290	GRET	SVC	8/16/2021	1972	RET ABN	UG-SERVICE
42300904	GRET	SVC	11/1/2023	1972	RET ABN	UG-SERVICE
43746155	GRET	SVC	12/11/2024	1972	RET ABN	UG-SERVICE
43868498	GRET	SVC	11/26/2024	1972	RET ABN	UG-SERVICE
43740061	GRET	SVC	12/4/2024	1972	RET ABN	UG-SERVICE
43739938	GRET	SVC	12/4/2024	1972	RET ABN	UG-SERVICE
42049249	GRET	SVC	8/30/2023	1972	RET ABN	UG-SERVICE
36199035	GRET	SVC	4/23/2020	1972	RET ABN	UG-SERVICE
41253576	GRET	SVC	2/10/2023	1972	RET ABN	UG-SERVICE
41677672	GRET	SVC	5/27/2023	1972	RET ABN	UG-SERVICE
41839631	GRET	SVC	7/6/2023	1972	RET ABN	UG-SERVICE
39759516	GRET	SVC	2/7/2022	1972	RET ABN	UG-SERVICE
39926695	GRET	SVC	4/9/2022	1972	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
39532710	GRET	SVC	12/14/2021	1972	RET ABN	UG-SERVICE
41654517	GRET	SVC	5/18/2023	1972	RET ABN	UG-SERVICE
39346682	GRET	SVC	10/28/2021	1972	RET ABN	UG-SERVICE
37070751	GRET	SVC	10/13/2020	1972	RET ABN	UG-SERVICE
37926012	GRET	SVC	12/16/2020	1972	RET ABN	UG-SERVICE
42834341	GRET	SVC	7/23/2024	1972	RET ABN	UG-SERVICE
42833380	GRET	SVC	7/22/2024	1972	RET ABN	UG-SERVICE
43480658	GRET	SVC	9/11/2024	1972	RET ABN	UG-SERVICE
36672292	GRET	SVC	7/23/2020	1972	RET ABN	UG-SERVICE
40552246	GRET	SVC	8/11/2022	1972	RET ABN	UG-SERVICE
38469249	GRET	SVC	6/1/2021	1972	RET ABN	UG-SERVICE
41273360	GRET	SVC	2/16/2023	1972	RET ABN	UG-SERVICE
43760724	GRET	SVC	10/23/2024	1972	RET ABN	UG-SERVICE
40333213	GRET	SVC	6/23/2022	1972	RET ABN	UG-SERVICE
43480998	GRET	SVC	11/16/2024	1972	RET ABN	UG-SERVICE
37926212	GRET	SVC	12/15/2020	1972	RET ABN	UG-SERVICE
41411234	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
41448025	GRET	SVC	3/26/2023	1972	RET ABN	UG-SERVICE
41188560	GRET	SVC	2/13/2023	1972	RET ABN	UG-SERVICE
39930272	GRET	SVC	3/31/2022	1972	RET ABN	UG-SERVICE
43739936	GRET	SVC	12/4/2024	1972	RET ABN	UG-SERVICE
39947193	GRET	SVC	3/29/2022	1972	RET ABN	UG-SERVICE
40418092	GRET	SVC	7/14/2022	1972	RET ABN	UG-SERVICE
43120516	GRET	SVC	5/21/2024	1972	RET ABN	UG-SERVICE
41411268	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
40933307	GRET	SVC	11/15/2022	1972	RET ABN	UG-SERVICE
39797719	GRET	SVC	2/15/2022	1972	RET ABN	UG-SERVICE
42381531	GRET	SVC	11/17/2023	1972	RET ABN	UG-SERVICE
43862097	GRET	SVC	12/9/2024	1972	RET ABN	UG-SERVICE
39935371	GRET	SVC	6/2/2022	1972	RET ABN	UG-SERVICE
42072075	GRET	SVC	9/5/2023	1972	RET ABN	UG-SERVICE
43342129	GRET	SVC	7/29/2024	1972	RET ABN	UG-SERVICE
41411275	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
35772295	GRET	SVC	1/2/2020	1972	RET ABN	UG-SERVICE
43480928	GRET	SVC	9/14/2024	1972	RET ABN	UG-SERVICE
38432241	GRET	SVC	4/29/2021	1972	RET ABN	UG-SERVICE
41740533	GRET	SVC	6/13/2023	1972	RET ABN	UG-SERVICE
43740062	GRET	SVC	12/4/2024	1972	RET ABN	UG-SERVICE
43186501	GRET	SVC	6/17/2024	1972	RET ABN	UG-SERVICE
41860698	GRET	SVC	7/13/2023	1972	RET ABN	UG-SERVICE
38343815	GRET	SVC	4/10/2021	1972	RET ABN	UG-SERVICE
41273211	GRET	SVC	2/16/2023	1972	RET ABN	UG-SERVICE
38703736	GRET	SVC	7/7/2021	1972	RET ABN	UG-SERVICE
39016838	GRET	SVC	8/16/2021	1972	RET ABN	UG-SERVICE
42412478	GRET	SVC	11/28/2023	1972	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41284187	GRET	SVC	3/15/2023	1972	RET ABN	UG-SERVICE
42294230	GRET	SVC	10/30/2023	1972	RET ABN	UG-SERVICE
36339718	GRET	SVC	5/20/2020	1972	RET ABN	UG-SERVICE
42286974	GRET	SVC	10/30/2023	1972	RET ABN	UG-SERVICE
39243683	GRET	SVC	11/19/2021	1972	RET ABN	UG-SERVICE
39830345	GRET	SVC	8/3/2022	1972	RET ABN	UG-SERVICE
41424508	GRET	SVC	10/18/2023	1972	RET ABN	UG-SERVICE
38557501	GRET	SVC	6/2/2021	1972	RET ABN	UG-SERVICE
38795268	GRET	SVC	7/17/2021	1972	RET ABN	UG-SERVICE
43480927	GRET	SVC	9/14/2024	1972	RET ABN	UG-SERVICE
42427053	GRET	SVC	9/19/2024	1972	RET ABN	UG-SERVICE
43156137	GRET	SVC	6/1/2024	1972	RET ABN	UG-SERVICE
43008937	GRET	SVC	5/3/2024	1972	RET ABN	UG-SERVICE
40394919	GRET	SVC	7/7/2022	1972	RET ABN	UG-SERVICE
39830356	GRET	SVC	8/3/2022	1972	RET ABN	UG-SERVICE
42833350	GRET	SVC	7/22/2024	1972	RET ABN	UG-SERVICE
38776468	GRET	SVC	8/2/2021	1972	RET ABN	UG-SERVICE
41032552	GRET	SVC	12/15/2022	1972	RET ABN	UG-SERVICE
39848783	GRET	SVC	3/4/2022	1972	RET ABN	UG-SERVICE
42585505	GRET	SVC	1/29/2024	1972	RET ABN	UG-SERVICE
41887706	GRET	SVC	7/17/2023	1972	RET ABN	UG-SERVICE
43678698	GRET	SVC	10/16/2024	1972	RET ABN	UG-SERVICE
43649102	GRET	SVC	10/8/2024	1972	RET ABN	UG-SERVICE
43529723	GRET	SVC	12/16/2024	1972	RET ABN	UG-SERVICE
40245550	GRET	SVC	9/9/2022	1972	RET ABN	UG-SERVICE
38490941	GRET	SVC	5/17/2021	1972	RET ABN	UG-SERVICE
42487347	GRET	SVC	7/18/2024	1972	RET ABN	UG-SERVICE
43739939	GRET	SVC	12/4/2024	1972	RET ABN	UG-SERVICE
41279525	GRET	SVC	2/15/2023	1972	RET ABN	UG-SERVICE
41008615	GRET	SVC	12/8/2022	1972	RET ABN	UG-SERVICE
38525559	GRET	SVC	5/24/2021	1972	RET ABN	UG-SERVICE
43189275	GRET	SVC	6/17/2024	1972	RET ABN	UG-SERVICE
40340999	GRET	SVC	6/23/2022	1972	RET ABN	UG-SERVICE
39916056	GRET	SVC	5/2/2022	1972	RET ABN	UG-SERVICE
39471032	GRET	SVC	12/2/2021	1972	RET ABN	UG-SERVICE
37052222	GRET	SVC	8/29/2020	1972	RET ABN	UG-SERVICE
41223060	GRET	SVC	1/30/2023	1972	RET ABN	UG-SERVICE
42833349	GRET	SVC	7/22/2024	1972	RET ABN	UG-SERVICE
37141842	GRET	SVC	11/17/2020	1972	RET ABN	UG-SERVICE
41411273	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
41411280	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
40019113	GRET	SVC	5/27/2022	1972	RET ABN	UG-SERVICE
43223752	GRET	SVC	6/13/2024	1972	RET ABN	UG-SERVICE
36701097	GRET	SVC	9/8/2020	1972	RET ABN	UG-SERVICE
41411079	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41423578	GRET	SVC	10/18/2023	1972	RET ABN	UG-SERVICE
41242610	GRET	SVC	3/13/2023	1972	RET ABN	UG-SERVICE
36335575	GRET	SVC	5/19/2020	1972	RET ABN	UG-SERVICE
41407816	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
43480929	GRET	SVC	9/14/2024	1972	RET ABN	UG-SERVICE
43480930	GRET	SVC	9/14/2024	1972	RET ABN	UG-SERVICE
39668979	GRET	SVC	1/19/2022	1972	RET ABN	UG-SERVICE
38622330	GRET	SVC	8/23/2021	1972	RET ABN	UG-SERVICE
41255101	GRET	SVC	2/15/2023	1972	RET ABN	UG-SERVICE
36786482	GRET	SVC	8/17/2020	1972	RET ABN	UG-SERVICE
42584903	GRET	SVC	1/25/2024	1972	RET ABN	UG-SERVICE
42006056	GRET	SVC	8/14/2023	1972	RET ABN	UG-SERVICE
37887072	GRET	SVC	12/10/2020	1972	RET ABN	UG-SERVICE
36709891	GRET	SVC	8/5/2020	1972	RET ABN	UG-SERVICE
41411286	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
43295385	GRET	SVC	7/12/2024	1972	RET ABN	UG-SERVICE
43481241	GRET	SVC	10/23/2024	1972	RET ABN	UG-SERVICE
38041014	GRET	SVC	1/15/2021	1972	RET ABN	UG-SERVICE
41006872	GRET	SVC	12/7/2022	1972	RET ABN	UG-SERVICE
40308701	GRET	SVC	6/27/2022	1972	RET ABN	UG-SERVICE
42284433	GRET	SVC	10/26/2023	1972	RET ABN	UG-SERVICE
36820378	GRET	SVC	8/25/2020	1972	RET ABN	UG-SERVICE
38179976	GRET	SVC	4/28/2021	1972	RET ABN	UG-SERVICE
41614118	GRET	SVC	5/9/2023	1972	RET ABN	UG-SERVICE
43620359	GRET	SVC	9/23/2024	1972	RET ABN	UG-SERVICE
41411277	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
42566873	GRET	SVC	2/2/2024	1972	RET ABN	UG-SERVICE
36366705	GRET	SVC	6/16/2020	1972	RET ABN	UG-SERVICE
43946099	GRET	SVC	12/30/2024	1972	RET ABN	UG-SERVICE
38327111	GRET	SVC	4/8/2021	1972	RET ABN	UG-SERVICE
42970529	GRET	SVC	4/24/2024	1972	RET ABN	UG-SERVICE
43365789	GRET	SVC	12/19/2024	1972	RET ABN	UG-SERVICE
43063274	GRET	SVC	5/13/2024	1972	RET ABN	UG-SERVICE
42150870	GRET	SVC	10/13/2023	1972	RET ABN	UG-SERVICE
37898091	GRET	SVC	12/10/2020	1972	RET ABN	UG-SERVICE
43481250	GRET	SVC	9/10/2024	1972	RET ABN	UG-SERVICE
41258757	GRET	SVC	3/14/2023	1972	RET ABN	UG-SERVICE
38278785	GRET	SVC	4/28/2021	1972	RET ABN	UG-SERVICE
40953284	GRET	SVC	11/29/2022	1972	RET ABN	UG-SERVICE
40895627	GRET	SVC	11/7/2022	1972	RET ABN	UG-SERVICE
40916562	GRET	SVC	11/8/2022	1972	RET ABN	UG-SERVICE
40265392	GRET	SVC	6/7/2022	1972	RET ABN	UG-SERVICE
42166121	GRET	SVC	9/19/2023	1972	RET ABN	UG-SERVICE
43173863	GRET	SVC	7/17/2024	1972	RET ABN	UG-SERVICE
38427776	GRET	SVC	4/29/2021	1972	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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39570775	GRET	SVC	12/13/2021	1972	RET ABN	UG-SERVICE
40699291	GRET	SVC	9/29/2022	1972	RET ABN	UG-SERVICE
43217425	GRET	SVC	6/24/2024	1972	RET ABN	UG-SERVICE
37887986	GRET	SVC	12/9/2020	1972	RET ABN	UG-SERVICE
35868335	GRET	SVC	1/7/2020	1972	RET ABN	UG-SERVICE
39570921	GRET	SVC	12/13/2021	1972	RET ABN	UG-SERVICE
37036908	GRET	SVC	10/7/2020	1972	RET ABN	UG-SERVICE
38082511	GRET	SVC	2/2/2021	1972	RET ABN	UG-SERVICE
43480920	GRET	SVC	9/14/2024	1972	RET ABN	UG-SERVICE
41932791	GRET	SVC	9/18/2023	1972	RET ABN	UG-SERVICE
42227175	GRET	SVC	10/31/2023	1972	RET ABN	UG-SERVICE
38322528	GRET	SVC	11/3/2021	1972	RET ABN	UG-SERVICE
43120561	GRET	SVC	7/15/2024	1972	RET ABN	UG-SERVICE
42833359	GRET	SVC	7/23/2024	1972	RET ABN	UG-SERVICE
42579294	GRET	SVC	1/19/2024	1972	RET ABN	UG-SERVICE
41407749	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
41411271	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
40514385	GRET	SVC	8/2/2022	1973	RET ABN	UG-SERVICE
42957430	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
43477543	GRET	SVC	8/26/2024	1973	RET ABN	UG-SERVICE
43346735	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42956758	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42227366	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42956467	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42098663	GRET	SVC	9/14/2023	1973	RET ABN	UG-SERVICE
42228021	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42957959	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
41721134	GRET	SVC	6/8/2023	1973	RET ABN	UG-SERVICE
42487710	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
42227957	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
41277765	GRET	SVC	2/14/2023	1973	RET ABN	UG-SERVICE
41279351	GRET	SVC	3/15/2023	1973	RET ABN	UG-SERVICE
39257945	GRET	SVC	10/11/2021	1973	RET ABN	UG-SERVICE
42227364	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42957390	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42155783	GRET	SVC	9/27/2023	1973	RET ABN	UG-SERVICE
43554106	GRET	SVC	9/12/2024	1973	RET ABN	UG-SERVICE
38955723	GRET	SVC	8/22/2021	1973	RET ABN	UG-SERVICE
42487716	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
41922366	GRET	SVC	7/27/2023	1973	RET ABN	UG-SERVICE
43529736	GRET	SVC	12/6/2024	1973	RET ABN	UG-SERVICE
40581035	GRET	SVC	8/15/2022	1973	RET ABN	UG-SERVICE
40784117	GRET	SVC	10/10/2022	1973	RET ABN	UG-SERVICE
39544059	GRET	SVC	12/13/2021	1973	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41969570	GRET	SVC	8/1/2024	1973	RET ABN	UG-SERVICE
42227177	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
36839682	GRET	SVC	7/15/2020	1973	RET ABN	UG-SERVICE
42956332	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
41273667	GRET	SVC	3/2/2023	1973	RET ABN	UG-SERVICE
42956845	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
42767218	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
36192099	GRET	SVC	4/23/2020	1973	RET ABN	UG-SERVICE
42228023	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
38662181	GRET	SVC	6/24/2021	1973	RET ABN	UG-SERVICE
43245014	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42487724	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
42227833	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
43480926	GRET	SVC	9/14/2024	1973	RET ABN	UG-SERVICE
42956477	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
41722788	GRET	SVC	6/12/2023	1973	RET ABN	UG-SERVICE
42956759	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
41277884	GRET	SVC	2/14/2023	1973	RET ABN	UG-SERVICE
42227319	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227945	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42509340	GRET	SVC	7/31/2024	1973	RET ABN	UG-SERVICE
42227302	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42530678	GRET	SVC	12/20/2023	1973	RET ABN	UG-SERVICE
41969077	GRET	SVC	8/1/2024	1973	RET ABN	UG-SERVICE
40528003	GRET	SVC	8/9/2022	1973	RET ABN	UG-SERVICE
42957332	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42227735	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227550	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
40140878	GRET	SVC	5/11/2022	1973	RET ABN	UG-SERVICE
42227317	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
38637830	GRET	SVC	7/23/2021	1973	RET ABN	UG-SERVICE
43613267	GRET	SVC	9/13/2024	1973	RET ABN	UG-SERVICE
41340689	GRET	SVC	3/18/2023	1973	RET ABN	UG-SERVICE
43480924	GRET	SVC	9/14/2024	1973	RET ABN	UG-SERVICE
43318481	GRET	SVC	8/15/2024	1973	RET ABN	UG-SERVICE
42227375	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
39970244	GRET	SVC	5/11/2022	1973	RET ABN	UG-SERVICE
42957394	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
41316693	GRET	SVC	3/6/2023	1973	RET ABN	UG-SERVICE
42600438	GRET	SVC	1/25/2024	1973	RET ABN	UG-SERVICE
36003455	GRET	SVC	2/10/2020	1973	RET ABN	UG-SERVICE
42228028	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227949	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
41414916	GRET	SVC	3/20/2023	1973	RET ABN	UG-SERVICE
36268686	GRET	SVC	5/4/2020	1973	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41027618	GRET	SVC	12/14/2022	1973	RET ABN	UG-SERVICE
41774608	GRET	SVC	6/23/2023	1973	RET ABN	UG-SERVICE
35934476	GRET	SVC	1/22/2020	1973	RET ABN	UG-SERVICE
39438659	GRET	SVC	11/18/2021	1973	RET ABN	UG-SERVICE
43423329	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42228027	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
41273369	GRET	SVC	2/11/2023	1973	RET ABN	UG-SERVICE
39904817	GRET	SVC	4/11/2022	1973	RET ABN	UG-SERVICE
43244990	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
41969340	GRET	SVC	7/30/2024	1973	RET ABN	UG-SERVICE
41414175	GRET	SVC	4/2/2024	1973	RET ABN	UG-SERVICE
38469920	GRET	SVC	5/10/2021	1973	RET ABN	UG-SERVICE
42283973	GRET	SVC	10/21/2023	1973	RET ABN	UG-SERVICE
42227316	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227315	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42957684	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
40372244	GRET	SVC	7/18/2022	1973	RET ABN	UG-SERVICE
42227303	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
39576175	GRET	SVC	7/8/2021	1973	RET ABN	UG-SERVICE
42227850	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
36208642	GRET	SVC	4/7/2021	1973	RET ABN	UG-SERVICE
41486042	GRET	SVC	4/11/2023	1973	RET ABN	UG-SERVICE
42956755	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
43245007	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
40338689	GRET	SVC	7/8/2022	1973	RET ABN	UG-SERVICE
42957391	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
36331192	GRET	SVC	5/15/2020	1973	RET ABN	UG-SERVICE
35936301	GRET	SVC	1/23/2020	1973	RET ABN	UG-SERVICE
36728962	GRET	SVC	8/3/2020	1973	RET ABN	UG-SERVICE
43365793	GRET	SVC	12/6/2024	1973	RET ABN	UG-SERVICE
42227737	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
36450481	GRET	SVC	6/16/2020	1973	RET ABN	UG-SERVICE
41273560	GRET	SVC	2/11/2023	1973	RET ABN	UG-SERVICE
42227955	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
40360389	GRET	SVC	6/22/2022	1973	RET ABN	UG-SERVICE
40309193	GRET	SVC	8/12/2022	1973	RET ABN	UG-SERVICE
42227176	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
36839691	GRET	SVC	7/15/2020	1973	RET ABN	UG-SERVICE
41101699	GRET	SVC	12/29/2022	1973	RET ABN	UG-SERVICE
42389920	GRET	SVC	11/18/2023	1973	RET ABN	UG-SERVICE
42956338	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42957337	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42020459	GRET	SVC	11/1/2023	1973	RET ABN	UG-SERVICE
43347824	GRET	SVC	7/22/2024	1973	RET ABN	UG-SERVICE
40015632	GRET	SVC	4/17/2022	1973	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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41242859	GRET	SVC	2/10/2023	1973	RET ABN	UG-SERVICE
40054754	GRET	SVC	12/23/2021	1973	RET ABN	UG-SERVICE
41241968	GRET	SVC	3/2/2023	1973	RET ABN	UG-SERVICE
36495864	GRET	SVC	7/7/2020	1973	RET ABN	UG-SERVICE
41211685	GRET	SVC	12/11/2023	1973	RET ABN	UG-SERVICE
42227736	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
39929212	GRET	SVC	3/10/2022	1973	RET ABN	UG-SERVICE
41963559	GRET	SVC	8/9/2023	1973	RET ABN	UG-SERVICE
42227360	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227314	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227551	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
41246612	GRET	SVC	2/6/2023	1973	RET ABN	UG-SERVICE
41243052	GRET	SVC	3/17/2023	1973	RET ABN	UG-SERVICE
42520550	GRET	SVC	12/27/2023	1973	RET ABN	UG-SERVICE
37896433	GRET	SVC	12/23/2020	1973	RET ABN	UG-SERVICE
41774602	GRET	SVC	6/27/2023	1973	RET ABN	UG-SERVICE
42509250	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
42227840	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227856	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
39211483	GRET	SVC	9/27/2021	1973	RET ABN	UG-SERVICE
41273574	GRET	SVC	2/19/2023	1973	RET ABN	UG-SERVICE
35926924	GRET	SVC	1/22/2020	1973	RET ABN	UG-SERVICE
43589203	GRET	SVC	9/24/2024	1973	RET ABN	UG-SERVICE
42228030	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
41279002	GRET	SVC	2/16/2023	1973	RET ABN	UG-SERVICE
42956841	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42487344	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
42487351	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
41247242	GRET	SVC	3/6/2023	1973	RET ABN	UG-SERVICE
38561880	GRET	SVC	4/17/2021	1973	RET ABN	UG-SERVICE
43155559	GRET	SVC	6/10/2024	1973	RET ABN	UG-SERVICE
42227365	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227844	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42957683	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
37094886	GRET	SVC	10/20/2020	1973	RET ABN	UG-SERVICE
41279350	GRET	SVC	2/16/2023	1973	RET ABN	UG-SERVICE
40671557	GRET	SVC	9/13/2022	1973	RET ABN	UG-SERVICE
40418545	GRET	SVC	7/13/2022	1973	RET ABN	UG-SERVICE
42227739	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42957389	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42227954	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
39293408	GRET	SVC	10/12/2021	1973	RET ABN	UG-SERVICE
42227300	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
43245107	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40756551	GRET	SVC	10/4/2022	1973	RET ABN	UG-SERVICE
42227853	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
43244992	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42487720	GRET	SVC	7/31/2024	1973	RET ABN	UG-SERVICE
42483428	GRET	SVC	4/15/2024	1973	RET ABN	UG-SERVICE
43347635	GRET	SVC	7/22/2024	1973	RET ABN	UG-SERVICE
41818864	GRET	SVC	7/21/2023	1973	RET ABN	UG-SERVICE
41247078	GRET	SVC	3/7/2023	1973	RET ABN	UG-SERVICE
42483430	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
38272431	GRET	SVC	2/25/2021	1973	RET ABN	UG-SERVICE
39728731	GRET	SVC	1/28/2022	1973	RET ABN	UG-SERVICE
42227721	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227953	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42846212	GRET	SVC	7/30/2024	1973	RET ABN	UG-SERVICE
41304277	GRET	SVC	9/18/2023	1973	RET ABN	UG-SERVICE
43480923	GRET	SVC	9/14/2024	1973	RET ABN	UG-SERVICE
36153326	GRET	SVC	3/19/2020	1973	RET ABN	UG-SERVICE
43122877	GRET	SVC	5/28/2024	1973	RET ABN	UG-SERVICE
41243177	GRET	SVC	2/10/2023	1973	RET ABN	UG-SERVICE
43506831	GRET	SVC	10/4/2024	1973	RET ABN	UG-SERVICE
38162884	GRET	SVC	2/22/2021	1973	RET ABN	UG-SERVICE
39665660	GRET	SVC	8/3/2022	1973	RET ABN	UG-SERVICE
43004209	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
35960589	GRET	SVC	1/28/2020	1973	RET ABN	UG-SERVICE
42228032	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
41245808	GRET	SVC	2/11/2023	1973	RET ABN	UG-SERVICE
39570884	GRET	SVC	12/7/2021	1973	RET ABN	UG-SERVICE
41245801	GRET	SVC	2/11/2023	1973	RET ABN	UG-SERVICE
42551744	GRET	SVC	1/8/2024	1973	RET ABN	UG-SERVICE
43663930	GRET	SVC	10/7/2024	1973	RET ABN	UG-SERVICE
37094896	GRET	SVC	10/23/2020	1973	RET ABN	UG-SERVICE
43205044	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
40989015	GRET	SVC	11/29/2022	1973	RET ABN	UG-SERVICE
42487701	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
42228025	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
38397396	GRET	SVC	4/20/2021	1973	RET ABN	UG-SERVICE
42956474	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42227942	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
38894836	GRET	SVC	8/13/2021	1973	RET ABN	UG-SERVICE
38427246	GRET	SVC	4/27/2021	1973	RET ABN	UG-SERVICE
42227720	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227841	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
41277767	GRET	SVC	2/13/2023	1973	RET ABN	UG-SERVICE
36392249	GRET	SVC	6/4/2020	1973	RET ABN	UG-SERVICE
42227763	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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41273374	GRET	SVC	2/11/2023	1973	RET ABN	UG-SERVICE
41279262	GRET	SVC	2/14/2023	1973	RET ABN	UG-SERVICE
38561619	GRET	SVC	4/19/2021	1973	RET ABN	UG-SERVICE
43480925	GRET	SVC	9/14/2024	1973	RET ABN	UG-SERVICE
42380984	GRET	SVC	11/17/2023	1973	RET ABN	UG-SERVICE
41247074	GRET	SVC	3/7/2023	1973	RET ABN	UG-SERVICE
40388837	GRET	SVC	10/24/2022	1973	RET ABN	UG-SERVICE
42227843	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
41179138	GRET	SVC	1/18/2023	1973	RET ABN	UG-SERVICE
42228029	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227664	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
38396306	GRET	SVC	4/20/2021	1973	RET ABN	UG-SERVICE
42627232	GRET	SVC	1/29/2024	1973	RET ABN	UG-SERVICE
40498641	GRET	SVC	7/28/2022	1973	RET ABN	UG-SERVICE
43005058	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
36960587	GRET	SVC	9/22/2020	1973	RET ABN	UG-SERVICE
41279156	GRET	SVC	2/16/2023	1973	RET ABN	UG-SERVICE
42958051	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
43245012	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42227178	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
36741661	GRET	SVC	8/5/2020	1973	RET ABN	UG-SERVICE
43705442	GRET	SVC	10/18/2024	1973	RET ABN	UG-SERVICE
42228022	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
39284203	GRET	SVC	10/12/2021	1973	RET ABN	UG-SERVICE
41273567	GRET	SVC	2/19/2023	1973	RET ABN	UG-SERVICE
39093693	GRET	SVC	9/7/2021	1973	RET ABN	UG-SERVICE
42227172	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
41427448	GRET	SVC	3/21/2023	1973	RET ABN	UG-SERVICE
43974668	GRET	SVC	11/16/2024	1973	RET ABN	UG-SERVICE
43711580	GRET	SVC	11/22/2024	1973	RET ABN	UG-SERVICE
42228031	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42487754	GRET	SVC	7/31/2024	1973	RET ABN	UG-SERVICE
40558487	GRET	SVC	8/13/2022	1973	RET ABN	UG-SERVICE
41247244	GRET	SVC	3/6/2023	1973	RET ABN	UG-SERVICE
36363719	GRET	SVC	5/19/2020	1973	RET ABN	UG-SERVICE
38839899	GRET	SVC	7/26/2021	1973	RET ABN	UG-SERVICE
38156971	GRET	SVC	2/20/2021	1973	RET ABN	UG-SERVICE
41247068	GRET	SVC	2/8/2023	1973	RET ABN	UG-SERVICE
42227958	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42509251	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
40022949	GRET	SVC	4/11/2022	1973	RET ABN	UG-SERVICE
43282341	GRET	SVC	7/23/2024	1973	RET ABN	UG-SERVICE
41279141	GRET	SVC	3/24/2023	1973	RET ABN	UG-SERVICE
36876466	GRET	SVC	8/31/2020	1973	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41277772	GRET	SVC	3/1/2023	1973	RET ABN	UG-SERVICE
42956468	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42227306	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42833097	GRET	SVC	7/22/2024	1973	RET ABN	UG-SERVICE
43868699	GRET	SVC	11/26/2024	1973	RET ABN	UG-SERVICE
39901915	GRET	SVC	3/17/2022	1973	RET ABN	UG-SERVICE
42227956	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227845	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227760	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227944	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
43115657	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
41479996	GRET	SVC	4/6/2023	1973	RET ABN	UG-SERVICE
40054753	GRET	SVC	12/23/2021	1973	RET ABN	UG-SERVICE
41279540	GRET	SVC	3/8/2023	1973	RET ABN	UG-SERVICE
36007595	GRET	SVC	2/12/2020	1973	RET ABN	UG-SERVICE
42227959	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227679	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227761	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42679360	GRET	SVC	2/6/2024	1973	RET ABN	UG-SERVICE
42054745	GRET	SVC	8/29/2023	1973	RET ABN	UG-SERVICE
42487443	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
42227834	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
41245805	GRET	SVC	2/11/2023	1973	RET ABN	UG-SERVICE
43480921	GRET	SVC	9/14/2024	1973	RET ABN	UG-SERVICE
42227820	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42833358	GRET	SVC	7/23/2024	1973	RET ABN	UG-SERVICE
42227738	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
41242858	GRET	SVC	3/21/2023	1973	RET ABN	UG-SERVICE
42227842	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227943	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
41436540	GRET	SVC	3/29/2023	1973	RET ABN	UG-SERVICE
43145111	GRET	SVC	6/7/2024	1973	RET ABN	UG-SERVICE
43729863	GRET	SVC	10/22/2024	1973	RET ABN	UG-SERVICE
37973580	GRET	SVC	1/4/2021	1973	RET ABN	UG-SERVICE
41818653	GRET	SVC	7/27/2023	1973	RET ABN	UG-SERVICE
42670284	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42483434	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
40847419	GRET	SVC	10/24/2022	1973	RET ABN	UG-SERVICE
42487711	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
36260075	GRET	SVC	3/20/2020	1973	RET ABN	UG-SERVICE
42509258	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
42227304	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
43613521	GRET	SVC	9/30/2024	1973	RET ABN	UG-SERVICE
42957338	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42227313	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43318350	GRET	SVC	8/5/2024	1973	RET ABN	UG-SERVICE
40683501	GRET	SVC	9/24/2022	1973	RET ABN	UG-SERVICE
42227835	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42509257	GRET	SVC	7/31/2024	1974	RET ABN	UG-SERVICE
42228034	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227732	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227549	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
37782096	GRET	SVC	11/25/2020	1974	RET ABN	UG-SERVICE
42227837	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
43369052	GRET	SVC	8/19/2024	1974	RET ABN	UG-SERVICE
36194666	GRET	SVC	4/23/2020	1974	RET ABN	UG-SERVICE
41407766	GRET	SVC	10/19/2023	1974	RET ABN	UG-SERVICE
38301295	GRET	SVC	5/18/2021	1974	RET ABN	UG-SERVICE
39844903	GRET	SVC	2/28/2022	1974	RET ABN	UG-SERVICE
42227773	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
37216516	GRET	SVC	11/2/2020	1974	RET ABN	UG-SERVICE
39090763	GRET	SVC	9/21/2021	1974	RET ABN	UG-SERVICE
41533537	GRET	SVC	9/8/2023	1974	RET ABN	UG-SERVICE
40959691	GRET	SVC	11/21/2022	1974	RET ABN	UG-SERVICE
43667743	GRET	SVC	10/9/2024	1974	RET ABN	UG-SERVICE
42227821	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
36072400	GRET	SVC	6/2/2020	1974	RET ABN	UG-SERVICE
42227824	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227363	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
36036482	GRET	SVC	2/25/2020	1974	RET ABN	UG-SERVICE
42227307	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
40801836	GRET	SVC	10/14/2022	1974	RET ABN	UG-SERVICE
42227839	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
43380802	GRET	SVC	7/25/2024	1974	RET ABN	UG-SERVICE
42227830	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227669	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
40595812	GRET	SVC	8/22/2022	1974	RET ABN	UG-SERVICE
43318352	GRET	SVC	11/6/2024	1974	RET ABN	UG-SERVICE
42227662	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
40156382	GRET	SVC	5/3/2022	1974	RET ABN	UG-SERVICE
38453815	GRET	SVC	5/4/2021	1974	RET ABN	UG-SERVICE
41428615	GRET	SVC	3/22/2023	1974	RET ABN	UG-SERVICE
38014215	GRET	SVC	1/12/2021	1974	RET ABN	UG-SERVICE
42227545	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
38156953	GRET	SVC	7/30/2021	1974	RET ABN	UG-SERVICE
43711732	GRET	SVC	10/15/2024	1974	RET ABN	UG-SERVICE
42227731	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227671	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42956849	GRET	SVC	7/18/2024	1974	RET ABN	UG-SERVICE
39551371	GRET	SVC	12/16/2021	1974	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42227727	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
35888215	GRET	SVC	1/13/2020	1974	RET ABN	UG-SERVICE
38052297	GRET	SVC	1/25/2021	1974	RET ABN	UG-SERVICE
42227733	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227776	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
43226784	GRET	SVC	6/25/2024	1974	RET ABN	UG-SERVICE
42915049	GRET	SVC	4/18/2024	1974	RET ABN	UG-SERVICE
42678881	GRET	SVC	2/5/2024	1974	RET ABN	UG-SERVICE
38934857	GRET	SVC	8/23/2021	1974	RET ABN	UG-SERVICE
42227318	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
36946724	GRET	SVC	9/14/2020	1974	RET ABN	UG-SERVICE
35941119	GRET	SVC	1/27/2020	1974	RET ABN	UG-SERVICE
42227769	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
43592553	GRET	SVC	9/25/2024	1974	RET ABN	UG-SERVICE
43324302	GRET	SVC	8/2/2024	1974	RET ABN	UG-SERVICE
42227765	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42571143	GRET	SVC	2/21/2024	1974	RET ABN	UG-SERVICE
42284186	GRET	SVC	10/23/2023	1974	RET ABN	UG-SERVICE
42781675	GRET	SVC	3/6/2024	1974	RET ABN	UG-SERVICE
42227723	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
38287708	GRET	SVC	3/30/2021	1974	RET ABN	UG-SERVICE
41969806	GRET	SVC	8/7/2023	1974	RET ABN	UG-SERVICE
38881005	GRET	SVC	8/11/2021	1974	RET ABN	UG-SERVICE
42227722	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
37957971	GRET	SVC	12/27/2020	1974	RET ABN	UG-SERVICE
38042123	GRET	SVC	1/25/2021	1974	RET ABN	UG-SERVICE
42227855	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227728	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
43674680	GRET	SVC	10/11/2024	1974	RET ABN	UG-SERVICE
41917199	GRET	SVC	7/28/2023	1974	RET ABN	UG-SERVICE
39436536	GRET	SVC	12/4/2021	1974	RET ABN	UG-SERVICE
42227730	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42055908	GRET	SVC	8/29/2023	1974	RET ABN	UG-SERVICE
39388355	GRET	SVC	11/5/2021	1974	RET ABN	UG-SERVICE
37811150	GRET	SVC	12/4/2020	1974	RET ABN	UG-SERVICE
38975815	GRET	SVC	8/31/2021	1974	RET ABN	UG-SERVICE
37891114	GRET	SVC	12/8/2020	1974	RET ABN	UG-SERVICE
42227557	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227854	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
35861892	GRET	SVC	1/8/2020	1974	RET ABN	UG-SERVICE
38217834	GRET	SVC	3/10/2021	1974	RET ABN	UG-SERVICE
42227374	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227554	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227822	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
36736359	GRET	SVC	8/6/2020	1974	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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42227310	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
35958586	GRET	SVC	1/28/2020	1974	RET ABN	UG-SERVICE
42227377	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
40113542	GRET	SVC	5/4/2022	1974	RET ABN	UG-SERVICE
37053180	GRET	SVC	10/12/2020	1974	RET ABN	UG-SERVICE
42549252	GRET	SVC	1/8/2024	1974	RET ABN	UG-SERVICE
43030227	GRET	SVC	5/15/2024	1974	RET ABN	UG-SERVICE
42227729	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227376	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227556	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227548	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227940	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
40819779	GRET	SVC	10/18/2022	1974	RET ABN	UG-SERVICE
42227543	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
43464646	GRET	SVC	8/20/2024	1974	RET ABN	UG-SERVICE
38447998	GRET	SVC	5/3/2021	1974	RET ABN	UG-SERVICE
42227768	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
36992975	GRET	SVC	9/29/2020	1974	RET ABN	UG-SERVICE
39489548	GRET	SVC	12/11/2021	1974	RET ABN	UG-SERVICE
42227674	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
35316596	GRET	SVC	1/22/2021	1974	RET ABN	UG-SERVICE
42227725	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
41243542	GRET	SVC	2/7/2023	1974	RET ABN	UG-SERVICE
42227309	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
41922368	GRET	SVC	7/27/2023	1974	RET ABN	UG-SERVICE
42227777	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227672	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227670	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227673	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
41834898	GRET	SVC	7/10/2023	1974	RET ABN	UG-SERVICE
42227676	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
43598257	GRET	SVC	9/23/2024	1974	RET ABN	UG-SERVICE
36315324	GRET	SVC	5/12/2020	1974	RET ABN	UG-SERVICE
40724321	GRET	SVC	9/20/2022	1974	RET ABN	UG-SERVICE
42227858	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227774	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
43282149	GRET	SVC	12/2/2024	1974	RET ABN	UG-SERVICE
42227851	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
43515343	GRET	SVC	9/5/2024	1974	RET ABN	UG-SERVICE
36835404	GRET	SVC	8/26/2020	1974	RET ABN	UG-SERVICE
42227724	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
38499443	GRET	SVC	4/2/2021	1974	RET ABN	UG-SERVICE
43608047	GRET	SVC	10/1/2024	1974	RET ABN	UG-SERVICE
42227779	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42670283	GRET	SVC	9/19/2024	1974	RET ABN	UG-SERVICE
42227827	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227726	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
39803711	GRET	SVC	2/16/2022	1974	RET ABN	UG-SERVICE
36471396	GRET	SVC	7/11/2020	1974	RET ABN	UG-SERVICE
42227663	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227675	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
38324623	GRET	SVC	4/6/2021	1974	RET ABN	UG-SERVICE
43282145	GRET	SVC	12/2/2024	1974	RET ABN	UG-SERVICE
43862285	GRET	SVC	11/22/2024	1974	RET ABN	UG-SERVICE
42227859	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227771	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
38122752	GRET	SVC	2/12/2021	1974	RET ABN	UG-SERVICE
37094277	GRET	SVC	10/20/2020	1974	RET ABN	UG-SERVICE
42227546	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227775	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227941	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
43963064	GRET	SVC	12/19/2024	1974	RET ABN	UG-SERVICE
42227553	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
40254567	GRET	SVC	9/12/2022	1974	RET ABN	UG-SERVICE
42227836	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
40091749	GRET	SVC	5/13/2022	1974	RET ABN	UG-SERVICE
37041461	GRET	SVC	10/8/2020	1974	RET ABN	UG-SERVICE
42227362	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
36031274	GRET	SVC	2/17/2020	1974	RET ABN	UG-SERVICE
42227857	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
35919174	GRET	SVC	2/19/2020	1974	RET ABN	UG-SERVICE
42227778	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227828	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227823	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
41706827	GRET	SVC	8/21/2023	1974	RET ABN	UG-SERVICE
43205303	GRET	SVC	6/15/2024	1974	RET ABN	UG-SERVICE
42227552	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227174	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227734	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
43530074	GRET	SVC	9/6/2024	1974	RET ABN	UG-SERVICE
42227544	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227825	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227555	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
35945529	GRET	SVC	1/26/2020	1974	RET ABN	UG-SERVICE
39233301	GRET	SVC	9/30/2021	1974	RET ABN	UG-SERVICE
42227308	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227838	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
40754061	GRET	SVC	9/28/2022	1974	RET ABN	UG-SERVICE
42227678	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43109290	GRET	SVC	5/30/2024	1974	RET ABN	UG-SERVICE
42227667	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227831	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227179	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227311	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
40900806	GRET	SVC	12/6/2022	1974	RET ABN	UG-SERVICE
40357997	GRET	SVC	8/2/2022	1974	RET ABN	UG-SERVICE
42227666	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
38640384	GRET	SVC	6/21/2021	1974	RET ABN	UG-SERVICE
42227764	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
36730703	GRET	SVC	9/8/2020	1974	RET ABN	UG-SERVICE
40572525	GRET	SVC	8/15/2022	1974	RET ABN	UG-SERVICE
42828610	GRET	SVC	3/18/2024	1974	RET ABN	UG-SERVICE
42227173	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227767	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
43327222	GRET	SVC	7/30/2024	1974	RET ABN	UG-SERVICE
38638881	GRET	SVC	8/2/2021	1974	RET ABN	UG-SERVICE
42227661	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227660	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42899349	GRET	SVC	4/15/2024	1974	RET ABN	UG-SERVICE
41888298	GRET	SVC	7/18/2023	1974	RET ABN	UG-SERVICE
42177761	GRET	SVC	11/16/2023	1975	RET ABN	UG-SERVICE
37869004	GRET	SVC	12/2/2020	1975	RET ABN	UG-SERVICE
40751251	GRET	SVC	9/30/2022	1975	RET ABN	UG-SERVICE
41279008	GRET	SVC	2/15/2023	1975	RET ABN	UG-SERVICE
43448530	GRET	SVC	12/11/2024	1975	RET ABN	UG-SERVICE
38591974	GRET	SVC	4/20/2021	1975	RET ABN	UG-SERVICE
39835902	GRET	SVC	2/28/2022	1975	RET ABN	UG-SERVICE
40078415	GRET	SVC	4/27/2022	1975	RET ABN	UG-SERVICE
38571057	GRET	SVC	6/11/2021	1975	RET ABN	UG-SERVICE
39550151	GRET	SVC	12/17/2021	1975	RET ABN	UG-SERVICE
43867068	GRET	SVC	11/25/2024	1975	RET ABN	UG-SERVICE
43631731	GRET	SVC	9/30/2024	1975	RET ABN	UG-SERVICE
36165982	GRET	SVC	3/24/2020	1975	RET ABN	UG-SERVICE
42584864	GRET	SVC	1/22/2024	1975	RET ABN	UG-SERVICE
41426040	GRET	SVC	3/22/2023	1975	RET ABN	UG-SERVICE
41528449	GRET	SVC	4/26/2023	1975	RET ABN	UG-SERVICE
38053254	GRET	SVC	1/25/2021	1975	RET ABN	UG-SERVICE
36029864	GRET	SVC	2/18/2020	1975	RET ABN	UG-SERVICE
40507365	GRET	SVC	7/30/2022	1975	RET ABN	UG-SERVICE
36298477	GRET	SVC	4/8/2020	1975	RET ABN	UG-SERVICE
40062912	GRET	SVC	4/25/2022	1975	RET ABN	UG-SERVICE
39824976	GRET	SVC	2/23/2022	1975	RET ABN	UG-SERVICE
38192814	GRET	SVC	3/3/2021	1975	RET ABN	UG-SERVICE
38886010	GRET	SVC	8/9/2021	1975	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36882321	GRET	SVC	9/1/2020	1975	RET ABN	UG-SERVICE
41283333	GRET	SVC	2/16/2023	1975	RET ABN	UG-SERVICE
43905665	GRET	SVC	12/4/2024	1975	RET ABN	UG-SERVICE
42584534	GRET	SVC	1/22/2024	1975	RET ABN	UG-SERVICE
42052653	GRET	SVC	8/31/2023	1975	RET ABN	UG-SERVICE
41162248	GRET	SVC	1/12/2023	1975	RET ABN	UG-SERVICE
42760336	GRET	SVC	8/1/2024	1975	RET ABN	UG-SERVICE
41277769	GRET	SVC	2/14/2023	1975	RET ABN	UG-SERVICE
41498695	GRET	SVC	4/21/2023	1975	RET ABN	UG-SERVICE
38582326	GRET	SVC	6/15/2021	1975	RET ABN	UG-SERVICE
41279152	GRET	SVC	2/15/2023	1975	RET ABN	UG-SERVICE
36119482	GRET	SVC	11/5/2020	1975	RET ABN	UG-SERVICE
37926339	GRET	SVC	12/13/2020	1975	RET ABN	UG-SERVICE
40561480	GRET	SVC	8/15/2022	1975	RET ABN	UG-SERVICE
43228186	GRET	SVC	9/19/2024	1975	RET ABN	UG-SERVICE
40669708	GRET	SVC	10/22/2022	1975	RET ABN	UG-SERVICE
40328415	GRET	SVC	8/2/2022	1975	RET ABN	UG-SERVICE
43820162	GRET	SVC	11/12/2024	1975	RET ABN	UG-SERVICE
43473374	GRET	SVC	9/7/2024	1975	RET ABN	UG-SERVICE
41283327	GRET	SVC	2/16/2023	1975	RET ABN	UG-SERVICE
37064875	GRET	SVC	10/12/2020	1975	RET ABN	UG-SERVICE
37099276	GRET	SVC	9/9/2020	1975	RET ABN	UG-SERVICE
43240063	GRET	SVC	6/30/2024	1975	RET ABN	UG-SERVICE
41342698	GRET	SVC	3/7/2023	1975	RET ABN	UG-SERVICE
43743877	GRET	SVC	10/23/2024	1975	RET ABN	UG-SERVICE
40352832	GRET	SVC	6/28/2022	1975	RET ABN	UG-SERVICE
41279013	GRET	SVC	2/15/2023	1975	RET ABN	UG-SERVICE
36701068	GRET	SVC	7/28/2020	1975	RET ABN	UG-SERVICE
39560483	GRET	SVC	12/20/2021	1975	RET ABN	UG-SERVICE
42252699	GRET	SVC	10/20/2023	1975	RET ABN	UG-SERVICE
41497631	GRET	SVC	4/21/2023	1975	RET ABN	UG-SERVICE
41033159	GRET	SVC	12/15/2022	1975	RET ABN	UG-SERVICE
39657981	GRET	SVC	2/10/2022	1975	RET ABN	UG-SERVICE
40431528	GRET	SVC	7/14/2022	1975	RET ABN	UG-SERVICE
42956743	GRET	SVC	9/19/2024	1975	RET ABN	UG-SERVICE
41646104	GRET	SVC	5/17/2023	1975	RET ABN	UG-SERVICE
36882136	GRET	SVC	9/1/2020	1975	RET ABN	UG-SERVICE
39281140	GRET	SVC	10/7/2021	1975	RET ABN	UG-SERVICE
36735967	GRET	SVC	8/3/2020	1975	RET ABN	UG-SERVICE
40218720	GRET	SVC	6/7/2022	1975	RET ABN	UG-SERVICE
38930274	GRET	SVC	8/23/2021	1975	RET ABN	UG-SERVICE
41906711	GRET	SVC	7/24/2023	1975	RET ABN	UG-SERVICE
39619526	GRET	SVC	1/3/2022	1975	RET ABN	UG-SERVICE
39251887	GRET	SVC	10/6/2021	1975	RET ABN	UG-SERVICE
40431115	GRET	SVC	7/15/2022	1975	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43929086	GRET	SVC	12/13/2024	1975	RET ABN	UG-SERVICE
37926322	GRET	SVC	12/16/2020	1975	RET ABN	UG-SERVICE
43309760	GRET	SVC	7/13/2024	1975	RET ABN	UG-SERVICE
38884105	GRET	SVC	8/18/2021	1975	RET ABN	UG-SERVICE
41423574	GRET	SVC	10/18/2023	1975	RET ABN	UG-SERVICE
38749947	GRET	SVC	7/22/2021	1975	RET ABN	UG-SERVICE
41636672	GRET	SVC	5/14/2023	1975	RET ABN	UG-SERVICE
42834267	GRET	SVC	7/23/2024	1975	RET ABN	UG-SERVICE
36580064	GRET	SVC	7/6/2020	1975	RET ABN	UG-SERVICE
36040618	GRET	SVC	2/19/2020	1975	RET ABN	UG-SERVICE
41580112	GRET	SVC	5/3/2023	1975	RET ABN	UG-SERVICE
36662570	GRET	SVC	7/20/2020	1975	RET ABN	UG-SERVICE
40497358	GRET	SVC	7/26/2022	1975	RET ABN	UG-SERVICE
39960894	GRET	SVC	5/25/2022	1975	RET ABN	UG-SERVICE
40327034	GRET	SVC	6/20/2022	1975	RET ABN	UG-SERVICE
37875936	GRET	SVC	12/3/2020	1975	RET ABN	UG-SERVICE
42584519	GRET	SVC	1/22/2024	1975	RET ABN	UG-SERVICE
41182816	GRET	SVC	1/19/2023	1975	RET ABN	UG-SERVICE
41287921	GRET	SVC	3/16/2023	1975	RET ABN	UG-SERVICE
41411231	GRET	SVC	4/2/2024	1975	RET ABN	UG-SERVICE
42379497	GRET	SVC	11/28/2023	1975	RET ABN	UG-SERVICE
41445566	GRET	SVC	3/28/2023	1975	RET ABN	UG-SERVICE
40900676	GRET	SVC	11/12/2022	1975	RET ABN	UG-SERVICE
40062210	GRET	SVC	5/2/2022	1975	RET ABN	UG-SERVICE
38212855	GRET	SVC	3/7/2021	1975	RET ABN	UG-SERVICE
38534582	GRET	SVC	5/25/2021	1975	RET ABN	UG-SERVICE
43469767	GRET	SVC	8/21/2024	1975	RET ABN	UG-SERVICE
41606960	GRET	SVC	5/8/2023	1975	RET ABN	UG-SERVICE
38200998	GRET	SVC	3/6/2021	1975	RET ABN	UG-SERVICE
41567772	GRET	SVC	5/2/2023	1975	RET ABN	UG-SERVICE
41467224	GRET	SVC	4/27/2023	1975	RET ABN	UG-SERVICE
41316863	GRET	SVC	2/28/2023	1975	RET ABN	UG-SERVICE
39236000	GRET	SVC	9/30/2021	1975	RET ABN	UG-SERVICE
40419741	GRET	SVC	8/31/2022	1975	RET ABN	UG-SERVICE
38160985	GRET	SVC	2/27/2021	1975	RET ABN	UG-SERVICE
42509254	GRET	SVC	7/18/2024	1975	RET ABN	UG-SERVICE
38455304	GRET	SVC	5/7/2021	1975	RET ABN	UG-SERVICE
38492184	GRET	SVC	5/13/2021	1975	RET ABN	UG-SERVICE
38865047	GRET	SVC	8/4/2021	1975	RET ABN	UG-SERVICE
39395577	GRET	SVC	11/23/2021	1975	RET ABN	UG-SERVICE
37067280	GRET	SVC	10/27/2020	1976	RET ABN	UG-SERVICE
42530674	GRET	SVC	12/20/2023	1976	RET ABN	UG-SERVICE
40761856	GRET	SVC	10/18/2022	1976	RET ABN	UG-SERVICE
42626212	GRET	SVC	1/29/2024	1976	RET ABN	UG-SERVICE
36980370	GRET	SVC	9/23/2020	1976	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40990267	GRET	SVC	11/17/2022	1976	RET ABN	UG-SERVICE
41450915	GRET	SVC	3/29/2023	1976	RET ABN	UG-SERVICE
38397906	GRET	SVC	4/26/2021	1976	RET ABN	UG-SERVICE
41520905	GRET	SVC	4/27/2023	1976	RET ABN	UG-SERVICE
42509255	GRET	SVC	7/18/2024	1976	RET ABN	UG-SERVICE
41482053	GRET	SVC	4/9/2023	1976	RET ABN	UG-SERVICE
39547480	GRET	SVC	12/12/2021	1976	RET ABN	UG-SERVICE
42004203	GRET	SVC	8/13/2023	1976	RET ABN	UG-SERVICE
42744659	GRET	SVC	2/17/2024	1976	RET ABN	UG-SERVICE
37936716	GRET	SVC	12/20/2020	1976	RET ABN	UG-SERVICE
38744414	GRET	SVC	7/12/2021	1976	RET ABN	UG-SERVICE
37971323	GRET	SVC	12/28/2020	1976	RET ABN	UG-SERVICE
40656087	GRET	SVC	8/30/2022	1976	RET ABN	UG-SERVICE
38601905	GRET	SVC	7/7/2021	1976	RET ABN	UG-SERVICE
36672285	GRET	SVC	7/22/2020	1976	RET ABN	UG-SERVICE
35151335	GRET	SVC	1/6/2020	1976	RET ABN	UG-SERVICE
41860024	GRET	SVC	7/8/2023	1976	RET ABN	UG-SERVICE
39369426	GRET	SVC	11/1/2021	1976	RET ABN	UG-SERVICE
41041907	GRET	SVC	11/1/2022	1976	RET ABN	UG-SERVICE
36656230	GRET	SVC	7/21/2020	1976	RET ABN	UG-SERVICE
37142284	GRET	SVC	10/29/2020	1976	RET ABN	UG-SERVICE
40512849	GRET	SVC	8/5/2022	1976	RET ABN	UG-SERVICE
37926328	GRET	SVC	12/13/2020	1976	RET ABN	UG-SERVICE
36041151	GRET	SVC	2/17/2020	1976	RET ABN	UG-SERVICE
38707020	GRET	SVC	8/3/2021	1976	RET ABN	UG-SERVICE
42391940	GRET	SVC	11/20/2023	1976	RET ABN	UG-SERVICE
37952658	GRET	SVC	12/22/2020	1976	RET ABN	UG-SERVICE
39515604	GRET	SVC	12/23/2021	1976	RET ABN	UG-SERVICE
39143438	GRET	SVC	9/20/2021	1976	RET ABN	UG-SERVICE
36178247	GRET	SVC	3/2/2020	1976	RET ABN	UG-SERVICE
38441449	GRET	SVC	1/3/2022	1976	RET ABN	UG-SERVICE
40963331	GRET	SVC	11/19/2022	1976	RET ABN	UG-SERVICE
39580230	GRET	SVC	12/27/2021	1976	RET ABN	UG-SERVICE
41759598	GRET	SVC	7/13/2023	1976	RET ABN	UG-SERVICE
38098602	GRET	SVC	2/8/2021	1976	RET ABN	UG-SERVICE
42612164	GRET	SVC	1/29/2024	1976	RET ABN	UG-SERVICE
40488326	GRET	SVC	8/11/2022	1976	RET ABN	UG-SERVICE
41411294	GRET	SVC	4/2/2024	1976	RET ABN	UG-SERVICE
43694923	GRET	SVC	10/24/2024	1976	RET ABN	UG-SERVICE
42115195	GRET	SVC	9/11/2023	1976	RET ABN	UG-SERVICE
43582448	GRET	SVC	9/16/2024	1976	RET ABN	UG-SERVICE
42555015	GRET	SVC	1/6/2024	1976	RET ABN	UG-SERVICE
40492798	GRET	SVC	8/3/2022	1976	RET ABN	UG-SERVICE
43624063	GRET	SVC	9/27/2024	1976	RET ABN	UG-SERVICE
41439585	GRET	SVC	3/29/2023	1976	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
37214711	GRET	SVC	12/8/2020	1976	RET ABN	UG-SERVICE
42221082	GRET	SVC	10/11/2023	1976	RET ABN	UG-SERVICE
36612956	GRET	SVC	7/13/2020	1976	RET ABN	UG-SERVICE
42107582	GRET	SVC	9/12/2023	1976	RET ABN	UG-SERVICE
37998238	GRET	SVC	1/11/2021	1976	RET ABN	UG-SERVICE
41424229	GRET	SVC	6/21/2023	1976	RET ABN	UG-SERVICE
37674075	GRET	SVC	12/29/2020	1976	RET ABN	UG-SERVICE
38140474	GRET	SVC	2/18/2021	1976	RET ABN	UG-SERVICE
36200170	GRET	SVC	5/6/2020	1976	RET ABN	UG-SERVICE
35986883	GRET	SVC	2/17/2020	1976	RET ABN	UG-SERVICE
42794394	GRET	SVC	3/4/2024	1976	RET ABN	UG-SERVICE
43364930	GRET	SVC	10/15/2024	1976	RET ABN	UG-SERVICE
36309007	GRET	SVC	5/12/2020	1976	RET ABN	UG-SERVICE
42584912	GRET	SVC	1/22/2024	1976	RET ABN	UG-SERVICE
41979984	GRET	SVC	8/18/2023	1976	RET ABN	UG-SERVICE
41411766	GRET	SVC	4/2/2024	1976	RET ABN	UG-SERVICE
36883686	GRET	SVC	8/30/2020	1976	RET ABN	UG-SERVICE
38441378	GRET	SVC	1/6/2022	1976	RET ABN	UG-SERVICE
39242981	GRET	SVC	9/29/2021	1976	RET ABN	UG-SERVICE
39660249	GRET	SVC	1/28/2022	1976	RET ABN	UG-SERVICE
43758690	GRET	SVC	11/7/2024	1977	RET ABN	UG-SERVICE
43923634	GRET	SVC	12/11/2024	1977	RET ABN	UG-SERVICE
40492802	GRET	SVC	7/26/2022	1977	RET ABN	UG-SERVICE
43767472	GRET	SVC	10/28/2024	1977	RET ABN	UG-SERVICE
43107587	GRET	SVC	5/28/2024	1977	RET ABN	UG-SERVICE
43976845	GRET	SVC	11/15/2024	1977	RET ABN	UG-SERVICE
42026562	GRET	SVC	8/24/2023	1977	RET ABN	UG-SERVICE
42950784	GRET	SVC	4/26/2024	1977	RET ABN	UG-SERVICE
40879585	GRET	SVC	11/11/2022	1977	RET ABN	UG-SERVICE
41273664	GRET	SVC	3/15/2023	1977	RET ABN	UG-SERVICE
42590191	GRET	SVC	1/24/2024	1977	RET ABN	UG-SERVICE
43909859	GRET	SVC	12/2/2024	1977	RET ABN	UG-SERVICE
42567332	GRET	SVC	1/17/2024	1977	RET ABN	UG-SERVICE
39552045	GRET	SVC	12/3/2021	1977	RET ABN	UG-SERVICE
40675412	GRET	SVC	11/15/2022	1977	RET ABN	UG-SERVICE
38637747	GRET	SVC	6/16/2021	1977	RET ABN	UG-SERVICE
43800154	GRET	SVC	11/12/2024	1977	RET ABN	UG-SERVICE
37886408	GRET	SVC	12/5/2020	1977	RET ABN	UG-SERVICE
38181886	GRET	SVC	3/2/2021	1977	RET ABN	UG-SERVICE
37052904	GRET	SVC	10/14/2020	1977	RET ABN	UG-SERVICE
36918090	GRET	SVC	9/15/2020	1977	RET ABN	UG-SERVICE
37887387	GRET	SVC	12/8/2020	1977	RET ABN	UG-SERVICE
38364546	GRET	SVC	4/12/2021	1977	RET ABN	UG-SERVICE
42837425	GRET	SVC	3/20/2024	1977	RET ABN	UG-SERVICE
36146405	GRET	SVC	3/16/2020	1977	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42949532	GRET	SVC	4/26/2024	1977	RET ABN	UG-SERVICE
35844806	GRET	SVC	1/2/2020	1977	RET ABN	UG-SERVICE
41331746	GRET	SVC	3/1/2023	1977	RET ABN	UG-SERVICE
38089364	GRET	SVC	1/29/2021	1977	RET ABN	UG-SERVICE
38034709	GRET	SVC	1/19/2021	1977	RET ABN	UG-SERVICE
38352723	GRET	SVC	7/27/2021	1977	RET ABN	UG-SERVICE
43654659	GRET	SVC	10/18/2024	1977	RET ABN	UG-SERVICE
36472441	GRET	SVC	6/22/2020	1977	RET ABN	UG-SERVICE
40395627	GRET	SVC	6/30/2022	1977	RET ABN	UG-SERVICE
38171193	GRET	SVC	2/26/2021	1977	RET ABN	UG-SERVICE
41556508	GRET	SVC	4/25/2023	1977	RET ABN	UG-SERVICE
36566413	GRET	SVC	7/1/2020	1977	RET ABN	UG-SERVICE
40561488	GRET	SVC	8/27/2022	1977	RET ABN	UG-SERVICE
41099636	GRET	SVC	12/30/2022	1977	RET ABN	UG-SERVICE
36915179	GRET	SVC	7/30/2020	1977	RET ABN	UG-SERVICE
40702313	GRET	SVC	9/14/2022	1977	RET ABN	UG-SERVICE
38268372	GRET	SVC	3/23/2021	1977	RET ABN	UG-SERVICE
37926236	GRET	SVC	12/13/2020	1977	RET ABN	UG-SERVICE
41411229	GRET	SVC	4/2/2024	1977	RET ABN	UG-SERVICE
36727255	GRET	SVC	8/4/2020	1977	RET ABN	UG-SERVICE
39552046	GRET	SVC	12/29/2021	1977	RET ABN	UG-SERVICE
42427484	GRET	SVC	9/19/2024	1977	RET ABN	UG-SERVICE
40692811	GRET	SVC	9/30/2022	1977	RET ABN	UG-SERVICE
41411763	GRET	SVC	4/2/2024	1977	RET ABN	UG-SERVICE
38107383	GRET	SVC	2/8/2021	1977	RET ABN	UG-SERVICE
41084050	GRET	SVC	12/21/2022	1977	RET ABN	UG-SERVICE
42277299	GRET	SVC	10/24/2023	1977	RET ABN	UG-SERVICE
43442180	GRET	SVC	8/14/2024	1977	RET ABN	UG-SERVICE
38352929	GRET	SVC	2/17/2023	1977	RET ABN	UG-SERVICE
36345939	GRET	SVC	5/18/2020	1977	RET ABN	UG-SERVICE
42650726	GRET	SVC	1/29/2024	1977	RET ABN	UG-SERVICE
39492215	GRET	SVC	12/7/2021	1977	RET ABN	UG-SERVICE
42020567	GRET	SVC	8/23/2023	1977	RET ABN	UG-SERVICE
42461273	GRET	SVC	12/14/2023	1977	RET ABN	UG-SERVICE
41242715	GRET	SVC	2/4/2023	1977	RET ABN	UG-SERVICE
43650299	GRET	SVC	10/2/2024	1977	RET ABN	UG-SERVICE
39299100	GRET	SVC	10/14/2021	1977	RET ABN	UG-SERVICE
37642997	GRET	SVC	11/18/2020	1977	RET ABN	UG-SERVICE
36202016	GRET	SVC	4/23/2020	1977	RET ABN	UG-SERVICE
43525354	GRET	SVC	10/15/2024	1977	RET ABN	UG-SERVICE
41859267	GRET	SVC	7/10/2023	1977	RET ABN	UG-SERVICE
42065386	GRET	SVC	9/7/2023	1977	RET ABN	UG-SERVICE
36451833	GRET	SVC	6/16/2020	1977	RET ABN	UG-SERVICE
38148103	GRET	SVC	2/21/2021	1977	RET ABN	UG-SERVICE
40708496	GRET	SVC	9/16/2022	1977	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43281289	GRET	SVC	7/9/2024	1977	RET ABN	UG-SERVICE
43007247	GRET	SVC	4/29/2024	1977	RET ABN	UG-SERVICE
42025488	GRET	SVC	8/22/2023	1977	RET ABN	UG-SERVICE
35151134	GRET	SVC	1/6/2020	1977	RET ABN	UG-SERVICE
41009656	GRET	SVC	12/5/2022	1977	RET ABN	UG-SERVICE
38845329	GRET	SVC	8/2/2021	1977	RET ABN	UG-SERVICE
40996102	GRET	SVC	12/28/2022	1977	RET ABN	UG-SERVICE
36185404	GRET	SVC	5/28/2020	1977	RET ABN	UG-SERVICE
38441174	GRET	SVC	1/3/2022	1977	RET ABN	UG-SERVICE
38441399	GRET	SVC	12/22/2021	1977	RET ABN	UG-SERVICE
41834503	GRET	SVC	7/21/2023	1977	RET ABN	UG-SERVICE
42903278	GRET	SVC	4/9/2024	1978	RET ABN	UG-SERVICE
35872099	GRET	SVC	1/7/2020	1978	RET ABN	UG-SERVICE
39518355	GRET	SVC	1/3/2022	1978	RET ABN	UG-SERVICE
43086904	GRET	SVC	8/5/2024	1978	RET ABN	UG-SERVICE
41051001	GRET	SVC	6/16/2023	1978	RET ABN	UG-SERVICE
43876310	GRET	SVC	11/27/2024	1978	RET ABN	UG-SERVICE
37149839	GRET	SVC	10/29/2020	1978	RET ABN	UG-SERVICE
43151675	GRET	SVC	7/18/2024	1978	RET ABN	UG-SERVICE
41182813	GRET	SVC	1/18/2023	1978	RET ABN	UG-SERVICE
41482107	GRET	SVC	4/11/2023	1978	RET ABN	UG-SERVICE
39705070	GRET	SVC	2/5/2024	1978	RET ABN	UG-SERVICE
41330349	GRET	SVC	3/3/2023	1978	RET ABN	UG-SERVICE
39599855	GRET	SVC	1/12/2022	1978	RET ABN	UG-SERVICE
41424707	GRET	SVC	10/18/2023	1978	RET ABN	UG-SERVICE
38407205	GRET	SVC	3/17/2021	1978	RET ABN	UG-SERVICE
36197812	GRET	SVC	4/22/2020	1978	RET ABN	UG-SERVICE
37415010	GRET	SVC	11/9/2020	1978	RET ABN	UG-SERVICE
39532048	GRET	SVC	12/14/2021	1978	RET ABN	UG-SERVICE
38278377	GRET	SVC	4/28/2021	1978	RET ABN	UG-SERVICE
39705136	GRET	SVC	2/6/2024	1978	RET ABN	UG-SERVICE
39983692	GRET	SVC	3/25/2022	1978	RET ABN	UG-SERVICE
36218763	GRET	SVC	4/24/2020	1978	RET ABN	UG-SERVICE
42707518	GRET	SVC	3/13/2024	1978	RET ABN	UG-SERVICE
36148266	GRET	SVC	3/17/2020	1978	RET ABN	UG-SERVICE
41860453	GRET	SVC	7/12/2023	1978	RET ABN	UG-SERVICE
41050845	GRET	SVC	6/16/2023	1978	RET ABN	UG-SERVICE
40753033	GRET	SVC	10/10/2022	1978	RET ABN	UG-SERVICE
38621996	GRET	SVC	6/15/2021	1978	RET ABN	UG-SERVICE
42021084	GRET	SVC	8/21/2023	1978	RET ABN	UG-SERVICE
43612739	GRET	SVC	9/24/2024	1978	RET ABN	UG-SERVICE
41213038	GRET	SVC	1/31/2023	1978	RET ABN	UG-SERVICE
39745751	GRET	SVC	2/11/2022	1978	RET ABN	UG-SERVICE
40371186	GRET	SVC	7/6/2022	1978	RET ABN	UG-SERVICE
43543531	GRET	SVC	10/1/2024	1978	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43370684	GRET	SVC	11/9/2024	1978	RET ABN	UG-SERVICE
43005602	GRET	SVC	5/9/2024	1978	RET ABN	UG-SERVICE
37809859	GRET	SVC	11/24/2020	1978	RET ABN	UG-SERVICE
41119459	GRET	SVC	1/5/2023	1978	RET ABN	UG-SERVICE
40889164	GRET	SVC	11/14/2022	1978	RET ABN	UG-SERVICE
43542641	GRET	SVC	10/1/2024	1978	RET ABN	UG-SERVICE
42644685	GRET	SVC	1/31/2024	1978	RET ABN	UG-SERVICE
43700500	GRET	SVC	11/1/2024	1978	RET ABN	UG-SERVICE
43951709	GRET	SVC	12/26/2024	1978	RET ABN	UG-SERVICE
39705079	GRET	SVC	2/6/2024	1978	RET ABN	UG-SERVICE
42300614	GRET	SVC	10/30/2023	1978	RET ABN	UG-SERVICE
39234653	GRET	SVC	10/20/2021	1978	RET ABN	UG-SERVICE
41330352	GRET	SVC	3/3/2023	1978	RET ABN	UG-SERVICE
40499687	GRET	SVC	8/3/2022	1978	RET ABN	UG-SERVICE
39998868	GRET	SVC	4/13/2022	1978	RET ABN	UG-SERVICE
39022826	GRET	SVC	8/18/2021	1978	RET ABN	UG-SERVICE
36519628	GRET	SVC	6/27/2020	1978	RET ABN	UG-SERVICE
41424183	GRET	SVC	10/18/2023	1978	RET ABN	UG-SERVICE
40301430	GRET	SVC	6/13/2022	1978	RET ABN	UG-SERVICE
43370804	GRET	SVC	11/9/2024	1978	RET ABN	UG-SERVICE
41335186	GRET	SVC	3/8/2023	1978	RET ABN	UG-SERVICE
37953916	GRET	SVC	12/28/2020	1978	RET ABN	UG-SERVICE
41318361	GRET	SVC	3/3/2023	1978	RET ABN	UG-SERVICE
36040243	GRET	SVC	2/18/2020	1978	RET ABN	UG-SERVICE
41423881	GRET	SVC	10/18/2023	1978	RET ABN	UG-SERVICE
40009217	GRET	SVC	3/3/2022	1978	RET ABN	UG-SERVICE
38203369	GRET	SVC	3/9/2021	1978	RET ABN	UG-SERVICE
38504593	GRET	SVC	4/5/2021	1978	RET ABN	UG-SERVICE
39413160	GRET	SVC	11/13/2021	1978	RET ABN	UG-SERVICE
36988771	GRET	SVC	10/2/2020	1978	RET ABN	UG-SERVICE
43825011	GRET	SVC	11/18/2024	1978	RET ABN	UG-SERVICE
41411750	GRET	SVC	4/2/2024	1978	RET ABN	UG-SERVICE
41330357	GRET	SVC	3/5/2023	1978	RET ABN	UG-SERVICE
41471842	GRET	SVC	3/29/2023	1978	RET ABN	UG-SERVICE
43245141	GRET	SVC	9/11/2024	1978	RET ABN	UG-SERVICE
39475295	GRET	SVC	12/6/2021	1978	RET ABN	UG-SERVICE
40897251	GRET	SVC	10/29/2022	1978	RET ABN	UG-SERVICE
41954710	GRET	SVC	8/6/2023	1978	RET ABN	UG-SERVICE
36440772	GRET	SVC	7/20/2020	1978	RET ABN	UG-SERVICE
39391060	GRET	SVC	11/7/2021	1978	RET ABN	UG-SERVICE
40277150	GRET	SVC	4/27/2023	1978	RET ABN	UG-SERVICE
39336889	GRET	SVC	12/21/2021	1978	RET ABN	UG-SERVICE
43364929	GRET	SVC	10/18/2024	1978	RET ABN	UG-SERVICE
36878600	GRET	SVC	8/29/2020	1978	RET ABN	UG-SERVICE
40513379	GRET	SVC	8/2/2022	1978	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
39741831	GRET	SVC	2/23/2022	1978	RET ABN	UG-SERVICE
41342922	GRET	SVC	3/7/2023	1978	RET ABN	UG-SERVICE
43947177	GRET	SVC	12/23/2024	1978	RET ABN	UG-SERVICE
40793579	GRET	SVC	10/10/2022	1978	RET ABN	UG-SERVICE
40492819	GRET	SVC	7/25/2022	1978	RET ABN	UG-SERVICE
43371414	GRET	SVC	7/31/2024	1978	RET ABN	UG-SERVICE
43774808	GRET	SVC	11/1/2024	1978	RET ABN	UG-SERVICE
39721125	GRET	SVC	1/24/2022	1978	RET ABN	UG-SERVICE
41182811	GRET	SVC	1/18/2023	1978	RET ABN	UG-SERVICE
43923876	GRET	SVC	12/9/2024	1978	RET ABN	UG-SERVICE
41408200	GRET	SVC	4/2/2024	1978	RET ABN	UG-SERVICE
39894611	GRET	SVC	3/15/2022	1978	RET ABN	UG-SERVICE
43244991	GRET	SVC	9/19/2024	1978	RET ABN	UG-SERVICE
36074093	GRET	SVC	3/2/2020	1978	RET ABN	UG-SERVICE
41622981	GRET	SVC	5/12/2023	1978	RET ABN	UG-SERVICE
39552038	GRET	SVC	12/16/2021	1978	RET ABN	UG-SERVICE
38441388	GRET	SVC	1/6/2022	1978	RET ABN	UG-SERVICE
43245062	GRET	SVC	9/19/2024	1978	RET ABN	UG-SERVICE
41049774	GRET	SVC	2/20/2023	1978	RET ABN	UG-SERVICE
38252172	GRET	SVC	3/18/2021	1978	RET ABN	UG-SERVICE
42480931	GRET	SVC	12/14/2023	1978	RET ABN	UG-SERVICE
41222788	GRET	SVC	1/31/2023	1978	RET ABN	UG-SERVICE
36203639	GRET	SVC	4/23/2020	1978	RET ABN	UG-SERVICE
43680139	GRET	SVC	12/11/2024	1978	RET ABN	UG-SERVICE
43860695	GRET	SVC	11/21/2024	1978	RET ABN	UG-SERVICE
39413281	GRET	SVC	11/10/2021	1978	RET ABN	UG-SERVICE
41569451	GRET	SVC	4/25/2023	1978	RET ABN	UG-SERVICE
41099611	GRET	SVC	1/12/2023	1978	RET ABN	UG-SERVICE
35843287	GRET	SVC	1/2/2020	1978	RET ABN	UG-SERVICE
39757423	GRET	SVC	2/1/2022	1978	RET ABN	UG-SERVICE
43680103	GRET	SVC	10/29/2024	1978	RET ABN	UG-SERVICE
40744233	GRET	SVC	9/24/2022	1978	RET ABN	UG-SERVICE
43468973	GRET	SVC	8/22/2024	1978	RET ABN	UG-SERVICE
37982150	GRET	SVC	12/28/2020	1978	RET ABN	UG-SERVICE
41916724	GRET	SVC	7/26/2023	1978	RET ABN	UG-SERVICE
36180723	GRET	SVC	5/4/2020	1978	RET ABN	UG-SERVICE
41080842	GRET	SVC	12/19/2022	1978	RET ABN	UG-SERVICE
43680027	GRET	SVC	10/29/2024	1978	RET ABN	UG-SERVICE
35888172	GRET	SVC	1/14/2020	1978	RET ABN	UG-SERVICE
40707534	GRET	SVC	10/10/2022	1978	RET ABN	UG-SERVICE
36087638	GRET	SVC	3/4/2020	1978	RET ABN	UG-SERVICE
36122136	GRET	SVC	11/5/2020	1978	RET ABN	UG-SERVICE
39570477	GRET	SVC	12/13/2021	1978	RET ABN	UG-SERVICE
43245144	GRET	SVC	9/11/2024	1978	RET ABN	UG-SERVICE
42295854	GRET	SVC	10/31/2023	1978	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36038974	GRET	SVC	2/18/2020	1978	RET ABN	UG-SERVICE
39705128	GRET	SVC	2/6/2024	1978	RET ABN	UG-SERVICE
41182814	GRET	SVC	1/18/2023	1978	RET ABN	UG-SERVICE
40046866	GRET	SVC	12/17/2021	1978	RET ABN	UG-SERVICE
41913837	GRET	SVC	7/21/2023	1978	RET ABN	UG-SERVICE
42745903	GRET	SVC	2/20/2024	1978	RET ABN	UG-SERVICE
41423793	GRET	SVC	9/12/2023	1978	RET ABN	UG-SERVICE
38113503	GRET	SVC	2/9/2021	1978	RET ABN	UG-SERVICE
40111760	GRET	SVC	4/27/2022	1978	RET ABN	UG-SERVICE
39666667	GRET	SVC	11/18/2022	1978	RET ABN	UG-SERVICE
38362961	GRET	SVC	4/13/2021	1978	RET ABN	UG-SERVICE
38565188	GRET	SVC	6/1/2021	1978	RET ABN	UG-SERVICE
37070642	GRET	SVC	10/12/2020	1978	RET ABN	UG-SERVICE
43573408	GRET	SVC	9/17/2024	1978	RET ABN	UG-SERVICE
43250335	GRET	SVC	12/11/2024	1978	RET ABN	UG-SERVICE
42487756	GRET	SVC	7/18/2024	1978	RET ABN	UG-SERVICE
32667132	GRET	SVC	9/30/2020	1978	RET ABN	UG-SERVICE
43245142	GRET	SVC	9/11/2024	1978	RET ABN	UG-SERVICE
39717292	GRET	SVC	1/25/2022	1978	RET ABN	UG-SERVICE
36119409	GRET	SVC	11/5/2020	1978	RET ABN	UG-SERVICE
43407213	GRET	SVC	10/21/2024	1978	RET ABN	UG-SERVICE
40352826	GRET	SVC	7/1/2022	1978	RET ABN	UG-SERVICE
41140321	GRET	SVC	1/5/2023	1978	RET ABN	UG-SERVICE
36425707	GRET	SVC	6/26/2020	1978	RET ABN	UG-SERVICE
39727358	GRET	SVC	2/16/2022	1978	RET ABN	UG-SERVICE
40488448	GRET	SVC	7/26/2022	1978	RET ABN	UG-SERVICE
38446270	GRET	SVC	5/7/2021	1978	RET ABN	UG-SERVICE
36017684	GRET	SVC	3/11/2020	1978	RET ABN	UG-SERVICE
39067277	GRET	SVC	2/12/2022	1978	RET ABN	UG-SERVICE
41347207	GRET	SVC	3/11/2023	1978	RET ABN	UG-SERVICE
41969349	GRET	SVC	7/30/2024	1978	RET ABN	UG-SERVICE
36916408	GRET	SVC	9/10/2020	1978	RET ABN	UG-SERVICE
36173900	GRET	SVC	6/16/2020	1978	RET ABN	UG-SERVICE
43339919	GRET	SVC	7/23/2024	1978	RET ABN	UG-SERVICE
40840408	GRET	SVC	10/26/2022	1978	RET ABN	UG-SERVICE
39413164	GRET	SVC	11/13/2021	1978	RET ABN	UG-SERVICE
36698675	GRET	SVC	7/21/2020	1979	RET ABN	UG-SERVICE
42413837	GRET	SVC	4/2/2024	1979	RET ABN	UG-SERVICE
39466825	GRET	SVC	11/27/2021	1979	RET ABN	UG-SERVICE
39520886	GRET	SVC	12/14/2021	1979	RET ABN	UG-SERVICE
42376801	GRET	SVC	11/16/2023	1979	RET ABN	UG-SERVICE
41429216	GRET	SVC	3/22/2023	1979	RET ABN	UG-SERVICE
38070432	GRET	SVC	2/1/2021	1979	RET ABN	UG-SERVICE
40644173	GRET	SVC	9/9/2022	1979	RET ABN	UG-SERVICE
39409453	GRET	SVC	12/2/2021	1979	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41284215	GRET	SVC	2/17/2023	1979	RET ABN	UG-SERVICE
42138662	GRET	SVC	9/22/2023	1979	RET ABN	UG-SERVICE
36207568	GRET	SVC	4/24/2020	1979	RET ABN	UG-SERVICE
36959592	GRET	SVC	9/16/2020	1979	RET ABN	UG-SERVICE
41341619	GRET	SVC	3/21/2023	1979	RET ABN	UG-SERVICE
40448086	GRET	SVC	7/12/2022	1979	RET ABN	UG-SERVICE
39567730	GRET	SVC	12/20/2021	1979	RET ABN	UG-SERVICE
39860344	GRET	SVC	3/5/2022	1979	RET ABN	UG-SERVICE
39077881	GRET	SVC	1/31/2022	1979	RET ABN	UG-SERVICE
41604795	GRET	SVC	5/8/2023	1979	RET ABN	UG-SERVICE
43063052	GRET	SVC	5/16/2024	1979	RET ABN	UG-SERVICE
40448799	GRET	SVC	7/18/2022	1979	RET ABN	UG-SERVICE
39555445	GRET	SVC	12/20/2021	1979	RET ABN	UG-SERVICE
43967973	GRET	SVC	12/23/2024	1979	RET ABN	UG-SERVICE
40793521	GRET	SVC	10/11/2022	1979	RET ABN	UG-SERVICE
41408290	GRET	SVC	4/2/2024	1979	RET ABN	UG-SERVICE
40719004	GRET	SVC	9/19/2022	1979	RET ABN	UG-SERVICE
41531000	GRET	SVC	4/22/2023	1979	RET ABN	UG-SERVICE
40371191	GRET	SVC	7/6/2022	1979	RET ABN	UG-SERVICE
43318359	GRET	SVC	8/6/2024	1979	RET ABN	UG-SERVICE
41530832	GRET	SVC	4/22/2023	1979	RET ABN	UG-SERVICE
43632714	GRET	SVC	9/27/2024	1979	RET ABN	UG-SERVICE
42192216	GRET	SVC	10/6/2023	1979	RET ABN	UG-SERVICE
41513722	GRET	SVC	5/30/2023	1979	RET ABN	UG-SERVICE
41411408	GRET	SVC	4/2/2024	1979	RET ABN	UG-SERVICE
41146781	GRET	SVC	1/11/2023	1979	RET ABN	UG-SERVICE
39619065	GRET	SVC	12/30/2021	1979	RET ABN	UG-SERVICE
39768731	GRET	SVC	2/9/2022	1979	RET ABN	UG-SERVICE
41429924	GRET	SVC	9/13/2023	1979	RET ABN	UG-SERVICE
43703190	GRET	SVC	10/17/2024	1979	RET ABN	UG-SERVICE
40805615	GRET	SVC	10/11/2022	1979	RET ABN	UG-SERVICE
43371587	GRET	SVC	7/31/2024	1979	RET ABN	UG-SERVICE
37918344	GRET	SVC	12/13/2020	1979	RET ABN	UG-SERVICE
38603605	GRET	SVC	6/7/2021	1979	RET ABN	UG-SERVICE
36916073	GRET	SVC	9/10/2020	1979	RET ABN	UG-SERVICE
38044488	GRET	SVC	1/22/2021	1979	RET ABN	UG-SERVICE
43792013	GRET	SVC	11/12/2024	1979	RET ABN	UG-SERVICE
40943515	GRET	SVC	11/15/2022	1979	RET ABN	UG-SERVICE
43481040	GRET	SVC	11/2/2024	1979	RET ABN	UG-SERVICE
39731727	GRET	SVC	1/26/2022	1979	RET ABN	UG-SERVICE
37286082	GRET	SVC	12/13/2020	1979	RET ABN	UG-SERVICE
39273719	GRET	SVC	10/12/2021	1979	RET ABN	UG-SERVICE
41906506	GRET	SVC	7/26/2023	1979	RET ABN	UG-SERVICE
43477773	GRET	SVC	8/26/2024	1979	RET ABN	UG-SERVICE
42212040	GRET	SVC	10/11/2023	1979	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36042960	GRET	SVC	2/19/2020	1979	RET ABN	UG-SERVICE
41075200	GRET	SVC	12/21/2022	1979	RET ABN	UG-SERVICE
38671336	GRET	SVC	6/25/2021	1979	RET ABN	UG-SERVICE
39731099	GRET	SVC	1/27/2022	1979	RET ABN	UG-SERVICE
41808286	GRET	SVC	6/27/2023	1979	RET ABN	UG-SERVICE
42330195	GRET	SVC	11/4/2023	1979	RET ABN	UG-SERVICE
39389319	GRET	SVC	12/10/2021	1979	RET ABN	UG-SERVICE
43014476	GRET	SVC	5/3/2024	1979	RET ABN	UG-SERVICE
41212060	GRET	SVC	1/19/2023	1979	RET ABN	UG-SERVICE
41706450	GRET	SVC	6/5/2023	1979	RET ABN	UG-SERVICE
41227101	GRET	SVC	1/31/2023	1979	RET ABN	UG-SERVICE
43408598	GRET	SVC	8/10/2024	1979	RET ABN	UG-SERVICE
42405114	GRET	SVC	4/2/2024	1979	RET ABN	UG-SERVICE
40855584	GRET	SVC	10/24/2022	1979	RET ABN	UG-SERVICE
38370542	GRET	SVC	4/14/2021	1979	RET ABN	UG-SERVICE
43632137	GRET	SVC	9/27/2024	1979	RET ABN	UG-SERVICE
36134998	GRET	SVC	3/19/2020	1979	RET ABN	UG-SERVICE
41429927	GRET	SVC	9/13/2023	1979	RET ABN	UG-SERVICE
40737732	GRET	SVC	9/26/2022	1979	RET ABN	UG-SERVICE
41701506	GRET	SVC	5/31/2023	1979	RET ABN	UG-SERVICE
41411403	GRET	SVC	4/2/2024	1979	RET ABN	UG-SERVICE
42519603	GRET	SVC	12/28/2023	1979	RET ABN	UG-SERVICE
40192726	GRET	SVC	5/25/2022	1979	RET ABN	UG-SERVICE
43365689	GRET	SVC	12/18/2024	1979	RET ABN	UG-SERVICE
41443234	GRET	SVC	3/27/2023	1979	RET ABN	UG-SERVICE
36255845	GRET	SVC	4/24/2020	1979	RET ABN	UG-SERVICE
42587539	GRET	SVC	1/30/2024	1979	RET ABN	UG-SERVICE
43888459	GRET	SVC	12/2/2024	1979	RET ABN	UG-SERVICE
36918267	GRET	SVC	9/3/2020	1979	RET ABN	UG-SERVICE
39735998	GRET	SVC	1/26/2022	1979	RET ABN	UG-SERVICE
39034555	GRET	SVC	9/13/2021	1979	RET ABN	UG-SERVICE
41278228	GRET	SVC	2/13/2023	1979	RET ABN	UG-SERVICE
43966498	GRET	SVC	12/23/2024	1979	RET ABN	UG-SERVICE
41424712	GRET	SVC	10/18/2023	1979	RET ABN	UG-SERVICE
38513285	GRET	SVC	5/17/2021	1979	RET ABN	UG-SERVICE
38741032	GRET	SVC	7/28/2021	1979	RET ABN	UG-SERVICE
39495068	GRET	SVC	12/6/2021	1979	RET ABN	UG-SERVICE
40353038	GRET	SVC	6/25/2022	1979	RET ABN	UG-SERVICE
42404220	GRET	SVC	11/18/2023	1979	RET ABN	UG-SERVICE
41321707	GRET	SVC	3/2/2023	1979	RET ABN	UG-SERVICE
40778899	GRET	SVC	10/5/2022	1979	RET ABN	UG-SERVICE
42556259	GRET	SVC	1/4/2024	1979	RET ABN	UG-SERVICE
42550578	GRET	SVC	1/6/2024	1979	RET ABN	UG-SERVICE
41015459	GRET	SVC	12/3/2022	1979	RET ABN	UG-SERVICE
39495073	GRET	SVC	12/6/2021	1979	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
39731383	GRET	SVC	1/26/2022	1979	RET ABN	UG-SERVICE
43569826	GRET	SVC	9/16/2024	1979	RET ABN	UG-SERVICE
41969560	GRET	SVC	8/1/2024	1979	RET ABN	UG-SERVICE
42021625	GRET	SVC	8/19/2023	1979	RET ABN	UG-SERVICE
41102804	GRET	SVC	1/12/2023	1979	RET ABN	UG-SERVICE
43605573	GRET	SVC	9/26/2024	1979	RET ABN	UG-SERVICE
38304985	GRET	SVC	4/5/2021	1979	RET ABN	UG-SERVICE
36959590	GRET	SVC	9/16/2020	1979	RET ABN	UG-SERVICE
40486333	GRET	SVC	7/30/2022	1979	RET ABN	UG-SERVICE
39437797	GRET	SVC	11/17/2021	1979	RET ABN	UG-SERVICE
41411517	GRET	SVC	4/2/2024	1979	RET ABN	UG-SERVICE
37776578	GRET	SVC	11/23/2020	1979	RET ABN	UG-SERVICE
42774031	GRET	SVC	2/21/2024	1979	RET ABN	UG-SERVICE
39236819	GRET	SVC	10/11/2021	1979	RET ABN	UG-SERVICE
41407353	GRET	SVC	4/2/2024	1979	RET ABN	UG-SERVICE
37887887	GRET	SVC	12/11/2020	1979	RET ABN	UG-SERVICE
36373986	GRET	SVC	6/1/2020	1979	RET ABN	UG-SERVICE
41408298	GRET	SVC	4/2/2024	1979	RET ABN	UG-SERVICE
41302289	GRET	SVC	2/27/2023	1979	RET ABN	UG-SERVICE
42503354	GRET	SVC	12/21/2023	1979	RET ABN	UG-SERVICE
36282087	GRET	SVC	4/29/2020	1979	RET ABN	UG-SERVICE
40022702	GRET	SVC	4/20/2022	1979	RET ABN	UG-SERVICE
40341585	GRET	SVC	7/14/2022	1979	RET ABN	UG-SERVICE
42165917	GRET	SVC	9/19/2023	1979	RET ABN	UG-SERVICE
41407285	GRET	SVC	4/2/2024	1979	RET ABN	UG-SERVICE
43864215	GRET	SVC	11/8/2024	1979	RET ABN	UG-SERVICE
39903448	GRET	SVC	3/25/2022	1979	RET ABN	UG-SERVICE
41429930	GRET	SVC	9/13/2023	1979	RET ABN	UG-SERVICE
39077658	GRET	SVC	1/31/2022	1979	RET ABN	UG-SERVICE
39674940	GRET	SVC	1/11/2022	1979	RET ABN	UG-SERVICE
38315073	GRET	SVC	2/26/2021	1979	RET ABN	UG-SERVICE
40813755	GRET	SVC	10/19/2022	1979	RET ABN	UG-SERVICE
38437018	GRET	SVC	5/5/2021	1979	RET ABN	UG-SERVICE
41411563	GRET	SVC	4/2/2024	1979	RET ABN	UG-SERVICE
36177526	GRET	SVC	2/14/2020	1979	RET ABN	UG-SERVICE
41321748	GRET	SVC	2/28/2023	1979	RET ABN	UG-SERVICE
40537448	GRET	SVC	8/5/2022	1979	RET ABN	UG-SERVICE
36976514	GRET	SVC	9/25/2020	1979	RET ABN	UG-SERVICE
42185413	GRET	SVC	10/25/2023	1979	RET ABN	UG-SERVICE
37564157	GRET	SVC	11/23/2020	1979	RET ABN	UG-SERVICE
42745648	GRET	SVC	2/20/2024	1979	RET ABN	UG-SERVICE
41531391	GRET	SVC	4/17/2023	1979	RET ABN	UG-SERVICE
41424717	GRET	SVC	10/18/2023	1979	RET ABN	UG-SERVICE
36366991	GRET	SVC	5/28/2020	1979	RET ABN	UG-SERVICE
41083738	GRET	SVC	1/10/2023	1979	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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38491638	GRET	SVC	5/12/2021	1979	RET ABN	UG-SERVICE
41408203	GRET	SVC	10/19/2023	1979	RET ABN	UG-SERVICE
40144600	GRET	SVC	5/12/2022	1979	RET ABN	UG-SERVICE
38728537	GRET	SVC	7/6/2021	1979	RET ABN	UG-SERVICE
40802737	GRET	SVC	10/13/2022	1979	RET ABN	UG-SERVICE
41529726	GRET	SVC	4/17/2023	1979	RET ABN	UG-SERVICE
41621213	GRET	SVC	5/10/2023	1979	RET ABN	UG-SERVICE
43610664	GRET	SVC	12/12/2024	1979	RET ABN	UG-SERVICE
38671333	GRET	SVC	6/25/2021	1979	RET ABN	UG-SERVICE
38251709	GRET	SVC	3/22/2021	1979	RET ABN	UG-SERVICE
37894668	GRET	SVC	12/9/2020	1979	RET ABN	UG-SERVICE
35379334	GRET	SVC	3/6/2020	1979	RET ABN	UG-SERVICE
38849352	GRET	SVC	8/17/2021	1979	RET ABN	UG-SERVICE
42079301	GRET	SVC	9/6/2023	1979	RET ABN	UG-SERVICE
43506881	GRET	SVC	10/8/2024	1979	RET ABN	UG-SERVICE
40481577	GRET	SVC	7/28/2022	1979	RET ABN	UG-SERVICE
40578133	GRET	SVC	8/17/2022	1979	RET ABN	UG-SERVICE
43245022	GRET	SVC	9/11/2024	1979	RET ABN	UG-SERVICE
43224670	GRET	SVC	6/18/2024	1979	RET ABN	UG-SERVICE
38604517	GRET	SVC	6/13/2021	1979	RET ABN	UG-SERVICE
41273677	GRET	SVC	2/13/2023	1979	RET ABN	UG-SERVICE
36750102	GRET	SVC	9/21/2020	1979	RET ABN	UG-SERVICE
39731089	GRET	SVC	1/26/2022	1979	RET ABN	UG-SERVICE
36581451	GRET	SVC	7/22/2020	1979	RET ABN	UG-SERVICE
39257959	GRET	SVC	10/12/2021	1979	RET ABN	UG-SERVICE
37022478	GRET	SVC	10/6/2020	1979	RET ABN	UG-SERVICE
37925673	GRET	SVC	12/16/2020	1979	RET ABN	UG-SERVICE
43565699	GRET	SVC	9/17/2024	1979	RET ABN	UG-SERVICE
39761607	GRET	SVC	2/25/2022	1979	RET ABN	UG-SERVICE
40963050	GRET	SVC	12/15/2022	1979	RET ABN	UG-SERVICE
42247047	GRET	SVC	10/16/2023	1979	RET ABN	UG-SERVICE
36265671	GRET	SVC	5/1/2020	1979	RET ABN	UG-SERVICE
30804651	GRET	SVC	1/13/2020	1979	RET ABN	UG-SERVICE
36874995	GRET	SVC	8/31/2020	1979	RET ABN	UG-SERVICE
39466091	GRET	SVC	11/29/2021	1979	RET ABN	UG-SERVICE
43885143	GRET	SVC	11/27/2024	1979	RET ABN	UG-SERVICE
40156829	GRET	SVC	5/11/2022	1979	RET ABN	UG-SERVICE
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35925193	GRET	SVC	5/5/2020	1979	RET ABN	UG-SERVICE
41445652	GRET	SVC	4/14/2023	1979	RET ABN	UG-SERVICE
42806750	GRET	SVC	3/11/2024	1979	RET ABN	UG-SERVICE
41411564	GRET	SVC	4/2/2024	1979	RET ABN	UG-SERVICE
36046011	GRET	SVC	3/17/2020	1979	RET ABN	UG-SERVICE
42320556	GRET	SVC	11/4/2023	1979	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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41429217	GRET	SVC	3/22/2023	1979	RET ABN	UG-SERVICE
42407612	GRET	SVC	11/20/2023	1979	RET ABN	UG-SERVICE
38737824	GRET	SVC	7/8/2021	1979	RET ABN	UG-SERVICE
39958596	GRET	SVC	4/20/2022	1979	RET ABN	UG-SERVICE
38947476	GRET	SVC	8/10/2021	1979	RET ABN	UG-SERVICE
40826587	GRET	SVC	10/18/2022	1979	RET ABN	UG-SERVICE
40147210	GRET	SVC	5/10/2022	1979	RET ABN	UG-SERVICE
40909894	GRET	SVC	11/8/2022	1979	RET ABN	UG-SERVICE
41067104	GRET	SVC	12/15/2022	1979	RET ABN	UG-SERVICE
39921796	GRET	SVC	3/23/2022	1979	RET ABN	UG-SERVICE
35866021	GRET	SVC	1/30/2020	1980	RET ABN	UG-SERVICE
38507917	GRET	SVC	5/19/2021	1980	RET ABN	UG-SERVICE
36867885	GRET	SVC	9/15/2020	1980	RET ABN	UG-SERVICE
42646850	GRET	SVC	2/1/2024	1980	RET ABN	UG-SERVICE
40806772	GRET	SVC	10/13/2022	1980	RET ABN	UG-SERVICE
37918342	GRET	SVC	12/14/2020	1980	RET ABN	UG-SERVICE
42498461	GRET	SVC	12/20/2023	1980	RET ABN	UG-SERVICE
42682551	GRET	SVC	2/12/2024	1980	RET ABN	UG-SERVICE
39609361	GRET	SVC	12/23/2021	1980	RET ABN	UG-SERVICE
43245011	GRET	SVC	9/19/2024	1980	RET ABN	UG-SERVICE
40837418	GRET	SVC	10/20/2022	1980	RET ABN	UG-SERVICE
43052299	GRET	SVC	5/13/2024	1980	RET ABN	UG-SERVICE
43477897	GRET	SVC	9/5/2024	1980	RET ABN	UG-SERVICE
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35938717	GRET	SVC	1/27/2020	1980	RET ABN	UG-SERVICE
37082344	GRET	SVC	10/16/2020	1980	RET ABN	UG-SERVICE
37887831	GRET	SVC	12/8/2020	1980	RET ABN	UG-SERVICE
38116253	GRET	SVC	2/9/2021	1980	RET ABN	UG-SERVICE
38170941	GRET	SVC	2/19/2021	1980	RET ABN	UG-SERVICE
36822003	GRET	SVC	8/20/2020	1980	RET ABN	UG-SERVICE
43985794	GRET	SVC	12/28/2024	1980	RET ABN	UG-SERVICE
40863154	GRET	SVC	10/22/2022	1980	RET ABN	UG-SERVICE
39194660	GRET	SVC	9/29/2021	1980	RET ABN	UG-SERVICE
38200822	GRET	SVC	3/11/2021	1980	RET ABN	UG-SERVICE
36926676	GRET	SVC	9/15/2020	1980	RET ABN	UG-SERVICE
36727692	GRET	SVC	7/30/2020	1980	RET ABN	UG-SERVICE
38808386	GRET	SVC	7/26/2021	1980	RET ABN	UG-SERVICE
40359797	GRET	SVC	12/12/2022	1980	RET ABN	UG-SERVICE
36047670	GRET	SVC	2/20/2020	1980	RET ABN	UG-SERVICE
39745882	GRET	SVC	1/31/2022	1980	RET ABN	UG-SERVICE
42217287	GRET	SVC	10/13/2023	1980	RET ABN	UG-SERVICE
36730903	GRET	SVC	8/14/2020	1980	RET ABN	UG-SERVICE
42405116	GRET	SVC	12/1/2023	1980	RET ABN	UG-SERVICE
41965367	GRET	SVC	8/12/2023	1980	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38880419	GRET	SVC	8/26/2021	1980	RET ABN	UG-SERVICE
35945211	GRET	SVC	1/27/2020	1980	RET ABN	UG-SERVICE
39534511	GRET	SVC	12/14/2021	1980	RET ABN	UG-SERVICE
38113255	GRET	SVC	2/8/2021	1980	RET ABN	UG-SERVICE
38284674	GRET	SVC	5/17/2021	1980	RET ABN	UG-SERVICE
43177005	GRET	SVC	6/17/2024	1980	RET ABN	UG-SERVICE
37087444	GRET	SVC	10/16/2020	1980	RET ABN	UG-SERVICE
38692011	GRET	SVC	7/16/2021	1980	RET ABN	UG-SERVICE
43324199	GRET	SVC	8/23/2024	1980	RET ABN	UG-SERVICE
38666432	GRET	SVC	6/24/2021	1980	RET ABN	UG-SERVICE
36006012	GRET	SVC	2/11/2020	1980	RET ABN	UG-SERVICE
43737110	GRET	SVC	10/22/2024	1980	RET ABN	UG-SERVICE
43345778	GRET	SVC	7/22/2024	1980	RET ABN	UG-SERVICE
43506825	GRET	SVC	10/3/2024	1980	RET ABN	UG-SERVICE
37834392	GRET	SVC	11/30/2020	1980	RET ABN	UG-SERVICE
40637086	GRET	SVC	8/30/2022	1980	RET ABN	UG-SERVICE
40788026	GRET	SVC	10/10/2022	1980	RET ABN	UG-SERVICE
41118205	GRET	SVC	1/3/2023	1980	RET ABN	UG-SERVICE
36404827	GRET	SVC	6/10/2020	1980	RET ABN	UG-SERVICE
41431153	GRET	SVC	3/28/2023	1980	RET ABN	UG-SERVICE
39977279	GRET	SVC	4/7/2022	1980	RET ABN	UG-SERVICE
40701293	GRET	SVC	9/13/2022	1980	RET ABN	UG-SERVICE
38135257	GRET	SVC	2/9/2021	1980	RET ABN	UG-SERVICE
39408469	GRET	SVC	11/6/2021	1980	RET ABN	UG-SERVICE
40400195	GRET	SVC	8/10/2022	1980	RET ABN	UG-SERVICE
40616873	GRET	SVC	8/25/2022	1980	RET ABN	UG-SERVICE
40829046	GRET	SVC	10/22/2022	1980	RET ABN	UG-SERVICE
36297314	GRET	SVC	5/13/2020	1980	RET ABN	UG-SERVICE
40737880	GRET	SVC	10/1/2022	1980	RET ABN	UG-SERVICE
39940127	GRET	SVC	6/27/2022	1980	RET ABN	UG-SERVICE
38414865	GRET	SVC	4/27/2021	1980	RET ABN	UG-SERVICE
36876670	GRET	SVC	9/10/2020	1980	RET ABN	UG-SERVICE
43974740	GRET	SVC	12/26/2024	1980	RET ABN	UG-SERVICE
40619135	GRET	SVC	8/11/2022	1980	RET ABN	UG-SERVICE
41277505	GRET	SVC	2/13/2023	1980	RET ABN	UG-SERVICE
36039967	GRET	SVC	2/13/2020	1980	RET ABN	UG-SERVICE
40275027	GRET	SVC	7/5/2022	1980	RET ABN	UG-SERVICE
38251173	GRET	SVC	3/16/2021	1980	RET ABN	UG-SERVICE
41083441	GRET	SVC	12/20/2022	1980	RET ABN	UG-SERVICE
36709895	GRET	SVC	8/3/2020	1980	RET ABN	UG-SERVICE
41318142	GRET	SVC	3/3/2023	1980	RET ABN	UG-SERVICE
38113254	GRET	SVC	2/8/2021	1980	RET ABN	UG-SERVICE
39730649	GRET	SVC	1/28/2022	1980	RET ABN	UG-SERVICE
39808430	GRET	SVC	2/16/2022	1980	RET ABN	UG-SERVICE
36198374	GRET	SVC	5/1/2020	1980	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43767434	GRET	SVC	11/12/2024	1980	RET ABN	UG-SERVICE
43125485	GRET	SVC	6/7/2024	1980	RET ABN	UG-SERVICE
43678617	GRET	SVC	11/1/2024	1980	RET ABN	UG-SERVICE
38167316	GRET	SVC	2/19/2021	1980	RET ABN	UG-SERVICE
43703191	GRET	SVC	10/18/2024	1980	RET ABN	UG-SERVICE
38167318	GRET	SVC	2/19/2021	1980	RET ABN	UG-SERVICE
36297313	GRET	SVC	5/13/2020	1980	RET ABN	UG-SERVICE
38342400	GRET	SVC	4/12/2021	1980	RET ABN	UG-SERVICE
36590784	GRET	SVC	7/12/2020	1980	RET ABN	UG-SERVICE
37560682	GRET	SVC	11/13/2020	1980	RET ABN	UG-SERVICE
40518272	GRET	SVC	8/3/2022	1980	RET ABN	UG-SERVICE
38260202	GRET	SVC	4/9/2021	1980	RET ABN	UG-SERVICE
39977276	GRET	SVC	4/7/2022	1980	RET ABN	UG-SERVICE
36805445	GRET	SVC	8/20/2020	1980	RET ABN	UG-SERVICE
43793034	GRET	SVC	11/4/2024	1980	RET ABN	UG-SERVICE
41043685	GRET	SVC	12/12/2022	1980	RET ABN	UG-SERVICE
40400196	GRET	SVC	8/10/2022	1980	RET ABN	UG-SERVICE
40513288	GRET	SVC	8/4/2022	1980	RET ABN	UG-SERVICE
42435570	GRET	SVC	12/15/2023	1980	RET ABN	UG-SERVICE
38170519	GRET	SVC	2/19/2021	1980	RET ABN	UG-SERVICE
41411765	GRET	SVC	4/2/2024	1980	RET ABN	UG-SERVICE
35960002	GRET	SVC	1/27/2020	1980	RET ABN	UG-SERVICE
43623490	GRET	SVC	12/5/2024	1980	RET ABN	UG-SERVICE
40618740	GRET	SVC	9/2/2022	1980	RET ABN	UG-SERVICE
41407774	GRET	SVC	4/2/2024	1980	RET ABN	UG-SERVICE
38766858	GRET	SVC	7/12/2021	1980	RET ABN	UG-SERVICE
42217502	GRET	SVC	10/13/2023	1980	RET ABN	UG-SERVICE
38159499	GRET	SVC	2/18/2021	1980	RET ABN	UG-SERVICE
42767217	GRET	SVC	9/19/2024	1980	RET ABN	UG-SERVICE
39663182	GRET	SVC	12/29/2021	1980	RET ABN	UG-SERVICE
42696012	GRET	SVC	2/14/2024	1980	RET ABN	UG-SERVICE
42083849	GRET	SVC	9/10/2023	1980	RET ABN	UG-SERVICE
42678185	GRET	SVC	2/7/2024	1980	RET ABN	UG-SERVICE
39341151	GRET	SVC	10/26/2021	1980	RET ABN	UG-SERVICE
36715000	GRET	SVC	8/4/2020	1980	RET ABN	UG-SERVICE
41117034	GRET	SVC	1/12/2023	1980	RET ABN	UG-SERVICE
43324508	GRET	SVC	10/15/2024	1980	RET ABN	UG-SERVICE
43144648	GRET	SVC	6/7/2024	1980	RET ABN	UG-SERVICE
43318347	GRET	SVC	8/13/2024	1980	RET ABN	UG-SERVICE
41063071	GRET	SVC	12/11/2022	1980	RET ABN	UG-SERVICE
42784886	GRET	SVC	3/4/2024	1980	RET ABN	UG-SERVICE
39989337	GRET	SVC	4/25/2022	1980	RET ABN	UG-SERVICE
39097214	GRET	SVC	9/10/2021	1980	RET ABN	UG-SERVICE
42165918	GRET	SVC	9/19/2023	1980	RET ABN	UG-SERVICE
42190592	GRET	SVC	10/4/2023	1980	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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38159497	GRET	SVC	2/16/2021	1980	RET ABN	UG-SERVICE
36690178	GRET	SVC	7/29/2020	1980	RET ABN	UG-SERVICE
42973050	GRET	SVC	4/22/2024	1980	RET ABN	UG-SERVICE
42904312	GRET	SVC	4/11/2024	1980	RET ABN	UG-SERVICE
37423846	GRET	SVC	11/10/2020	1980	RET ABN	UG-SERVICE
36139991	GRET	SVC	3/16/2020	1980	RET ABN	UG-SERVICE
38113253	GRET	SVC	2/8/2021	1980	RET ABN	UG-SERVICE
39876288	GRET	SVC	3/14/2022	1980	RET ABN	UG-SERVICE
39895862	GRET	SVC	4/22/2022	1980	RET ABN	UG-SERVICE
43471134	GRET	SVC	8/20/2024	1980	RET ABN	UG-SERVICE
36066959	GRET	SVC	2/27/2020	1980	RET ABN	UG-SERVICE
36657935	GRET	SVC	6/11/2020	1980	RET ABN	UG-SERVICE
42217358	GRET	SVC	10/13/2023	1980	RET ABN	UG-SERVICE
36704634	GRET	SVC	7/29/2020	1980	RET ABN	UG-SERVICE
41187919	GRET	SVC	1/17/2023	1980	RET ABN	UG-SERVICE
40396051	GRET	SVC	7/6/2022	1980	RET ABN	UG-SERVICE
42865500	GRET	SVC	2/15/2024	1980	RET ABN	UG-SERVICE
37004084	GRET	SVC	10/16/2020	1980	RET ABN	UG-SERVICE
40900946	GRET	SVC	12/3/2022	1980	RET ABN	UG-SERVICE
38534653	GRET	SVC	5/25/2021	1980	RET ABN	UG-SERVICE
43440669	GRET	SVC	8/14/2024	1980	RET ABN	UG-SERVICE
36953644	GRET	SVC	9/20/2020	1980	RET ABN	UG-SERVICE
40036782	GRET	SVC	4/24/2022	1980	RET ABN	UG-SERVICE
40962785	GRET	SVC	11/22/2022	1980	RET ABN	UG-SERVICE
43610731	GRET	SVC	10/20/2024	1980	RET ABN	UG-SERVICE
40372553	GRET	SVC	7/5/2022	1980	RET ABN	UG-SERVICE
39378017	GRET	SVC	11/2/2021	1980	RET ABN	UG-SERVICE
43506592	GRET	SVC	9/18/2024	1980	RET ABN	UG-SERVICE
43167495	GRET	SVC	7/5/2024	1980	RET ABN	UG-SERVICE
35960719	GRET	SVC	1/31/2020	1980	RET ABN	UG-SERVICE
38116247	GRET	SVC	2/9/2021	1980	RET ABN	UG-SERVICE
37089338	GRET	SVC	10/20/2020	1980	RET ABN	UG-SERVICE
43244748	GRET	SVC	9/13/2024	1980	RET ABN	UG-SERVICE
42522515	GRET	SVC	12/27/2023	1980	RET ABN	UG-SERVICE
38217494	GRET	SVC	3/22/2021	1980	RET ABN	UG-SERVICE
41774863	GRET	SVC	6/22/2023	1980	RET ABN	UG-SERVICE
39701495	GRET	SVC	1/18/2022	1980	RET ABN	UG-SERVICE
38786025	GRET	SVC	8/2/2021	1980	RET ABN	UG-SERVICE
38401291	GRET	SVC	4/20/2021	1980	RET ABN	UG-SERVICE
38353000	GRET	SVC	2/14/2023	1980	RET ABN	UG-SERVICE
41436522	GRET	SVC	3/27/2023	1980	RET ABN	UG-SERVICE
36260361	GRET	SVC	5/7/2020	1980	RET ABN	UG-SERVICE
40865777	GRET	SVC	10/27/2022	1980	RET ABN	UG-SERVICE
38167319	GRET	SVC	2/19/2021	1980	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42217394	GRET	SVC	10/13/2023	1980	RET ABN	UG-SERVICE
43379746	GRET	SVC	7/27/2024	1980	RET ABN	UG-SERVICE
42413380	GRET	SVC	11/27/2023	1980	RET ABN	UG-SERVICE
36759048	GRET	SVC	8/10/2020	1980	RET ABN	UG-SERVICE
43566832	GRET	SVC	10/3/2024	1980	RET ABN	UG-SERVICE
43673036	GRET	SVC	10/9/2024	1980	RET ABN	UG-SERVICE
41277506	GRET	SVC	2/24/2023	1980	RET ABN	UG-SERVICE
40497353	GRET	SVC	8/3/2022	1980	RET ABN	UG-SERVICE
38747941	GRET	SVC	7/16/2021	1980	RET ABN	UG-SERVICE
41585947	GRET	SVC	5/3/2023	1980	RET ABN	UG-SERVICE
40099808	GRET	SVC	5/2/2022	1980	RET ABN	UG-SERVICE
42194936	GRET	SVC	10/9/2023	1980	RET ABN	UG-SERVICE
39452999	GRET	SVC	11/22/2021	1980	RET ABN	UG-SERVICE
38116252	GRET	SVC	2/9/2021	1980	RET ABN	UG-SERVICE
39817525	GRET	SVC	2/23/2022	1980	RET ABN	UG-SERVICE
41509580	GRET	SVC	4/10/2023	1980	RET ABN	UG-SERVICE
38159496	GRET	SVC	2/16/2021	1980	RET ABN	UG-SERVICE
42083826	GRET	SVC	8/28/2023	1980	RET ABN	UG-SERVICE
42170550	GRET	SVC	10/3/2023	1980	RET ABN	UG-SERVICE
43506834	GRET	SVC	9/16/2024	1980	RET ABN	UG-SERVICE
35919327	GRET	SVC	1/16/2020	1980	RET ABN	UG-SERVICE
38662723	GRET	SVC	6/23/2021	1980	RET ABN	UG-SERVICE
39067596	GRET	SVC	9/23/2021	1980	RET ABN	UG-SERVICE
39855421	GRET	SVC	3/7/2022	1980	RET ABN	UG-SERVICE
35965176	GRET	SVC	1/26/2020	1980	RET ABN	UG-SERVICE
38331751	GRET	SVC	4/8/2021	1980	RET ABN	UG-SERVICE
39958831	GRET	SVC	4/26/2022	1980	RET ABN	UG-SERVICE
43245145	GRET	SVC	9/11/2024	1980	RET ABN	UG-SERVICE
42554523	GRET	SVC	1/9/2024	1980	RET ABN	UG-SERVICE
41051917	GRET	SVC	1/12/2023	1980	RET ABN	UG-SERVICE
42290696	GRET	SVC	9/16/2023	1980	RET ABN	UG-SERVICE
43540690	GRET	SVC	9/17/2024	1980	RET ABN	UG-SERVICE
39211525	GRET	SVC	9/27/2021	1980	RET ABN	UG-SERVICE
40905625	GRET	SVC	11/9/2022	1980	RET ABN	UG-SERVICE
37593381	GRET	SVC	11/16/2020	1980	RET ABN	UG-SERVICE
43551265	GRET	SVC	9/7/2024	1980	RET ABN	UG-SERVICE
40957854	GRET	SVC	11/21/2022	1980	RET ABN	UG-SERVICE
38135258	GRET	SVC	2/9/2021	1980	RET ABN	UG-SERVICE
43190559	GRET	SVC	6/14/2024	1980	RET ABN	UG-SERVICE
38520452	GRET	SVC	5/19/2021	1980	RET ABN	UG-SERVICE
42220667	GRET	SVC	10/16/2023	1980	RET ABN	UG-SERVICE
41186303	GRET	SVC	1/20/2023	1980	RET ABN	UG-SERVICE
40561831	GRET	SVC	8/17/2022	1980	RET ABN	UG-SERVICE
36734820	GRET	SVC	8/6/2020	1980	RET ABN	UG-SERVICE
39424078	GRET	SVC	4/29/2022	1980	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41284183	GRET	SVC	2/26/2023	1980	RET ABN	UG-SERVICE
38082913	GRET	SVC	2/1/2021	1980	RET ABN	UG-SERVICE
37288139	GRET	SVC	11/9/2020	1980	RET ABN	UG-SERVICE
41084274	GRET	SVC	12/21/2022	1980	RET ABN	UG-SERVICE
39917684	GRET	SVC	4/26/2022	1980	RET ABN	UG-SERVICE
42514792	GRET	SVC	12/29/2023	1980	RET ABN	UG-SERVICE
41411047	GRET	SVC	4/2/2024	1980	RET ABN	UG-SERVICE
38172263	GRET	SVC	2/25/2021	1980	RET ABN	UG-SERVICE
41296111	GRET	SVC	2/20/2023	1980	RET ABN	UG-SERVICE
35964247	GRET	SVC	1/31/2020	1980	RET ABN	UG-SERVICE
40515691	GRET	SVC	8/5/2022	1981	RET ABN	UG-SERVICE
40108945	GRET	SVC	5/6/2022	1981	RET ABN	UG-SERVICE
42957322	GRET	SVC	9/19/2024	1981	RET ABN	UG-SERVICE
36504620	GRET	SVC	7/21/2020	1981	RET ABN	UG-SERVICE
39158783	GRET	SVC	9/17/2021	1981	RET ABN	UG-SERVICE
41988878	GRET	SVC	8/14/2023	1981	RET ABN	UG-SERVICE
39114621	GRET	SVC	9/27/2021	1981	RET ABN	UG-SERVICE
36699118	GRET	SVC	7/28/2020	1981	RET ABN	UG-SERVICE
41529177	GRET	SVC	4/18/2023	1981	RET ABN	UG-SERVICE
42429557	GRET	SVC	11/28/2023	1981	RET ABN	UG-SERVICE
42427059	GRET	SVC	9/19/2024	1981	RET ABN	UG-SERVICE
42678163	GRET	SVC	2/7/2024	1981	RET ABN	UG-SERVICE
43612750	GRET	SVC	9/23/2024	1981	RET ABN	UG-SERVICE
42255111	GRET	SVC	4/2/2024	1981	RET ABN	UG-SERVICE
40777231	GRET	SVC	10/7/2022	1981	RET ABN	UG-SERVICE
40824097	GRET	SVC	10/18/2022	1981	RET ABN	UG-SERVICE
42205149	GRET	SVC	10/18/2023	1981	RET ABN	UG-SERVICE
37867772	GRET	SVC	12/6/2020	1981	RET ABN	UG-SERVICE
39372952	GRET	SVC	11/1/2021	1981	RET ABN	UG-SERVICE
40817911	GRET	SVC	11/3/2022	1981	RET ABN	UG-SERVICE
39829823	GRET	SVC	2/28/2022	1981	RET ABN	UG-SERVICE
39292398	GRET	SVC	11/8/2021	1981	RET ABN	UG-SERVICE
39821845	GRET	SVC	2/24/2022	1981	RET ABN	UG-SERVICE
42522226	GRET	SVC	12/28/2023	1981	RET ABN	UG-SERVICE
36448752	GRET	SVC	6/16/2020	1981	RET ABN	UG-SERVICE
41083935	GRET	SVC	12/21/2022	1981	RET ABN	UG-SERVICE
40824189	GRET	SVC	10/18/2022	1981	RET ABN	UG-SERVICE
43364936	GRET	SVC	10/15/2024	1981	RET ABN	UG-SERVICE
43587179	GRET	SVC	9/20/2024	1981	RET ABN	UG-SERVICE
40656092	GRET	SVC	9/16/2022	1981	RET ABN	UG-SERVICE
42175607	GRET	SVC	9/25/2023	1981	RET ABN	UG-SERVICE
42428954	GRET	SVC	4/2/2024	1981	RET ABN	UG-SERVICE
36207010	GRET	SVC	4/28/2020	1981	RET ABN	UG-SERVICE
39950829	GRET	SVC	5/14/2022	1981	RET ABN	UG-SERVICE
38037820	GRET	SVC	1/19/2021	1981	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43364935	GRET	SVC	10/15/2024	1981	RET ABN	UG-SERVICE
36469542	GRET	SVC	7/8/2020	1981	RET ABN	UG-SERVICE
41184328	GRET	SVC	1/18/2023	1981	RET ABN	UG-SERVICE
36177527	GRET	SVC	2/14/2020	1981	RET ABN	UG-SERVICE
40189511	GRET	SVC	5/24/2022	1981	RET ABN	UG-SERVICE
37639332	GRET	SVC	11/9/2020	1981	RET ABN	UG-SERVICE
40345195	GRET	SVC	6/27/2022	1981	RET ABN	UG-SERVICE
41288086	GRET	SVC	2/24/2023	1981	RET ABN	UG-SERVICE
38971803	GRET	SVC	8/30/2021	1981	RET ABN	UG-SERVICE
43765696	GRET	SVC	10/18/2024	1981	RET ABN	UG-SERVICE
41407667	GRET	SVC	4/2/2024	1981	RET ABN	UG-SERVICE
40751127	GRET	SVC	9/30/2022	1981	RET ABN	UG-SERVICE
36058338	GRET	SVC	2/25/2020	1981	RET ABN	UG-SERVICE
43364937	GRET	SVC	10/16/2024	1981	RET ABN	UG-SERVICE
41628115	GRET	SVC	5/16/2023	1981	RET ABN	UG-SERVICE
43456236	GRET	SVC	8/20/2024	1981	RET ABN	UG-SERVICE
36885931	GRET	SVC	9/2/2020	1981	RET ABN	UG-SERVICE
41164933	GRET	SVC	1/18/2023	1981	RET ABN	UG-SERVICE
42535827	GRET	SVC	12/28/2023	1981	RET ABN	UG-SERVICE
38616755	GRET	SVC	6/14/2021	1981	RET ABN	UG-SERVICE
41025632	GRET	SVC	4/4/2023	1981	RET ABN	UG-SERVICE
37113299	GRET	SVC	10/26/2020	1981	RET ABN	UG-SERVICE
41119447	GRET	SVC	1/5/2023	1981	RET ABN	UG-SERVICE
40825319	GRET	SVC	11/1/2022	1981	RET ABN	UG-SERVICE
42070210	GRET	SVC	9/1/2023	1981	RET ABN	UG-SERVICE
42216869	GRET	SVC	10/11/2023	1981	RET ABN	UG-SERVICE
41161391	GRET	SVC	1/18/2023	1981	RET ABN	UG-SERVICE
36977367	GRET	SVC	9/23/2020	1981	RET ABN	UG-SERVICE
42227312	GRET	SVC	10/31/2023	1981	RET ABN	UG-SERVICE
37004001	GRET	SVC	10/9/2020	1981	RET ABN	UG-SERVICE
43364938	GRET	SVC	10/19/2024	1981	RET ABN	UG-SERVICE
36712286	GRET	SVC	8/10/2020	1981	RET ABN	UG-SERVICE
40138088	GRET	SVC	5/9/2022	1981	RET ABN	UG-SERVICE
39439687	GRET	SVC	11/19/2021	1981	RET ABN	UG-SERVICE
36056285	GRET	SVC	2/24/2020	1981	RET ABN	UG-SERVICE
38324631	GRET	SVC	3/1/2021	1981	RET ABN	UG-SERVICE
38804665	GRET	SVC	8/2/2021	1981	RET ABN	UG-SERVICE
43801210	GRET	SVC	11/6/2024	1981	RET ABN	UG-SERVICE
37181835	GRET	SVC	10/29/2020	1981	RET ABN	UG-SERVICE
40821937	GRET	SVC	10/18/2022	1981	RET ABN	UG-SERVICE
42838191	GRET	SVC	3/20/2024	1981	RET ABN	UG-SERVICE
43318356	GRET	SVC	8/1/2024	1981	RET ABN	UG-SERVICE
36987348	GRET	SVC	9/23/2020	1981	RET ABN	UG-SERVICE
38484804	GRET	SVC	5/10/2021	1981	RET ABN	UG-SERVICE
37018536	GRET	SVC	10/1/2020	1981	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36207016	GRET	SVC	4/28/2020	1981	RET ABN	UG-SERVICE
36957850	GRET	SVC	9/9/2020	1981	RET ABN	UG-SERVICE
42248421	GRET	SVC	10/18/2023	1981	RET ABN	UG-SERVICE
43069749	GRET	SVC	5/20/2024	1981	RET ABN	UG-SERVICE
35969641	GRET	SVC	2/3/2020	1981	RET ABN	UG-SERVICE
39571349	GRET	SVC	11/22/2021	1981	RET ABN	UG-SERVICE
41388637	GRET	SVC	3/15/2023	1981	RET ABN	UG-SERVICE
39444730	GRET	SVC	12/2/2021	1981	RET ABN	UG-SERVICE
41516430	GRET	SVC	4/27/2023	1981	RET ABN	UG-SERVICE
40952957	GRET	SVC	11/17/2022	1981	RET ABN	UG-SERVICE
41411426	GRET	SVC	11/2/2023	1981	RET ABN	UG-SERVICE
40736068	GRET	SVC	9/27/2022	1981	RET ABN	UG-SERVICE
40865906	GRET	SVC	8/22/2023	1981	RET ABN	UG-SERVICE
43506821	GRET	SVC	10/11/2024	1981	RET ABN	UG-SERVICE
38289760	GRET	SVC	4/1/2021	1981	RET ABN	UG-SERVICE
38682325	GRET	SVC	7/1/2021	1981	RET ABN	UG-SERVICE
38606748	GRET	SVC	6/11/2021	1981	RET ABN	UG-SERVICE
43323973	GRET	SVC	10/14/2024	1981	RET ABN	UG-SERVICE
38741847	GRET	SVC	7/12/2021	1981	RET ABN	UG-SERVICE
42335278	GRET	SVC	4/2/2024	1981	RET ABN	UG-SERVICE
41185105	GRET	SVC	1/21/2023	1981	RET ABN	UG-SERVICE
40015541	GRET	SVC	4/16/2022	1981	RET ABN	UG-SERVICE
38266117	GRET	SVC	10/27/2021	1981	RET ABN	UG-SERVICE
43323972	GRET	SVC	7/22/2024	1981	RET ABN	UG-SERVICE
40386083	GRET	SVC	7/6/2022	1981	RET ABN	UG-SERVICE
36122706	GRET	SVC	11/5/2020	1981	RET ABN	UG-SERVICE
43564234	GRET	SVC	9/14/2024	1981	RET ABN	UG-SERVICE
41209954	GRET	SVC	1/31/2023	1981	RET ABN	UG-SERVICE
42965256	GRET	SVC	4/24/2024	1981	RET ABN	UG-SERVICE
39843596	GRET	SVC	3/2/2022	1981	RET ABN	UG-SERVICE
38407202	GRET	SVC	3/16/2021	1982	RET ABN	UG-SERVICE
40814058	GRET	SVC	10/19/2022	1982	RET ABN	UG-SERVICE
38505994	GRET	SVC	6/9/2021	1982	RET ABN	UG-SERVICE
40313520	GRET	SVC	6/15/2022	1982	RET ABN	UG-SERVICE
37564159	GRET	SVC	11/25/2020	1982	RET ABN	UG-SERVICE
36666826	GRET	SVC	7/20/2020	1982	RET ABN	UG-SERVICE
41968002	GRET	SVC	8/9/2023	1982	RET ABN	UG-SERVICE
36119404	GRET	SVC	11/5/2020	1982	RET ABN	UG-SERVICE
38091659	GRET	SVC	2/4/2021	1982	RET ABN	UG-SERVICE
39109977	GRET	SVC	9/8/2021	1982	RET ABN	UG-SERVICE
43896268	GRET	SVC	12/5/2024	1982	RET ABN	UG-SERVICE
42006525	GRET	SVC	8/16/2023	1982	RET ABN	UG-SERVICE
43329182	GRET	SVC	7/16/2024	1982	RET ABN	UG-SERVICE
39104840	GRET	SVC	7/30/2021	1982	RET ABN	UG-SERVICE
40831950	GRET	SVC	10/19/2022	1982	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
37848473	GRET	SVC	11/30/2020	1982	RET ABN	UG-SERVICE
38113506	GRET	SVC	2/10/2021	1982	RET ABN	UG-SERVICE
43428930	GRET	SVC	8/10/2024	1982	RET ABN	UG-SERVICE
40612445	GRET	SVC	10/27/2022	1982	RET ABN	UG-SERVICE
37848478	GRET	SVC	11/30/2020	1982	RET ABN	UG-SERVICE
43469158	GRET	SVC	8/24/2024	1982	RET ABN	UG-SERVICE
41436390	GRET	SVC	3/27/2023	1982	RET ABN	UG-SERVICE
40942685	GRET	SVC	11/28/2022	1982	RET ABN	UG-SERVICE
43324195	GRET	SVC	7/29/2024	1982	RET ABN	UG-SERVICE
37004013	GRET	SVC	9/29/2020	1982	RET ABN	UG-SERVICE
43353737	GRET	SVC	12/6/2024	1982	RET ABN	UG-SERVICE
38352970	GRET	SVC	2/17/2023	1982	RET ABN	UG-SERVICE
36916863	GRET	SVC	9/11/2020	1982	RET ABN	UG-SERVICE
41279149	GRET	SVC	2/13/2023	1982	RET ABN	UG-SERVICE
43883405	GRET	SVC	11/27/2024	1982	RET ABN	UG-SERVICE
43916042	GRET	SVC	12/7/2024	1982	RET ABN	UG-SERVICE
39243194	GRET	SVC	10/4/2021	1982	RET ABN	UG-SERVICE
40522355	GRET	SVC	8/13/2022	1982	RET ABN	UG-SERVICE
35865617	GRET	SVC	1/6/2020	1982	RET ABN	UG-SERVICE
41877455	GRET	SVC	8/28/2023	1982	RET ABN	UG-SERVICE
36255513	GRET	SVC	5/20/2020	1982	RET ABN	UG-SERVICE
43423327	GRET	SVC	9/11/2024	1982	RET ABN	UG-SERVICE
37739218	GRET	SVC	11/23/2020	1982	RET ABN	UG-SERVICE
41814868	GRET	SVC	6/27/2023	1982	RET ABN	UG-SERVICE
42332553	GRET	SVC	11/7/2023	1982	RET ABN	UG-SERVICE
38461565	GRET	SVC	5/5/2021	1982	RET ABN	UG-SERVICE
36121696	GRET	SVC	10/12/2020	1982	RET ABN	UG-SERVICE
39271873	GRET	SVC	10/26/2021	1982	RET ABN	UG-SERVICE
42408187	GRET	SVC	11/20/2023	1982	RET ABN	UG-SERVICE
42887631	GRET	SVC	4/4/2024	1982	RET ABN	UG-SERVICE
43934271	GRET	SVC	12/17/2024	1982	RET ABN	UG-SERVICE
40283208	GRET	SVC	6/9/2022	1982	RET ABN	UG-SERVICE
38844205	GRET	SVC	7/30/2021	1982	RET ABN	UG-SERVICE
41145263	GRET	SVC	1/9/2023	1982	RET ABN	UG-SERVICE
40860630	GRET	SVC	10/25/2022	1982	RET ABN	UG-SERVICE
42419098	GRET	SVC	12/14/2023	1982	RET ABN	UG-SERVICE
43496524	GRET	SVC	12/4/2024	1982	RET ABN	UG-SERVICE
38352971	GRET	SVC	2/17/2023	1982	RET ABN	UG-SERVICE
41463374	GRET	SVC	4/7/2023	1982	RET ABN	UG-SERVICE
39577719	GRET	SVC	12/27/2021	1982	RET ABN	UG-SERVICE
43205045	GRET	SVC	9/19/2024	1982	RET ABN	UG-SERVICE
36994454	GRET	SVC	9/28/2020	1982	RET ABN	UG-SERVICE
43312118	GRET	SVC	9/19/2024	1982	RET ABN	UG-SERVICE
42340279	GRET	SVC	11/7/2023	1982	RET ABN	UG-SERVICE
43272247	GRET	SVC	8/1/2024	1982	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41130361	GRET	SVC	6/10/2024	1982	RET ABN	UG-SERVICE
42327296	GRET	SVC	11/3/2023	1982	RET ABN	UG-SERVICE
43752302	GRET	SVC	11/23/2024	1982	RET ABN	UG-SERVICE
36566275	GRET	SVC	7/28/2020	1982	RET ABN	UG-SERVICE
35518622	GRET	SVC	3/8/2021	1983	RET ABN	UG-SERVICE
36348439	GRET	SVC	5/20/2020	1983	RET ABN	UG-SERVICE
37957717	GRET	SVC	12/29/2020	1983	RET ABN	UG-SERVICE
41776760	GRET	SVC	6/23/2023	1983	RET ABN	UG-SERVICE
40973240	GRET	SVC	12/7/2022	1983	RET ABN	UG-SERVICE
39724957	GRET	SVC	1/31/2022	1983	RET ABN	UG-SERVICE
39439476	GRET	SVC	11/23/2021	1983	RET ABN	UG-SERVICE
42564000	GRET	SVC	1/9/2024	1983	RET ABN	UG-SERVICE
38490764	GRET	SVC	5/14/2021	1983	RET ABN	UG-SERVICE
43245019	GRET	SVC	9/11/2024	1983	RET ABN	UG-SERVICE
41390194	GRET	SVC	3/17/2023	1983	RET ABN	UG-SERVICE
36004758	GRET	SVC	2/10/2020	1983	RET ABN	UG-SERVICE
43600685	GRET	SVC	10/10/2024	1983	RET ABN	UG-SERVICE
36044453	GRET	SVC	2/19/2020	1983	RET ABN	UG-SERVICE
40959765	GRET	SVC	11/28/2022	1983	RET ABN	UG-SERVICE
35849018	GRET	SVC	1/6/2020	1983	RET ABN	UG-SERVICE
42866693	GRET	SVC	3/27/2024	1983	RET ABN	UG-SERVICE
37639162	GRET	SVC	11/17/2020	1983	RET ABN	UG-SERVICE
39169119	GRET	SVC	9/22/2021	1983	RET ABN	UG-SERVICE
40860201	GRET	SVC	11/3/2022	1983	RET ABN	UG-SERVICE
40831308	GRET	SVC	10/17/2022	1983	RET ABN	UG-SERVICE
38894178	GRET	SVC	8/16/2021	1983	RET ABN	UG-SERVICE
38394513	GRET	SVC	4/20/2021	1983	RET ABN	UG-SERVICE
41538513	GRET	SVC	5/2/2023	1983	RET ABN	UG-SERVICE
36402419	GRET	SVC	6/5/2020	1983	RET ABN	UG-SERVICE
39749529	GRET	SVC	2/9/2022	1983	RET ABN	UG-SERVICE
41407380	GRET	SVC	4/2/2024	1983	RET ABN	UG-SERVICE
40457105	GRET	SVC	7/23/2022	1983	RET ABN	UG-SERVICE
42817043	GRET	SVC	3/13/2024	1983	RET ABN	UG-SERVICE
41426175	GRET	SVC	10/18/2023	1983	RET ABN	UG-SERVICE
43028594	GRET	SVC	5/7/2024	1983	RET ABN	UG-SERVICE
37946275	GRET	SVC	12/22/2020	1983	RET ABN	UG-SERVICE
38247963	GRET	SVC	3/17/2021	1983	RET ABN	UG-SERVICE
41818617	GRET	SVC	7/27/2023	1983	RET ABN	UG-SERVICE
41407392	GRET	SVC	4/2/2024	1983	RET ABN	UG-SERVICE
42249669	GRET	SVC	10/18/2023	1983	RET ABN	UG-SERVICE
39368073	GRET	SVC	11/9/2021	1983	RET ABN	UG-SERVICE
36817898	GRET	SVC	9/22/2020	1983	RET ABN	UG-SERVICE
43679595	GRET	SVC	10/21/2024	1983	RET ABN	UG-SERVICE
36360514	GRET	SVC	5/26/2020	1983	RET ABN	UG-SERVICE
41594739	GRET	SVC	5/4/2023	1983	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36951886	GRET	SVC	9/4/2020	1983	RET ABN	UG-SERVICE
41475077	GRET	SVC	10/27/2023	1983	RET ABN	UG-SERVICE
39353250	GRET	SVC	10/27/2021	1983	RET ABN	UG-SERVICE
39234516	GRET	SVC	10/4/2021	1983	RET ABN	UG-SERVICE
36173759	GRET	SVC	6/16/2020	1983	RET ABN	UG-SERVICE
42144356	GRET	SVC	9/24/2023	1983	RET ABN	UG-SERVICE
42206096	GRET	SVC	10/12/2023	1983	RET ABN	UG-SERVICE
41408228	GRET	SVC	4/2/2024	1983	RET ABN	UG-SERVICE
40634724	GRET	SVC	8/30/2022	1983	RET ABN	UG-SERVICE
43416405	GRET	SVC	8/12/2024	1983	RET ABN	UG-SERVICE
35963738	GRET	SVC	2/3/2020	1983	RET ABN	UG-SERVICE
43762376	GRET	SVC	10/31/2024	1983	RET ABN	UG-SERVICE
39858143	GRET	SVC	3/8/2022	1983	RET ABN	UG-SERVICE
36724022	GRET	SVC	8/4/2020	1983	RET ABN	UG-SERVICE
37216830	GRET	SVC	11/2/2020	1983	RET ABN	UG-SERVICE
43423090	GRET	SVC	8/13/2024	1983	RET ABN	UG-SERVICE
41903992	GRET	SVC	7/25/2023	1983	RET ABN	UG-SERVICE
40375226	GRET	SVC	7/5/2022	1983	RET ABN	UG-SERVICE
43923005	GRET	SVC	12/10/2024	1983	RET ABN	UG-SERVICE
42971127	GRET	SVC	4/24/2024	1983	RET ABN	UG-SERVICE
42302679	GRET	SVC	10/30/2023	1983	RET ABN	UG-SERVICE
41407742	GRET	SVC	4/2/2024	1983	RET ABN	UG-SERVICE
41323150	GRET	SVC	2/28/2023	1983	RET ABN	UG-SERVICE
38382270	GRET	SVC	11/22/2021	1983	RET ABN	UG-SERVICE
38378812	GRET	SVC	4/20/2021	1983	RET ABN	UG-SERVICE
43867006	GRET	SVC	11/27/2024	1983	RET ABN	UG-SERVICE
41578426	GRET	SVC	5/1/2023	1983	RET ABN	UG-SERVICE
43424927	GRET	SVC	8/13/2024	1983	RET ABN	UG-SERVICE
43245018	GRET	SVC	9/11/2024	1983	RET ABN	UG-SERVICE
42678903	GRET	SVC	2/5/2024	1983	RET ABN	UG-SERVICE
38192213	GRET	SVC	3/5/2021	1983	RET ABN	UG-SERVICE
40754598	GRET	SVC	10/3/2022	1983	RET ABN	UG-SERVICE
43365783	GRET	SVC	12/12/2024	1983	RET ABN	UG-SERVICE
41969559	GRET	SVC	8/1/2024	1983	RET ABN	UG-SERVICE
38040117	GRET	SVC	5/20/2021	1983	RET ABN	UG-SERVICE
38312994	GRET	SVC	4/7/2021	1983	RET ABN	UG-SERVICE
41904300	GRET	SVC	7/25/2023	1983	RET ABN	UG-SERVICE
38352967	GRET	SVC	2/14/2023	1983	RET ABN	UG-SERVICE
43424839	GRET	SVC	8/13/2024	1983	RET ABN	UG-SERVICE
40266897	GRET	SVC	6/8/2022	1983	RET ABN	UG-SERVICE
38186947	GRET	SVC	3/8/2021	1983	RET ABN	UG-SERVICE
43148395	GRET	SVC	6/4/2024	1983	RET ABN	UG-SERVICE
41901535	GRET	SVC	7/26/2023	1983	RET ABN	UG-SERVICE
39188037	GRET	SVC	10/1/2021	1983	RET ABN	UG-SERVICE
41084278	GRET	SVC	12/21/2022	1983	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43000538	GRET	SVC	5/8/2024	1983	RET ABN	UG-SERVICE
41918001	GRET	SVC	7/21/2023	1983	RET ABN	UG-SERVICE
40492808	GRET	SVC	8/3/2022	1983	RET ABN	UG-SERVICE
40948679	GRET	SVC	11/16/2022	1983	RET ABN	UG-SERVICE
40406351	GRET	SVC	7/11/2022	1983	RET ABN	UG-SERVICE
38274569	GRET	SVC	3/24/2021	1983	RET ABN	UG-SERVICE
35940350	GRET	SVC	1/23/2020	1983	RET ABN	UG-SERVICE
38561319	GRET	SVC	6/1/2021	1983	RET ABN	UG-SERVICE
43108029	GRET	SVC	6/3/2024	1983	RET ABN	UG-SERVICE
35960290	GRET	SVC	1/29/2020	1983	RET ABN	UG-SERVICE
42277980	GRET	SVC	10/23/2023	1983	RET ABN	UG-SERVICE
43108266	GRET	SVC	6/4/2024	1983	RET ABN	UG-SERVICE
41407674	GRET	SVC	4/2/2024	1983	RET ABN	UG-SERVICE
36252614	GRET	SVC	4/27/2020	1983	RET ABN	UG-SERVICE
41464831	GRET	SVC	4/4/2023	1983	RET ABN	UG-SERVICE
43027931	GRET	SVC	5/8/2024	1983	RET ABN	UG-SERVICE
37070146	GRET	SVC	12/9/2020	1983	RET ABN	UG-SERVICE
36862813	GRET	SVC	9/1/2020	1983	RET ABN	UG-SERVICE
36917247	GRET	SVC	9/9/2020	1983	RET ABN	UG-SERVICE
39577167	GRET	SVC	12/10/2021	1984	RET ABN	UG-SERVICE
40202183	GRET	SVC	5/13/2022	1984	RET ABN	UG-SERVICE
38084329	GRET	SVC	2/4/2021	1984	RET ABN	UG-SERVICE
41260666	GRET	SVC	2/8/2023	1984	RET ABN	UG-SERVICE
43312240	GRET	SVC	9/11/2024	1984	RET ABN	UG-SERVICE
43245089	GRET	SVC	9/11/2024	1984	RET ABN	UG-SERVICE
38268354	GRET	SVC	3/25/2021	1984	RET ABN	UG-SERVICE
41694385	GRET	SVC	6/1/2023	1984	RET ABN	UG-SERVICE
38000677	GRET	SVC	1/11/2021	1984	RET ABN	UG-SERVICE
40374657	GRET	SVC	8/6/2022	1984	RET ABN	UG-SERVICE
41000056	GRET	SVC	12/12/2022	1984	RET ABN	UG-SERVICE
38287710	GRET	SVC	3/30/2021	1984	RET ABN	UG-SERVICE
41411260	GRET	SVC	4/2/2024	1984	RET ABN	UG-SERVICE
43198365	GRET	SVC	6/17/2024	1984	RET ABN	UG-SERVICE
38435374	GRET	SVC	5/5/2021	1984	RET ABN	UG-SERVICE
40407477	GRET	SVC	7/11/2022	1984	RET ABN	UG-SERVICE
38047952	GRET	SVC	1/19/2021	1984	RET ABN	UG-SERVICE
41579803	GRET	SVC	4/29/2023	1984	RET ABN	UG-SERVICE
36890789	GRET	SVC	9/2/2020	1984	RET ABN	UG-SERVICE
41279382	GRET	SVC	2/24/2023	1984	RET ABN	UG-SERVICE
39662446	GRET	SVC	1/5/2022	1984	RET ABN	UG-SERVICE
37998833	GRET	SVC	1/12/2021	1984	RET ABN	UG-SERVICE
40990212	GRET	SVC	11/23/2022	1984	RET ABN	UG-SERVICE
36167955	GRET	SVC	3/23/2020	1984	RET ABN	UG-SERVICE
39390799	GRET	SVC	12/3/2021	1984	RET ABN	UG-SERVICE
40392685	GRET	SVC	7/7/2022	1984	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41424034	GRET	SVC	10/18/2023	1984	RET ABN	UG-SERVICE
37799668	GRET	SVC	11/25/2020	1984	RET ABN	UG-SERVICE
41713847	GRET	SVC	6/5/2023	1984	RET ABN	UG-SERVICE
40496069	GRET	SVC	8/4/2022	1984	RET ABN	UG-SERVICE
42131793	GRET	SVC	9/20/2023	1984	RET ABN	UG-SERVICE
41179518	GRET	SVC	5/18/2023	1984	RET ABN	UG-SERVICE
41411227	GRET	SVC	4/2/2024	1984	RET ABN	UG-SERVICE
43428103	GRET	SVC	8/12/2024	1984	RET ABN	UG-SERVICE
38616144	GRET	SVC	6/14/2021	1984	RET ABN	UG-SERVICE
43245026	GRET	SVC	9/11/2024	1984	RET ABN	UG-SERVICE
41026846	GRET	SVC	10/27/2022	1984	RET ABN	UG-SERVICE
40900985	GRET	SVC	12/3/2022	1984	RET ABN	UG-SERVICE
43245028	GRET	SVC	9/11/2024	1984	RET ABN	UG-SERVICE
36341688	GRET	SVC	5/5/2020	1984	RET ABN	UG-SERVICE
41085375	GRET	SVC	1/11/2023	1984	RET ABN	UG-SERVICE
41411199	GRET	SVC	4/2/2024	1984	RET ABN	UG-SERVICE
40458767	GRET	SVC	7/19/2022	1984	RET ABN	UG-SERVICE
43245025	GRET	SVC	9/11/2024	1984	RET ABN	UG-SERVICE
38630801	GRET	SVC	5/3/2021	1984	RET ABN	UG-SERVICE
41977429	GRET	SVC	8/11/2023	1984	RET ABN	UG-SERVICE
40242276	GRET	SVC	6/1/2022	1984	RET ABN	UG-SERVICE
40113736	GRET	SVC	5/2/2022	1984	RET ABN	UG-SERVICE
42827763	GRET	SVC	3/18/2024	1984	RET ABN	UG-SERVICE
41411238	GRET	SVC	4/2/2024	1984	RET ABN	UG-SERVICE
38874544	GRET	SVC	8/3/2021	1984	RET ABN	UG-SERVICE
37054166	GRET	SVC	10/13/2020	1984	RET ABN	UG-SERVICE
38392192	GRET	SVC	4/20/2021	1984	RET ABN	UG-SERVICE
40231466	GRET	SVC	5/31/2022	1984	RET ABN	UG-SERVICE
39312451	GRET	SVC	10/25/2021	1984	RET ABN	UG-SERVICE
41179468	GRET	SVC	1/18/2023	1984	RET ABN	UG-SERVICE
42415178	GRET	SVC	12/11/2023	1984	RET ABN	UG-SERVICE
43346953	GRET	SVC	7/22/2024	1984	RET ABN	UG-SERVICE
36177529	GRET	SVC	2/14/2020	1984	RET ABN	UG-SERVICE
36657160	GRET	SVC	7/28/2020	1984	RET ABN	UG-SERVICE
43249480	GRET	SVC	7/3/2024	1984	RET ABN	UG-SERVICE
43312241	GRET	SVC	9/11/2024	1984	RET ABN	UG-SERVICE
41183044	GRET	SVC	1/18/2023	1984	RET ABN	UG-SERVICE
43323078	GRET	SVC	8/13/2024	1984	RET ABN	UG-SERVICE
40395216	GRET	SVC	7/8/2022	1984	RET ABN	UG-SERVICE
39410505	GRET	SVC	11/10/2021	1984	RET ABN	UG-SERVICE
43312119	GRET	SVC	9/11/2024	1984	RET ABN	UG-SERVICE
41411239	GRET	SVC	4/2/2024	1984	RET ABN	UG-SERVICE
42112724	GRET	SVC	9/13/2023	1984	RET ABN	UG-SERVICE
38455370	GRET	SVC	5/5/2021	1984	RET ABN	UG-SERVICE
39513647	GRET	SVC	12/6/2021	1984	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41179478	GRET	SVC	1/17/2023	1984	RET ABN	UG-SERVICE
42834268	GRET	SVC	7/23/2024	1984	RET ABN	UG-SERVICE
42068094	GRET	SVC	9/8/2023	1984	RET ABN	UG-SERVICE
41477529	GRET	SVC	4/11/2023	1984	RET ABN	UG-SERVICE
42083819	GRET	SVC	8/28/2023	1984	RET ABN	UG-SERVICE
35996987	GRET	SVC	2/11/2020	1984	RET ABN	UG-SERVICE
41411222	GRET	SVC	4/2/2024	1984	RET ABN	UG-SERVICE
38713955	GRET	SVC	7/2/2021	1984	RET ABN	UG-SERVICE
41411220	GRET	SVC	4/2/2024	1984	RET ABN	UG-SERVICE
41334096	GRET	SVC	3/6/2023	1984	RET ABN	UG-SERVICE
41969676	GRET	SVC	8/1/2024	1984	RET ABN	UG-SERVICE
41411230	GRET	SVC	4/2/2024	1984	RET ABN	UG-SERVICE
42467159	GRET	SVC	12/22/2023	1984	RET ABN	UG-SERVICE
39501371	GRET	SVC	12/6/2021	1984	RET ABN	UG-SERVICE
43402111	GRET	SVC	8/12/2024	1985	RET ABN	UG-SERVICE
41590369	GRET	SVC	4/19/2023	1985	RET ABN	UG-SERVICE
36185114	GRET	SVC	4/23/2020	1985	RET ABN	UG-SERVICE
43353726	GRET	SVC	12/6/2024	1985	RET ABN	UG-SERVICE
43544497	GRET	SVC	9/11/2024	1985	RET ABN	UG-SERVICE
40693854	GRET	SVC	9/15/2022	1985	RET ABN	UG-SERVICE
40563205	GRET	SVC	8/21/2022	1985	RET ABN	UG-SERVICE
41067836	GRET	SVC	1/13/2023	1985	RET ABN	UG-SERVICE
40394467	GRET	SVC	7/9/2022	1985	RET ABN	UG-SERVICE
41297487	GRET	SVC	2/24/2023	1985	RET ABN	UG-SERVICE
37116580	GRET	SVC	10/28/2020	1985	RET ABN	UG-SERVICE
41969668	GRET	SVC	8/1/2024	1985	RET ABN	UG-SERVICE
42427483	GRET	SVC	9/19/2024	1985	RET ABN	UG-SERVICE
41408149	GRET	SVC	4/2/2024	1985	RET ABN	UG-SERVICE
40358442	GRET	SVC	6/17/2022	1985	RET ABN	UG-SERVICE
40316315	GRET	SVC	7/14/2022	1985	RET ABN	UG-SERVICE
42487735	GRET	SVC	7/31/2024	1985	RET ABN	UG-SERVICE
40571823	GRET	SVC	8/15/2022	1985	RET ABN	UG-SERVICE
40563206	GRET	SVC	8/21/2022	1985	RET ABN	UG-SERVICE
39401740	GRET	SVC	11/9/2021	1985	RET ABN	UG-SERVICE
41277891	GRET	SVC	3/1/2023	1985	RET ABN	UG-SERVICE
43324303	GRET	SVC	7/26/2024	1985	RET ABN	UG-SERVICE
39809488	GRET	SVC	8/3/2022	1985	RET ABN	UG-SERVICE
41858058	GRET	SVC	7/18/2023	1985	RET ABN	UG-SERVICE
41273675	GRET	SVC	2/15/2023	1985	RET ABN	UG-SERVICE
41408150	GRET	SVC	4/2/2024	1985	RET ABN	UG-SERVICE
40818513	GRET	SVC	10/17/2022	1985	RET ABN	UG-SERVICE
41650434	GRET	SVC	6/22/2023	1985	RET ABN	UG-SERVICE
39553633	GRET	SVC	12/13/2021	1985	RET ABN	UG-SERVICE
43029315	GRET	SVC	5/9/2024	1985	RET ABN	UG-SERVICE
43470857	GRET	SVC	8/23/2024	1985	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36198376	GRET	SVC	4/29/2020	1985	RET ABN	UG-SERVICE
40645039	GRET	SVC	9/3/2022	1985	RET ABN	UG-SERVICE
42921105	GRET	SVC	3/30/2024	1985	RET ABN	UG-SERVICE
43470802	GRET	SVC	8/26/2024	1985	RET ABN	UG-SERVICE
42767882	GRET	SVC	3/4/2024	1985	RET ABN	UG-SERVICE
43268813	GRET	SVC	8/12/2024	1985	RET ABN	UG-SERVICE
35145582	GRET	SVC	1/6/2020	1985	RET ABN	UG-SERVICE
40564946	GRET	SVC	8/21/2022	1985	RET ABN	UG-SERVICE
40564985	GRET	SVC	8/21/2022	1985	RET ABN	UG-SERVICE
43245041	GRET	SVC	9/19/2024	1985	RET ABN	UG-SERVICE
41430206	GRET	SVC	9/13/2023	1985	RET ABN	UG-SERVICE
40564889	GRET	SVC	8/21/2022	1985	RET ABN	UG-SERVICE
43353628	GRET	SVC	11/20/2024	1985	RET ABN	UG-SERVICE
40880404	GRET	SVC	11/3/2022	1985	RET ABN	UG-SERVICE
43353727	GRET	SVC	12/6/2024	1985	RET ABN	UG-SERVICE
40883583	GRET	SVC	11/9/2022	1985	RET ABN	UG-SERVICE
40564947	GRET	SVC	8/21/2022	1985	RET ABN	UG-SERVICE
42670285	GRET	SVC	9/19/2024	1985	RET ABN	UG-SERVICE
39556040	GRET	SVC	12/21/2021	1985	RET ABN	UG-SERVICE
40610960	GRET	SVC	8/31/2022	1985	RET ABN	UG-SERVICE
41246619	GRET	SVC	2/8/2023	1985	RET ABN	UG-SERVICE
41467793	GRET	SVC	4/4/2023	1985	RET ABN	UG-SERVICE
41423575	GRET	SVC	10/18/2023	1985	RET ABN	UG-SERVICE
41007066	GRET	SVC	12/6/2022	1985	RET ABN	UG-SERVICE
40901066	GRET	SVC	11/7/2022	1985	RET ABN	UG-SERVICE
41146285	GRET	SVC	1/13/2023	1985	RET ABN	UG-SERVICE
39971213	GRET	SVC	5/16/2022	1985	RET ABN	UG-SERVICE
35968817	GRET	SVC	2/17/2020	1985	RET ABN	UG-SERVICE
41224501	GRET	SVC	3/6/2023	1985	RET ABN	UG-SERVICE
42227665	GRET	SVC	10/31/2023	1985	RET ABN	UG-SERVICE
43226717	GRET	SVC	6/25/2024	1985	RET ABN	UG-SERVICE
43184567	GRET	SVC	6/21/2024	1985	RET ABN	UG-SERVICE
43196207	GRET	SVC	11/25/2024	1985	RET ABN	UG-SERVICE
39464272	GRET	SVC	11/26/2021	1985	RET ABN	UG-SERVICE
43353729	GRET	SVC	12/9/2024	1985	RET ABN	UG-SERVICE
38769233	GRET	SVC	8/30/2021	1985	RET ABN	UG-SERVICE
42246561	GRET	SVC	10/3/2023	1985	RET ABN	UG-SERVICE
38014205	GRET	SVC	1/11/2021	1985	RET ABN	UG-SERVICE
40880416	GRET	SVC	11/3/2022	1985	RET ABN	UG-SERVICE
42236041	GRET	SVC	10/18/2023	1985	RET ABN	UG-SERVICE
41015753	GRET	SVC	12/14/2022	1985	RET ABN	UG-SERVICE
40564888	GRET	SVC	8/21/2022	1985	RET ABN	UG-SERVICE
42958105	GRET	SVC	9/19/2024	1985	RET ABN	UG-SERVICE
40564904	GRET	SVC	8/21/2022	1985	RET ABN	UG-SERVICE
38373204	GRET	SVC	4/14/2021	1985	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40564714	GRET	SVC	8/21/2022	1985	RET ABN	UG-SERVICE
43769717	GRET	SVC	9/19/2024	1985	RET ABN	UG-SERVICE
41430117	GRET	SVC	9/13/2023	1985	RET ABN	UG-SERVICE
43353800	GRET	SVC	12/9/2024	1985	RET ABN	UG-SERVICE
41408077	GRET	SVC	4/2/2024	1985	RET ABN	UG-SERVICE
41067835	GRET	SVC	1/13/2023	1985	RET ABN	UG-SERVICE
35973037	GRET	SVC	2/4/2020	1985	RET ABN	UG-SERVICE
43353809	GRET	SVC	12/11/2024	1985	RET ABN	UG-SERVICE
40577493	GRET	SVC	8/16/2022	1985	RET ABN	UG-SERVICE
40564411	GRET	SVC	8/21/2022	1985	RET ABN	UG-SERVICE
41185583	GRET	SVC	1/17/2023	1985	RET ABN	UG-SERVICE
41843595	GRET	SVC	7/3/2023	1985	RET ABN	UG-SERVICE
40973113	GRET	SVC	11/18/2022	1985	RET ABN	UG-SERVICE
38221177	GRET	SVC	3/13/2021	1985	RET ABN	UG-SERVICE
43604511	GRET	SVC	9/23/2024	1985	RET ABN	UG-SERVICE
42427399	GRET	SVC	9/19/2024	1985	RET ABN	UG-SERVICE
43353739	GRET	SVC	12/3/2024	1985	RET ABN	UG-SERVICE
40900910	GRET	SVC	11/7/2022	1985	RET ABN	UG-SERVICE
38623200	GRET	SVC	6/16/2021	1985	RET ABN	UG-SERVICE
42427101	GRET	SVC	9/19/2024	1985	RET ABN	UG-SERVICE
40856537	GRET	SVC	10/25/2022	1985	RET ABN	UG-SERVICE
42903980	GRET	SVC	4/18/2024	1985	RET ABN	UG-SERVICE
43850749	GRET	SVC	11/18/2024	1985	RET ABN	UG-SERVICE
41411773	GRET	SVC	4/2/2024	1985	RET ABN	UG-SERVICE
41273670	GRET	SVC	2/28/2023	1985	RET ABN	UG-SERVICE
40883590	GRET	SVC	11/9/2022	1985	RET ABN	UG-SERVICE
41409102	GRET	SVC	4/2/2024	1986	RET ABN	UG-SERVICE
36142601	GRET	SVC	3/18/2020	1986	RET ABN	UG-SERVICE
41430201	GRET	SVC	9/13/2023	1986	RET ABN	UG-SERVICE
40778394	GRET	SVC	10/3/2022	1986	RET ABN	UG-SERVICE
43858607	GRET	SVC	11/23/2024	1986	RET ABN	UG-SERVICE
40915198	GRET	SVC	11/9/2022	1986	RET ABN	UG-SERVICE
40641380	GRET	SVC	8/30/2022	1986	RET ABN	UG-SERVICE
38090689	GRET	SVC	2/5/2021	1986	RET ABN	UG-SERVICE
41062439	GRET	SVC	12/14/2022	1986	RET ABN	UG-SERVICE
37335731	GRET	SVC	2/26/2021	1986	RET ABN	UG-SERVICE
43353631	GRET	SVC	11/20/2024	1986	RET ABN	UG-SERVICE
41430200	GRET	SVC	9/13/2023	1986	RET ABN	UG-SERVICE
38562884	GRET	SVC	6/7/2021	1986	RET ABN	UG-SERVICE
41325531	GRET	SVC	3/20/2023	1986	RET ABN	UG-SERVICE
41469915	GRET	SVC	4/4/2023	1986	RET ABN	UG-SERVICE
43353806	GRET	SVC	12/12/2024	1986	RET ABN	UG-SERVICE
42316691	GRET	SVC	4/2/2024	1986	RET ABN	UG-SERVICE
38562880	GRET	SVC	6/7/2021	1986	RET ABN	UG-SERVICE
41556036	GRET	SVC	4/24/2023	1986	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40919248	GRET	SVC	1/6/2023	1986	RET ABN	UG-SERVICE
39335724	GRET	SVC	10/26/2021	1986	RET ABN	UG-SERVICE
42873728	GRET	SVC	4/1/2024	1986	RET ABN	UG-SERVICE
43816202	GRET	SVC	12/9/2024	1986	RET ABN	UG-SERVICE
39923622	GRET	SVC	3/22/2022	1986	RET ABN	UG-SERVICE
39126541	GRET	SVC	9/3/2021	1986	RET ABN	UG-SERVICE
38592110	GRET	SVC	4/17/2021	1986	RET ABN	UG-SERVICE
43353730	GRET	SVC	12/9/2024	1986	RET ABN	UG-SERVICE
43353457	GRET	SVC	11/18/2024	1986	RET ABN	UG-SERVICE
38299044	GRET	SVC	3/31/2021	1986	RET ABN	UG-SERVICE
38352974	GRET	SVC	2/14/2023	1986	RET ABN	UG-SERVICE
40141357	GRET	SVC	5/23/2022	1986	RET ABN	UG-SERVICE
40100832	GRET	SVC	3/18/2022	1986	RET ABN	UG-SERVICE
35960077	GRET	SVC	1/30/2020	1986	RET ABN	UG-SERVICE
40618650	GRET	SVC	8/25/2022	1986	RET ABN	UG-SERVICE
40530414	GRET	SVC	11/7/2022	1986	RET ABN	UG-SERVICE
37325498	GRET	SVC	2/25/2021	1986	RET ABN	UG-SERVICE
41821347	GRET	SVC	6/26/2023	1986	RET ABN	UG-SERVICE
41940034	GRET	SVC	8/6/2023	1986	RET ABN	UG-SERVICE
37561056	GRET	SVC	11/19/2020	1986	RET ABN	UG-SERVICE
43353722	GRET	SVC	12/18/2024	1986	RET ABN	UG-SERVICE
36886014	GRET	SVC	9/1/2020	1986	RET ABN	UG-SERVICE
42048632	GRET	SVC	9/13/2023	1986	RET ABN	UG-SERVICE
41298437	GRET	SVC	8/31/2023	1986	RET ABN	UG-SERVICE
36347720	GRET	SVC	6/29/2020	1986	RET ABN	UG-SERVICE
39335722	GRET	SVC	10/26/2021	1986	RET ABN	UG-SERVICE
43328639	GRET	SVC	7/18/2024	1986	RET ABN	UG-SERVICE
39739689	GRET	SVC	2/10/2022	1986	RET ABN	UG-SERVICE
42203605	GRET	SVC	10/11/2023	1986	RET ABN	UG-SERVICE
40778618	GRET	SVC	10/2/2022	1986	RET ABN	UG-SERVICE
42824956	GRET	SVC	3/13/2024	1986	RET ABN	UG-SERVICE
37115998	GRET	SVC	10/29/2020	1986	RET ABN	UG-SERVICE
41085615	GRET	SVC	12/21/2022	1986	RET ABN	UG-SERVICE
41834505	GRET	SVC	7/21/2023	1986	RET ABN	UG-SERVICE
40303912	GRET	SVC	6/14/2022	1986	RET ABN	UG-SERVICE
42992822	GRET	SVC	4/29/2024	1986	RET ABN	UG-SERVICE
40395529	GRET	SVC	7/7/2022	1986	RET ABN	UG-SERVICE
43324511	GRET	SVC	10/11/2024	1986	RET ABN	UG-SERVICE
41082947	GRET	SVC	12/21/2022	1986	RET ABN	UG-SERVICE
42425594	GRET	SVC	11/30/2023	1986	RET ABN	UG-SERVICE
39177336	GRET	SVC	9/23/2021	1986	RET ABN	UG-SERVICE
42176861	GRET	SVC	10/6/2023	1986	RET ABN	UG-SERVICE
41411501	GRET	SVC	4/2/2024	1986	RET ABN	UG-SERVICE
38441491	GRET	SVC	1/6/2022	1986	RET ABN	UG-SERVICE
38286666	GRET	SVC	3/31/2021	1986	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41959905	GRET	SVC	8/7/2023	1986	RET ABN	UG-SERVICE
40944977	GRET	SVC	11/17/2022	1986	RET ABN	UG-SERVICE
43364933	GRET	SVC	12/4/2024	1986	RET ABN	UG-SERVICE
39930692	GRET	SVC	4/7/2022	1986	RET ABN	UG-SERVICE
43353733	GRET	SVC	12/11/2024	1986	RET ABN	UG-SERVICE
41407743	GRET	SVC	4/2/2024	1986	RET ABN	UG-SERVICE
41185589	GRET	SVC	1/21/2023	1986	RET ABN	UG-SERVICE
38635574	GRET	SVC	6/17/2021	1986	RET ABN	UG-SERVICE
38562886	GRET	SVC	6/7/2021	1986	RET ABN	UG-SERVICE
41325581	GRET	SVC	3/20/2023	1986	RET ABN	UG-SERVICE
41333801	GRET	SVC	3/3/2023	1986	RET ABN	UG-SERVICE
36064582	GRET	SVC	2/26/2020	1986	RET ABN	UG-SERVICE
40124292	GRET	SVC	5/10/2022	1986	RET ABN	UG-SERVICE
41411506	GRET	SVC	4/2/2024	1986	RET ABN	UG-SERVICE
43917756	GRET	SVC	12/9/2024	1986	RET ABN	UG-SERVICE
41555032	GRET	SVC	5/11/2023	1986	RET ABN	UG-SERVICE
37561059	GRET	SVC	11/19/2020	1986	RET ABN	UG-SERVICE
41766898	GRET	SVC	6/20/2023	1986	RET ABN	UG-SERVICE
41129397	GRET	SVC	1/4/2023	1986	RET ABN	UG-SERVICE
35940152	GRET	SVC	1/17/2020	1986	RET ABN	UG-SERVICE
41324834	GRET	SVC	3/20/2023	1986	RET ABN	UG-SERVICE
36485751	GRET	SVC	6/24/2020	1986	RET ABN	UG-SERVICE
37335724	GRET	SVC	2/25/2021	1986	RET ABN	UG-SERVICE
40157835	GRET	SVC	5/17/2022	1986	RET ABN	UG-SERVICE
43353456	GRET	SVC	11/18/2024	1986	RET ABN	UG-SERVICE
39922170	GRET	SVC	3/22/2022	1986	RET ABN	UG-SERVICE
37561057	GRET	SVC	11/19/2020	1986	RET ABN	UG-SERVICE
42954554	GRET	SVC	4/17/2024	1986	RET ABN	UG-SERVICE
41808857	GRET	SVC	6/24/2023	1986	RET ABN	UG-SERVICE
39311633	GRET	SVC	10/27/2021	1986	RET ABN	UG-SERVICE
40656089	GRET	SVC	8/31/2022	1986	RET ABN	UG-SERVICE
42227361	GRET	SVC	10/31/2023	1986	RET ABN	UG-SERVICE
38448870	GRET	SVC	5/5/2021	1986	RET ABN	UG-SERVICE
41427441	GRET	SVC	3/24/2023	1986	RET ABN	UG-SERVICE
37561058	GRET	SVC	12/15/2020	1986	RET ABN	UG-SERVICE
42278935	GRET	SVC	10/27/2023	1986	RET ABN	UG-SERVICE
43353731	GRET	SVC	12/6/2024	1986	RET ABN	UG-SERVICE
38059384	GRET	SVC	1/28/2021	1986	RET ABN	UG-SERVICE
40035473	GRET	SVC	4/19/2022	1986	RET ABN	UG-SERVICE
39930697	GRET	SVC	4/7/2022	1986	RET ABN	UG-SERVICE
41185585	GRET	SVC	1/21/2023	1986	RET ABN	UG-SERVICE
43353805	GRET	SVC	12/12/2024	1986	RET ABN	UG-SERVICE
41325543	GRET	SVC	3/20/2023	1986	RET ABN	UG-SERVICE
40264630	GRET	SVC	6/7/2022	1986	RET ABN	UG-SERVICE
36994489	GRET	SVC	9/28/2020	1986	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41775175	GRET	SVC	6/22/2023	1987	RET ABN	UG-SERVICE
43353620	GRET	SVC	11/22/2024	1987	RET ABN	UG-SERVICE
41289007	GRET	SVC	2/22/2023	1987	RET ABN	UG-SERVICE
36776304	GRET	SVC	8/4/2020	1987	RET ABN	UG-SERVICE
40487118	GRET	SVC	7/25/2022	1987	RET ABN	UG-SERVICE
38272961	GRET	SVC	3/24/2021	1987	RET ABN	UG-SERVICE
38357053	GRET	SVC	2/17/2023	1987	RET ABN	UG-SERVICE
39831464	GRET	SVC	8/3/2022	1987	RET ABN	UG-SERVICE
41283634	GRET	SVC	2/18/2023	1987	RET ABN	UG-SERVICE
40953701	GRET	SVC	11/23/2022	1987	RET ABN	UG-SERVICE
38609048	GRET	SVC	6/10/2021	1987	RET ABN	UG-SERVICE
40124284	GRET	SVC	5/6/2022	1987	RET ABN	UG-SERVICE
42526562	GRET	SVC	1/18/2024	1987	RET ABN	UG-SERVICE
38352978	GRET	SVC	2/17/2023	1987	RET ABN	UG-SERVICE
36949436	GRET	SVC	10/4/2020	1987	RET ABN	UG-SERVICE
38413341	GRET	SVC	8/30/2021	1987	RET ABN	UG-SERVICE
41283623	GRET	SVC	3/15/2023	1987	RET ABN	UG-SERVICE
38542012	GRET	SVC	5/27/2021	1987	RET ABN	UG-SERVICE
41357646	GRET	SVC	3/9/2023	1987	RET ABN	UG-SERVICE
42468286	GRET	SVC	12/12/2023	1987	RET ABN	UG-SERVICE
42870507	GRET	SVC	4/25/2024	1987	RET ABN	UG-SERVICE
43353636	GRET	SVC	12/18/2024	1987	RET ABN	UG-SERVICE
36369313	GRET	SVC	5/27/2020	1987	RET ABN	UG-SERVICE
42671592	GRET	SVC	2/6/2024	1987	RET ABN	UG-SERVICE
39750438	GRET	SVC	5/11/2022	1987	RET ABN	UG-SERVICE
38352927	GRET	SVC	2/17/2023	1987	RET ABN	UG-SERVICE
40976952	GRET	SVC	11/23/2022	1987	RET ABN	UG-SERVICE
42373244	GRET	SVC	11/16/2023	1987	RET ABN	UG-SERVICE
38416005	GRET	SVC	4/26/2021	1987	RET ABN	UG-SERVICE
41509119	GRET	SVC	5/28/2023	1987	RET ABN	UG-SERVICE
39411207	GRET	SVC	11/11/2021	1987	RET ABN	UG-SERVICE
36122361	GRET	SVC	11/5/2020	1987	RET ABN	UG-SERVICE
43241926	GRET	SVC	12/27/2024	1987	RET ABN	UG-SERVICE
43480985	GRET	SVC	10/6/2024	1987	RET ABN	UG-SERVICE
38353001	GRET	SVC	2/14/2023	1987	RET ABN	UG-SERVICE
37973581	GRET	SVC	1/5/2021	1987	RET ABN	UG-SERVICE
36306799	GRET	SVC	6/10/2020	1987	RET ABN	UG-SERVICE
42022519	GRET	SVC	8/19/2023	1987	RET ABN	UG-SERVICE
41283432	GRET	SVC	2/14/2023	1987	RET ABN	UG-SERVICE
42962467	GRET	SVC	4/20/2024	1987	RET ABN	UG-SERVICE
38230875	GRET	SVC	3/16/2021	1987	RET ABN	UG-SERVICE
39093243	GRET	SVC	9/8/2021	1987	RET ABN	UG-SERVICE
36741663	GRET	SVC	8/3/2020	1987	RET ABN	UG-SERVICE
40420448	GRET	SVC	7/11/2022	1987	RET ABN	UG-SERVICE
36992843	GRET	SVC	10/1/2020	1987	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43347390	GRET	SVC	7/24/2024	1987	RET ABN	UG-SERVICE
41283621	GRET	SVC	2/25/2023	1987	RET ABN	UG-SERVICE
38207399	GRET	SVC	3/10/2021	1987	RET ABN	UG-SERVICE
38097603	GRET	SVC	1/29/2021	1987	RET ABN	UG-SERVICE
38887676	GRET	SVC	8/19/2021	1987	RET ABN	UG-SERVICE
43219819	GRET	SVC	6/24/2024	1987	RET ABN	UG-SERVICE
40516609	GRET	SVC	8/5/2022	1987	RET ABN	UG-SERVICE
42313715	GRET	SVC	10/27/2023	1987	RET ABN	UG-SERVICE
42503102	GRET	SVC	12/19/2023	1987	RET ABN	UG-SERVICE
40395538	GRET	SVC	7/6/2022	1987	RET ABN	UG-SERVICE
36602938	GRET	SVC	7/7/2020	1987	RET ABN	UG-SERVICE
39848408	GRET	SVC	6/10/2022	1987	RET ABN	UG-SERVICE
43353621	GRET	SVC	11/22/2024	1987	RET ABN	UG-SERVICE
36955071	GRET	SVC	9/17/2020	1987	RET ABN	UG-SERVICE
40396047	GRET	SVC	7/8/2022	1987	RET ABN	UG-SERVICE
36330971	GRET	SVC	5/19/2020	1987	RET ABN	UG-SERVICE
36122291	GRET	SVC	11/5/2020	1987	RET ABN	UG-SERVICE
39491988	GRET	SVC	12/6/2021	1987	RET ABN	UG-SERVICE
42435909	GRET	SVC	9/19/2024	1987	RET ABN	UG-SERVICE
38083269	GRET	SVC	2/1/2021	1987	RET ABN	UG-SERVICE
40805952	GRET	SVC	10/10/2022	1987	RET ABN	UG-SERVICE
36063444	GRET	SVC	2/24/2020	1987	RET ABN	UG-SERVICE
42007814	GRET	SVC	8/15/2023	1987	RET ABN	UG-SERVICE
43738581	GRET	SVC	10/19/2024	1987	RET ABN	UG-SERVICE
40424138	GRET	SVC	7/12/2022	1987	RET ABN	UG-SERVICE
43481041	GRET	SVC	11/2/2024	1987	RET ABN	UG-SERVICE
41954550	GRET	SVC	8/21/2023	1987	RET ABN	UG-SERVICE
38560872	GRET	SVC	6/1/2021	1987	RET ABN	UG-SERVICE
39750719	GRET	SVC	2/1/2022	1987	RET ABN	UG-SERVICE
41325600	GRET	SVC	3/20/2023	1987	RET ABN	UG-SERVICE
41283330	GRET	SVC	3/15/2023	1987	RET ABN	UG-SERVICE
42962575	GRET	SVC	4/20/2024	1987	RET ABN	UG-SERVICE
41528448	GRET	SVC	5/2/2023	1987	RET ABN	UG-SERVICE
41528299	GRET	SVC	5/2/2023	1987	RET ABN	UG-SERVICE
39497286	GRET	SVC	12/7/2021	1987	RET ABN	UG-SERVICE
39553322	GRET	SVC	12/20/2021	1987	RET ABN	UG-SERVICE
42905534	GRET	SVC	4/1/2024	1987	RET ABN	UG-SERVICE
39671168	GRET	SVC	1/10/2022	1987	RET ABN	UG-SERVICE
40188718	GRET	SVC	5/18/2022	1987	RET ABN	UG-SERVICE
41509377	GRET	SVC	5/5/2023	1987	RET ABN	UG-SERVICE
41176377	GRET	SVC	3/13/2023	1987	RET ABN	UG-SERVICE
36969026	GRET	SVC	12/9/2020	1987	RET ABN	UG-SERVICE
38137182	GRET	SVC	2/18/2021	1987	RET ABN	UG-SERVICE
42487739	GRET	SVC	7/31/2024	1987	RET ABN	UG-SERVICE
37956427	GRET	SVC	12/21/2020	1987	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36630719	GRET	SVC	7/16/2020	1987	RET ABN	UG-SERVICE
42453416	GRET	SVC	12/2/2023	1987	RET ABN	UG-SERVICE
38352547	GRET	SVC	2/14/2023	1987	RET ABN	UG-SERVICE
36009861	GRET	SVC	2/13/2020	1987	RET ABN	UG-SERVICE
43219492	GRET	SVC	6/24/2024	1987	RET ABN	UG-SERVICE
42204420	GRET	SVC	10/9/2023	1987	RET ABN	UG-SERVICE
39418862	GRET	SVC	11/15/2021	1987	RET ABN	UG-SERVICE
40023412	GRET	SVC	3/8/2022	1987	RET ABN	UG-SERVICE
38376390	GRET	SVC	4/19/2021	1987	RET ABN	UG-SERVICE
43832784	GRET	SVC	12/17/2024	1987	RET ABN	UG-SERVICE
41953092	GRET	SVC	8/5/2023	1987	RET ABN	UG-SERVICE
43888925	GRET	SVC	12/2/2024	1987	RET ABN	UG-SERVICE
41497634	GRET	SVC	4/24/2023	1987	RET ABN	UG-SERVICE
36730526	GRET	SVC	8/18/2020	1987	RET ABN	UG-SERVICE
39837092	GRET	SVC	3/2/2022	1987	RET ABN	UG-SERVICE
38356734	GRET	SVC	2/17/2023	1987	RET ABN	UG-SERVICE
43353639	GRET	SVC	11/19/2024	1987	RET ABN	UG-SERVICE
41544094	GRET	SVC	4/24/2023	1987	RET ABN	UG-SERVICE
40640652	GRET	SVC	8/30/2022	1987	RET ABN	UG-SERVICE
40359842	GRET	SVC	6/22/2022	1988	RET ABN	UG-SERVICE
42482398	GRET	SVC	12/13/2023	1988	RET ABN	UG-SERVICE
43529721	GRET	SVC	11/23/2024	1988	RET ABN	UG-SERVICE
41348101	GRET	SVC	3/8/2023	1988	RET ABN	UG-SERVICE
42131094	GRET	SVC	10/2/2023	1988	RET ABN	UG-SERVICE
43424554	GRET	SVC	8/13/2024	1988	RET ABN	UG-SERVICE
41484000	GRET	SVC	4/18/2023	1988	RET ABN	UG-SERVICE
42902358	GRET	SVC	4/10/2024	1988	RET ABN	UG-SERVICE
40802832	GRET	SVC	10/10/2022	1988	RET ABN	UG-SERVICE
38664195	GRET	SVC	6/24/2021	1988	RET ABN	UG-SERVICE
41330583	GRET	SVC	3/6/2023	1988	RET ABN	UG-SERVICE
39726224	GRET	SVC	1/28/2022	1988	RET ABN	UG-SERVICE
43347989	GRET	SVC	7/21/2024	1988	RET ABN	UG-SERVICE
41484001	GRET	SVC	4/18/2023	1988	RET ABN	UG-SERVICE
43344816	GRET	SVC	7/24/2024	1988	RET ABN	UG-SERVICE
43353720	GRET	SVC	11/20/2024	1988	RET ABN	UG-SERVICE
43356661	GRET	SVC	8/5/2024	1988	RET ABN	UG-SERVICE
40690298	GRET	SVC	9/14/2022	1988	RET ABN	UG-SERVICE
38019271	GRET	SVC	1/15/2021	1988	RET ABN	UG-SERVICE
41672952	GRET	SVC	5/24/2023	1988	RET ABN	UG-SERVICE
40318193	GRET	SVC	6/17/2022	1988	RET ABN	UG-SERVICE
42033831	GRET	SVC	8/21/2023	1988	RET ABN	UG-SERVICE
38352353	GRET	SVC	2/14/2023	1988	RET ABN	UG-SERVICE
41317157	GRET	SVC	3/5/2023	1988	RET ABN	UG-SERVICE
40330082	GRET	SVC	6/22/2022	1988	RET ABN	UG-SERVICE
41509368	GRET	SVC	4/18/2023	1988	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38936983	GRET	SVC	9/29/2021	1988	RET ABN	UG-SERVICE
43522111	GRET	SVC	8/20/2024	1988	RET ABN	UG-SERVICE
40312080	GRET	SVC	6/22/2022	1988	RET ABN	UG-SERVICE
36664628	GRET	SVC	7/23/2020	1988	RET ABN	UG-SERVICE
42130053	GRET	SVC	9/20/2023	1988	RET ABN	UG-SERVICE
43230016	GRET	SVC	6/30/2024	1988	RET ABN	UG-SERVICE
39091925	GRET	SVC	9/7/2021	1988	RET ABN	UG-SERVICE
40384102	GRET	SVC	7/5/2022	1988	RET ABN	UG-SERVICE
39904611	GRET	SVC	3/21/2022	1988	RET ABN	UG-SERVICE
38353007	GRET	SVC	2/17/2023	1988	RET ABN	UG-SERVICE
42646567	GRET	SVC	1/29/2024	1988	RET ABN	UG-SERVICE
38352960	GRET	SVC	2/17/2023	1988	RET ABN	UG-SERVICE
39831389	GRET	SVC	8/3/2022	1988	RET ABN	UG-SERVICE
39429947	GRET	SVC	11/18/2021	1988	RET ABN	UG-SERVICE
43417615	GRET	SVC	8/13/2024	1988	RET ABN	UG-SERVICE
43060076	GRET	SVC	5/14/2024	1988	RET ABN	UG-SERVICE
37809721	GRET	SVC	11/21/2020	1988	RET ABN	UG-SERVICE
41483262	GRET	SVC	4/11/2023	1988	RET ABN	UG-SERVICE
41509363	GRET	SVC	4/17/2023	1988	RET ABN	UG-SERVICE
43909688	GRET	SVC	12/19/2024	1988	RET ABN	UG-SERVICE
41484578	GRET	SVC	4/11/2023	1988	RET ABN	UG-SERVICE
38548333	GRET	SVC	6/1/2021	1988	RET ABN	UG-SERVICE
38353011	GRET	SVC	2/14/2023	1988	RET ABN	UG-SERVICE
43028883	GRET	SVC	5/15/2024	1988	RET ABN	UG-SERVICE
38352963	GRET	SVC	2/17/2023	1988	RET ABN	UG-SERVICE
43680029	GRET	SVC	10/31/2024	1988	RET ABN	UG-SERVICE
43868034	GRET	SVC	11/25/2024	1988	RET ABN	UG-SERVICE
43086380	GRET	SVC	5/20/2024	1988	RET ABN	UG-SERVICE
38333914	GRET	SVC	4/8/2021	1988	RET ABN	UG-SERVICE
41339575	GRET	SVC	3/19/2023	1988	RET ABN	UG-SERVICE
38353002	GRET	SVC	2/14/2023	1988	RET ABN	UG-SERVICE
39735614	GRET	SVC	1/27/2022	1988	RET ABN	UG-SERVICE
39831200	GRET	SVC	8/3/2022	1988	RET ABN	UG-SERVICE
36085780	GRET	SVC	2/28/2020	1988	RET ABN	UG-SERVICE
38356735	GRET	SVC	2/17/2023	1988	RET ABN	UG-SERVICE
40461419	GRET	SVC	7/22/2022	1988	RET ABN	UG-SERVICE
41411401	GRET	SVC	4/2/2024	1988	RET ABN	UG-SERVICE
41784366	GRET	SVC	4/25/2024	1988	RET ABN	UG-SERVICE
38352964	GRET	SVC	2/17/2023	1988	RET ABN	UG-SERVICE
40150983	GRET	SVC	4/27/2022	1988	RET ABN	UG-SERVICE
41473285	GRET	SVC	4/6/2023	1988	RET ABN	UG-SERVICE
41480838	GRET	SVC	4/8/2023	1988	RET ABN	UG-SERVICE
42115092	GRET	SVC	9/15/2023	1988	RET ABN	UG-SERVICE
39579981	GRET	SVC	12/27/2021	1988	RET ABN	UG-SERVICE
43070081	GRET	SVC	5/17/2024	1988	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42272964	GRET	SVC	12/21/2023	1988	RET ABN	UG-SERVICE
38536246	GRET	SVC	5/26/2021	1988	RET ABN	UG-SERVICE
41859584	GRET	SVC	7/12/2023	1988	RET ABN	UG-SERVICE
43635664	GRET	SVC	9/27/2024	1988	RET ABN	UG-SERVICE
41485401	GRET	SVC	4/10/2023	1988	RET ABN	UG-SERVICE
40701884	GRET	SVC	9/15/2022	1988	RET ABN	UG-SERVICE
43516694	GRET	SVC	9/4/2024	1988	RET ABN	UG-SERVICE
39843561	GRET	SVC	3/1/2022	1988	RET ABN	UG-SERVICE
36173692	GRET	SVC	3/24/2020	1988	RET ABN	UG-SERVICE
38134101	GRET	SVC	2/15/2021	1988	RET ABN	UG-SERVICE
39654874	GRET	SVC	6/28/2022	1988	RET ABN	UG-SERVICE
41484635	GRET	SVC	4/14/2023	1988	RET ABN	UG-SERVICE
40860141	GRET	SVC	10/25/2022	1988	RET ABN	UG-SERVICE
38776342	GRET	SVC	7/16/2021	1988	RET ABN	UG-SERVICE
38536250	GRET	SVC	5/26/2021	1988	RET ABN	UG-SERVICE
41347538	GRET	SVC	3/17/2023	1988	RET ABN	UG-SERVICE
40353605	GRET	SVC	6/27/2022	1988	RET ABN	UG-SERVICE
41411428	GRET	SVC	11/2/2023	1988	RET ABN	UG-SERVICE
43173752	GRET	SVC	7/17/2024	1988	RET ABN	UG-SERVICE
41655778	GRET	SVC	5/22/2023	1988	RET ABN	UG-SERVICE
38681133	GRET	SVC	6/28/2021	1988	RET ABN	UG-SERVICE
40952592	GRET	SVC	11/17/2022	1988	RET ABN	UG-SERVICE
37809726	GRET	SVC	11/21/2020	1988	RET ABN	UG-SERVICE
42833095	GRET	SVC	7/22/2024	1988	RET ABN	UG-SERVICE
41484824	GRET	SVC	4/18/2023	1988	RET ABN	UG-SERVICE
39390980	GRET	SVC	11/22/2021	1988	RET ABN	UG-SERVICE
42902622	GRET	SVC	4/10/2024	1988	RET ABN	UG-SERVICE
41483261	GRET	SVC	4/11/2023	1988	RET ABN	UG-SERVICE
42878215	GRET	SVC	4/1/2024	1988	RET ABN	UG-SERVICE
43388730	GRET	SVC	8/8/2024	1988	RET ABN	UG-SERVICE
38352939	GRET	SVC	2/17/2023	1988	RET ABN	UG-SERVICE
41339786	GRET	SVC	3/20/2023	1988	RET ABN	UG-SERVICE
39255672	GRET	SVC	10/6/2021	1988	RET ABN	UG-SERVICE
41427597	GRET	SVC	4/11/2023	1988	RET ABN	UG-SERVICE
43907132	GRET	SVC	12/2/2024	1988	RET ABN	UG-SERVICE
40897519	GRET	SVC	10/20/2022	1988	RET ABN	UG-SERVICE
42233736	GRET	SVC	10/17/2023	1988	RET ABN	UG-SERVICE
41183431	GRET	SVC	1/21/2023	1988	RET ABN	UG-SERVICE
36119470	GRET	SVC	3/11/2020	1988	RET ABN	UG-SERVICE
37561228	GRET	SVC	11/18/2020	1988	RET ABN	UG-SERVICE
41728023	GRET	SVC	6/8/2023	1988	RET ABN	UG-SERVICE
41918029	GRET	SVC	7/25/2023	1988	RET ABN	UG-SERVICE
43648056	GRET	SVC	10/8/2024	1988	RET ABN	UG-SERVICE
36330193	GRET	SVC	5/13/2020	1988	RET ABN	UG-SERVICE
41339783	GRET	SVC	3/19/2023	1988	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40371068	GRET	SVC	7/6/2022	1988	RET ABN	UG-SERVICE
38409136	GRET	SVC	5/11/2021	1988	RET ABN	UG-SERVICE
43704279	GRET	SVC	10/18/2024	1988	RET ABN	UG-SERVICE
40005608	GRET	SVC	5/4/2022	1988	RET ABN	UG-SERVICE
38353010	GRET	SVC	2/14/2023	1988	RET ABN	UG-SERVICE
38352962	GRET	SVC	2/17/2023	1988	RET ABN	UG-SERVICE
39979951	GRET	SVC	4/12/2022	1988	RET ABN	UG-SERVICE
40869760	GRET	SVC	11/14/2022	1988	RET ABN	UG-SERVICE
39780198	GRET	SVC	2/10/2022	1988	RET ABN	UG-SERVICE
38353009	GRET	SVC	2/14/2023	1988	RET ABN	UG-SERVICE
42902291	GRET	SVC	4/10/2024	1988	RET ABN	UG-SERVICE
39903260	GRET	SVC	3/17/2022	1988	RET ABN	UG-SERVICE
40360328	GRET	SVC	6/30/2022	1989	RET ABN	UG-SERVICE
40806360	GRET	SVC	10/13/2022	1989	RET ABN	UG-SERVICE
38326366	GRET	SVC	4/7/2021	1989	RET ABN	UG-SERVICE
43826495	GRET	SVC	11/21/2024	1989	RET ABN	UG-SERVICE
36045098	GRET	SVC	2/17/2020	1989	RET ABN	UG-SERVICE
41528451	GRET	SVC	4/26/2023	1989	RET ABN	UG-SERVICE
39657989	GRET	SVC	2/11/2022	1989	RET ABN	UG-SERVICE
41411417	GRET	SVC	11/2/2023	1989	RET ABN	UG-SERVICE
42097440	GRET	SVC	9/12/2023	1989	RET ABN	UG-SERVICE
43711682	GRET	SVC	10/17/2024	1989	RET ABN	UG-SERVICE
42338142	GRET	SVC	11/5/2023	1989	RET ABN	UG-SERVICE
36397955	GRET	SVC	5/31/2020	1989	RET ABN	UG-SERVICE
35965101	GRET	SVC	1/25/2020	1989	RET ABN	UG-SERVICE
43606775	GRET	SVC	9/23/2024	1989	RET ABN	UG-SERVICE
43364867	GRET	SVC	11/15/2024	1989	RET ABN	UG-SERVICE
40524623	GRET	SVC	8/20/2022	1989	RET ABN	UG-SERVICE
42841262	GRET	SVC	3/20/2024	1989	RET ABN	UG-SERVICE
40861132	GRET	SVC	11/3/2022	1989	RET ABN	UG-SERVICE
43889223	GRET	SVC	12/2/2024	1989	RET ABN	UG-SERVICE
38326368	GRET	SVC	4/7/2021	1989	RET ABN	UG-SERVICE
40954338	GRET	SVC	11/25/2022	1989	RET ABN	UG-SERVICE
42672485	GRET	SVC	2/7/2024	1989	RET ABN	UG-SERVICE
39531120	GRET	SVC	11/11/2021	1989	RET ABN	UG-SERVICE
38326367	GRET	SVC	4/7/2021	1989	RET ABN	UG-SERVICE
42833107	GRET	SVC	3/20/2024	1989	RET ABN	UG-SERVICE
39306862	GRET	SVC	10/25/2021	1989	RET ABN	UG-SERVICE
43741572	GRET	SVC	10/23/2024	1989	RET ABN	UG-SERVICE
42338153	GRET	SVC	11/5/2023	1989	RET ABN	UG-SERVICE
40988811	GRET	SVC	11/29/2022	1989	RET ABN	UG-SERVICE
42338155	GRET	SVC	11/5/2023	1989	RET ABN	UG-SERVICE
40974231	GRET	SVC	11/30/2022	1989	RET ABN	UG-SERVICE
40664487	GRET	SVC	9/6/2022	1989	RET ABN	UG-SERVICE
36953283	GRET	SVC	9/17/2020	1989	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36177524	GRET	SVC	2/14/2020	1989	RET ABN	UG-SERVICE
43547702	GRET	SVC	10/21/2024	1989	RET ABN	UG-SERVICE
40845456	GRET	SVC	10/25/2022	1989	RET ABN	UG-SERVICE
36967478	GRET	SVC	9/21/2020	1989	RET ABN	UG-SERVICE
38326365	GRET	SVC	4/7/2021	1989	RET ABN	UG-SERVICE
40361069	GRET	SVC	6/29/2022	1989	RET ABN	UG-SERVICE
36732249	GRET	SVC	8/3/2020	1989	RET ABN	UG-SERVICE
39436428	GRET	SVC	11/18/2021	1989	RET ABN	UG-SERVICE
43324191	GRET	SVC	12/17/2024	1989	RET ABN	UG-SERVICE
42484631	GRET	SVC	12/9/2023	1989	RET ABN	UG-SERVICE
40282633	GRET	SVC	6/8/2022	1989	RET ABN	UG-SERVICE
36918313	GRET	SVC	9/14/2020	1989	RET ABN	UG-SERVICE
40385554	GRET	SVC	7/7/2022	1989	RET ABN	UG-SERVICE
40757102	GRET	SVC	10/3/2022	1989	RET ABN	UG-SERVICE
35985008	GRET	SVC	2/5/2020	1989	RET ABN	UG-SERVICE
36804284	GRET	SVC	9/15/2020	1989	RET ABN	UG-SERVICE
42338143	GRET	SVC	11/5/2023	1989	RET ABN	UG-SERVICE
42921460	GRET	SVC	5/20/2024	1989	RET ABN	UG-SERVICE
42337785	GRET	SVC	11/5/2023	1989	RET ABN	UG-SERVICE
39394755	GRET	SVC	11/9/2021	1989	RET ABN	UG-SERVICE
40282639	GRET	SVC	6/7/2022	1989	RET ABN	UG-SERVICE
40370779	GRET	SVC	7/6/2022	1989	RET ABN	UG-SERVICE
40309945	GRET	SVC	6/15/2022	1989	RET ABN	UG-SERVICE
41635508	GRET	SVC	5/18/2023	1989	RET ABN	UG-SERVICE
41272666	GRET	SVC	2/13/2023	1989	RET ABN	UG-SERVICE
43280669	GRET	SVC	11/25/2024	1989	RET ABN	UG-SERVICE
39423117	GRET	SVC	6/27/2022	1989	RET ABN	UG-SERVICE
37928572	GRET	SVC	1/4/2021	1989	RET ABN	UG-SERVICE
40282857	GRET	SVC	6/13/2022	1989	RET ABN	UG-SERVICE
41768371	GRET	SVC	6/23/2023	1989	RET ABN	UG-SERVICE
36603046	GRET	SVC	7/8/2020	1989	RET ABN	UG-SERVICE
42653097	GRET	SVC	2/6/2024	1989	RET ABN	UG-SERVICE
43930219	GRET	SVC	12/11/2024	1989	RET ABN	UG-SERVICE
40846907	GRET	SVC	10/22/2022	1989	RET ABN	UG-SERVICE
43280670	GRET	SVC	11/25/2024	1989	RET ABN	UG-SERVICE
42338149	GRET	SVC	11/5/2023	1989	RET ABN	UG-SERVICE
42763040	GRET	SVC	3/1/2024	1989	RET ABN	UG-SERVICE
43972041	GRET	SVC	12/23/2024	1989	RET ABN	UG-SERVICE
43195851	GRET	SVC	6/18/2024	1989	RET ABN	UG-SERVICE
42344385	GRET	SVC	11/9/2023	1989	RET ABN	UG-SERVICE
43075712	GRET	SVC	5/24/2024	1989	RET ABN	UG-SERVICE
40973100	GRET	SVC	11/30/2022	1989	RET ABN	UG-SERVICE
36369084	GRET	SVC	5/23/2020	1989	RET ABN	UG-SERVICE
36925972	GRET	SVC	9/14/2020	1989	RET ABN	UG-SERVICE
38532479	GRET	SVC	6/11/2021	1989	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41881436	GRET	SVC	7/18/2023	1989	RET ABN	UG-SERVICE
38813221	GRET	SVC	8/2/2021	1989	RET ABN	UG-SERVICE
41433911	GRET	SVC	3/27/2023	1989	RET ABN	UG-SERVICE
38376263	GRET	SVC	4/20/2021	1989	RET ABN	UG-SERVICE
43506885	GRET	SVC	9/27/2024	1989	RET ABN	UG-SERVICE
38613459	GRET	SVC	8/5/2021	1989	RET ABN	UG-SERVICE
42534000	GRET	SVC	1/4/2024	1990	RET ABN	UG-SERVICE
38413345	GRET	SVC	5/25/2021	1990	RET ABN	UG-SERVICE
41397684	GRET	SVC	3/15/2023	1990	RET ABN	UG-SERVICE
39084496	GRET	SVC	9/7/2021	1990	RET ABN	UG-SERVICE
41427450	GRET	SVC	3/21/2023	1990	RET ABN	UG-SERVICE
43600748	GRET	SVC	9/23/2024	1990	RET ABN	UG-SERVICE
41543906	GRET	SVC	4/24/2023	1990	RET ABN	UG-SERVICE
42236828	GRET	SVC	10/16/2023	1990	RET ABN	UG-SERVICE
43353453	GRET	SVC	11/21/2024	1990	RET ABN	UG-SERVICE
40981807	GRET	SVC	11/28/2022	1990	RET ABN	UG-SERVICE
41129074	GRET	SVC	1/5/2023	1990	RET ABN	UG-SERVICE
40491493	GRET	SVC	7/27/2022	1990	RET ABN	UG-SERVICE
36199499	GRET	SVC	4/22/2020	1990	RET ABN	UG-SERVICE
40978232	GRET	SVC	11/28/2022	1990	RET ABN	UG-SERVICE
36125170	GRET	SVC	6/13/2020	1990	RET ABN	UG-SERVICE
40981882	GRET	SVC	11/28/2022	1990	RET ABN	UG-SERVICE
43398030	GRET	SVC	8/6/2024	1990	RET ABN	UG-SERVICE
41447891	GRET	SVC	3/30/2023	1990	RET ABN	UG-SERVICE
43330190	GRET	SVC	7/18/2024	1990	RET ABN	UG-SERVICE
40278530	GRET	SVC	6/10/2022	1990	RET ABN	UG-SERVICE
38698665	GRET	SVC	8/10/2021	1990	RET ABN	UG-SERVICE
40507607	GRET	SVC	9/9/2022	1990	RET ABN	UG-SERVICE
42823916	GRET	SVC	4/15/2024	1990	RET ABN	UG-SERVICE
36281347	GRET	SVC	4/29/2020	1990	RET ABN	UG-SERVICE
41320813	GRET	SVC	2/28/2023	1990	RET ABN	UG-SERVICE
41767341	GRET	SVC	6/19/2023	1990	RET ABN	UG-SERVICE
41447525	GRET	SVC	3/30/2023	1990	RET ABN	UG-SERVICE
43765822	GRET	SVC	10/30/2024	1990	RET ABN	UG-SERVICE
40621518	GRET	SVC	8/31/2022	1990	RET ABN	UG-SERVICE
40594519	GRET	SVC	9/16/2022	1990	RET ABN	UG-SERVICE
39378868	GRET	SVC	12/2/2021	1990	RET ABN	UG-SERVICE
42020315	GRET	SVC	8/21/2023	1990	RET ABN	UG-SERVICE
38517629	GRET	SVC	4/12/2021	1990	RET ABN	UG-SERVICE
43353452	GRET	SVC	11/20/2024	1990	RET ABN	UG-SERVICE
40075583	GRET	SVC	4/26/2022	1990	RET ABN	UG-SERVICE
40347345	GRET	SVC	6/27/2022	1990	RET ABN	UG-SERVICE
42362055	GRET	SVC	11/9/2023	1990	RET ABN	UG-SERVICE
40658820	GRET	SVC	8/31/2022	1990	RET ABN	UG-SERVICE
40222107	GRET	SVC	5/18/2022	1990	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43480988	GRET	SVC	11/8/2024	1990	RET ABN	UG-SERVICE
38283684	GRET	SVC	3/29/2021	1990	RET ABN	UG-SERVICE
43486706	GRET	SVC	8/26/2024	1990	RET ABN	UG-SERVICE
36998793	GRET	SVC	9/30/2020	1990	RET ABN	UG-SERVICE
37810891	GRET	SVC	11/25/2020	1990	RET ABN	UG-SERVICE
41447893	GRET	SVC	3/30/2023	1990	RET ABN	UG-SERVICE
43084799	GRET	SVC	5/22/2024	1990	RET ABN	UG-SERVICE
37424443	GRET	SVC	11/24/2020	1990	RET ABN	UG-SERVICE
36758848	GRET	SVC	7/27/2020	1990	RET ABN	UG-SERVICE
40896368	GRET	SVC	11/21/2022	1990	RET ABN	UG-SERVICE
41920514	GRET	SVC	8/4/2023	1990	RET ABN	UG-SERVICE
41447165	GRET	SVC	3/28/2023	1990	RET ABN	UG-SERVICE
41295790	GRET	SVC	2/20/2023	1990	RET ABN	UG-SERVICE
42163979	GRET	SVC	9/26/2023	1990	RET ABN	UG-SERVICE
40223284	GRET	SVC	6/5/2022	1990	RET ABN	UG-SERVICE
41283320	GRET	SVC	2/15/2023	1990	RET ABN	UG-SERVICE
43353801	GRET	SVC	12/3/2024	1990	RET ABN	UG-SERVICE
42992788	GRET	SVC	4/29/2024	1990	RET ABN	UG-SERVICE
41324893	GRET	SVC	2/28/2023	1990	RET ABN	UG-SERVICE
42045510	GRET	SVC	9/5/2023	1990	RET ABN	UG-SERVICE
40266841	GRET	SVC	7/5/2022	1990	RET ABN	UG-SERVICE
41568304	GRET	SVC	4/23/2023	1990	RET ABN	UG-SERVICE
42534948	GRET	SVC	2/5/2024	1990	RET ABN	UG-SERVICE
38352930	GRET	SVC	2/17/2023	1990	RET ABN	UG-SERVICE
36051642	GRET	SVC	2/22/2020	1990	RET ABN	UG-SERVICE
38441385	GRET	SVC	1/6/2022	1990	RET ABN	UG-SERVICE
41544072	GRET	SVC	4/26/2023	1990	RET ABN	UG-SERVICE
40223294	GRET	SVC	5/31/2022	1990	RET ABN	UG-SERVICE
41015444	GRET	SVC	12/16/2022	1990	RET ABN	UG-SERVICE
41428821	GRET	SVC	3/28/2023	1990	RET ABN	UG-SERVICE
43203102	GRET	SVC	6/24/2024	1990	RET ABN	UG-SERVICE
38697861	GRET	SVC	7/7/2021	1990	RET ABN	UG-SERVICE
38044256	GRET	SVC	1/16/2021	1990	RET ABN	UG-SERVICE
42745580	GRET	SVC	3/5/2024	1990	RET ABN	UG-SERVICE
41447886	GRET	SVC	3/30/2023	1990	RET ABN	UG-SERVICE
38050812	GRET	SVC	1/25/2021	1990	RET ABN	UG-SERVICE
41317496	GRET	SVC	3/3/2023	1990	RET ABN	UG-SERVICE
40241979	GRET	SVC	5/21/2022	1990	RET ABN	UG-SERVICE
40514680	GRET	SVC	7/30/2022	1990	RET ABN	UG-SERVICE
41418432	GRET	SVC	3/20/2023	1990	RET ABN	UG-SERVICE
41398461	GRET	SVC	3/13/2023	1990	RET ABN	UG-SERVICE
39932756	GRET	SVC	4/1/2022	1990	RET ABN	UG-SERVICE
36108718	GRET	SVC	3/10/2020	1990	RET ABN	UG-SERVICE
41411510	GRET	SVC	4/2/2024	1990	RET ABN	UG-SERVICE
42320050	GRET	SVC	11/3/2023	1990	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41419857	GRET	SVC	3/21/2023	1990	RET ABN	UG-SERVICE
43634479	GRET	SVC	10/3/2024	1990	RET ABN	UG-SERVICE
42449339	GRET	SVC	12/5/2023	1990	RET ABN	UG-SERVICE
41896733	GRET	SVC	7/18/2023	1990	RET ABN	UG-SERVICE
41425508	GRET	SVC	3/31/2023	1990	RET ABN	UG-SERVICE
41273858	GRET	SVC	2/14/2023	1990	RET ABN	UG-SERVICE
40334904	GRET	SVC	10/6/2022	1990	RET ABN	UG-SERVICE
41282918	GRET	SVC	2/15/2023	1990	RET ABN	UG-SERVICE
42226640	GRET	SVC	10/16/2023	1990	RET ABN	UG-SERVICE
43318037	GRET	SVC	8/12/2024	1990	RET ABN	UG-SERVICE
40683519	GRET	SVC	9/14/2022	1990	RET ABN	UG-SERVICE
39161965	GRET	SVC	9/13/2021	1990	RET ABN	UG-SERVICE
41235835	GRET	SVC	2/4/2023	1990	RET ABN	UG-SERVICE
43268084	GRET	SVC	7/9/2024	1990	RET ABN	UG-SERVICE
41961264	GRET	SVC	8/8/2023	1990	RET ABN	UG-SERVICE
42361115	GRET	SVC	11/13/2023	1990	RET ABN	UG-SERVICE
41670040	GRET	SVC	5/20/2023	1990	RET ABN	UG-SERVICE
40557697	GRET	SVC	8/19/2022	1990	RET ABN	UG-SERVICE
43529746	GRET	SVC	11/7/2024	1990	RET ABN	UG-SERVICE
36061274	GRET	SVC	2/22/2020	1990	RET ABN	UG-SERVICE
41288524	GRET	SVC	3/17/2023	1990	RET ABN	UG-SERVICE
40400410	GRET	SVC	7/14/2022	1990	RET ABN	UG-SERVICE
36626255	GRET	SVC	6/29/2020	1990	RET ABN	UG-SERVICE
37951728	GRET	SVC	12/22/2020	1990	RET ABN	UG-SERVICE
38168857	GRET	SVC	2/24/2021	1990	RET ABN	UG-SERVICE
35960295	GRET	SVC	1/29/2020	1990	RET ABN	UG-SERVICE
37847687	GRET	SVC	12/1/2020	1990	RET ABN	UG-SERVICE
39337455	GRET	SVC	10/26/2021	1990	RET ABN	UG-SERVICE
43210020	GRET	SVC	7/1/2024	1990	RET ABN	UG-SERVICE
40807464	GRET	SVC	10/11/2022	1990	RET ABN	UG-SERVICE
37145164	GRET	SVC	10/26/2020	1990	RET ABN	UG-SERVICE
43328055	GRET	SVC	7/15/2024	1990	RET ABN	UG-SERVICE
41418436	GRET	SVC	3/20/2023	1990	RET ABN	UG-SERVICE
41418538	GRET	SVC	3/20/2023	1990	RET ABN	UG-SERVICE
43353808	GRET	SVC	12/17/2024	1990	RET ABN	UG-SERVICE
43353807	GRET	SVC	12/17/2024	1990	RET ABN	UG-SERVICE
39893102	GRET	SVC	7/11/2022	1991	RET ABN	UG-SERVICE
36409445	GRET	SVC	6/8/2020	1991	RET ABN	UG-SERVICE
42430283	GRET	SVC	11/26/2023	1991	RET ABN	UG-SERVICE
40327028	GRET	SVC	6/21/2022	1991	RET ABN	UG-SERVICE
35983294	GRET	SVC	3/2/2020	1991	RET ABN	UG-SERVICE
37914954	GRET	SVC	12/17/2020	1991	RET ABN	UG-SERVICE
43481043	GRET	SVC	10/25/2024	1991	RET ABN	UG-SERVICE
42353448	GRET	SVC	11/13/2023	1991	RET ABN	UG-SERVICE
41144784	GRET	SVC	1/11/2023	1991	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43713034	GRET	SVC	10/21/2024	1991	RET ABN	UG-SERVICE
36625393	GRET	SVC	7/11/2020	1991	RET ABN	UG-SERVICE
38357401	GRET	SVC	2/14/2023	1991	RET ABN	UG-SERVICE
38647500	GRET	SVC	6/22/2021	1991	RET ABN	UG-SERVICE
43318170	GRET	SVC	8/9/2024	1991	RET ABN	UG-SERVICE
40860216	GRET	SVC	11/3/2022	1991	RET ABN	UG-SERVICE
42904493	GRET	SVC	4/7/2024	1991	RET ABN	UG-SERVICE
41733397	GRET	SVC	6/12/2023	1991	RET ABN	UG-SERVICE
43345647	GRET	SVC	7/22/2024	1991	RET ABN	UG-SERVICE
43529732	GRET	SVC	11/22/2024	1991	RET ABN	UG-SERVICE
38352828	GRET	SVC	2/17/2023	1991	RET ABN	UG-SERVICE
40883285	GRET	SVC	10/30/2022	1991	RET ABN	UG-SERVICE
40571828	GRET	SVC	8/16/2022	1991	RET ABN	UG-SERVICE
36962757	GRET	SVC	9/21/2020	1991	RET ABN	UG-SERVICE
36356345	GRET	SVC	5/18/2020	1991	RET ABN	UG-SERVICE
36199822	GRET	SVC	5/1/2020	1991	RET ABN	UG-SERVICE
41222791	GRET	SVC	1/31/2023	1991	RET ABN	UG-SERVICE
36511655	GRET	SVC	6/18/2020	1991	RET ABN	UG-SERVICE
41304549	GRET	SVC	3/6/2023	1991	RET ABN	UG-SERVICE
41428831	GRET	SVC	3/23/2023	1991	RET ABN	UG-SERVICE
38913622	GRET	SVC	8/9/2021	1991	RET ABN	UG-SERVICE
40858949	GRET	SVC	10/24/2022	1991	RET ABN	UG-SERVICE
41144636	GRET	SVC	7/31/2023	1991	RET ABN	UG-SERVICE
41803088	GRET	SVC	7/7/2023	1991	RET ABN	UG-SERVICE
42112489	GRET	SVC	9/12/2023	1991	RET ABN	UG-SERVICE
39544010	GRET	SVC	12/14/2021	1991	RET ABN	UG-SERVICE
40990263	GRET	SVC	11/18/2022	1991	RET ABN	UG-SERVICE
42953403	GRET	SVC	4/17/2024	1991	RET ABN	UG-SERVICE
41144491	GRET	SVC	7/31/2023	1991	RET ABN	UG-SERVICE
40949368	GRET	SVC	11/16/2022	1991	RET ABN	UG-SERVICE
41582634	GRET	SVC	5/3/2023	1991	RET ABN	UG-SERVICE
40190769	GRET	SVC	5/21/2022	1991	RET ABN	UG-SERVICE
43329557	GRET	SVC	7/19/2024	1991	RET ABN	UG-SERVICE
36659846	GRET	SVC	7/21/2020	1991	RET ABN	UG-SERVICE
38938944	GRET	SVC	8/15/2021	1991	RET ABN	UG-SERVICE
43000634	GRET	SVC	5/23/2024	1991	RET ABN	UG-SERVICE
40883588	GRET	SVC	11/9/2022	1991	RET ABN	UG-SERVICE
38352829	GRET	SVC	2/17/2023	1991	RET ABN	UG-SERVICE
36683352	GRET	SVC	7/27/2020	1991	RET ABN	UG-SERVICE
41321352	GRET	SVC	3/16/2023	1991	RET ABN	UG-SERVICE
41144604	GRET	SVC	1/7/2023	1991	RET ABN	UG-SERVICE
36363706	GRET	SVC	5/19/2020	1991	RET ABN	UG-SERVICE
41144755	GRET	SVC	1/11/2023	1991	RET ABN	UG-SERVICE
40991251	GRET	SVC	11/18/2022	1991	RET ABN	UG-SERVICE
37958000	GRET	SVC	12/29/2020	1991	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42105047	GRET	SVC	9/13/2023	1991	RET ABN	UG-SERVICE
43529729	GRET	SVC	12/22/2024	1991	RET ABN	UG-SERVICE
41142029	GRET	SVC	7/31/2023	1991	RET ABN	UG-SERVICE
41482052	GRET	SVC	4/9/2023	1991	RET ABN	UG-SERVICE
42462806	GRET	SVC	12/9/2023	1991	RET ABN	UG-SERVICE
43364876	GRET	SVC	12/12/2024	1991	RET ABN	UG-SERVICE
36267690	GRET	SVC	3/24/2020	1991	RET ABN	UG-SERVICE
36302290	GRET	SVC	5/5/2020	1991	RET ABN	UG-SERVICE
41424367	GRET	SVC	3/24/2023	1991	RET ABN	UG-SERVICE
41143808	GRET	SVC	7/31/2023	1991	RET ABN	UG-SERVICE
36234314	GRET	SVC	5/15/2020	1991	RET ABN	UG-SERVICE
43260047	GRET	SVC	8/12/2024	1991	RET ABN	UG-SERVICE
42872613	GRET	SVC	4/2/2024	1991	RET ABN	UG-SERVICE
38603828	GRET	SVC	6/15/2021	1991	RET ABN	UG-SERVICE
41015443	GRET	SVC	12/4/2022	1991	RET ABN	UG-SERVICE
39330552	GRET	SVC	10/26/2021	1991	RET ABN	UG-SERVICE
41321340	GRET	SVC	3/15/2023	1991	RET ABN	UG-SERVICE
41143388	GRET	SVC	7/31/2023	1991	RET ABN	UG-SERVICE
41321345	GRET	SVC	3/15/2023	1991	RET ABN	UG-SERVICE
42873152	GRET	SVC	4/2/2024	1991	RET ABN	UG-SERVICE
41421864	GRET	SVC	3/23/2023	1991	RET ABN	UG-SERVICE
39543628	GRET	SVC	12/14/2021	1991	RET ABN	UG-SERVICE
42195837	GRET	SVC	10/9/2023	1991	RET ABN	UG-SERVICE
38906642	GRET	SVC	8/31/2021	1991	RET ABN	UG-SERVICE
40302997	GRET	SVC	6/13/2022	1991	RET ABN	UG-SERVICE
41321354	GRET	SVC	3/16/2023	1991	RET ABN	UG-SERVICE
40859701	GRET	SVC	11/30/2022	1991	RET ABN	UG-SERVICE
41065389	GRET	SVC	12/14/2022	1991	RET ABN	UG-SERVICE
40860841	GRET	SVC	10/28/2022	1991	RET ABN	UG-SERVICE
43529375	GRET	SVC	11/24/2024	1991	RET ABN	UG-SERVICE
37251258	GRET	SVC	11/2/2020	1991	RET ABN	UG-SERVICE
43857177	GRET	SVC	11/20/2024	1991	RET ABN	UG-SERVICE
42145812	GRET	SVC	9/25/2023	1991	RET ABN	UG-SERVICE
42216031	GRET	SVC	10/10/2023	1991	RET ABN	UG-SERVICE
38352827	GRET	SVC	2/17/2023	1991	RET ABN	UG-SERVICE
38098231	GRET	SVC	2/7/2021	1991	RET ABN	UG-SERVICE
43329564	GRET	SVC	7/19/2024	1991	RET ABN	UG-SERVICE
38326248	GRET	SVC	4/9/2021	1991	RET ABN	UG-SERVICE
40036272	GRET	SVC	4/19/2022	1991	RET ABN	UG-SERVICE
41144462	GRET	SVC	7/31/2023	1991	RET ABN	UG-SERVICE
41083867	GRET	SVC	12/21/2022	1991	RET ABN	UG-SERVICE
41877226	GRET	SVC	7/17/2023	1991	RET ABN	UG-SERVICE
43324307	GRET	SVC	10/17/2024	1991	RET ABN	UG-SERVICE
42562269	GRET	SVC	1/12/2024	1991	RET ABN	UG-SERVICE
41320413	GRET	SVC	3/3/2023	1991	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42025605	GRET	SVC	8/22/2023	1991	RET ABN	UG-SERVICE
39743323	GRET	SVC	1/27/2022	1991	RET ABN	UG-SERVICE
40775520	GRET	SVC	10/4/2022	1991	RET ABN	UG-SERVICE
36016960	GRET	SVC	2/11/2020	1991	RET ABN	UG-SERVICE
40899890	GRET	SVC	11/8/2022	1991	RET ABN	UG-SERVICE
40395847	GRET	SVC	7/6/2022	1991	RET ABN	UG-SERVICE
40571973	GRET	SVC	8/16/2022	1991	RET ABN	UG-SERVICE
39657988	GRET	SVC	2/5/2022	1991	RET ABN	UG-SERVICE
41321122	GRET	SVC	3/16/2023	1991	RET ABN	UG-SERVICE
43358252	GRET	SVC	7/19/2024	1991	RET ABN	UG-SERVICE
40162498	GRET	SVC	5/18/2022	1991	RET ABN	UG-SERVICE
41182810	GRET	SVC	1/18/2023	1991	RET ABN	UG-SERVICE
36487200	GRET	SVC	6/18/2020	1991	RET ABN	UG-SERVICE
41143459	GRET	SVC	1/11/2023	1991	RET ABN	UG-SERVICE
41464722	GRET	SVC	4/3/2023	1991	RET ABN	UG-SERVICE
40868641	GRET	SVC	11/3/2022	1991	RET ABN	UG-SERVICE
35844797	GRET	SVC	2/4/2020	1991	RET ABN	UG-SERVICE
38352830	GRET	SVC	2/17/2023	1991	RET ABN	UG-SERVICE
38402399	GRET	SVC	4/23/2021	1991	RET ABN	UG-SERVICE
41482054	GRET	SVC	4/8/2023	1991	RET ABN	UG-SERVICE
36301314	GRET	SVC	5/5/2020	1991	RET ABN	UG-SERVICE
41064586	GRET	SVC	12/15/2022	1991	RET ABN	UG-SERVICE
43325562	GRET	SVC	7/15/2024	1991	RET ABN	UG-SERVICE
36597389	GRET	SVC	6/27/2020	1991	RET ABN	UG-SERVICE
40883299	GRET	SVC	10/30/2022	1991	RET ABN	UG-SERVICE
41065407	GRET	SVC	12/14/2022	1991	RET ABN	UG-SERVICE
41144071	GRET	SVC	1/9/2023	1991	RET ABN	UG-SERVICE
41247249	GRET	SVC	2/7/2023	1991	RET ABN	UG-SERVICE
41143964	GRET	SVC	1/10/2023	1991	RET ABN	UG-SERVICE
39544351	GRET	SVC	12/13/2021	1991	RET ABN	UG-SERVICE
41143554	GRET	SVC	7/31/2023	1991	RET ABN	UG-SERVICE
38146655	GRET	SVC	2/17/2021	1991	RET ABN	UG-SERVICE
36901871	GRET	SVC	9/9/2020	1991	RET ABN	UG-SERVICE
41144319	GRET	SVC	7/31/2023	1991	RET ABN	UG-SERVICE
36283868	GRET	SVC	5/12/2020	1991	RET ABN	UG-SERVICE
41675410	GRET	SVC	5/30/2023	1991	RET ABN	UG-SERVICE
43329720	GRET	SVC	7/19/2024	1991	RET ABN	UG-SERVICE
36356885	GRET	SVC	5/18/2020	1991	RET ABN	UG-SERVICE
39874650	GRET	SVC	3/11/2022	1991	RET ABN	UG-SERVICE
38441559	GRET	SVC	1/6/2022	1991	RET ABN	UG-SERVICE
38480827	GRET	SVC	5/11/2021	1991	RET ABN	UG-SERVICE
37935135	GRET	SVC	12/19/2020	1991	RET ABN	UG-SERVICE
42588325	GRET	SVC	1/24/2024	1991	RET ABN	UG-SERVICE
41143738	GRET	SVC	7/31/2023	1991	RET ABN	UG-SERVICE
43955127	GRET	SVC	12/30/2024	1991	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41321353	GRET	SVC	3/16/2023	1991	RET ABN	UG-SERVICE
40752909	GRET	SVC	9/26/2022	1991	RET ABN	UG-SERVICE
41144786	GRET	SVC	1/11/2023	1991	RET ABN	UG-SERVICE
36739594	GRET	SVC	8/4/2020	1991	RET ABN	UG-SERVICE
38146652	GRET	SVC	2/17/2021	1991	RET ABN	UG-SERVICE
42425332	GRET	SVC	5/29/2024	1991	RET ABN	UG-SERVICE
40142745	GRET	SVC	5/11/2022	1991	RET ABN	UG-SERVICE
43318485	GRET	SVC	9/26/2024	1991	RET ABN	UG-SERVICE
41428828	GRET	SVC	3/23/2023	1991	RET ABN	UG-SERVICE
38146653	GRET	SVC	2/17/2021	1991	RET ABN	UG-SERVICE
41479993	GRET	SVC	4/10/2023	1991	RET ABN	UG-SERVICE
43481258	GRET	SVC	11/1/2024	1991	RET ABN	UG-SERVICE
41139511	GRET	SVC	1/13/2023	1991	RET ABN	UG-SERVICE
42187329	GRET	SVC	10/5/2023	1991	RET ABN	UG-SERVICE
40883288	GRET	SVC	10/30/2022	1991	RET ABN	UG-SERVICE
38232683	GRET	SVC	3/15/2021	1991	RET ABN	UG-SERVICE
41321129	GRET	SVC	3/15/2023	1991	RET ABN	UG-SERVICE
41430970	GRET	SVC	3/29/2023	1992	RET ABN	UG-SERVICE
43462114	GRET	SVC	9/3/2024	1992	RET ABN	UG-SERVICE
41411236	GRET	SVC	4/2/2024	1992	RET ABN	UG-SERVICE
41324884	GRET	SVC	3/1/2023	1992	RET ABN	UG-SERVICE
41243169	GRET	SVC	2/5/2023	1992	RET ABN	UG-SERVICE
41032256	GRET	SVC	12/15/2022	1992	RET ABN	UG-SERVICE
43481091	GRET	SVC	10/31/2024	1992	RET ABN	UG-SERVICE
40286467	GRET	SVC	6/11/2022	1992	RET ABN	UG-SERVICE
37291022	GRET	SVC	11/9/2020	1992	RET ABN	UG-SERVICE
40385556	GRET	SVC	7/6/2022	1992	RET ABN	UG-SERVICE
39154112	GRET	SVC	9/20/2021	1992	RET ABN	UG-SERVICE
43717068	GRET	SVC	10/25/2024	1992	RET ABN	UG-SERVICE
41180365	GRET	SVC	1/19/2023	1992	RET ABN	UG-SERVICE
42520346	GRET	SVC	12/26/2023	1992	RET ABN	UG-SERVICE
38910599	GRET	SVC	8/11/2021	1992	RET ABN	UG-SERVICE
37843371	GRET	SVC	11/30/2020	1992	RET ABN	UG-SERVICE
40827593	GRET	SVC	10/17/2022	1992	RET ABN	UG-SERVICE
40952735	GRET	SVC	11/18/2022	1992	RET ABN	UG-SERVICE
43481183	GRET	SVC	11/20/2024	1992	RET ABN	UG-SERVICE
39803732	GRET	SVC	3/22/2022	1992	RET ABN	UG-SERVICE
40813403	GRET	SVC	10/15/2022	1992	RET ABN	UG-SERVICE
41222784	GRET	SVC	3/3/2023	1992	RET ABN	UG-SERVICE
37887981	GRET	SVC	12/5/2020	1992	RET ABN	UG-SERVICE
43318038	GRET	SVC	7/29/2024	1992	RET ABN	UG-SERVICE
40468999	GRET	SVC	7/22/2022	1992	RET ABN	UG-SERVICE
41205592	GRET	SVC	1/27/2023	1992	RET ABN	UG-SERVICE
40395840	GRET	SVC	7/6/2022	1992	RET ABN	UG-SERVICE
39476682	GRET	SVC	11/26/2021	1992	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41483269	GRET	SVC	4/13/2023	1992	RET ABN	UG-SERVICE
41143413	GRET	SVC	1/10/2023	1992	RET ABN	UG-SERVICE
41144751	GRET	SVC	1/12/2023	1992	RET ABN	UG-SERVICE
43902683	GRET	SVC	12/5/2024	1992	RET ABN	UG-SERVICE
36881227	GRET	SVC	8/29/2020	1992	RET ABN	UG-SERVICE
36834327	GRET	SVC	8/27/2020	1992	RET ABN	UG-SERVICE
40831607	GRET	SVC	10/19/2022	1992	RET ABN	UG-SERVICE
43529748	GRET	SVC	12/4/2024	1992	RET ABN	UG-SERVICE
41179464	GRET	SVC	1/18/2023	1992	RET ABN	UG-SERVICE
41937404	GRET	SVC	8/1/2023	1992	RET ABN	UG-SERVICE
42265988	GRET	SVC	10/23/2023	1992	RET ABN	UG-SERVICE
40867634	GRET	SVC	11/3/2022	1992	RET ABN	UG-SERVICE
39461251	GRET	SVC	11/24/2021	1992	RET ABN	UG-SERVICE
43591085	GRET	SVC	9/16/2024	1992	RET ABN	UG-SERVICE
43627285	GRET	SVC	9/30/2024	1992	RET ABN	UG-SERVICE
41873064	GRET	SVC	7/11/2023	1992	RET ABN	UG-SERVICE
41347204	GRET	SVC	3/6/2023	1992	RET ABN	UG-SERVICE
39487063	GRET	SVC	12/20/2021	1992	RET ABN	UG-SERVICE
41144816	GRET	SVC	1/12/2023	1992	RET ABN	UG-SERVICE
41420314	GRET	SVC	3/24/2023	1992	RET ABN	UG-SERVICE
42277344	GRET	SVC	10/23/2023	1992	RET ABN	UG-SERVICE
43899043	GRET	SVC	12/4/2024	1992	RET ABN	UG-SERVICE
42760798	GRET	SVC	8/1/2024	1992	RET ABN	UG-SERVICE
38747325	GRET	SVC	7/20/2021	1992	RET ABN	UG-SERVICE
35865564	GRET	SVC	1/4/2020	1992	RET ABN	UG-SERVICE
42004114	GRET	SVC	8/16/2023	1992	RET ABN	UG-SERVICE
41242848	GRET	SVC	3/27/2023	1992	RET ABN	UG-SERVICE
38315072	GRET	SVC	2/26/2021	1992	RET ABN	UG-SERVICE
42506615	GRET	SVC	12/27/2023	1992	RET ABN	UG-SERVICE
42658671	GRET	SVC	2/4/2024	1992	RET ABN	UG-SERVICE
41143610	GRET	SVC	1/10/2023	1992	RET ABN	UG-SERVICE
41429207	GRET	SVC	3/22/2023	1992	RET ABN	UG-SERVICE
41177079	GRET	SVC	1/18/2023	1992	RET ABN	UG-SERVICE
40973551	GRET	SVC	12/5/2022	1992	RET ABN	UG-SERVICE
36878132	GRET	SVC	9/1/2020	1992	RET ABN	UG-SERVICE
41144495	GRET	SVC	1/12/2023	1992	RET ABN	UG-SERVICE
41568141	GRET	SVC	4/26/2023	1992	RET ABN	UG-SERVICE
42290060	GRET	SVC	10/30/2023	1992	RET ABN	UG-SERVICE
41429214	GRET	SVC	3/22/2023	1992	RET ABN	UG-SERVICE
40898338	GRET	SVC	11/10/2022	1992	RET ABN	UG-SERVICE
41143375	GRET	SVC	4/26/2023	1992	RET ABN	UG-SERVICE
41418435	GRET	SVC	3/21/2023	1992	RET ABN	UG-SERVICE
42905382	GRET	SVC	4/7/2024	1992	RET ABN	UG-SERVICE
41143373	GRET	SVC	1/12/2023	1992	RET ABN	UG-SERVICE
40899525	GRET	SVC	11/10/2022	1992	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40420603	GRET	SVC	6/27/2022	1992	RET ABN	UG-SERVICE
41317140	GRET	SVC	3/2/2023	1992	RET ABN	UG-SERVICE
40308199	GRET	SVC	6/13/2022	1992	RET ABN	UG-SERVICE
40772093	GRET	SVC	10/3/2022	1992	RET ABN	UG-SERVICE
40952953	GRET	SVC	11/18/2022	1992	RET ABN	UG-SERVICE
39070846	GRET	SVC	8/30/2021	1992	RET ABN	UG-SERVICE
41143735	GRET	SVC	7/31/2023	1992	RET ABN	UG-SERVICE
39832165	GRET	SVC	2/24/2022	1992	RET ABN	UG-SERVICE
41429212	GRET	SVC	3/22/2023	1992	RET ABN	UG-SERVICE
42773918	GRET	SVC	2/21/2024	1992	RET ABN	UG-SERVICE
41177539	GRET	SVC	1/20/2023	1992	RET ABN	UG-SERVICE
43481180	GRET	SVC	11/20/2024	1992	RET ABN	UG-SERVICE
42816107	GRET	SVC	3/11/2024	1992	RET ABN	UG-SERVICE
42626582	GRET	SVC	1/31/2024	1992	RET ABN	UG-SERVICE
40241954	GRET	SVC	5/21/2022	1992	RET ABN	UG-SERVICE
41330187	GRET	SVC	3/2/2023	1992	RET ABN	UG-SERVICE
40870056	GRET	SVC	11/9/2022	1992	RET ABN	UG-SERVICE
43481099	GRET	SVC	11/20/2024	1992	RET ABN	UG-SERVICE
35970017	GRET	SVC	2/3/2020	1992	RET ABN	UG-SERVICE
41143703	GRET	SVC	1/12/2023	1992	RET ABN	UG-SERVICE
43529740	GRET	SVC	12/13/2024	1992	RET ABN	UG-SERVICE
40683517	GRET	SVC	10/21/2022	1992	RET ABN	UG-SERVICE
42353320	GRET	SVC	11/13/2023	1992	RET ABN	UG-SERVICE
41904630	GRET	SVC	7/25/2023	1992	RET ABN	UG-SERVICE
42774030	GRET	SVC	2/21/2024	1992	RET ABN	UG-SERVICE
42015112	GRET	SVC	8/21/2023	1992	RET ABN	UG-SERVICE
40396046	GRET	SVC	7/6/2022	1992	RET ABN	UG-SERVICE
40813635	GRET	SVC	10/21/2022	1992	RET ABN	UG-SERVICE
38917203	GRET	SVC	8/13/2021	1992	RET ABN	UG-SERVICE
36609816	GRET	SVC	7/13/2020	1992	RET ABN	UG-SERVICE
39320982	GRET	SVC	10/19/2021	1992	RET ABN	UG-SERVICE
42479754	GRET	SVC	12/15/2023	1992	RET ABN	UG-SERVICE
38302240	GRET	SVC	5/26/2021	1992	RET ABN	UG-SERVICE
43108074	GRET	SVC	5/29/2024	1992	RET ABN	UG-SERVICE
42313855	GRET	SVC	10/31/2023	1992	RET ABN	UG-SERVICE
38276821	GRET	SVC	3/25/2021	1992	RET ABN	UG-SERVICE
42669945	GRET	SVC	2/3/2024	1992	RET ABN	UG-SERVICE
39876268	GRET	SVC	3/14/2022	1992	RET ABN	UG-SERVICE
41316946	GRET	SVC	3/2/2023	1992	RET ABN	UG-SERVICE
41334394	GRET	SVC	3/8/2023	1992	RET ABN	UG-SERVICE
41143633	GRET	SVC	7/31/2023	1992	RET ABN	UG-SERVICE
36888540	GRET	SVC	9/29/2020	1992	RET ABN	UG-SERVICE
36306734	GRET	SVC	5/7/2020	1992	RET ABN	UG-SERVICE
43481256	GRET	SVC	11/20/2024	1992	RET ABN	UG-SERVICE
41427192	GRET	SVC	3/23/2023	1992	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40898981	GRET	SVC	11/10/2022	1992	RET ABN	UG-SERVICE
39487066	GRET	SVC	12/20/2021	1992	RET ABN	UG-SERVICE
40973242	GRET	SVC	12/9/2022	1992	RET ABN	UG-SERVICE
42487565	GRET	SVC	4/23/2024	1992	RET ABN	UG-SERVICE
36218872	GRET	SVC	4/23/2020	1992	RET ABN	UG-SERVICE
42539236	GRET	SVC	12/27/2023	1992	RET ABN	UG-SERVICE
41177533	GRET	SVC	1/19/2023	1992	RET ABN	UG-SERVICE
40883298	GRET	SVC	10/30/2022	1992	RET ABN	UG-SERVICE
41144453	GRET	SVC	7/31/2023	1992	RET ABN	UG-SERVICE
41143729	GRET	SVC	4/25/2023	1992	RET ABN	UG-SERVICE
41422538	GRET	SVC	3/24/2023	1992	RET ABN	UG-SERVICE
40584964	GRET	SVC	8/19/2022	1992	RET ABN	UG-SERVICE
41428836	GRET	SVC	3/22/2023	1992	RET ABN	UG-SERVICE
43481181	GRET	SVC	11/20/2024	1992	RET ABN	UG-SERVICE
40396049	GRET	SVC	7/6/2022	1992	RET ABN	UG-SERVICE
41177525	GRET	SVC	1/19/2023	1992	RET ABN	UG-SERVICE
40694438	GRET	SVC	9/28/2022	1992	RET ABN	UG-SERVICE
40690733	GRET	SVC	9/14/2022	1992	RET ABN	UG-SERVICE
37032864	GRET	SVC	10/6/2020	1992	RET ABN	UG-SERVICE
40952583	GRET	SVC	11/17/2022	1992	RET ABN	UG-SERVICE
37887897	GRET	SVC	12/5/2020	1992	RET ABN	UG-SERVICE
43481097	GRET	SVC	11/20/2024	1992	RET ABN	UG-SERVICE
38862869	GRET	SVC	8/4/2021	1992	RET ABN	UG-SERVICE
43901346	GRET	SVC	12/13/2024	1992	RET ABN	UG-SERVICE
43414289	GRET	SVC	8/13/2024	1992	RET ABN	UG-SERVICE
41324891	GRET	SVC	3/1/2023	1992	RET ABN	UG-SERVICE
36089527	GRET	SVC	3/4/2020	1992	RET ABN	UG-SERVICE
41007068	GRET	SVC	12/9/2022	1992	RET ABN	UG-SERVICE
42409788	GRET	SVC	11/22/2023	1992	RET ABN	UG-SERVICE
43469644	GRET	SVC	8/23/2024	1992	RET ABN	UG-SERVICE
41411482	GRET	SVC	11/2/2023	1992	RET ABN	UG-SERVICE
41650006	GRET	SVC	5/14/2023	1992	RET ABN	UG-SERVICE
41177536	GRET	SVC	1/20/2023	1992	RET ABN	UG-SERVICE
39837492	GRET	SVC	2/28/2022	1992	RET ABN	UG-SERVICE
41245809	GRET	SVC	2/11/2023	1992	RET ABN	UG-SERVICE
42487444	GRET	SVC	4/15/2024	1992	RET ABN	UG-SERVICE
43347163	GRET	SVC	7/26/2024	1992	RET ABN	UG-SERVICE
41428834	GRET	SVC	3/22/2023	1992	RET ABN	UG-SERVICE
36199251	GRET	SVC	5/18/2020	1992	RET ABN	UG-SERVICE
40973553	GRET	SVC	12/9/2022	1992	RET ABN	UG-SERVICE
41258479	GRET	SVC	3/17/2023	1992	RET ABN	UG-SERVICE
40353366	GRET	SVC	6/27/2022	1992	RET ABN	UG-SERVICE
43607356	GRET	SVC	10/8/2024	1992	RET ABN	UG-SERVICE
40899522	GRET	SVC	11/10/2022	1992	RET ABN	UG-SERVICE
38052661	GRET	SVC	1/30/2021	1992	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41243171	GRET	SVC	2/5/2023	1992	RET ABN	UG-SERVICE
40916722	GRET	SVC	11/28/2022	1992	RET ABN	UG-SERVICE
43662628	GRET	SVC	10/9/2024	1992	RET ABN	UG-SERVICE
41177703	GRET	SVC	1/20/2023	1992	RET ABN	UG-SERVICE
38713758	GRET	SVC	7/20/2021	1992	RET ABN	UG-SERVICE
36712372	GRET	SVC	8/4/2020	1992	RET ABN	UG-SERVICE
42353480	GRET	SVC	11/13/2023	1992	RET ABN	UG-SERVICE
41144787	GRET	SVC	1/12/2023	1992	RET ABN	UG-SERVICE
38882775	GRET	SVC	8/10/2021	1992	RET ABN	UG-SERVICE
40466749	GRET	SVC	7/25/2022	1992	RET ABN	UG-SERVICE
43856858	GRET	SVC	11/20/2024	1992	RET ABN	UG-SERVICE
43244752	GRET	SVC	9/19/2024	1992	RET ABN	UG-SERVICE
39984699	GRET	SVC	10/14/2022	1993	RET ABN	UG-SERVICE
36380971	GRET	SVC	6/9/2020	1993	RET ABN	UG-SERVICE
43957767	GRET	SVC	12/10/2024	1993	RET ABN	UG-SERVICE
41031151	GRET	SVC	12/7/2022	1993	RET ABN	UG-SERVICE
36262294	GRET	SVC	4/27/2020	1993	RET ABN	UG-SERVICE
37863208	GRET	SVC	11/22/2020	1993	RET ABN	UG-SERVICE
38739429	GRET	SVC	7/12/2021	1993	RET ABN	UG-SERVICE
41497869	GRET	SVC	4/10/2023	1993	RET ABN	UG-SERVICE
42207700	GRET	SVC	10/9/2023	1993	RET ABN	UG-SERVICE
38857281	GRET	SVC	8/4/2021	1993	RET ABN	UG-SERVICE
37935104	GRET	SVC	12/20/2020	1993	RET ABN	UG-SERVICE
41407556	GRET	SVC	4/2/2024	1993	RET ABN	UG-SERVICE
43327227	GRET	SVC	8/22/2024	1993	RET ABN	UG-SERVICE
39937838	GRET	SVC	2/14/2022	1993	RET ABN	UG-SERVICE
41179724	GRET	SVC	1/18/2023	1993	RET ABN	UG-SERVICE
40913278	GRET	SVC	11/16/2022	1993	RET ABN	UG-SERVICE
40643028	GRET	SVC	9/2/2022	1993	RET ABN	UG-SERVICE
43241683	GRET	SVC	9/19/2024	1993	RET ABN	UG-SERVICE
43205832	GRET	SVC	6/17/2024	1993	RET ABN	UG-SERVICE
40352156	GRET	SVC	6/27/2022	1993	RET ABN	UG-SERVICE
41035751	GRET	SVC	12/13/2022	1993	RET ABN	UG-SERVICE
42111992	GRET	SVC	9/14/2023	1993	RET ABN	UG-SERVICE
43480989	GRET	SVC	11/8/2024	1993	RET ABN	UG-SERVICE
42344241	GRET	SVC	11/12/2023	1993	RET ABN	UG-SERVICE
36778382	GRET	SVC	8/13/2020	1993	RET ABN	UG-SERVICE
41411585	GRET	SVC	4/2/2024	1993	RET ABN	UG-SERVICE
39984698	GRET	SVC	5/2/2022	1993	RET ABN	UG-SERVICE
41146290	GRET	SVC	1/9/2023	1993	RET ABN	UG-SERVICE
43506820	GRET	SVC	9/25/2024	1993	RET ABN	UG-SERVICE
40900096	GRET	SVC	11/7/2022	1993	RET ABN	UG-SERVICE
38493263	GRET	SVC	5/18/2021	1993	RET ABN	UG-SERVICE
39903271	GRET	SVC	3/18/2022	1993	RET ABN	UG-SERVICE
38191772	GRET	SVC	3/8/2021	1993	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42205741	GRET	SVC	10/13/2023	1993	RET ABN	UG-SERVICE
36837125	GRET	SVC	8/27/2020	1993	RET ABN	UG-SERVICE
43026498	GRET	SVC	5/8/2024	1993	RET ABN	UG-SERVICE
38779477	GRET	SVC	7/15/2021	1993	RET ABN	UG-SERVICE
39665676	GRET	SVC	8/3/2022	1993	RET ABN	UG-SERVICE
40952498	GRET	SVC	11/20/2022	1993	RET ABN	UG-SERVICE
41427198	GRET	SVC	3/23/2023	1993	RET ABN	UG-SERVICE
41411596	GRET	SVC	4/2/2024	1993	RET ABN	UG-SERVICE
36427762	GRET	SVC	6/6/2020	1993	RET ABN	UG-SERVICE
38040119	GRET	SVC	5/4/2021	1993	RET ABN	UG-SERVICE
40989593	GRET	SVC	11/17/2022	1993	RET ABN	UG-SERVICE
41185240	GRET	SVC	1/19/2023	1993	RET ABN	UG-SERVICE
42227547	GRET	SVC	10/31/2023	1993	RET ABN	UG-SERVICE
43241279	GRET	SVC	9/19/2024	1993	RET ABN	UG-SERVICE
41411655	GRET	SVC	4/2/2024	1993	RET ABN	UG-SERVICE
40425799	GRET	SVC	7/13/2022	1993	RET ABN	UG-SERVICE
40749752	GRET	SVC	9/29/2022	1993	RET ABN	UG-SERVICE
40883287	GRET	SVC	10/30/2022	1993	RET ABN	UG-SERVICE
37896727	GRET	SVC	12/9/2020	1993	RET ABN	UG-SERVICE
38376930	GRET	SVC	1/22/2021	1993	RET ABN	UG-SERVICE
41770798	GRET	SVC	6/23/2023	1993	RET ABN	UG-SERVICE
43982688	GRET	SVC	12/12/2024	1993	RET ABN	UG-SERVICE
41497865	GRET	SVC	4/6/2023	1993	RET ABN	UG-SERVICE
36152589	GRET	SVC	3/24/2020	1993	RET ABN	UG-SERVICE
41420312	GRET	SVC	3/23/2023	1993	RET ABN	UG-SERVICE
41320579	GRET	SVC	3/3/2023	1993	RET ABN	UG-SERVICE
38568738	GRET	SVC	6/9/2021	1993	RET ABN	UG-SERVICE
39098295	GRET	SVC	9/8/2021	1993	RET ABN	UG-SERVICE
43957768	GRET	SVC	12/9/2024	1993	RET ABN	UG-SERVICE
41497626	GRET	SVC	4/17/2023	1993	RET ABN	UG-SERVICE
41035836	GRET	SVC	12/3/2022	1993	RET ABN	UG-SERVICE
36984588	GRET	SVC	9/21/2020	1993	RET ABN	UG-SERVICE
41401756	GRET	SVC	3/15/2023	1993	RET ABN	UG-SERVICE
38153161	GRET	SVC	2/23/2021	1993	RET ABN	UG-SERVICE
36992556	GRET	SVC	9/30/2020	1993	RET ABN	UG-SERVICE
42586960	GRET	SVC	1/12/2024	1993	RET ABN	UG-SERVICE
40644077	GRET	SVC	9/3/2022	1993	RET ABN	UG-SERVICE
36002277	GRET	SVC	2/8/2020	1993	RET ABN	UG-SERVICE
42589413	GRET	SVC	1/26/2024	1993	RET ABN	UG-SERVICE
38783978	GRET	SVC	7/15/2021	1993	RET ABN	UG-SERVICE
42048234	GRET	SVC	8/30/2023	1993	RET ABN	UG-SERVICE
40952485	GRET	SVC	11/20/2022	1993	RET ABN	UG-SERVICE
42259859	GRET	SVC	11/6/2023	1993	RET ABN	UG-SERVICE
40748422	GRET	SVC	10/4/2022	1993	RET ABN	UG-SERVICE
39484906	GRET	SVC	11/29/2021	1993	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41035832	GRET	SVC	12/8/2022	1993	RET ABN	UG-SERVICE
43021641	GRET	SVC	4/22/2024	1993	RET ABN	UG-SERVICE
43481182	GRET	SVC	11/20/2024	1993	RET ABN	UG-SERVICE
43623426	GRET	SVC	12/6/2024	1993	RET ABN	UG-SERVICE
39266989	GRET	SVC	10/4/2021	1993	RET ABN	UG-SERVICE
39184089	GRET	SVC	9/22/2021	1993	RET ABN	UG-SERVICE
41411593	GRET	SVC	4/2/2024	1993	RET ABN	UG-SERVICE
43957764	GRET	SVC	12/19/2024	1993	RET ABN	UG-SERVICE
43957763	GRET	SVC	12/11/2024	1993	RET ABN	UG-SERVICE
39739691	GRET	SVC	2/10/2022	1993	RET ABN	UG-SERVICE
41082585	GRET	SVC	12/21/2022	1993	RET ABN	UG-SERVICE
39786419	GRET	SVC	2/21/2022	1993	RET ABN	UG-SERVICE
38133227	GRET	SVC	2/15/2021	1993	RET ABN	UG-SERVICE
43241680	GRET	SVC	9/19/2024	1993	RET ABN	UG-SERVICE
39352989	GRET	SVC	10/28/2021	1993	RET ABN	UG-SERVICE
42344678	GRET	SVC	11/6/2023	1993	RET ABN	UG-SERVICE
36882130	GRET	SVC	9/1/2020	1993	RET ABN	UG-SERVICE
41768365	GRET	SVC	6/23/2023	1993	RET ABN	UG-SERVICE
42170232	GRET	SVC	10/16/2023	1993	RET ABN	UG-SERVICE
41016209	GRET	SVC	12/12/2022	1993	RET ABN	UG-SERVICE
40514003	GRET	SVC	8/2/2022	1993	RET ABN	UG-SERVICE
42511205	GRET	SVC	4/15/2024	1993	RET ABN	UG-SERVICE
40370774	GRET	SVC	7/6/2022	1993	RET ABN	UG-SERVICE
39254599	GRET	SVC	10/5/2021	1993	RET ABN	UG-SERVICE
41411589	GRET	SVC	4/2/2024	1993	RET ABN	UG-SERVICE
40327786	GRET	SVC	9/30/2022	1993	RET ABN	UG-SERVICE
42426287	GRET	SVC	11/28/2023	1993	RET ABN	UG-SERVICE
36397063	GRET	SVC	6/4/2020	1993	RET ABN	UG-SERVICE
43241682	GRET	SVC	9/19/2024	1993	RET ABN	UG-SERVICE
36826472	GRET	SVC	8/24/2020	1993	RET ABN	UG-SERVICE
40952329	GRET	SVC	11/18/2022	1993	RET ABN	UG-SERVICE
38153564	GRET	SVC	2/10/2021	1993	RET ABN	UG-SERVICE
35924715	GRET	SVC	1/16/2020	1993	RET ABN	UG-SERVICE
43957760	GRET	SVC	12/9/2024	1993	RET ABN	UG-SERVICE
41083459	GRET	SVC	1/7/2023	1993	RET ABN	UG-SERVICE
40883591	GRET	SVC	11/8/2022	1993	RET ABN	UG-SERVICE
38793267	GRET	SVC	7/22/2021	1993	RET ABN	UG-SERVICE
42589550	GRET	SVC	1/26/2024	1993	RET ABN	UG-SERVICE
41006861	GRET	SVC	12/7/2022	1993	RET ABN	UG-SERVICE
39903766	GRET	SVC	3/18/2022	1993	RET ABN	UG-SERVICE
39906731	GRET	SVC	6/3/2022	1993	RET ABN	UG-SERVICE
41411954	GRET	SVC	4/2/2024	1993	RET ABN	UG-SERVICE
39825103	GRET	SVC	2/22/2022	1993	RET ABN	UG-SERVICE
39302358	GRET	SVC	10/18/2021	1993	RET ABN	UG-SERVICE
43498333	GRET	SVC	8/26/2024	1993	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
37528691	GRET	SVC	11/18/2020	1993	RET ABN	UG-SERVICE
38779079	GRET	SVC	7/15/2021	1993	RET ABN	UG-SERVICE
39838385	GRET	SVC	2/21/2022	1993	RET ABN	UG-SERVICE
42116060	GRET	SVC	9/15/2023	1993	RET ABN	UG-SERVICE
37059285	GRET	SVC	10/28/2020	1993	RET ABN	UG-SERVICE
39306786	GRET	SVC	10/25/2021	1993	RET ABN	UG-SERVICE
38817197	GRET	SVC	7/21/2021	1993	RET ABN	UG-SERVICE
41872475	GRET	SVC	7/12/2023	1993	RET ABN	UG-SERVICE
43481246	GRET	SVC	9/28/2024	1993	RET ABN	UG-SERVICE
43481255	GRET	SVC	11/20/2024	1993	RET ABN	UG-SERVICE
36868129	GRET	SVC	8/29/2020	1993	RET ABN	UG-SERVICE
39691376	GRET	SVC	1/18/2022	1993	RET ABN	UG-SERVICE
39060316	GRET	SVC	9/16/2021	1993	RET ABN	UG-SERVICE
40153194	GRET	SVC	5/10/2022	1993	RET ABN	UG-SERVICE
41411653	GRET	SVC	4/2/2024	1993	RET ABN	UG-SERVICE
42517560	GRET	SVC	12/27/2023	1993	RET ABN	UG-SERVICE
41584965	GRET	SVC	5/1/2023	1993	RET ABN	UG-SERVICE
43241684	GRET	SVC	9/19/2024	1993	RET ABN	UG-SERVICE
36436503	GRET	SVC	6/6/2020	1993	RET ABN	UG-SERVICE
39895906	GRET	SVC	3/16/2022	1993	RET ABN	UG-SERVICE
38851993	GRET	SVC	11/2/2021	1993	RET ABN	UG-SERVICE
38207650	GRET	SVC	3/15/2021	1993	RET ABN	UG-SERVICE
42208707	GRET	SVC	10/10/2023	1993	RET ABN	UG-SERVICE
41573436	GRET	SVC	5/1/2023	1993	RET ABN	UG-SERVICE
43957762	GRET	SVC	12/11/2024	1993	RET ABN	UG-SERVICE
36769541	GRET	SVC	7/4/2020	1993	RET ABN	UG-SERVICE
42956492	GRET	SVC	4/20/2024	1993	RET ABN	UG-SERVICE
43318026	GRET	SVC	7/29/2024	1993	RET ABN	UG-SERVICE
42336298	GRET	SVC	4/16/2024	1993	RET ABN	UG-SERVICE
36709888	GRET	SVC	8/4/2020	1993	RET ABN	UG-SERVICE
40395344	GRET	SVC	7/5/2022	1993	RET ABN	UG-SERVICE
42245667	GRET	SVC	10/4/2023	1993	RET ABN	UG-SERVICE
40595240	GRET	SVC	8/14/2022	1993	RET ABN	UG-SERVICE
41411919	GRET	SVC	4/2/2024	1993	RET ABN	UG-SERVICE
39785597	GRET	SVC	2/21/2022	1993	RET ABN	UG-SERVICE
41036020	GRET	SVC	12/7/2022	1993	RET ABN	UG-SERVICE
43957765	GRET	SVC	12/19/2024	1993	RET ABN	UG-SERVICE
39191278	GRET	SVC	9/24/2021	1993	RET ABN	UG-SERVICE
43506884	GRET	SVC	9/25/2024	1993	RET ABN	UG-SERVICE
38632600	GRET	SVC	6/14/2021	1993	RET ABN	UG-SERVICE
39177676	GRET	SVC	9/21/2021	1993	RET ABN	UG-SERVICE
41390581	GRET	SVC	3/17/2023	1993	RET ABN	UG-SERVICE
41677520	GRET	SVC	5/30/2023	1993	RET ABN	UG-SERVICE
43250695	GRET	SVC	12/26/2024	1993	RET ABN	UG-SERVICE
36793069	GRET	SVC	8/18/2020	1993	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41497335	GRET	SVC	4/6/2023	1993	RET ABN	UG-SERVICE
38441439	GRET	SVC	1/6/2022	1993	RET ABN	UG-SERVICE
36886591	GRET	SVC	7/7/2021	1993	RET ABN	UG-SERVICE
42588548	GRET	SVC	1/31/2024	1993	RET ABN	UG-SERVICE
42317372	GRET	SVC	10/24/2023	1993	RET ABN	UG-SERVICE
43241688	GRET	SVC	9/19/2024	1993	RET ABN	UG-SERVICE
41088874	GRET	SVC	12/22/2022	1993	RET ABN	UG-SERVICE
41411587	GRET	SVC	4/2/2024	1993	RET ABN	UG-SERVICE
43978376	GRET	SVC	12/23/2024	1993	RET ABN	UG-SERVICE
39552702	GRET	SVC	12/17/2021	1993	RET ABN	UG-SERVICE
41184946	GRET	SVC	1/19/2023	1993	RET ABN	UG-SERVICE
41411595	GRET	SVC	4/2/2024	1993	RET ABN	UG-SERVICE
40277457	GRET	SVC	4/27/2023	1993	RET ABN	UG-SERVICE
41101692	GRET	SVC	1/30/2023	1993	RET ABN	UG-SERVICE
43241278	GRET	SVC	9/17/2024	1993	RET ABN	UG-SERVICE
43957769	GRET	SVC	12/9/2024	1993	RET ABN	UG-SERVICE
41727358	GRET	SVC	6/16/2023	1993	RET ABN	UG-SERVICE
41187076	GRET	SVC	1/18/2023	1993	RET ABN	UG-SERVICE
41083458	GRET	SVC	1/4/2023	1993	RET ABN	UG-SERVICE
42201247	GRET	SVC	10/9/2023	1993	RET ABN	UG-SERVICE
37924849	GRET	SVC	12/16/2020	1993	RET ABN	UG-SERVICE
35868779	GRET	SVC	2/11/2020	1993	RET ABN	UG-SERVICE
37934852	GRET	SVC	12/19/2020	1993	RET ABN	UG-SERVICE
39984017	GRET	SVC	6/9/2022	1993	RET ABN	UG-SERVICE
41928924	GRET	SVC	7/19/2023	1993	RET ABN	UG-SERVICE
42156958	GRET	SVC	9/27/2023	1993	RET ABN	UG-SERVICE
41507925	GRET	SVC	4/13/2023	1993	RET ABN	UG-SERVICE
37048150	GRET	SVC	10/5/2020	1993	RET ABN	UG-SERVICE
36710983	GRET	SVC	8/3/2020	1993	RET ABN	UG-SERVICE
40558161	GRET	SVC	8/12/2022	1993	RET ABN	UG-SERVICE
40813750	GRET	SVC	10/17/2022	1993	RET ABN	UG-SERVICE
39890620	GRET	SVC	3/14/2022	1993	RET ABN	UG-SERVICE
42442496	GRET	SVC	12/2/2023	1993	RET ABN	UG-SERVICE
41392507	GRET	SVC	3/26/2023	1993	RET ABN	UG-SERVICE
43957771	GRET	SVC	12/9/2024	1993	RET ABN	UG-SERVICE
42505488	GRET	SVC	12/26/2023	1993	RET ABN	UG-SERVICE
38779467	GRET	SVC	7/15/2021	1993	RET ABN	UG-SERVICE
41933546	GRET	SVC	10/13/2023	1993	RET ABN	UG-SERVICE
40199012	GRET	SVC	5/31/2022	1993	RET ABN	UG-SERVICE
43191348	GRET	SVC	6/25/2024	1993	RET ABN	UG-SERVICE
40732875	GRET	SVC	10/1/2022	1993	RET ABN	UG-SERVICE
36221953	GRET	SVC	4/23/2020	1993	RET ABN	UG-SERVICE
42658316	GRET	SVC	2/5/2024	1993	RET ABN	UG-SERVICE
40318182	GRET	SVC	6/17/2022	1993	RET ABN	UG-SERVICE
43498111	GRET	SVC	8/26/2024	1993	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
37098566	GRET	SVC	10/29/2020	1993	RET ABN	UG-SERVICE
42137945	GRET	SVC	9/22/2023	1993	RET ABN	UG-SERVICE
41083721	GRET	SVC	12/21/2022	1993	RET ABN	UG-SERVICE
41813702	GRET	SVC	6/29/2023	1994	RET ABN	UG-SERVICE
40943969	GRET	SVC	11/28/2022	1994	RET ABN	UG-SERVICE
43492538	GRET	SVC	12/3/2024	1994	RET ABN	UG-SERVICE
40395859	GRET	SVC	7/6/2022	1994	RET ABN	UG-SERVICE
41099795	GRET	SVC	1/5/2023	1994	RET ABN	UG-SERVICE
43951150	GRET	SVC	12/17/2024	1994	RET ABN	UG-SERVICE
38783975	GRET	SVC	7/13/2021	1994	RET ABN	UG-SERVICE
43529376	GRET	SVC	10/27/2024	1994	RET ABN	UG-SERVICE
43529753	GRET	SVC	12/22/2024	1994	RET ABN	UG-SERVICE
42322524	GRET	SVC	4/2/2024	1994	RET ABN	UG-SERVICE
41877018	GRET	SVC	7/18/2023	1994	RET ABN	UG-SERVICE
39681495	GRET	SVC	1/14/2022	1994	RET ABN	UG-SERVICE
38900666	GRET	SVC	10/12/2021	1994	RET ABN	UG-SERVICE
39753654	GRET	SVC	1/26/2022	1994	RET ABN	UG-SERVICE
40987271	GRET	SVC	11/30/2022	1994	RET ABN	UG-SERVICE
36177525	GRET	SVC	2/14/2020	1994	RET ABN	UG-SERVICE
36470402	GRET	SVC	6/22/2020	1994	RET ABN	UG-SERVICE
41426054	GRET	SVC	3/24/2023	1994	RET ABN	UG-SERVICE
42344007	GRET	SVC	4/2/2024	1994	RET ABN	UG-SERVICE
39854795	GRET	SVC	3/9/2022	1994	RET ABN	UG-SERVICE
37929078	GRET	SVC	12/16/2020	1994	RET ABN	UG-SERVICE
37120664	GRET	SVC	10/24/2020	1994	RET ABN	UG-SERVICE
42418511	GRET	SVC	10/14/2023	1994	RET ABN	UG-SERVICE
43020926	GRET	SVC	5/24/2024	1994	RET ABN	UG-SERVICE
38875200	GRET	SVC	8/4/2021	1994	RET ABN	UG-SERVICE
43135174	GRET	SVC	6/4/2024	1994	RET ABN	UG-SERVICE
41411424	GRET	SVC	11/2/2023	1994	RET ABN	UG-SERVICE
41244977	GRET	SVC	2/6/2023	1994	RET ABN	UG-SERVICE
41195734	GRET	SVC	1/24/2023	1994	RET ABN	UG-SERVICE
37987403	GRET	SVC	1/5/2021	1994	RET ABN	UG-SERVICE
38499745	GRET	SVC	5/18/2021	1994	RET ABN	UG-SERVICE
43909723	GRET	SVC	12/6/2024	1994	RET ABN	UG-SERVICE
43365780	GRET	SVC	12/3/2024	1994	RET ABN	UG-SERVICE
43529730	GRET	SVC	11/27/2024	1994	RET ABN	UG-SERVICE
41288879	GRET	SVC	3/17/2023	1994	RET ABN	UG-SERVICE
41207591	GRET	SVC	1/24/2023	1994	RET ABN	UG-SERVICE
37120663	GRET	SVC	10/24/2020	1994	RET ABN	UG-SERVICE
42825292	GRET	SVC	3/11/2024	1994	RET ABN	UG-SERVICE
43529378	GRET	SVC	11/2/2024	1994	RET ABN	UG-SERVICE
41185660	GRET	SVC	1/26/2023	1994	RET ABN	UG-SERVICE
43623435	GRET	SVC	12/2/2024	1994	RET ABN	UG-SERVICE
41288866	GRET	SVC	3/17/2023	1994	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40723313	GRET	SVC	10/7/2022	1994	RET ABN	UG-SERVICE
36998791	GRET	SVC	9/28/2020	1994	RET ABN	UG-SERVICE
40864102	GRET	SVC	10/31/2022	1994	RET ABN	UG-SERVICE
41552451	GRET	SVC	4/28/2023	1994	RET ABN	UG-SERVICE
36576775	GRET	SVC	8/6/2020	1994	RET ABN	UG-SERVICE
39390797	GRET	SVC	11/19/2021	1994	RET ABN	UG-SERVICE
38779469	GRET	SVC	7/13/2021	1994	RET ABN	UG-SERVICE
40116597	GRET	SVC	5/6/2022	1994	RET ABN	UG-SERVICE
38189719	GRET	SVC	3/15/2021	1994	RET ABN	UG-SERVICE
42506402	GRET	SVC	12/28/2023	1994	RET ABN	UG-SERVICE
41211396	GRET	SVC	1/30/2023	1994	RET ABN	UG-SERVICE
41649933	GRET	SVC	5/16/2023	1994	RET ABN	UG-SERVICE
39721214	GRET	SVC	1/25/2022	1994	RET ABN	UG-SERVICE
40222490	GRET	SVC	5/31/2022	1994	RET ABN	UG-SERVICE
41085376	GRET	SVC	1/4/2023	1994	RET ABN	UG-SERVICE
36605914	GRET	SVC	7/9/2020	1994	RET ABN	UG-SERVICE
39455877	GRET	SVC	11/22/2021	1994	RET ABN	UG-SERVICE
40318192	GRET	SVC	6/17/2022	1994	RET ABN	UG-SERVICE
38146654	GRET	SVC	2/17/2021	1994	RET ABN	UG-SERVICE
38095982	GRET	SVC	2/15/2021	1994	RET ABN	UG-SERVICE
36485802	GRET	SVC	6/20/2020	1994	RET ABN	UG-SERVICE
43617825	GRET	SVC	9/24/2024	1994	RET ABN	UG-SERVICE
36707376	GRET	SVC	7/21/2020	1994	RET ABN	UG-SERVICE
36142355	GRET	SVC	3/17/2020	1994	RET ABN	UG-SERVICE
41427447	GRET	SVC	3/21/2023	1994	RET ABN	UG-SERVICE
43042233	GRET	SVC	5/14/2024	1994	RET ABN	UG-SERVICE
42705990	GRET	SVC	2/14/2024	1994	RET ABN	UG-SERVICE
42855625	GRET	SVC	3/26/2024	1994	RET ABN	UG-SERVICE
43529726	GRET	SVC	11/27/2024	1994	RET ABN	UG-SERVICE
41139009	GRET	SVC	1/21/2023	1994	RET ABN	UG-SERVICE
43529731	GRET	SVC	11/2/2024	1994	RET ABN	UG-SERVICE
43300973	GRET	SVC	7/13/2024	1994	RET ABN	UG-SERVICE
39224492	GRET	SVC	9/30/2021	1994	RET ABN	UG-SERVICE
41317489	GRET	SVC	3/3/2023	1994	RET ABN	UG-SERVICE
39966172	GRET	SVC	2/22/2022	1994	RET ABN	UG-SERVICE
39299440	GRET	SVC	10/18/2021	1994	RET ABN	UG-SERVICE
43323975	GRET	SVC	7/24/2024	1994	RET ABN	UG-SERVICE
43731861	GRET	SVC	10/21/2024	1994	RET ABN	UG-SERVICE
36505784	GRET	SVC	6/23/2020	1994	RET ABN	UG-SERVICE
41123319	GRET	SVC	1/4/2023	1994	RET ABN	UG-SERVICE
41057669	GRET	SVC	12/14/2022	1994	RET ABN	UG-SERVICE
39630749	GRET	SVC	1/4/2022	1994	RET ABN	UG-SERVICE
39333382	GRET	SVC	11/2/2021	1994	RET ABN	UG-SERVICE
40973116	GRET	SVC	11/18/2022	1994	RET ABN	UG-SERVICE
43529744	GRET	SVC	12/6/2024	1994	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
39666486	GRET	SVC	11/18/2022	1994	RET ABN	UG-SERVICE
43493327	GRET	SVC	10/22/2024	1994	RET ABN	UG-SERVICE
43826770	GRET	SVC	11/12/2024	1994	RET ABN	UG-SERVICE
43529728	GRET	SVC	10/27/2024	1994	RET ABN	UG-SERVICE
39277584	GRET	SVC	10/11/2021	1994	RET ABN	UG-SERVICE
42135700	GRET	SVC	9/20/2023	1994	RET ABN	UG-SERVICE
42113245	GRET	SVC	9/11/2023	1994	RET ABN	UG-SERVICE
38298837	GRET	SVC	3/25/2021	1994	RET ABN	UG-SERVICE
41425309	GRET	SVC	3/21/2023	1994	RET ABN	UG-SERVICE
37525595	GRET	SVC	11/16/2020	1994	RET ABN	UG-SERVICE
39070007	GRET	SVC	8/30/2021	1994	RET ABN	UG-SERVICE
43507270	GRET	SVC	9/9/2024	1994	RET ABN	UG-SERVICE
37082844	GRET	SVC	10/16/2020	1994	RET ABN	UG-SERVICE
43529751	GRET	SVC	12/13/2024	1994	RET ABN	UG-SERVICE
39666491	GRET	SVC	11/18/2022	1994	RET ABN	UG-SERVICE
40239927	GRET	SVC	5/28/2022	1994	RET ABN	UG-SERVICE
43529752	GRET	SVC	12/21/2024	1994	RET ABN	UG-SERVICE
38458599	GRET	SVC	5/5/2021	1994	RET ABN	UG-SERVICE
41277358	GRET	SVC	2/14/2023	1994	RET ABN	UG-SERVICE
42159014	GRET	SVC	9/22/2023	1994	RET ABN	UG-SERVICE
43529379	GRET	SVC	11/24/2024	1994	RET ABN	UG-SERVICE
40456748	GRET	SVC	7/18/2022	1994	RET ABN	UG-SERVICE
40498173	GRET	SVC	7/27/2022	1994	RET ABN	UG-SERVICE
43529720	GRET	SVC	11/24/2024	1994	RET ABN	UG-SERVICE
39398834	GRET	SVC	11/8/2021	1994	RET ABN	UG-SERVICE
41113796	GRET	SVC	12/28/2022	1994	RET ABN	UG-SERVICE
36009496	GRET	SVC	2/10/2020	1994	RET ABN	UG-SERVICE
40396838	GRET	SVC	7/11/2022	1994	RET ABN	UG-SERVICE
39992844	GRET	SVC	4/11/2022	1994	RET ABN	UG-SERVICE
41770913	GRET	SVC	8/7/2023	1994	RET ABN	UG-SERVICE
37020751	GRET	SVC	10/10/2020	1994	RET ABN	UG-SERVICE
36633102	GRET	SVC	7/14/2020	1994	RET ABN	UG-SERVICE
42695250	GRET	SVC	2/10/2024	1994	RET ABN	UG-SERVICE
36724026	GRET	SVC	8/4/2020	1994	RET ABN	UG-SERVICE
39744802	GRET	SVC	2/8/2022	1994	RET ABN	UG-SERVICE
38002843	GRET	SVC	1/11/2021	1994	RET ABN	UG-SERVICE
36576604	GRET	SVC	8/6/2020	1994	RET ABN	UG-SERVICE
41286923	GRET	SVC	2/15/2023	1994	RET ABN	UG-SERVICE
40847366	GRET	SVC	11/20/2022	1994	RET ABN	UG-SERVICE
38454097	GRET	SVC	5/7/2021	1994	RET ABN	UG-SERVICE
36120513	GRET	SVC	3/13/2020	1994	RET ABN	UG-SERVICE
36980371	GRET	SVC	9/21/2020	1994	RET ABN	UG-SERVICE
36791124	GRET	SVC	9/4/2020	1994	RET ABN	UG-SERVICE
43529725	GRET	SVC	11/27/2024	1994	RET ABN	UG-SERVICE
40561703	GRET	SVC	8/17/2022	1994	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43251087	GRET	SVC	6/24/2024	1994	RET ABN	UG-SERVICE
39820706	GRET	SVC	2/22/2022	1994	RET ABN	UG-SERVICE
40655356	GRET	SVC	10/21/2022	1994	RET ABN	UG-SERVICE
41428827	GRET	SVC	3/23/2023	1995	RET ABN	UG-SERVICE
42654196	GRET	SVC	2/2/2024	1995	RET ABN	UG-SERVICE
37070438	GRET	SVC	8/19/2020	1995	RET ABN	UG-SERVICE
42817716	GRET	SVC	4/17/2024	1995	RET ABN	UG-SERVICE
42419488	GRET	SVC	11/27/2023	1995	RET ABN	UG-SERVICE
41015454	GRET	SVC	12/16/2022	1995	RET ABN	UG-SERVICE
36672044	GRET	SVC	8/7/2020	1995	RET ABN	UG-SERVICE
41242177	GRET	SVC	3/1/2023	1995	RET ABN	UG-SERVICE
41760937	GRET	SVC	8/2/2023	1995	RET ABN	UG-SERVICE
40048048	GRET	SVC	4/22/2022	1995	RET ABN	UG-SERVICE
43705926	GRET	SVC	10/14/2024	1995	RET ABN	UG-SERVICE
43150812	GRET	SVC	6/6/2024	1995	RET ABN	UG-SERVICE
43245087	GRET	SVC	9/11/2024	1995	RET ABN	UG-SERVICE
42834263	GRET	SVC	7/23/2024	1995	RET ABN	UG-SERVICE
39903275	GRET	SVC	3/15/2022	1995	RET ABN	UG-SERVICE
41429218	GRET	SVC	3/24/2023	1995	RET ABN	UG-SERVICE
40749609	GRET	SVC	9/29/2022	1995	RET ABN	UG-SERVICE
36301953	GRET	SVC	5/13/2020	1995	RET ABN	UG-SERVICE
40870524	GRET	SVC	11/9/2022	1995	RET ABN	UG-SERVICE
41951085	GRET	SVC	8/4/2023	1995	RET ABN	UG-SERVICE
40551322	GRET	SVC	8/16/2022	1995	RET ABN	UG-SERVICE
41402081	GRET	SVC	3/15/2023	1995	RET ABN	UG-SERVICE
40396055	GRET	SVC	7/6/2022	1995	RET ABN	UG-SERVICE
40855837	GRET	SVC	10/22/2022	1995	RET ABN	UG-SERVICE
41244979	GRET	SVC	2/4/2023	1995	RET ABN	UG-SERVICE
42695047	GRET	SVC	2/14/2024	1995	RET ABN	UG-SERVICE
38521182	GRET	SVC	6/4/2021	1995	RET ABN	UG-SERVICE
36946066	GRET	SVC	9/15/2020	1995	RET ABN	UG-SERVICE
41375577	GRET	SVC	3/13/2023	1995	RET ABN	UG-SERVICE
40461409	GRET	SVC	7/21/2022	1995	RET ABN	UG-SERVICE
37490029	GRET	SVC	12/11/2020	1995	RET ABN	UG-SERVICE
39646756	GRET	SVC	4/11/2022	1995	RET ABN	UG-SERVICE
36399235	GRET	SVC	6/1/2020	1995	RET ABN	UG-SERVICE
40952499	GRET	SVC	11/19/2022	1995	RET ABN	UG-SERVICE
41279174	GRET	SVC	2/24/2023	1995	RET ABN	UG-SERVICE
43323976	GRET	SVC	7/25/2024	1995	RET ABN	UG-SERVICE
35959607	GRET	SVC	1/28/2020	1995	RET ABN	UG-SERVICE
39494528	GRET	SVC	12/14/2021	1995	RET ABN	UG-SERVICE
40174364	GRET	SVC	6/6/2022	1995	RET ABN	UG-SERVICE
40201045	GRET	SVC	6/6/2022	1995	RET ABN	UG-SERVICE
40661475	GRET	SVC	9/22/2022	1995	RET ABN	UG-SERVICE
41708455	GRET	SVC	6/5/2023	1995	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40013196	GRET	SVC	4/19/2022	1995	RET ABN	UG-SERVICE
43481122	GRET	SVC	10/28/2024	1995	RET ABN	UG-SERVICE
42611333	GRET	SVC	1/24/2024	1995	RET ABN	UG-SERVICE
39581789	GRET	SVC	12/26/2021	1995	RET ABN	UG-SERVICE
39554828	GRET	SVC	12/28/2021	1995	RET ABN	UG-SERVICE
41242172	GRET	SVC	3/2/2023	1995	RET ABN	UG-SERVICE
43862404	GRET	SVC	11/22/2024	1995	RET ABN	UG-SERVICE
42534910	GRET	SVC	1/4/2024	1995	RET ABN	UG-SERVICE
41332048	GRET	SVC	3/1/2023	1995	RET ABN	UG-SERVICE
41428823	GRET	SVC	3/27/2023	1995	RET ABN	UG-SERVICE
41513273	GRET	SVC	4/16/2023	1995	RET ABN	UG-SERVICE
38713913	GRET	SVC	7/7/2021	1995	RET ABN	UG-SERVICE
43535155	GRET	SVC	9/30/2024	1995	RET ABN	UG-SERVICE
42276448	GRET	SVC	10/26/2023	1995	RET ABN	UG-SERVICE
41223589	GRET	SVC	2/3/2023	1995	RET ABN	UG-SERVICE
41969540	GRET	SVC	8/1/2024	1995	RET ABN	UG-SERVICE
40951421	GRET	SVC	1/5/2023	1995	RET ABN	UG-SERVICE
41834504	GRET	SVC	7/21/2023	1995	RET ABN	UG-SERVICE
40841472	GRET	SVC	10/20/2022	1995	RET ABN	UG-SERVICE
41418707	GRET	SVC	3/22/2023	1995	RET ABN	UG-SERVICE
41175947	GRET	SVC	1/17/2023	1995	RET ABN	UG-SERVICE
42336324	GRET	SVC	4/16/2024	1995	RET ABN	UG-SERVICE
40913346	GRET	SVC	11/7/2022	1995	RET ABN	UG-SERVICE
36101932	GRET	SVC	2/8/2020	1995	RET ABN	UG-SERVICE
38109797	GRET	SVC	12/29/2020	1995	RET ABN	UG-SERVICE
38122800	GRET	SVC	2/10/2021	1995	RET ABN	UG-SERVICE
40862490	GRET	SVC	10/28/2022	1995	RET ABN	UG-SERVICE
40506086	GRET	SVC	8/2/2022	1995	RET ABN	UG-SERVICE
42959506	GRET	SVC	4/22/2024	1995	RET ABN	UG-SERVICE
42336327	GRET	SVC	4/19/2024	1995	RET ABN	UG-SERVICE
37143043	GRET	SVC	11/13/2020	1995	RET ABN	UG-SERVICE
36829570	GRET	SVC	8/27/2020	1995	RET ABN	UG-SERVICE
43633875	GRET	SVC	10/16/2024	1995	RET ABN	UG-SERVICE
43410047	GRET	SVC	8/28/2024	1995	RET ABN	UG-SERVICE
42560751	GRET	SVC	1/9/2024	1995	RET ABN	UG-SERVICE
39368598	GRET	SVC	11/2/2021	1995	RET ABN	UG-SERVICE
38567222	GRET	SVC	6/1/2021	1995	RET ABN	UG-SERVICE
41423930	GRET	SVC	3/22/2023	1995	RET ABN	UG-SERVICE
41015754	GRET	SVC	12/14/2022	1995	RET ABN	UG-SERVICE
41545676	GRET	SVC	4/23/2023	1995	RET ABN	UG-SERVICE
42226971	GRET	SVC	10/12/2023	1995	RET ABN	UG-SERVICE
42706083	GRET	SVC	2/6/2024	1995	RET ABN	UG-SERVICE
38429962	GRET	SVC	4/29/2021	1995	RET ABN	UG-SERVICE
39847437	GRET	SVC	3/2/2022	1995	RET ABN	UG-SERVICE
40801474	GRET	SVC	10/12/2022	1995	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36675373	GRET	SVC	8/18/2020	1995	RET ABN	UG-SERVICE
41389621	GRET	SVC	3/11/2023	1995	RET ABN	UG-SERVICE
42483429	GRET	SVC	4/15/2024	1995	RET ABN	UG-SERVICE
37102731	GRET	SVC	10/30/2020	1995	RET ABN	UG-SERVICE
42873783	GRET	SVC	4/1/2024	1995	RET ABN	UG-SERVICE
37041376	GRET	SVC	10/8/2020	1995	RET ABN	UG-SERVICE
35835931	GRET	SVC	1/2/2020	1995	RET ABN	UG-SERVICE
37979445	GRET	SVC	1/5/2021	1995	RET ABN	UG-SERVICE
35997397	GRET	SVC	2/10/2020	1995	RET ABN	UG-SERVICE
40813407	GRET	SVC	10/14/2022	1995	RET ABN	UG-SERVICE
40282845	GRET	SVC	6/9/2022	1995	RET ABN	UG-SERVICE
39636945	GRET	SVC	1/3/2022	1995	RET ABN	UG-SERVICE
39831207	GRET	SVC	8/3/2022	1995	RET ABN	UG-SERVICE
41183047	GRET	SVC	1/17/2023	1995	RET ABN	UG-SERVICE
43624700	GRET	SVC	9/30/2024	1995	RET ABN	UG-SERVICE
43812801	GRET	SVC	11/9/2024	1995	RET ABN	UG-SERVICE
43506833	GRET	SVC	9/16/2024	1995	RET ABN	UG-SERVICE
41428826	GRET	SVC	3/24/2023	1995	RET ABN	UG-SERVICE
39468936	GRET	SVC	12/27/2021	1995	RET ABN	UG-SERVICE
39830357	GRET	SVC	8/3/2022	1995	RET ABN	UG-SERVICE
41183046	GRET	SVC	1/17/2023	1995	RET ABN	UG-SERVICE
38766883	GRET	SVC	7/11/2021	1995	RET ABN	UG-SERVICE
40859973	GRET	SVC	11/3/2022	1995	RET ABN	UG-SERVICE
38252498	GRET	SVC	5/3/2021	1995	RET ABN	UG-SERVICE
39318304	GRET	SVC	10/18/2021	1995	RET ABN	UG-SERVICE
40855333	GRET	SVC	10/23/2022	1995	RET ABN	UG-SERVICE
36708021	GRET	SVC	7/28/2020	1995	RET ABN	UG-SERVICE
39658081	GRET	SVC	2/11/2022	1995	RET ABN	UG-SERVICE
41774605	GRET	SVC	6/19/2023	1995	RET ABN	UG-SERVICE
37981636	GRET	SVC	1/5/2021	1995	RET ABN	UG-SERVICE
40853497	GRET	SVC	10/28/2022	1995	RET ABN	UG-SERVICE
36255380	GRET	SVC	3/11/2020	1995	RET ABN	UG-SERVICE
41279363	GRET	SVC	2/15/2023	1995	RET ABN	UG-SERVICE
40092706	GRET	SVC	5/2/2022	1995	RET ABN	UG-SERVICE
38399319	GRET	SVC	4/21/2021	1995	RET ABN	UG-SERVICE
42881713	GRET	SVC	5/8/2024	1995	RET ABN	UG-SERVICE
41887923	GRET	SVC	8/23/2023	1995	RET ABN	UG-SERVICE
41423345	GRET	SVC	3/24/2023	1995	RET ABN	UG-SERVICE
43934140	GRET	SVC	12/21/2024	1995	RET ABN	UG-SERVICE
41589611	GRET	SVC	4/19/2023	1995	RET ABN	UG-SERVICE
43459327	GRET	SVC	8/26/2024	1995	RET ABN	UG-SERVICE
42407919	GRET	SVC	11/19/2023	1995	RET ABN	UG-SERVICE
43650873	GRET	SVC	9/28/2024	1995	RET ABN	UG-SERVICE
43678006	GRET	SVC	10/17/2024	1995	RET ABN	UG-SERVICE
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41322893	GRET	SVC	2/28/2023	1995	RET ABN	UG-SERVICE
38256071	GRET	SVC	3/22/2021	1995	RET ABN	UG-SERVICE
41145679	GRET	SVC	1/13/2023	1995	RET ABN	UG-SERVICE
40545203	GRET	SVC	8/9/2022	1995	RET ABN	UG-SERVICE
39795647	GRET	SVC	2/15/2022	1995	RET ABN	UG-SERVICE
43905495	GRET	SVC	12/23/2024	1996	RET ABN	UG-SERVICE
42938843	GRET	SVC	4/16/2024	1996	RET ABN	UG-SERVICE
42586939	GRET	SVC	1/17/2024	1996	RET ABN	UG-SERVICE
40525193	GRET	SVC	8/8/2022	1996	RET ABN	UG-SERVICE
36184262	GRET	SVC	3/30/2020	1996	RET ABN	UG-SERVICE
40654144	GRET	SVC	9/7/2022	1996	RET ABN	UG-SERVICE
43364924	GRET	SVC	12/2/2024	1996	RET ABN	UG-SERVICE
41545257	GRET	SVC	4/24/2023	1996	RET ABN	UG-SERVICE
40522172	GRET	SVC	9/1/2022	1996	RET ABN	UG-SERVICE
36036302	GRET	SVC	1/9/2020	1996	RET ABN	UG-SERVICE
41102022	GRET	SVC	1/5/2023	1996	RET ABN	UG-SERVICE
38271025	GRET	SVC	3/23/2021	1996	RET ABN	UG-SERVICE
38568364	GRET	SVC	8/18/2021	1996	RET ABN	UG-SERVICE
42087142	GRET	SVC	9/9/2023	1996	RET ABN	UG-SERVICE
38402622	GRET	SVC	4/22/2021	1996	RET ABN	UG-SERVICE
41061141	GRET	SVC	11/30/2022	1996	RET ABN	UG-SERVICE
43428601	GRET	SVC	9/6/2024	1996	RET ABN	UG-SERVICE
40551342	GRET	SVC	8/17/2022	1996	RET ABN	UG-SERVICE
41179720	GRET	SVC	1/17/2023	1996	RET ABN	UG-SERVICE
41407818	GRET	SVC	4/2/2024	1996	RET ABN	UG-SERVICE
43357267	GRET	SVC	7/26/2024	1996	RET ABN	UG-SERVICE
39367029	GRET	SVC	10/22/2021	1996	RET ABN	UG-SERVICE
36963476	GRET	SVC	9/21/2020	1996	RET ABN	UG-SERVICE
43971349	GRET	SVC	12/26/2024	1996	RET ABN	UG-SERVICE
40425685	GRET	SVC	7/12/2022	1996	RET ABN	UG-SERVICE
36310706	GRET	SVC	6/6/2020	1996	RET ABN	UG-SERVICE
36730565	GRET	SVC	8/3/2020	1996	RET ABN	UG-SERVICE
42037856	GRET	SVC	8/27/2023	1996	RET ABN	UG-SERVICE
43950611	GRET	SVC	12/17/2024	1996	RET ABN	UG-SERVICE
43861085	GRET	SVC	12/2/2024	1996	RET ABN	UG-SERVICE
38512754	GRET	SVC	5/17/2021	1996	RET ABN	UG-SERVICE
40481466	GRET	SVC	7/21/2022	1996	RET ABN	UG-SERVICE
39311784	GRET	SVC	11/21/2021	1996	RET ABN	UG-SERVICE
42177914	GRET	SVC	10/6/2023	1996	RET ABN	UG-SERVICE
41664559	GRET	SVC	5/23/2023	1996	RET ABN	UG-SERVICE
42406042	GRET	SVC	11/29/2023	1996	RET ABN	UG-SERVICE
40610690	GRET	SVC	8/23/2022	1996	RET ABN	UG-SERVICE
39795741	GRET	SVC	2/15/2022	1996	RET ABN	UG-SERVICE

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42514886	GRET	SVC	2/27/2024	1996	RET ABN	UG-SERVICE
40380288	GRET	SVC	5/23/2022	1996	RET ABN	UG-SERVICE
42372478	GRET	SVC	7/31/2024	1996	RET ABN	UG-SERVICE
36730127	GRET	SVC	8/3/2020	1996	RET ABN	UG-SERVICE
41287836	GRET	SVC	2/16/2023	1996	RET ABN	UG-SERVICE
40999434	GRET	SVC	11/30/2022	1996	RET ABN	UG-SERVICE
37883740	GRET	SVC	12/6/2020	1996	RET ABN	UG-SERVICE
41106614	GRET	SVC	12/27/2022	1996	RET ABN	UG-SERVICE
43916749	GRET	SVC	12/10/2024	1996	RET ABN	UG-SERVICE
35993672	GRET	SVC	2/10/2020	1996	RET ABN	UG-SERVICE
39470796	GRET	SVC	11/30/2021	1996	RET ABN	UG-SERVICE
37934865	GRET	SVC	12/13/2020	1996	RET ABN	UG-SERVICE
42514888	GRET	SVC	2/27/2024	1996	RET ABN	UG-SERVICE
36877204	GRET	SVC	9/3/2020	1996	RET ABN	UG-SERVICE
36480011	GRET	SVC	5/28/2020	1996	RET ABN	UG-SERVICE
40241209	GRET	SVC	5/25/2022	1996	RET ABN	UG-SERVICE
42193971	GRET	SVC	10/9/2023	1996	RET ABN	UG-SERVICE
41767756	GRET	SVC	6/24/2023	1996	RET ABN	UG-SERVICE
40668509	GRET	SVC	9/12/2022	1996	RET ABN	UG-SERVICE
41273851	GRET	SVC	2/13/2023	1996	RET ABN	UG-SERVICE
43071543	GRET	SVC	5/14/2024	1996	RET ABN	UG-SERVICE
41576705	GRET	SVC	5/1/2023	1996	RET ABN	UG-SERVICE
38489445	GRET	SVC	5/12/2021	1996	RET ABN	UG-SERVICE
43364923	GRET	SVC	10/15/2024	1996	RET ABN	UG-SERVICE
42437187	GRET	SVC	12/2/2023	1996	RET ABN	UG-SERVICE
42514885	GRET	SVC	2/27/2024	1996	RET ABN	UG-SERVICE
42514881	GRET	SVC	2/27/2024	1996	RET ABN	UG-SERVICE
39780070	GRET	SVC	2/8/2022	1996	RET ABN	UG-SERVICE
41440502	GRET	SVC	3/27/2023	1996	RET ABN	UG-SERVICE
36691476	GRET	SVC	8/20/2020	1996	RET ABN	UG-SERVICE
41245284	GRET	SVC	2/5/2023	1996	RET ABN	UG-SERVICE
42070933	GRET	SVC	10/6/2023	1996	RET ABN	UG-SERVICE
41274146	GRET	SVC	2/24/2023	1996	RET ABN	UG-SERVICE
39279671	GRET	SVC	10/13/2021	1996	RET ABN	UG-SERVICE
38033806	GRET	SVC	1/21/2021	1996	RET ABN	UG-SERVICE
43244754	GRET	SVC	9/18/2024	1996	RET ABN	UG-SERVICE
42405485	GRET	SVC	11/22/2023	1996	RET ABN	UG-SERVICE
39536369	GRET	SVC	12/14/2021	1996	RET ABN	UG-SERVICE
43318034	GRET	SVC	8/14/2024	1996	RET ABN	UG-SERVICE
41825568	GRET	SVC	7/3/2023	1996	RET ABN	UG-SERVICE
40576551	GRET	SVC	11/21/2022	1996	RET ABN	UG-SERVICE
40987514	GRET	SVC	12/5/2022	1996	RET ABN	UG-SERVICE
42142331	GRET	SVC	10/3/2023	1996	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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39809219	GRET	SVC	8/3/2022	1996	RET ABN	UG-SERVICE
40332290	GRET	SVC	6/20/2022	1996	RET ABN	UG-SERVICE
43356324	GRET	SVC	7/26/2024	1996	RET ABN	UG-SERVICE
42152239	GRET	SVC	9/25/2023	1996	RET ABN	UG-SERVICE
36152825	GRET	SVC	3/18/2020	1996	RET ABN	UG-SERVICE
37958743	GRET	SVC	12/29/2020	1996	RET ABN	UG-SERVICE
39084028	GRET	SVC	9/12/2021	1996	RET ABN	UG-SERVICE
42692586	GRET	SVC	2/12/2024	1996	RET ABN	UG-SERVICE
42514517	GRET	SVC	2/27/2024	1996	RET ABN	UG-SERVICE
41436546	GRET	SVC	3/26/2023	1996	RET ABN	UG-SERVICE
35994086	GRET	SVC	2/10/2020	1996	RET ABN	UG-SERVICE
35994083	GRET	SVC	2/10/2020	1996	RET ABN	UG-SERVICE
36900245	GRET	SVC	9/8/2020	1996	RET ABN	UG-SERVICE
40576820	GRET	SVC	8/17/2022	1996	RET ABN	UG-SERVICE
42514887	GRET	SVC	3/1/2024	1996	RET ABN	UG-SERVICE
41424021	GRET	SVC	8/7/2023	1996	RET ABN	UG-SERVICE
43916748	GRET	SVC	12/10/2024	1996	RET ABN	UG-SERVICE
42514882	GRET	SVC	2/27/2024	1996	RET ABN	UG-SERVICE
41503107	GRET	SVC	4/13/2023	1996	RET ABN	UG-SERVICE
41791634	GRET	SVC	6/25/2023	1996	RET ABN	UG-SERVICE
42270558	GRET	SVC	10/28/2023	1996	RET ABN	UG-SERVICE
43318486	GRET	SVC	7/19/2024	1996	RET ABN	UG-SERVICE
41906846	GRET	SVC	8/21/2023	1996	RET ABN	UG-SERVICE
36031413	GRET	SVC	2/20/2020	1996	RET ABN	UG-SERVICE
43330520	GRET	SVC	7/16/2024	1996	RET ABN	UG-SERVICE
39162854	GRET	SVC	9/29/2021	1996	RET ABN	UG-SERVICE
35866461	GRET	SVC	1/6/2020	1996	RET ABN	UG-SERVICE
36374976	GRET	SVC	6/1/2020	1996	RET ABN	UG-SERVICE
42227344	GRET	SVC	10/16/2023	1996	RET ABN	UG-SERVICE
39947534	GRET	SVC	3/31/2022	1996	RET ABN	UG-SERVICE
36908265	GRET	SVC	9/8/2020	1996	RET ABN	UG-SERVICE
42514884	GRET	SVC	2/27/2024	1996	RET ABN	UG-SERVICE
42819755	GRET	SVC	3/11/2024	1997	RET ABN	UG-SERVICE
43506837	GRET	SVC	10/3/2024	1997	RET ABN	UG-SERVICE
36184089	GRET	SVC	4/23/2020	1997	RET ABN	UG-SERVICE
42105249	GRET	SVC	9/13/2023	1997	RET ABN	UG-SERVICE
42010596	GRET	SVC	8/18/2023	1997	RET ABN	UG-SERVICE
39423758	GRET	SVC	6/27/2022	1997	RET ABN	UG-SERVICE
37033927	GRET	SVC	11/3/2020	1997	RET ABN	UG-SERVICE
36692253	GRET	SVC	8/6/2020	1997	RET ABN	UG-SERVICE
36835574	GRET	SVC	9/21/2020	1997	RET ABN	UG-SERVICE
40954748	GRET	SVC	11/21/2022	1997	RET ABN	UG-SERVICE
43902245	GRET	SVC	11/30/2024	1997	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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37973319	GRET	SVC	1/25/2021	1997	RET ABN	UG-SERVICE
38134204	GRET	SVC	2/17/2021	1997	RET ABN	UG-SERVICE
36146234	GRET	SVC	3/18/2020	1997	RET ABN	UG-SERVICE
43798077	GRET	SVC	11/7/2024	1997	RET ABN	UG-SERVICE
41872715	GRET	SVC	7/11/2023	1997	RET ABN	UG-SERVICE
36060667	GRET	SVC	3/20/2020	1997	RET ABN	UG-SERVICE
35816991	GRET	SVC	6/15/2021	1997	RET ABN	UG-SERVICE
42796846	GRET	SVC	4/4/2024	1997	RET ABN	UG-SERVICE
42412883	GRET	SVC	11/20/2023	1997	RET ABN	UG-SERVICE
41471664	GRET	SVC	4/4/2023	1997	RET ABN	UG-SERVICE
39280351	GRET	SVC	10/15/2021	1997	RET ABN	UG-SERVICE
41430973	GRET	SVC	3/28/2023	1997	RET ABN	UG-SERVICE
43475964	GRET	SVC	8/26/2024	1997	RET ABN	UG-SERVICE
40487332	GRET	SVC	7/27/2022	1997	RET ABN	UG-SERVICE
41399043	GRET	SVC	3/13/2023	1997	RET ABN	UG-SERVICE
40064748	GRET	SVC	4/29/2022	1997	RET ABN	UG-SERVICE
38437787	GRET	SVC	5/2/2021	1997	RET ABN	UG-SERVICE
40879834	GRET	SVC	10/28/2022	1997	RET ABN	UG-SERVICE
43418899	GRET	SVC	7/31/2024	1997	RET ABN	UG-SERVICE
39338467	GRET	SVC	11/1/2021	1997	RET ABN	UG-SERVICE
43610452	GRET	SVC	9/22/2024	1997	RET ABN	UG-SERVICE
37020175	GRET	SVC	10/1/2020	1997	RET ABN	UG-SERVICE
40824074	GRET	SVC	10/18/2022	1997	RET ABN	UG-SERVICE
39150297	GRET	SVC	9/13/2021	1997	RET ABN	UG-SERVICE
40802935	GRET	SVC	10/13/2022	1997	RET ABN	UG-SERVICE
41399041	GRET	SVC	3/13/2023	1997	RET ABN	UG-SERVICE
39816673	GRET	SVC	2/21/2022	1997	RET ABN	UG-SERVICE
39504173	GRET	SVC	12/6/2021	1997	RET ABN	UG-SERVICE
38240753	GRET	SVC	3/23/2021	1997	RET ABN	UG-SERVICE
36364821	GRET	SVC	6/5/2020	1997	RET ABN	UG-SERVICE
40883585	GRET	SVC	11/7/2022	1997	RET ABN	UG-SERVICE
40871925	GRET	SVC	11/8/2022	1997	RET ABN	UG-SERVICE
41426043	GRET	SVC	3/21/2023	1997	RET ABN	UG-SERVICE
40479240	GRET	SVC	7/25/2022	1997	RET ABN	UG-SERVICE
42297504	GRET	SVC	10/30/2023	1997	RET ABN	UG-SERVICE
40802345	GRET	SVC	10/10/2022	1997	RET ABN	UG-SERVICE
36838651	GRET	SVC	8/29/2020	1997	RET ABN	UG-SERVICE
36540298	GRET	SVC	7/15/2020	1997	RET ABN	UG-SERVICE
38239062	GRET	SVC	3/13/2021	1997	RET ABN	UG-SERVICE
42216810	GRET	SVC	12/6/2023	1997	RET ABN	UG-SERVICE
41129510	GRET	SVC	1/3/2023	1997	RET ABN	UG-SERVICE
36038825	GRET	SVC	2/18/2020	1997	RET ABN	UG-SERVICE
36400479	GRET	SVC	6/5/2020	1997	RET ABN	UG-SERVICE
42216817	GRET	SVC	12/12/2023	1997	RET ABN	UG-SERVICE

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42216818	GRET	SVC	12/12/2023	1997	RET ABN	UG-SERVICE
36202195	GRET	SVC	4/23/2020	1997	RET ABN	UG-SERVICE
41504298	GRET	SVC	4/14/2023	1997	RET ABN	UG-SERVICE
40784654	GRET	SVC	10/10/2022	1997	RET ABN	UG-SERVICE
42740575	GRET	SVC	2/20/2024	1997	RET ABN	UG-SERVICE
38132322	GRET	SVC	2/4/2021	1997	RET ABN	UG-SERVICE
41213829	GRET	SVC	12/11/2023	1997	RET ABN	UG-SERVICE
36704815	GRET	SVC	7/28/2020	1997	RET ABN	UG-SERVICE
41337380	GRET	SVC	3/6/2023	1997	RET ABN	UG-SERVICE
40871924	GRET	SVC	10/28/2022	1997	RET ABN	UG-SERVICE
41006860	GRET	SVC	12/9/2022	1997	RET ABN	UG-SERVICE
43495960	GRET	SVC	8/29/2024	1997	RET ABN	UG-SERVICE
39783820	GRET	SVC	2/17/2022	1997	RET ABN	UG-SERVICE
41006557	GRET	SVC	12/9/2022	1997	RET ABN	UG-SERVICE
39665275	GRET	SVC	8/3/2022	1997	RET ABN	UG-SERVICE
37422619	GRET	SVC	11/20/2020	1997	RET ABN	UG-SERVICE
38968696	GRET	SVC	8/30/2021	1997	RET ABN	UG-SERVICE
36252177	GRET	SVC	5/5/2020	1997	RET ABN	UG-SERVICE
41568419	GRET	SVC	4/28/2023	1997	RET ABN	UG-SERVICE
40919279	GRET	SVC	11/8/2022	1997	RET ABN	UG-SERVICE
43804914	GRET	SVC	11/21/2024	1997	RET ABN	UG-SERVICE
41088416	GRET	SVC	1/18/2023	1997	RET ABN	UG-SERVICE
40479242	GRET	SVC	7/25/2022	1997	RET ABN	UG-SERVICE
38406800	GRET	SVC	5/9/2021	1997	RET ABN	UG-SERVICE
41694326	GRET	SVC	10/6/2023	1997	RET ABN	UG-SERVICE
39992586	GRET	SVC	4/11/2022	1997	RET ABN	UG-SERVICE
40314683	GRET	SVC	6/15/2022	1997	RET ABN	UG-SERVICE
41006555	GRET	SVC	12/9/2022	1997	RET ABN	UG-SERVICE
42162126	GRET	SVC	9/23/2023	1997	RET ABN	UG-SERVICE
41969493	GRET	SVC	8/1/2024	1997	RET ABN	UG-SERVICE
43324305	GRET	SVC	7/24/2024	1997	RET ABN	UG-SERVICE
43506888	GRET	SVC	9/18/2024	1997	RET ABN	UG-SERVICE
41280027	GRET	SVC	3/3/2023	1997	RET ABN	UG-SERVICE
43396869	GRET	SVC	8/19/2024	1997	RET ABN	UG-SERVICE
41750595	GRET	SVC	6/10/2023	1997	RET ABN	UG-SERVICE
35868778	GRET	SVC	2/11/2020	1997	RET ABN	UG-SERVICE
38727537	GRET	SVC	7/12/2021	1997	RET ABN	UG-SERVICE
39386496	GRET	SVC	11/15/2021	1997	RET ABN	UG-SERVICE
38950424	GRET	SVC	8/17/2021	1997	RET ABN	UG-SERVICE
37606013	GRET	SVC	12/14/2020	1997	RET ABN	UG-SERVICE
41411155	GRET	SVC	4/2/2024	1997	RET ABN	UG-SERVICE
40629974	GRET	SVC	9/2/2022	1997	RET ABN	UG-SERVICE
39966710	GRET	SVC	5/26/2022	1997	RET ABN	UG-SERVICE
43583403	GRET	SVC	9/19/2024	1997	RET ABN	UG-SERVICE

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42261815	GRET	SVC	10/23/2023	1997	RET ABN	UG-SERVICE
40954445	GRET	SVC	12/12/2022	1997	RET ABN	UG-SERVICE
36371116	GRET	SVC	5/28/2020	1997	RET ABN	UG-SERVICE
43926050	GRET	SVC	12/11/2024	1997	RET ABN	UG-SERVICE
38875855	GRET	SVC	8/6/2021	1997	RET ABN	UG-SERVICE
40856523	GRET	SVC	10/30/2022	1997	RET ABN	UG-SERVICE
41876593	GRET	SVC	7/10/2023	1997	RET ABN	UG-SERVICE
41450868	GRET	SVC	7/12/2023	1997	RET ABN	UG-SERVICE
42433828	GRET	SVC	12/3/2023	1997	RET ABN	UG-SERVICE
41427496	GRET	SVC	3/28/2023	1997	RET ABN	UG-SERVICE
41213872	GRET	SVC	12/11/2023	1997	RET ABN	UG-SERVICE
43106678	GRET	SVC	5/28/2024	1997	RET ABN	UG-SERVICE
36569971	GRET	SVC	8/12/2020	1997	RET ABN	UG-SERVICE
39183553	GRET	SVC	9/23/2021	1997	RET ABN	UG-SERVICE
37867609	GRET	SVC	11/30/2020	1997	RET ABN	UG-SERVICE
39666090	GRET	SVC	8/3/2022	1997	RET ABN	UG-SERVICE
36392804	GRET	SVC	6/9/2020	1997	RET ABN	UG-SERVICE
41188707	GRET	SVC	1/18/2023	1998	RET ABN	UG-SERVICE
41528624	GRET	SVC	4/23/2023	1998	RET ABN	UG-SERVICE
38767419	GRET	SVC	7/20/2021	1998	RET ABN	UG-SERVICE
40563766	GRET	SVC	8/25/2022	1998	RET ABN	UG-SERVICE
36596097	GRET	SVC	7/29/2020	1998	RET ABN	UG-SERVICE
36826768	GRET	SVC	8/24/2020	1998	RET ABN	UG-SERVICE
41247252	GRET	SVC	2/8/2023	1998	RET ABN	UG-SERVICE
41576608	GRET	SVC	5/2/2023	1998	RET ABN	UG-SERVICE
42681619	GRET	SVC	2/12/2024	1998	RET ABN	UG-SERVICE
43318487	GRET	SVC	8/9/2024	1998	RET ABN	UG-SERVICE
41188703	GRET	SVC	1/20/2023	1998	RET ABN	UG-SERVICE
41195084	GRET	SVC	1/24/2023	1998	RET ABN	UG-SERVICE
42806300	GRET	SVC	3/12/2024	1998	RET ABN	UG-SERVICE
41253572	GRET	SVC	2/6/2023	1998	RET ABN	UG-SERVICE
38940808	GRET	SVC	8/19/2021	1998	RET ABN	UG-SERVICE
41036021	GRET	SVC	1/27/2023	1998	RET ABN	UG-SERVICE
37288381	GRET	SVC	11/9/2020	1998	RET ABN	UG-SERVICE
38791174	GRET	SVC	7/20/2021	1998	RET ABN	UG-SERVICE
41128958	GRET	SVC	1/4/2023	1998	RET ABN	UG-SERVICE
41068184	GRET	SVC	1/10/2023	1998	RET ABN	UG-SERVICE
37000459	GRET	SVC	11/3/2020	1998	RET ABN	UG-SERVICE
36745032	GRET	SVC	7/23/2020	1998	RET ABN	UG-SERVICE
39262300	GRET	SVC	10/26/2021	1998	RET ABN	UG-SERVICE
36792648	GRET	SVC	8/17/2020	1998	RET ABN	UG-SERVICE
39274158	GRET	SVC	10/14/2021	1998	RET ABN	UG-SERVICE
36480152	GRET	SVC	6/19/2020	1998	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41242473	GRET	SVC	2/21/2023	1998	RET ABN	UG-SERVICE
36915601	GRET	SVC	9/8/2020	1998	RET ABN	UG-SERVICE
39610822	GRET	SVC	12/26/2021	1998	RET ABN	UG-SERVICE
43090426	GRET	SVC	5/20/2024	1998	RET ABN	UG-SERVICE
41188567	GRET	SVC	1/19/2023	1998	RET ABN	UG-SERVICE
41472143	GRET	SVC	4/8/2023	1998	RET ABN	UG-SERVICE
40402788	GRET	SVC	7/12/2022	1998	RET ABN	UG-SERVICE
39978074	GRET	SVC	4/6/2022	1998	RET ABN	UG-SERVICE
41242608	GRET	SVC	2/21/2023	1998	RET ABN	UG-SERVICE
42787554	GRET	SVC	3/6/2024	1998	RET ABN	UG-SERVICE
41195093	GRET	SVC	1/27/2023	1998	RET ABN	UG-SERVICE
36435516	GRET	SVC	6/15/2020	1998	RET ABN	UG-SERVICE
40352474	GRET	SVC	7/1/2022	1998	RET ABN	UG-SERVICE
37934848	GRET	SVC	12/19/2020	1998	RET ABN	UG-SERVICE
35980848	GRET	SVC	2/6/2020	1998	RET ABN	UG-SERVICE
39904134	GRET	SVC	3/16/2022	1998	RET ABN	UG-SERVICE
36709896	GRET	SVC	8/5/2020	1998	RET ABN	UG-SERVICE
40141056	GRET	SVC	5/5/2022	1998	RET ABN	UG-SERVICE
41127312	GRET	SVC	1/5/2023	1998	RET ABN	UG-SERVICE
40812721	GRET	SVC	10/12/2022	1998	RET ABN	UG-SERVICE
41847581	GRET	SVC	7/13/2023	1998	RET ABN	UG-SERVICE
40669280	GRET	SVC	9/12/2022	1998	RET ABN	UG-SERVICE
38206744	GRET	SVC	3/13/2021	1998	RET ABN	UG-SERVICE
41188573	GRET	SVC	1/18/2023	1998	RET ABN	UG-SERVICE
38862872	GRET	SVC	8/4/2021	1998	RET ABN	UG-SERVICE
41246607	GRET	SVC	2/6/2023	1998	RET ABN	UG-SERVICE
41083456	GRET	SVC	1/4/2023	1998	RET ABN	UG-SERVICE
38481828	GRET	SVC	5/13/2021	1998	RET ABN	UG-SERVICE
38862875	GRET	SVC	8/4/2021	1998	RET ABN	UG-SERVICE
38769079	GRET	SVC	8/4/2021	1998	RET ABN	UG-SERVICE
41016211	GRET	SVC	12/12/2022	1998	RET ABN	UG-SERVICE
41195087	GRET	SVC	1/24/2023	1998	RET ABN	UG-SERVICE
42269392	GRET	SVC	11/3/2023	1998	RET ABN	UG-SERVICE
40514013	GRET	SVC	9/15/2022	1998	RET ABN	UG-SERVICE
42347999	GRET	SVC	11/20/2023	1998	RET ABN	UG-SERVICE
43469742	GRET	SVC	8/24/2024	1998	RET ABN	UG-SERVICE
41598850	GRET	SVC	5/25/2023	1998	RET ABN	UG-SERVICE
42383762	GRET	SVC	11/17/2023	1998	RET ABN	UG-SERVICE
40282165	GRET	SVC	6/13/2022	1998	RET ABN	UG-SERVICE
36302109	GRET	SVC	5/4/2020	1998	RET ABN	UG-SERVICE
37971361	GRET	SVC	12/29/2020	1998	RET ABN	UG-SERVICE
35933672	GRET	SVC	1/22/2020	1998	RET ABN	UG-SERVICE
39305036	GRET	SVC	10/25/2021	1998	RET ABN	UG-SERVICE
36914878	GRET	SVC	9/16/2020	1998	RET ABN	UG-SERVICE
41300695	GRET	SVC	2/28/2023	1998	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
39125203	GRET	SVC	9/14/2021	1998	RET ABN	UG-SERVICE
43409641	GRET	SVC	8/5/2024	1998	RET ABN	UG-SERVICE
39831571	GRET	SVC	8/3/2022	1998	RET ABN	UG-SERVICE
37842345	GRET	SVC	11/30/2020	1998	RET ABN	UG-SERVICE
41194834	GRET	SVC	1/22/2023	1998	RET ABN	UG-SERVICE
40731660	GRET	SVC	9/30/2022	1998	RET ABN	UG-SERVICE
41338302	GRET	SVC	3/1/2023	1998	RET ABN	UG-SERVICE
36710941	GRET	SVC	8/3/2020	1998	RET ABN	UG-SERVICE
41912317	GRET	SVC	7/27/2023	1998	RET ABN	UG-SERVICE
43650607	GRET	SVC	9/30/2024	1998	RET ABN	UG-SERVICE
42925411	GRET	SVC	4/25/2024	1998	RET ABN	UG-SERVICE
41242468	GRET	SVC	3/2/2023	1998	RET ABN	UG-SERVICE
41536200	GRET	SVC	4/18/2023	1998	RET ABN	UG-SERVICE
41974091	GRET	SVC	8/9/2023	1998	RET ABN	UG-SERVICE
43705212	GRET	SVC	10/12/2024	1998	RET ABN	UG-SERVICE
40469681	GRET	SVC	7/14/2022	1998	RET ABN	UG-SERVICE
41969578	GRET	SVC	8/1/2024	1998	RET ABN	UG-SERVICE
41188706	GRET	SVC	1/20/2023	1998	RET ABN	UG-SERVICE
42905583	GRET	SVC	4/1/2024	1998	RET ABN	UG-SERVICE
38862878	GRET	SVC	8/4/2021	1998	RET ABN	UG-SERVICE
41194837	GRET	SVC	1/21/2023	1998	RET ABN	UG-SERVICE
41974945	GRET	SVC	8/16/2023	1998	RET ABN	UG-SERVICE
41194830	GRET	SVC	1/22/2023	1998	RET ABN	UG-SERVICE
41188563	GRET	SVC	1/19/2023	1998	RET ABN	UG-SERVICE
41301033	GRET	SVC	2/20/2023	1998	RET ABN	UG-SERVICE
43464740	GRET	SVC	8/20/2024	1998	RET ABN	UG-SERVICE
41241354	GRET	SVC	3/7/2023	1998	RET ABN	UG-SERVICE
37051179	GRET	SVC	10/9/2020	1998	RET ABN	UG-SERVICE
41253571	GRET	SVC	2/6/2023	1998	RET ABN	UG-SERVICE
36792651	GRET	SVC	8/17/2020	1998	RET ABN	UG-SERVICE
39305663	GRET	SVC	10/18/2021	1998	RET ABN	UG-SERVICE
41194611	GRET	SVC	1/24/2023	1998	RET ABN	UG-SERVICE
42270913	GRET	SVC	10/23/2023	1998	RET ABN	UG-SERVICE
39484323	GRET	SVC	11/30/2021	1998	RET ABN	UG-SERVICE
38954562	GRET	SVC	8/20/2021	1998	RET ABN	UG-SERVICE
41383474	GRET	SVC	3/14/2023	1998	RET ABN	UG-SERVICE
40220224	GRET	SVC	5/26/2022	1998	RET ABN	UG-SERVICE
40093182	GRET	SVC	5/2/2022	1998	RET ABN	UG-SERVICE
38624921	GRET	SVC	5/1/2021	1998	RET ABN	UG-SERVICE
42570377	GRET	SVC	1/18/2024	1998	RET ABN	UG-SERVICE
35973634	GRET	SVC	2/3/2020	1998	RET ABN	UG-SERVICE
37934613	GRET	SVC	12/19/2020	1998	RET ABN	UG-SERVICE
39305039	GRET	SVC	10/25/2021	1998	RET ABN	UG-SERVICE
41503110	GRET	SVC	4/13/2023	1998	RET ABN	UG-SERVICE
41195082	GRET	SVC	1/21/2023	1998	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36914879	GRET	SVC	9/16/2020	1998	RET ABN	UG-SERVICE
39878518	GRET	SVC	6/2/2022	1998	RET ABN	UG-SERVICE
41188571	GRET	SVC	1/18/2023	1998	RET ABN	UG-SERVICE
41195088	GRET	SVC	1/24/2023	1998	RET ABN	UG-SERVICE
41067838	GRET	SVC	1/21/2023	1998	RET ABN	UG-SERVICE
39212890	GRET	SVC	9/28/2021	1998	RET ABN	UG-SERVICE
42914143	GRET	SVC	4/19/2024	1998	RET ABN	UG-SERVICE
42375997	GRET	SVC	11/22/2023	1999	RET ABN	UG-SERVICE
38875933	GRET	SVC	8/5/2021	1999	RET ABN	UG-SERVICE
43611901	GRET	SVC	10/2/2024	1999	RET ABN	UG-SERVICE
41830501	GRET	SVC	9/27/2023	1999	RET ABN	UG-SERVICE
42067507	GRET	SVC	9/6/2023	1999	RET ABN	UG-SERVICE
42216804	GRET	SVC	12/5/2023	1999	RET ABN	UG-SERVICE
40492265	GRET	SVC	8/11/2022	1999	RET ABN	UG-SERVICE
38947394	GRET	SVC	8/26/2021	1999	RET ABN	UG-SERVICE
36684436	GRET	SVC	7/26/2020	1999	RET ABN	UG-SERVICE
42216594	GRET	SVC	12/4/2023	1999	RET ABN	UG-SERVICE
39160109	GRET	SVC	9/12/2021	1999	RET ABN	UG-SERVICE
42453892	GRET	SVC	12/6/2023	1999	RET ABN	UG-SERVICE
38865033	GRET	SVC	8/3/2021	1999	RET ABN	UG-SERVICE
42023961	GRET	SVC	8/21/2023	1999	RET ABN	UG-SERVICE
43610587	GRET	SVC	12/6/2024	1999	RET ABN	UG-SERVICE
39444953	GRET	SVC	12/8/2021	1999	RET ABN	UG-SERVICE
39169287	GRET	SVC	6/3/2021	1999	RET ABN	UG-SERVICE
36016317	GRET	SVC	5/6/2020	1999	RET ABN	UG-SERVICE
38220190	GRET	SVC	3/15/2021	1999	RET ABN	UG-SERVICE
43529804	GRET	SVC	12/13/2024	1999	RET ABN	UG-SERVICE
36567677	GRET	SVC	6/30/2020	1999	RET ABN	UG-SERVICE
42216805	GRET	SVC	12/5/2023	1999	RET ABN	UG-SERVICE
42068096	GRET	SVC	9/13/2023	1999	RET ABN	UG-SERVICE
41428833	GRET	SVC	3/23/2023	1999	RET ABN	UG-SERVICE
43481197	GRET	SVC	11/23/2024	1999	RET ABN	UG-SERVICE
39414253	GRET	SVC	9/30/2021	1999	RET ABN	UG-SERVICE
35863418	GRET	SVC	1/7/2020	1999	RET ABN	UG-SERVICE
41282911	GRET	SVC	2/24/2023	1999	RET ABN	UG-SERVICE
43035947	GRET	SVC	6/7/2024	1999	RET ABN	UG-SERVICE
42660372	GRET	SVC	3/7/2024	1999	RET ABN	UG-SERVICE
39878723	GRET	SVC	6/2/2022	1999	RET ABN	UG-SERVICE
41282906	GRET	SVC	2/21/2023	1999	RET ABN	UG-SERVICE
43378910	GRET	SVC	8/5/2024	1999	RET ABN	UG-SERVICE
40500606	GRET	SVC	8/3/2022	1999	RET ABN	UG-SERVICE
39562050	GRET	SVC	11/8/2021	1999	RET ABN	UG-SERVICE
38358930	GRET	SVC	4/12/2021	1999	RET ABN	UG-SERVICE
39666612	GRET	SVC	11/18/2022	1999	RET ABN	UG-SERVICE
37898367	GRET	SVC	12/8/2020	1999	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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43547058	GRET	SVC	9/15/2024	1999	RET ABN	UG-SERVICE
41140303	GRET	SVC	1/5/2023	1999	RET ABN	UG-SERVICE
42881813	GRET	SVC	4/4/2024	1999	RET ABN	UG-SERVICE
41785388	GRET	SVC	6/22/2023	1999	RET ABN	UG-SERVICE
37892197	GRET	SVC	12/6/2020	1999	RET ABN	UG-SERVICE
37040165	GRET	SVC	10/22/2020	1999	RET ABN	UG-SERVICE
42467509	GRET	SVC	3/4/2024	1999	RET ABN	UG-SERVICE
37879007	GRET	SVC	12/5/2020	1999	RET ABN	UG-SERVICE
40813400	GRET	SVC	10/21/2022	1999	RET ABN	UG-SERVICE
41727399	GRET	SVC	6/8/2023	1999	RET ABN	UG-SERVICE
40018957	GRET	SVC	4/19/2022	1999	RET ABN	UG-SERVICE
36672939	GRET	SVC	7/27/2020	1999	RET ABN	UG-SERVICE
39217533	GRET	SVC	8/20/2021	1999	RET ABN	UG-SERVICE
43481189	GRET	SVC	10/15/2024	1999	RET ABN	UG-SERVICE
37077690	GRET	SVC	10/11/2020	1999	RET ABN	UG-SERVICE
41425689	GRET	SVC	3/26/2023	1999	RET ABN	UG-SERVICE
38642523	GRET	SVC	6/18/2021	1999	RET ABN	UG-SERVICE
43529756	GRET	SVC	12/16/2024	1999	RET ABN	UG-SERVICE
43364877	GRET	SVC	12/13/2024	1999	RET ABN	UG-SERVICE
40416195	GRET	SVC	6/27/2022	1999	RET ABN	UG-SERVICE
37895426	GRET	SVC	12/6/2020	1999	RET ABN	UG-SERVICE
42380213	GRET	SVC	11/29/2023	1999	RET ABN	UG-SERVICE
40446586	GRET	SVC	7/18/2022	1999	RET ABN	UG-SERVICE
42216816	GRET	SVC	12/7/2023	1999	RET ABN	UG-SERVICE
37892560	GRET	SVC	12/6/2020	1999	RET ABN	UG-SERVICE
35870559	GRET	SVC	1/13/2020	1999	RET ABN	UG-SERVICE
39666144	GRET	SVC	8/3/2022	1999	RET ABN	UG-SERVICE
41095697	GRET	SVC	1/17/2023	1999	RET ABN	UG-SERVICE
43145278	GRET	SVC	6/6/2024	1999	RET ABN	UG-SERVICE
40046869	GRET	SVC	12/22/2021	1999	RET ABN	UG-SERVICE
37892199	GRET	SVC	12/6/2020	1999	RET ABN	UG-SERVICE
39657986	GRET	SVC	3/28/2022	1999	RET ABN	UG-SERVICE
37925872	GRET	SVC	12/16/2020	1999	RET ABN	UG-SERVICE
41284193	GRET	SVC	2/15/2023	1999	RET ABN	UG-SERVICE
37077695	GRET	SVC	10/11/2020	1999	RET ABN	UG-SERVICE
43346349	GRET	SVC	7/23/2024	1999	RET ABN	UG-SERVICE
36881818	GRET	SVC	7/31/2020	1999	RET ABN	UG-SERVICE
42315524	GRET	SVC	10/25/2023	1999	RET ABN	UG-SERVICE
40722553	GRET	SVC	9/20/2022	1999	RET ABN	UG-SERVICE
39873511	GRET	SVC	3/15/2022	1999	RET ABN	UG-SERVICE
40613623	GRET	SVC	8/30/2022	1999	RET ABN	UG-SERVICE
40989692	GRET	SVC	12/2/2022	1999	RET ABN	UG-SERVICE
41242477	GRET	SVC	2/10/2023	1999	RET ABN	UG-SERVICE
39510760	GRET	SVC	12/9/2021	1999	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
35535542	GRET	SVC	1/9/2020	1999	RET ABN	UG-SERVICE
40155145	GRET	SVC	5/17/2022	1999	RET ABN	UG-SERVICE
39327948	GRET	SVC	10/27/2021	1999	RET ABN	UG-SERVICE
38191559	GRET	SVC	3/17/2021	1999	RET ABN	UG-SERVICE
36881999	GRET	SVC	8/30/2020	1999	RET ABN	UG-SERVICE
43901506	GRET	SVC	12/13/2024	1999	RET ABN	UG-SERVICE
38879126	GRET	SVC	8/9/2021	1999	RET ABN	UG-SERVICE
40524690	GRET	SVC	8/5/2022	1999	RET ABN	UG-SERVICE
40867635	GRET	SVC	11/7/2022	1999	RET ABN	UG-SERVICE
42434593	GRET	SVC	11/29/2023	1999	RET ABN	UG-SERVICE
36562307	GRET	SVC	7/1/2020	1999	RET ABN	UG-SERVICE
38108091	GRET	SVC	12/22/2021	1999	RET ABN	UG-SERVICE
43481190	GRET	SVC	10/26/2024	1999	RET ABN	UG-SERVICE
42216806	GRET	SVC	12/6/2023	1999	RET ABN	UG-SERVICE
38522082	GRET	SVC	5/21/2021	1999	RET ABN	UG-SERVICE
36495443	GRET	SVC	6/23/2020	1999	RET ABN	UG-SERVICE
41425681	GRET	SVC	3/26/2023	1999	RET ABN	UG-SERVICE
38303368	GRET	SVC	3/26/2021	2000	RET ABN	UG-SERVICE
37707370	GRET	SVC	11/24/2020	2000	RET ABN	UG-SERVICE
36919699	GRET	SVC	9/17/2020	2000	RET ABN	UG-SERVICE
42041818	GRET	SVC	8/28/2023	2000	RET ABN	UG-SERVICE
43889066	GRET	SVC	12/3/2024	2000	RET ABN	UG-SERVICE
36868331	GRET	SVC	8/30/2020	2000	RET ABN	UG-SERVICE
42771048	GRET	SVC	3/1/2024	2000	RET ABN	UG-SERVICE
43623429	GRET	SVC	12/16/2024	2000	RET ABN	UG-SERVICE
42589740	GRET	SVC	1/24/2024	2000	RET ABN	UG-SERVICE
38824668	GRET	SVC	7/28/2021	2000	RET ABN	UG-SERVICE
40802927	GRET	SVC	10/12/2022	2000	RET ABN	UG-SERVICE
36880252	GRET	SVC	9/1/2020	2000	RET ABN	UG-SERVICE
39670256	GRET	SVC	1/10/2022	2000	RET ABN	UG-SERVICE
36433745	GRET	SVC	6/10/2020	2000	RET ABN	UG-SERVICE
39025562	GRET	SVC	9/1/2021	2000	RET ABN	UG-SERVICE
40332125	GRET	SVC	7/8/2022	2000	RET ABN	UG-SERVICE
41968577	GRET	SVC	9/12/2023	2000	RET ABN	UG-SERVICE
43005048	GRET	SVC	9/19/2024	2000	RET ABN	UG-SERVICE
41436809	GRET	SVC	4/13/2023	2000	RET ABN	UG-SERVICE
40802837	GRET	SVC	10/10/2022	2000	RET ABN	UG-SERVICE
38884420	GRET	SVC	7/30/2021	2000	RET ABN	UG-SERVICE
42980534	GRET	SVC	4/23/2024	2000	RET ABN	UG-SERVICE
41064388	GRET	SVC	12/8/2022	2000	RET ABN	UG-SERVICE
41008796	GRET	SVC	12/5/2022	2000	RET ABN	UG-SERVICE
40722885	GRET	SVC	9/21/2022	2000	RET ABN	UG-SERVICE
41030225	GRET	SVC	12/8/2022	2000	RET ABN	UG-SERVICE
37424279	GRET	SVC	11/12/2020	2000	RET ABN	UG-SERVICE
37897527	GRET	SVC	12/11/2020	2000	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40812991	GRET	SVC	10/21/2022	2000	RET ABN	UG-SERVICE
39610702	GRET	SVC	9/21/2021	2000	RET ABN	UG-SERVICE
35844431	GRET	SVC	1/2/2020	2000	RET ABN	UG-SERVICE
43361452	GRET	SVC	7/30/2024	2000	RET ABN	UG-SERVICE
36421667	GRET	SVC	5/19/2020	2000	RET ABN	UG-SERVICE
37078266	GRET	SVC	10/14/2020	2000	RET ABN	UG-SERVICE
43344414	GRET	SVC	7/19/2024	2000	RET ABN	UG-SERVICE
38194555	GRET	SVC	3/12/2021	2000	RET ABN	UG-SERVICE
41431156	GRET	SVC	3/29/2023	2000	RET ABN	UG-SERVICE
42499932	GRET	SVC	12/13/2023	2000	RET ABN	UG-SERVICE
38791569	GRET	SVC	7/22/2021	2000	RET ABN	UG-SERVICE
35926514	GRET	SVC	2/6/2020	2000	RET ABN	UG-SERVICE
43481244	GRET	SVC	10/25/2024	2000	RET ABN	UG-SERVICE
41398463	GRET	SVC	3/15/2023	2000	RET ABN	UG-SERVICE
42177066	GRET	SVC	9/29/2023	2000	RET ABN	UG-SERVICE
41610596	GRET	SVC	5/9/2023	2000	RET ABN	UG-SERVICE
41436550	GRET	SVC	3/29/2023	2000	RET ABN	UG-SERVICE
43338309	GRET	SVC	7/22/2024	2000	RET ABN	UG-SERVICE
38176405	GRET	SVC	3/1/2021	2000	RET ABN	UG-SERVICE
42033600	GRET	SVC	8/23/2023	2000	RET ABN	UG-SERVICE
42866194	GRET	SVC	3/26/2024	2000	RET ABN	UG-SERVICE
38043897	GRET	SVC	1/20/2021	2000	RET ABN	UG-SERVICE
41283334	GRET	SVC	2/13/2023	2000	RET ABN	UG-SERVICE
40343946	GRET	SVC	6/27/2022	2000	RET ABN	UG-SERVICE
36421668	GRET	SVC	5/19/2020	2000	RET ABN	UG-SERVICE
37505359	GRET	SVC	9/20/2020	2000	RET ABN	UG-SERVICE
40802485	GRET	SVC	10/12/2022	2000	RET ABN	UG-SERVICE
40256570	GRET	SVC	6/14/2022	2000	RET ABN	UG-SERVICE
42600007	GRET	SVC	1/20/2024	2000	RET ABN	UG-SERVICE
36783423	GRET	SVC	8/15/2020	2000	RET ABN	UG-SERVICE
43272061	GRET	SVC	7/11/2024	2000	RET ABN	UG-SERVICE
38194559	GRET	SVC	3/12/2021	2000	RET ABN	UG-SERVICE
41064392	GRET	SVC	12/18/2022	2000	RET ABN	UG-SERVICE
37897528	GRET	SVC	12/11/2020	2000	RET ABN	UG-SERVICE
41498150	GRET	SVC	4/21/2023	2000	RET ABN	UG-SERVICE
36571480	GRET	SVC	6/30/2020	2000	RET ABN	UG-SERVICE
41436806	GRET	SVC	4/13/2023	2000	RET ABN	UG-SERVICE
38194704	GRET	SVC	3/10/2021	2000	RET ABN	UG-SERVICE
40883284	GRET	SVC	11/2/2022	2000	RET ABN	UG-SERVICE
40472864	GRET	SVC	7/27/2022	2000	RET ABN	UG-SERVICE
41116479	GRET	SVC	12/29/2022	2000	RET ABN	UG-SERVICE
43480659	GRET	SVC	10/11/2024	2000	RET ABN	UG-SERVICE
43480657	GRET	SVC	10/25/2024	2000	RET ABN	UG-SERVICE
37971090	GRET	SVC	1/5/2021	2000	RET ABN	UG-SERVICE
36049726	GRET	SVC	2/19/2020	2000	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43633368	GRET	SVC	10/2/2024	2000	RET ABN	UG-SERVICE
40921851	GRET	SVC	11/14/2022	2000	RET ABN	UG-SERVICE
41064380	GRET	SVC	12/8/2022	2000	RET ABN	UG-SERVICE
42810562	GRET	SVC	3/11/2024	2000	RET ABN	UG-SERVICE
40629871	GRET	SVC	8/26/2022	2000	RET ABN	UG-SERVICE
41498146	GRET	SVC	4/21/2023	2000	RET ABN	UG-SERVICE
39611828	GRET	SVC	12/28/2021	2000	RET ABN	UG-SERVICE
40395245	GRET	SVC	7/7/2022	2000	RET ABN	UG-SERVICE
41660704	GRET	SVC	5/23/2023	2000	RET ABN	UG-SERVICE
41895787	GRET	SVC	7/24/2023	2000	RET ABN	UG-SERVICE
41932128	GRET	SVC	6/22/2023	2000	RET ABN	UG-SERVICE
40367262	GRET	SVC	6/29/2022	2000	RET ABN	UG-SERVICE
43318025	GRET	SVC	7/19/2024	2000	RET ABN	UG-SERVICE
37000688	GRET	SVC	9/30/2020	2000	RET ABN	UG-SERVICE
41827231	GRET	SVC	7/5/2023	2000	RET ABN	UG-SERVICE
39915194	GRET	SVC	3/21/2022	2000	RET ABN	UG-SERVICE
39998636	GRET	SVC	4/18/2022	2000	RET ABN	UG-SERVICE
42995220	GRET	SVC	7/10/2024	2000	RET ABN	UG-SERVICE
36740596	GRET	SVC	8/8/2020	2000	RET ABN	UG-SERVICE
38176406	GRET	SVC	3/1/2021	2000	RET ABN	UG-SERVICE
40492805	GRET	SVC	7/27/2022	2000	RET ABN	UG-SERVICE
43849373	GRET	SVC	11/15/2024	2000	RET ABN	UG-SERVICE
39235699	GRET	SVC	9/30/2021	2000	RET ABN	UG-SERVICE
41064387	GRET	SVC	12/18/2022	2000	RET ABN	UG-SERVICE
39621131	GRET	SVC	1/4/2022	2000	RET ABN	UG-SERVICE
36173901	GRET	SVC	6/16/2020	2000	RET ABN	UG-SERVICE
42947563	GRET	SVC	4/16/2024	2000	RET ABN	UG-SERVICE
43796589	GRET	SVC	10/31/2024	2000	RET ABN	UG-SERVICE
41064382	GRET	SVC	12/17/2022	2000	RET ABN	UG-SERVICE
39316948	GRET	SVC	10/14/2021	2000	RET ABN	UG-SERVICE
37897531	GRET	SVC	12/11/2020	2000	RET ABN	UG-SERVICE
43613455	GRET	SVC	9/24/2024	2000	RET ABN	UG-SERVICE
43349767	GRET	SVC	7/24/2024	2001	RET ABN	UG-SERVICE
40900097	GRET	SVC	11/7/2022	2001	RET ABN	UG-SERVICE
41045286	GRET	SVC	12/12/2022	2001	RET ABN	UG-SERVICE
41538999	GRET	SVC	4/19/2023	2001	RET ABN	UG-SERVICE
43318358	GRET	SVC	7/31/2024	2001	RET ABN	UG-SERVICE
36418335	GRET	SVC	6/13/2020	2001	RET ABN	UG-SERVICE
38565574	GRET	SVC	6/1/2021	2001	RET ABN	UG-SERVICE
41388776	GRET	SVC	3/17/2023	2001	RET ABN	UG-SERVICE
38706673	GRET	SVC	7/12/2021	2001	RET ABN	UG-SERVICE
43914918	GRET	SVC	12/9/2024	2001	RET ABN	UG-SERVICE
39392830	GRET	SVC	11/9/2021	2001	RET ABN	UG-SERVICE
42967818	GRET	SVC	4/20/2024	2001	RET ABN	UG-SERVICE
39465548	GRET	SVC	11/22/2021	2001	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42073379	GRET	SVC	9/6/2023	2001	RET ABN	UG-SERVICE
43351576	GRET	SVC	7/29/2024	2001	RET ABN	UG-SERVICE
41465015	GRET	SVC	4/4/2023	2001	RET ABN	UG-SERVICE
38343718	GRET	SVC	4/12/2021	2001	RET ABN	UG-SERVICE
39615246	GRET	SVC	12/30/2021	2001	RET ABN	UG-SERVICE
43152901	GRET	SVC	6/11/2024	2001	RET ABN	UG-SERVICE
41969562	GRET	SVC	8/1/2024	2001	RET ABN	UG-SERVICE
40328438	GRET	SVC	7/12/2022	2001	RET ABN	UG-SERVICE
36881982	GRET	SVC	8/29/2020	2001	RET ABN	UG-SERVICE
40191460	GRET	SVC	5/23/2022	2001	RET ABN	UG-SERVICE
43123265	GRET	SVC	4/19/2024	2001	RET ABN	UG-SERVICE
40656085	GRET	SVC	9/7/2022	2001	RET ABN	UG-SERVICE
41273377	GRET	SVC	2/11/2023	2001	RET ABN	UG-SERVICE
40325461	GRET	SVC	6/21/2022	2001	RET ABN	UG-SERVICE
43499674	GRET	SVC	8/29/2024	2001	RET ABN	UG-SERVICE
41891997	GRET	SVC	7/19/2023	2001	RET ABN	UG-SERVICE
41429934	GRET	SVC	9/13/2023	2001	RET ABN	UG-SERVICE
39661991	GRET	SVC	1/19/2022	2001	RET ABN	UG-SERVICE
38192854	GRET	SVC	3/5/2021	2001	RET ABN	UG-SERVICE
41242470	GRET	SVC	2/16/2023	2001	RET ABN	UG-SERVICE
36997699	GRET	SVC	9/24/2020	2001	RET ABN	UG-SERVICE
36983987	GRET	SVC	9/24/2020	2001	RET ABN	UG-SERVICE
41436448	GRET	SVC	3/29/2023	2001	RET ABN	UG-SERVICE
39554485	GRET	SVC	12/23/2021	2001	RET ABN	UG-SERVICE
41485315	GRET	SVC	4/10/2023	2001	RET ABN	UG-SERVICE
43141890	GRET	SVC	6/5/2024	2001	RET ABN	UG-SERVICE
36862809	GRET	SVC	9/2/2020	2001	RET ABN	UG-SERVICE
43932203	GRET	SVC	12/20/2024	2001	RET ABN	UG-SERVICE
42221056	GRET	SVC	10/16/2023	2001	RET ABN	UG-SERVICE
40118446	GRET	SVC	5/2/2022	2001	RET ABN	UG-SERVICE
41283325	GRET	SVC	3/21/2023	2001	RET ABN	UG-SERVICE
38557584	GRET	SVC	6/7/2021	2001	RET ABN	UG-SERVICE
38604359	GRET	SVC	6/7/2021	2001	RET ABN	UG-SERVICE
36881758	GRET	SVC	8/30/2020	2001	RET ABN	UG-SERVICE
36484469	GRET	SVC	6/22/2020	2001	RET ABN	UG-SERVICE
39318777	GRET	SVC	11/2/2021	2001	RET ABN	UG-SERVICE
39891183	GRET	SVC	3/14/2022	2001	RET ABN	UG-SERVICE
40981283	GRET	SVC	11/30/2022	2001	RET ABN	UG-SERVICE
38302256	GRET	SVC	4/8/2021	2001	RET ABN	UG-SERVICE
38163054	GRET	SVC	2/2/2023	2001	RET ABN	UG-SERVICE
43973883	GRET	SVC	12/26/2024	2001	RET ABN	UG-SERVICE
41007407	GRET	SVC	12/16/2022	2001	RET ABN	UG-SERVICE
42418509	GRET	SVC	11/28/2023	2001	RET ABN	UG-SERVICE
36988776	GRET	SVC	10/1/2020	2001	RET ABN	UG-SERVICE
41721316	GRET	SVC	6/8/2023	2001	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38472023	GRET	SVC	5/10/2021	2001	RET ABN	UG-SERVICE
37087269	GRET	SVC	11/20/2020	2001	RET ABN	UG-SERVICE
42157164	GRET	SVC	9/27/2023	2001	RET ABN	UG-SERVICE
38084821	GRET	SVC	2/3/2021	2001	RET ABN	UG-SERVICE
36698308	GRET	SVC	7/28/2020	2001	RET ABN	UG-SERVICE
43494793	GRET	SVC	9/10/2024	2001	RET ABN	UG-SERVICE
40419926	GRET	SVC	6/28/2022	2001	RET ABN	UG-SERVICE
37673227	GRET	SVC	11/17/2020	2001	RET ABN	UG-SERVICE
36724029	GRET	SVC	8/4/2020	2001	RET ABN	UG-SERVICE
41743295	GRET	SVC	6/12/2023	2001	RET ABN	UG-SERVICE
36306576	GRET	SVC	5/26/2020	2001	RET ABN	UG-SERVICE
42967388	GRET	SVC	4/20/2024	2001	RET ABN	UG-SERVICE
43318354	GRET	SVC	8/1/2024	2001	RET ABN	UG-SERVICE
41179728	GRET	SVC	1/19/2023	2001	RET ABN	UG-SERVICE
41273577	GRET	SVC	2/19/2023	2001	RET ABN	UG-SERVICE
41645975	GRET	SVC	5/17/2023	2001	RET ABN	UG-SERVICE
37886691	GRET	SVC	12/7/2020	2001	RET ABN	UG-SERVICE
41640802	GRET	SVC	5/19/2023	2001	RET ABN	UG-SERVICE
41483265	GRET	SVC	4/11/2023	2001	RET ABN	UG-SERVICE
42942077	GRET	SVC	4/17/2024	2001	RET ABN	UG-SERVICE
38413342	GRET	SVC	4/29/2021	2001	RET ABN	UG-SERVICE
35960480	GRET	SVC	1/28/2020	2001	RET ABN	UG-SERVICE
39971774	GRET	SVC	4/7/2022	2001	RET ABN	UG-SERVICE
38571054	GRET	SVC	6/11/2021	2001	RET ABN	UG-SERVICE
36734782	GRET	SVC	8/4/2020	2001	RET ABN	UG-SERVICE
42940123	GRET	SVC	4/17/2024	2001	RET ABN	UG-SERVICE
42409026	GRET	SVC	11/22/2023	2001	RET ABN	UG-SERVICE
41149794	GRET	SVC	1/10/2023	2001	RET ABN	UG-SERVICE
43861502	GRET	SVC	11/20/2024	2001	RET ABN	UG-SERVICE
41016021	GRET	SVC	12/5/2022	2001	RET ABN	UG-SERVICE
37676416	GRET	SVC	11/18/2020	2001	RET ABN	UG-SERVICE
39330668	GRET	SVC	10/26/2021	2001	RET ABN	UG-SERVICE
40883580	GRET	SVC	10/30/2022	2001	RET ABN	UG-SERVICE
38708008	GRET	SVC	7/9/2021	2001	RET ABN	UG-SERVICE
41933549	GRET	SVC	10/4/2023	2001	RET ABN	UG-SERVICE
39554490	GRET	SVC	12/23/2021	2001	RET ABN	UG-SERVICE
43614554	GRET	SVC	10/1/2024	2001	RET ABN	UG-SERVICE
40943532	GRET	SVC	11/13/2022	2001	RET ABN	UG-SERVICE
38194703	GRET	SVC	3/5/2021	2001	RET ABN	UG-SERVICE
36801154	GRET	SVC	8/18/2020	2001	RET ABN	UG-SERVICE
36881756	GRET	SVC	8/30/2020	2001	RET ABN	UG-SERVICE
41697192	GRET	SVC	5/27/2023	2001	RET ABN	UG-SERVICE
43610591	GRET	SVC	11/21/2024	2001	RET ABN	UG-SERVICE
43326668	GRET	SVC	7/27/2024	2001	RET ABN	UG-SERVICE
42380946	GRET	SVC	2/26/2024	2001	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41242465	GRET	SVC	3/7/2023	2001	RET ABN	UG-SERVICE
37887068	GRET	SVC	12/7/2020	2001	RET ABN	UG-SERVICE
42670287	GRET	SVC	9/19/2024	2001	RET ABN	UG-SERVICE
42909599	GRET	SVC	4/11/2024	2001	RET ABN	UG-SERVICE
38862750	GRET	SVC	8/10/2021	2001	RET ABN	UG-SERVICE
37049087	GRET	SVC	10/13/2020	2001	RET ABN	UG-SERVICE
41420887	GRET	SVC	3/22/2023	2001	RET ABN	UG-SERVICE
43890028	GRET	SVC	12/5/2024	2001	RET ABN	UG-SERVICE
39725649	GRET	SVC	1/26/2022	2001	RET ABN	UG-SERVICE
42325245	GRET	SVC	11/7/2023	2001	RET ABN	UG-SERVICE
43267204	GRET	SVC	7/1/2024	2001	RET ABN	UG-SERVICE
41834508	GRET	SVC	8/1/2023	2001	RET ABN	UG-SERVICE
37146457	GRET	SVC	10/26/2020	2001	RET ABN	UG-SERVICE
39661053	GRET	SVC	1/6/2022	2001	RET ABN	UG-SERVICE
41409365	GRET	SVC	3/20/2023	2001	RET ABN	UG-SERVICE
40870057	GRET	SVC	11/7/2022	2001	RET ABN	UG-SERVICE
37084444	GRET	SVC	10/18/2020	2001	RET ABN	UG-SERVICE
38304357	GRET	SVC	4/5/2021	2002	RET ABN	UG-SERVICE
42399667	GRET	SVC	11/22/2023	2002	RET ABN	UG-SERVICE
37810974	GRET	SVC	11/28/2020	2002	RET ABN	UG-SERVICE
41427445	GRET	SVC	3/20/2023	2002	RET ABN	UG-SERVICE
41389205	GRET	SVC	3/11/2023	2002	RET ABN	UG-SERVICE
41245807	GRET	SVC	2/11/2023	2002	RET ABN	UG-SERVICE
37150059	GRET	SVC	10/27/2020	2002	RET ABN	UG-SERVICE
41411077	GRET	SVC	4/2/2024	2002	RET ABN	UG-SERVICE
37064274	GRET	SVC	10/12/2020	2002	RET ABN	UG-SERVICE
37896321	GRET	SVC	12/9/2020	2002	RET ABN	UG-SERVICE
41867849	GRET	SVC	7/30/2023	2002	RET ABN	UG-SERVICE
41073858	GRET	SVC	12/19/2022	2002	RET ABN	UG-SERVICE
37925617	GRET	SVC	12/15/2020	2002	RET ABN	UG-SERVICE
41428201	GRET	SVC	3/17/2023	2002	RET ABN	UG-SERVICE
40526714	GRET	SVC	8/15/2022	2002	RET ABN	UG-SERVICE
41940284	GRET	SVC	7/30/2023	2002	RET ABN	UG-SERVICE
39199257	GRET	SVC	9/16/2021	2002	RET ABN	UG-SERVICE
41578979	GRET	SVC	5/3/2023	2002	RET ABN	UG-SERVICE
36021539	GRET	SVC	2/27/2020	2002	RET ABN	UG-SERVICE
36253908	GRET	SVC	3/8/2021	2002	RET ABN	UG-SERVICE
41447522	GRET	SVC	3/28/2023	2002	RET ABN	UG-SERVICE
41672471	GRET	SVC	5/21/2023	2002	RET ABN	UG-SERVICE
43481129	GRET	SVC	10/17/2024	2002	RET ABN	UG-SERVICE
36068845	GRET	SVC	2/18/2020	2002	RET ABN	UG-SERVICE
38534793	GRET	SVC	5/25/2021	2002	RET ABN	UG-SERVICE
41749481	GRET	SVC	6/15/2023	2002	RET ABN	UG-SERVICE
40474020	GRET	SVC	7/23/2022	2002	RET ABN	UG-SERVICE
40302688	GRET	SVC	6/14/2022	2002	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
39174443	GRET	SVC	9/21/2021	2002	RET ABN	UG-SERVICE
41195274	GRET	SVC	2/3/2023	2002	RET ABN	UG-SERVICE
36731996	GRET	SVC	8/4/2020	2002	RET ABN	UG-SERVICE
41421866	GRET	SVC	3/22/2023	2002	RET ABN	UG-SERVICE
41379689	GRET	SVC	3/14/2023	2002	RET ABN	UG-SERVICE
43879552	GRET	SVC	11/25/2024	2002	RET ABN	UG-SERVICE
41356754	GRET	SVC	3/11/2023	2002	RET ABN	UG-SERVICE
40802652	GRET	SVC	10/14/2022	2002	RET ABN	UG-SERVICE
43480770	GRET	SVC	9/9/2024	2002	RET ABN	UG-SERVICE
42857255	GRET	SVC	3/25/2024	2002	RET ABN	UG-SERVICE
41774861	GRET	SVC	6/19/2023	2002	RET ABN	UG-SERVICE
39165294	GRET	SVC	10/4/2021	2002	RET ABN	UG-SERVICE
35861527	GRET	SVC	1/6/2020	2002	RET ABN	UG-SERVICE
41933968	GRET	SVC	9/7/2023	2002	RET ABN	UG-SERVICE
40143951	GRET	SVC	5/9/2022	2002	RET ABN	UG-SERVICE
35926820	GRET	SVC	1/20/2020	2002	RET ABN	UG-SERVICE
43126530	GRET	SVC	6/10/2024	2002	RET ABN	UG-SERVICE
43481248	GRET	SVC	10/31/2024	2002	RET ABN	UG-SERVICE
43329575	GRET	SVC	7/23/2024	2002	RET ABN	UG-SERVICE
37751453	GRET	SVC	11/24/2020	2002	RET ABN	UG-SERVICE
38415911	GRET	SVC	4/27/2021	2002	RET ABN	UG-SERVICE
36319105	GRET	SVC	9/14/2020	2002	RET ABN	UG-SERVICE
43480656	GRET	SVC	10/6/2024	2002	RET ABN	UG-SERVICE
40903183	GRET	SVC	11/9/2022	2002	RET ABN	UG-SERVICE
35987870	GRET	SVC	2/5/2020	2002	RET ABN	UG-SERVICE
40890406	GRET	SVC	11/7/2022	2002	RET ABN	UG-SERVICE
42846731	GRET	SVC	3/19/2024	2002	RET ABN	UG-SERVICE
41389215	GRET	SVC	3/11/2023	2002	RET ABN	UG-SERVICE
42766384	GRET	SVC	2/29/2024	2002	RET ABN	UG-SERVICE
41447265	GRET	SVC	3/28/2023	2002	RET ABN	UG-SERVICE
41353730	GRET	SVC	3/8/2023	2002	RET ABN	UG-SERVICE
41431601	GRET	SVC	3/29/2023	2002	RET ABN	UG-SERVICE
41379698	GRET	SVC	3/14/2023	2002	RET ABN	UG-SERVICE
42671362	GRET	SVC	2/9/2024	2002	RET ABN	UG-SERVICE
43120501	GRET	SVC	5/28/2024	2002	RET ABN	UG-SERVICE
38566433	GRET	SVC	6/2/2021	2002	RET ABN	UG-SERVICE
41232992	GRET	SVC	1/27/2023	2002	RET ABN	UG-SERVICE
40661316	GRET	SVC	9/8/2022	2002	RET ABN	UG-SERVICE
40103568	GRET	SVC	5/27/2022	2002	RET ABN	UG-SERVICE
40344678	GRET	SVC	6/24/2022	2002	RET ABN	UG-SERVICE
41827373	GRET	SVC	6/29/2023	2002	RET ABN	UG-SERVICE
41127770	GRET	SVC	1/5/2023	2002	RET ABN	UG-SERVICE
42556959	GRET	SVC	1/10/2024	2002	RET ABN	UG-SERVICE
41356022	GRET	SVC	3/11/2023	2002	RET ABN	UG-SERVICE
39084238	GRET	SVC	9/7/2021	2002	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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42044124	GRET	SVC	9/1/2023	2002	RET ABN	UG-SERVICE
38600943	GRET	SVC	10/10/2021	2002	RET ABN	UG-SERVICE
40092080	GRET	SVC	5/2/2022	2002	RET ABN	UG-SERVICE
41347205	GRET	SVC	3/11/2023	2002	RET ABN	UG-SERVICE
41564462	GRET	SVC	4/25/2023	2002	RET ABN	UG-SERVICE
41175129	GRET	SVC	1/18/2023	2002	RET ABN	UG-SERVICE
40989681	GRET	SVC	12/11/2022	2002	RET ABN	UG-SERVICE
43628634	GRET	SVC	10/3/2024	2002	RET ABN	UG-SERVICE
43245004	GRET	SVC	9/19/2024	2002	RET ABN	UG-SERVICE
42947767	GRET	SVC	4/12/2024	2002	RET ABN	UG-SERVICE
40282726	GRET	SVC	6/7/2022	2002	RET ABN	UG-SERVICE
42332589	GRET	SVC	11/9/2023	2002	RET ABN	UG-SERVICE
43870478	GRET	SVC	12/11/2024	2002	RET ABN	UG-SERVICE
37355647	GRET	SVC	11/4/2020	2002	RET ABN	UG-SERVICE
41427444	GRET	SVC	3/22/2023	2002	RET ABN	UG-SERVICE
36792659	GRET	SVC	8/17/2020	2002	RET ABN	UG-SERVICE
41098638	GRET	SVC	12/28/2022	2002	RET ABN	UG-SERVICE
39982794	GRET	SVC	4/11/2022	2002	RET ABN	UG-SERVICE
37003857	GRET	SVC	9/28/2020	2002	RET ABN	UG-SERVICE
40834140	GRET	SVC	10/17/2022	2002	RET ABN	UG-SERVICE
43347675	GRET	SVC	7/30/2024	2002	RET ABN	UG-SERVICE
41389208	GRET	SVC	3/11/2023	2002	RET ABN	UG-SERVICE
38348342	GRET	SVC	4/11/2021	2002	RET ABN	UG-SERVICE
41749310	GRET	SVC	6/12/2023	2002	RET ABN	UG-SERVICE
41389627	GRET	SVC	3/11/2023	2002	RET ABN	UG-SERVICE
39776978	GRET	SVC	2/10/2022	2002	RET ABN	UG-SERVICE
39853683	GRET	SVC	3/7/2022	2003	RET ABN	UG-SERVICE
38200838	GRET	SVC	3/10/2021	2003	RET ABN	UG-SERVICE
36121800	GRET	SVC	10/12/2020	2003	RET ABN	UG-SERVICE
41064399	GRET	SVC	12/13/2022	2003	RET ABN	UG-SERVICE
38470502	GRET	SVC	5/9/2021	2003	RET ABN	UG-SERVICE
41064581	GRET	SVC	12/13/2022	2003	RET ABN	UG-SERVICE
40630791	GRET	SVC	8/24/2022	2003	RET ABN	UG-SERVICE
40549630	GRET	SVC	8/11/2022	2003	RET ABN	UG-SERVICE
41009843	GRET	SVC	12/5/2022	2003	RET ABN	UG-SERVICE
36142357	GRET	SVC	3/17/2020	2003	RET ABN	UG-SERVICE
42427105	GRET	SVC	9/19/2024	2003	RET ABN	UG-SERVICE
42469806	GRET	SVC	12/11/2023	2003	RET ABN	UG-SERVICE
43480655	GRET	SVC	10/10/2024	2003	RET ABN	UG-SERVICE
40549831	GRET	SVC	8/11/2022	2003	RET ABN	UG-SERVICE
35841979	GRET	SVC	2/5/2020	2003	RET ABN	UG-SERVICE
40572770	GRET	SVC	8/24/2022	2003	RET ABN	UG-SERVICE
36622900	GRET	SVC	7/14/2020	2003	RET ABN	UG-SERVICE
40036010	GRET	SVC	5/9/2022	2003	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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43541484	GRET	SVC	9/7/2024	2003	RET ABN	UG-SERVICE
42203265	GRET	SVC	10/9/2023	2003	RET ABN	UG-SERVICE
37044199	GRET	SVC	10/8/2020	2003	RET ABN	UG-SERVICE
40247527	GRET	SVC	6/3/2022	2003	RET ABN	UG-SERVICE
39831648	GRET	SVC	8/3/2022	2003	RET ABN	UG-SERVICE
39724678	GRET	SVC	2/14/2022	2003	RET ABN	UG-SERVICE
42257656	GRET	SVC	10/17/2023	2003	RET ABN	UG-SERVICE
37107895	GRET	SVC	11/3/2020	2003	RET ABN	UG-SERVICE
41056876	GRET	SVC	12/14/2022	2003	RET ABN	UG-SERVICE
39970682	GRET	SVC	6/17/2022	2003	RET ABN	UG-SERVICE
40513377	GRET	SVC	8/2/2022	2003	RET ABN	UG-SERVICE
37935101	GRET	SVC	12/20/2020	2003	RET ABN	UG-SERVICE
43645446	GRET	SVC	10/2/2024	2003	RET ABN	UG-SERVICE
41062120	GRET	SVC	12/15/2022	2003	RET ABN	UG-SERVICE
40549745	GRET	SVC	8/11/2022	2003	RET ABN	UG-SERVICE
36370810	GRET	SVC	5/26/2020	2003	RET ABN	UG-SERVICE
37995172	GRET	SVC	1/7/2021	2003	RET ABN	UG-SERVICE
41407581	GRET	SVC	4/2/2024	2003	RET ABN	UG-SERVICE
40549515	GRET	SVC	8/11/2022	2003	RET ABN	UG-SERVICE
41062957	GRET	SVC	12/13/2022	2003	RET ABN	UG-SERVICE
36482418	GRET	SVC	6/24/2020	2003	RET ABN	UG-SERVICE
38312389	GRET	SVC	10/5/2021	2003	RET ABN	UG-SERVICE
40501628	GRET	SVC	8/1/2022	2003	RET ABN	UG-SERVICE
40549218	GRET	SVC	8/11/2022	2003	RET ABN	UG-SERVICE
38466241	GRET	SVC	5/11/2021	2003	RET ABN	UG-SERVICE
40371595	GRET	SVC	7/6/2022	2003	RET ABN	UG-SERVICE
42300691	GRET	SVC	10/30/2023	2003	RET ABN	UG-SERVICE
41896727	GRET	SVC	7/22/2023	2003	RET ABN	UG-SERVICE
43244858	GRET	SVC	9/19/2024	2003	RET ABN	UG-SERVICE
40498905	GRET	SVC	7/28/2022	2003	RET ABN	UG-SERVICE
36169905	GRET	SVC	4/23/2020	2003	RET ABN	UG-SERVICE
43222767	GRET	SVC	6/24/2024	2003	RET ABN	UG-SERVICE
41258462	GRET	SVC	3/14/2023	2003	RET ABN	UG-SERVICE
42520538	GRET	SVC	12/27/2023	2003	RET ABN	UG-SERVICE
40975075	GRET	SVC	11/28/2022	2003	RET ABN	UG-SERVICE
36982532	GRET	SVC	9/21/2020	2003	RET ABN	UG-SERVICE
36917243	GRET	SVC	9/10/2020	2003	RET ABN	UG-SERVICE
42860042	GRET	SVC	3/27/2024	2003	RET ABN	UG-SERVICE
43529739	GRET	SVC	12/6/2024	2003	RET ABN	UG-SERVICE
39772389	GRET	SVC	2/7/2022	2003	RET ABN	UG-SERVICE
36185118	GRET	SVC	4/23/2020	2003	RET ABN	UG-SERVICE
38720222	GRET	SVC	7/8/2021	2003	RET ABN	UG-SERVICE
43345642	GRET	SVC	7/23/2024	2004	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42356134	GRET	SVC	11/13/2023	2004	RET ABN	UG-SERVICE
38917715	GRET	SVC	9/10/2021	2004	RET ABN	UG-SERVICE
36283351	GRET	SVC	4/28/2020	2004	RET ABN	UG-SERVICE
42073632	GRET	SVC	9/1/2023	2004	RET ABN	UG-SERVICE
40233704	GRET	SVC	6/1/2022	2004	RET ABN	UG-SERVICE
42857414	GRET	SVC	3/25/2024	2004	RET ABN	UG-SERVICE
40599515	GRET	SVC	8/23/2022	2004	RET ABN	UG-SERVICE
39725947	GRET	SVC	1/26/2022	2004	RET ABN	UG-SERVICE
41143393	GRET	SVC	7/31/2023	2004	RET ABN	UG-SERVICE
43439588	GRET	SVC	8/15/2024	2004	RET ABN	UG-SERVICE
40658454	GRET	SVC	9/9/2022	2004	RET ABN	UG-SERVICE
41243163	GRET	SVC	2/5/2023	2004	RET ABN	UG-SERVICE
39449955	GRET	SVC	11/22/2021	2004	RET ABN	UG-SERVICE
43861615	GRET	SVC	12/4/2024	2004	RET ABN	UG-SERVICE
35768208	GRET	SVC	1/8/2020	2004	RET ABN	UG-SERVICE
43480983	GRET	SVC	10/6/2024	2004	RET ABN	UG-SERVICE
37020402	GRET	SVC	10/6/2020	2004	RET ABN	UG-SERVICE
38531959	GRET	SVC	6/24/2021	2004	RET ABN	UG-SERVICE
42586652	GRET	SVC	1/24/2024	2004	RET ABN	UG-SERVICE
42834266	GRET	SVC	8/5/2024	2004	RET ABN	UG-SERVICE
41513768	GRET	SVC	4/17/2023	2004	RET ABN	UG-SERVICE
36473507	GRET	SVC	6/16/2020	2004	RET ABN	UG-SERVICE
41242287	GRET	SVC	2/6/2023	2004	RET ABN	UG-SERVICE
42871432	GRET	SVC	3/30/2024	2004	RET ABN	UG-SERVICE
41063698	GRET	SVC	12/17/2022	2004	RET ABN	UG-SERVICE
41062537	GRET	SVC	12/15/2022	2004	RET ABN	UG-SERVICE
37006649	GRET	SVC	10/6/2020	2004	RET ABN	UG-SERVICE
40271975	GRET	SVC	6/9/2022	2004	RET ABN	UG-SERVICE
40812988	GRET	SVC	10/17/2022	2004	RET ABN	UG-SERVICE
41513769	GRET	SVC	4/17/2023	2004	RET ABN	UG-SERVICE
41062651	GRET	SVC	12/16/2022	2004	RET ABN	UG-SERVICE
41513764	GRET	SVC	4/17/2023	2004	RET ABN	UG-SERVICE
43948545	GRET	SVC	12/18/2024	2004	RET ABN	UG-SERVICE
41513760	GRET	SVC	4/16/2023	2004	RET ABN	UG-SERVICE
36303943	GRET	SVC	5/7/2020	2004	RET ABN	UG-SERVICE
41082594	GRET	SVC	1/12/2023	2004	RET ABN	UG-SERVICE
43041512	GRET	SVC	5/16/2024	2004	RET ABN	UG-SERVICE
42337122	GRET	SVC	11/29/2023	2004	RET ABN	UG-SERVICE
41436449	GRET	SVC	3/29/2023	2004	RET ABN	UG-SERVICE
37521263	GRET	SVC	11/13/2020	2004	RET ABN	UG-SERVICE
37811363	GRET	SVC	11/23/2020	2004	RET ABN	UG-SERVICE
41273663	GRET	SVC	3/16/2023	2004	RET ABN	UG-SERVICE
36730902	GRET	SVC	9/20/2020	2004	RET ABN	UG-SERVICE
36273752	GRET	SVC	5/8/2020	2004	RET ABN	UG-SERVICE
38944874	GRET	SVC	8/7/2021	2004	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40513962	GRET	SVC	8/1/2022	2004	RET ABN	UG-SERVICE
39126371	GRET	SVC	9/15/2021	2004	RET ABN	UG-SERVICE
41082950	GRET	SVC	1/5/2023	2004	RET ABN	UG-SERVICE
36303951	GRET	SVC	5/7/2020	2004	RET ABN	UG-SERVICE
39613259	GRET	SVC	12/29/2021	2004	RET ABN	UG-SERVICE
38060055	GRET	SVC	1/27/2021	2004	RET ABN	UG-SERVICE
41064396	GRET	SVC	12/8/2022	2004	RET ABN	UG-SERVICE
41283626	GRET	SVC	2/21/2023	2004	RET ABN	UG-SERVICE
36760761	GRET	SVC	8/11/2020	2004	RET ABN	UG-SERVICE
40208463	GRET	SVC	5/25/2022	2004	RET ABN	UG-SERVICE
41185736	GRET	SVC	1/27/2023	2004	RET ABN	UG-SERVICE
41082953	GRET	SVC	1/7/2023	2004	RET ABN	UG-SERVICE
40205522	GRET	SVC	5/23/2022	2004	RET ABN	UG-SERVICE
38631228	GRET	SVC	8/4/2021	2004	RET ABN	UG-SERVICE
41513766	GRET	SVC	4/17/2023	2004	RET ABN	UG-SERVICE
36977167	GRET	SVC	9/25/2020	2004	RET ABN	UG-SERVICE
36834103	GRET	SVC	8/29/2020	2004	RET ABN	UG-SERVICE
40652843	GRET	SVC	9/7/2022	2004	RET ABN	UG-SERVICE
41116665	GRET	SVC	1/21/2023	2004	RET ABN	UG-SERVICE
39542353	GRET	SVC	12/15/2021	2004	RET ABN	UG-SERVICE
38126148	GRET	SVC	2/15/2021	2004	RET ABN	UG-SERVICE
36609220	GRET	SVC	7/13/2020	2004	RET ABN	UG-SERVICE
36367091	GRET	SVC	5/27/2020	2004	RET ABN	UG-SERVICE
36304192	GRET	SVC	5/7/2020	2004	RET ABN	UG-SERVICE
41354136	GRET	SVC	3/13/2023	2004	RET ABN	UG-SERVICE
36303948	GRET	SVC	5/7/2020	2004	RET ABN	UG-SERVICE
43480982	GRET	SVC	10/6/2024	2004	RET ABN	UG-SERVICE
36839754	GRET	SVC	8/31/2020	2004	RET ABN	UG-SERVICE
40149164	GRET	SVC	5/17/2022	2004	RET ABN	UG-SERVICE
43618773	GRET	SVC	10/1/2024	2004	RET ABN	UG-SERVICE
41082951	GRET	SVC	1/7/2023	2004	RET ABN	UG-SERVICE
41243166	GRET	SVC	2/5/2023	2004	RET ABN	UG-SERVICE
37933095	GRET	SVC	12/14/2020	2004	RET ABN	UG-SERVICE
42164320	GRET	SVC	9/28/2023	2004	RET ABN	UG-SERVICE
36303952	GRET	SVC	5/7/2020	2004	RET ABN	UG-SERVICE
41436541	GRET	SVC	3/26/2023	2004	RET ABN	UG-SERVICE
39466802	GRET	SVC	11/27/2021	2004	RET ABN	UG-SERVICE
42412971	GRET	SVC	11/27/2023	2004	RET ABN	UG-SERVICE
36379833	GRET	SVC	6/1/2020	2004	RET ABN	UG-SERVICE
40344160	GRET	SVC	6/17/2022	2004	RET ABN	UG-SERVICE
37524106	GRET	SVC	11/13/2020	2004	RET ABN	UG-SERVICE
38807486	GRET	SVC	7/17/2021	2004	RET ABN	UG-SERVICE
43250333	GRET	SVC	12/11/2024	2004	RET ABN	UG-SERVICE
39317784	GRET	SVC	12/7/2021	2004	RET ABN	UG-SERVICE
40899533	GRET	SVC	11/11/2022	2004	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41185739	GRET	SVC	1/19/2023	2004	RET ABN	UG-SERVICE
42804378	GRET	SVC	3/9/2024	2004	RET ABN	UG-SERVICE
40867627	GRET	SVC	12/1/2022	2004	RET ABN	UG-SERVICE
37247562	GRET	SVC	11/2/2020	2004	RET ABN	UG-SERVICE
41144909	GRET	SVC	6/10/2024	2004	RET ABN	UG-SERVICE
41062644	GRET	SVC	12/15/2022	2004	RET ABN	UG-SERVICE
38187064	GRET	SVC	3/3/2021	2004	RET ABN	UG-SERVICE
37845210	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
41187060	GRET	SVC	1/18/2023	2005	RET ABN	UG-SERVICE
39360486	GRET	SVC	11/8/2021	2005	RET ABN	UG-SERVICE
41740862	GRET	SVC	6/13/2023	2005	RET ABN	UG-SERVICE
41117167	GRET	SVC	1/9/2023	2005	RET ABN	UG-SERVICE
38206747	GRET	SVC	3/10/2021	2005	RET ABN	UG-SERVICE
37845209	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
43624426	GRET	SVC	10/2/2024	2005	RET ABN	UG-SERVICE
40609430	GRET	SVC	8/25/2022	2005	RET ABN	UG-SERVICE
43481132	GRET	SVC	10/17/2024	2005	RET ABN	UG-SERVICE
37845208	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
37844978	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
43269460	GRET	SVC	7/6/2024	2005	RET ABN	UG-SERVICE
38206558	GRET	SVC	3/10/2021	2005	RET ABN	UG-SERVICE
36135027	GRET	SVC	3/17/2020	2005	RET ABN	UG-SERVICE
37845203	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
36036306	GRET	SVC	1/9/2020	2005	RET ABN	UG-SERVICE
43343790	GRET	SVC	7/30/2024	2005	RET ABN	UG-SERVICE
37989381	GRET	SVC	1/6/2021	2005	RET ABN	UG-SERVICE
39258151	GRET	SVC	10/12/2021	2005	RET ABN	UG-SERVICE
37844979	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
41289009	GRET	SVC	2/13/2023	2005	RET ABN	UG-SERVICE
37845200	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
37845201	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
36696343	GRET	SVC	7/27/2020	2005	RET ABN	UG-SERVICE
42188716	GRET	SVC	9/21/2023	2005	RET ABN	UG-SERVICE
41401971	GRET	SVC	3/9/2023	2005	RET ABN	UG-SERVICE
43205682	GRET	SVC	6/19/2024	2005	RET ABN	UG-SERVICE
41140329	GRET	SVC	12/31/2022	2005	RET ABN	UG-SERVICE
41083518	GRET	SVC	12/20/2022	2005	RET ABN	UG-SERVICE
42011212	GRET	SVC	8/16/2023	2005	RET ABN	UG-SERVICE
36962408	GRET	SVC	9/21/2020	2005	RET ABN	UG-SERVICE
41223064	GRET	SVC	1/31/2023	2005	RET ABN	UG-SERVICE
41284360	GRET	SVC	2/13/2023	2005	RET ABN	UG-SERVICE
36735977	GRET	SVC	8/10/2020	2005	RET ABN	UG-SERVICE
36827003	GRET	SVC	8/25/2020	2005	RET ABN	UG-SERVICE
37845205	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
43348357	GRET	SVC	7/24/2024	2005	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41062216	GRET	SVC	12/14/2022	2005	RET ABN	UG-SERVICE
38472037	GRET	SVC	5/10/2021	2005	RET ABN	UG-SERVICE
37844977	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
37845206	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
41186311	GRET	SVC	1/28/2023	2005	RET ABN	UG-SERVICE
41064314	GRET	SVC	12/15/2022	2005	RET ABN	UG-SERVICE
36564211	GRET	SVC	6/29/2020	2005	RET ABN	UG-SERVICE
43480997	GRET	SVC	11/16/2024	2005	RET ABN	UG-SERVICE
38520272	GRET	SVC	5/24/2021	2005	RET ABN	UG-SERVICE
41032548	GRET	SVC	12/15/2022	2005	RET ABN	UG-SERVICE
41062525	GRET	SVC	12/15/2022	2005	RET ABN	UG-SERVICE
37083566	GRET	SVC	10/19/2020	2005	RET ABN	UG-SERVICE
42185137	GRET	SVC	10/4/2023	2005	RET ABN	UG-SERVICE
41741068	GRET	SVC	6/13/2023	2005	RET ABN	UG-SERVICE
43480999	GRET	SVC	11/16/2024	2005	RET ABN	UG-SERVICE
37844976	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
42844671	GRET	SVC	3/20/2024	2005	RET ABN	UG-SERVICE
41062211	GRET	SVC	12/14/2022	2005	RET ABN	UG-SERVICE
39361790	GRET	SVC	11/2/2021	2005	RET ABN	UG-SERVICE
38677273	GRET	SVC	6/21/2021	2005	RET ABN	UG-SERVICE
37845204	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
39666497	GRET	SVC	11/18/2022	2005	RET ABN	UG-SERVICE
43075757	GRET	SVC	5/18/2024	2005	RET ABN	UG-SERVICE
43481133	GRET	SVC	11/1/2024	2005	RET ABN	UG-SERVICE
41183051	GRET	SVC	1/19/2023	2005	RET ABN	UG-SERVICE
41032545	GRET	SVC	12/4/2022	2005	RET ABN	UG-SERVICE
43053838	GRET	SVC	5/8/2024	2005	RET ABN	UG-SERVICE
41282902	GRET	SVC	3/21/2023	2005	RET ABN	UG-SERVICE
41186308	GRET	SVC	1/19/2023	2005	RET ABN	UG-SERVICE
41183057	GRET	SVC	1/20/2023	2005	RET ABN	UG-SERVICE
36744906	GRET	SVC	7/27/2020	2005	RET ABN	UG-SERVICE
37844974	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
41067829	GRET	SVC	12/22/2022	2005	RET ABN	UG-SERVICE
42866971	GRET	SVC	3/28/2024	2005	RET ABN	UG-SERVICE
37845207	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
41025862	GRET	SVC	4/4/2023	2005	RET ABN	UG-SERVICE
41414164	GRET	SVC	4/2/2023	2005	RET ABN	UG-SERVICE
42957328	GRET	SVC	9/19/2024	2005	RET ABN	UG-SERVICE
41183055	GRET	SVC	1/19/2023	2005	RET ABN	UG-SERVICE
35866707	GRET	SVC	1/7/2020	2005	RET ABN	UG-SERVICE
41327963	GRET	SVC	3/1/2023	2005	RET ABN	UG-SERVICE
39495065	GRET	SVC	12/8/2021	2005	RET ABN	UG-SERVICE
39998931	GRET	SVC	4/12/2022	2005	RET ABN	UG-SERVICE
36760744	GRET	SVC	8/10/2020	2005	RET ABN	UG-SERVICE
42628090	GRET	SVC	1/29/2024	2005	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41067832	GRET	SVC	2/4/2023	2005	RET ABN	UG-SERVICE
43329574	GRET	SVC	7/17/2024	2005	RET ABN	UG-SERVICE
41411191	GRET	SVC	4/2/2024	2005	RET ABN	UG-SERVICE
42177396	GRET	SVC	10/4/2023	2005	RET ABN	UG-SERVICE
38360334	GRET	SVC	4/12/2021	2005	RET ABN	UG-SERVICE
38248451	GRET	SVC	3/22/2021	2005	RET ABN	UG-SERVICE
42404191	GRET	SVC	11/20/2023	2005	RET ABN	UG-SERVICE
42076364	GRET	SVC	9/8/2023	2005	RET ABN	UG-SERVICE
38392796	GRET	SVC	4/23/2021	2005	RET ABN	UG-SERVICE
32667124	GRET	SVC	11/1/2020	2005	RET ABN	UG-SERVICE
38259673	GRET	SVC	3/23/2021	2005	RET ABN	UG-SERVICE
42744058	GRET	SVC	2/21/2024	2005	RET ABN	UG-SERVICE
41183045	GRET	SVC	1/17/2023	2005	RET ABN	UG-SERVICE
42652005	GRET	SVC	1/27/2024	2005	RET ABN	UG-SERVICE
43625732	GRET	SVC	9/30/2024	2005	RET ABN	UG-SERVICE
41396611	GRET	SVC	3/14/2023	2005	RET ABN	UG-SERVICE
42856665	GRET	SVC	3/28/2024	2005	RET ABN	UG-SERVICE
42006733	GRET	SVC	8/14/2023	2005	RET ABN	UG-SERVICE
43481252	GRET	SVC	11/20/2024	2005	RET ABN	UG-SERVICE
37052386	GRET	SVC	10/27/2020	2005	RET ABN	UG-SERVICE
42195313	GRET	SVC	10/11/2023	2005	RET ABN	UG-SERVICE
39291666	GRET	SVC	10/6/2021	2005	RET ABN	UG-SERVICE
40202961	GRET	SVC	5/24/2022	2005	RET ABN	UG-SERVICE
41186317	GRET	SVC	1/19/2023	2005	RET ABN	UG-SERVICE
40394911	GRET	SVC	7/8/2022	2005	RET ABN	UG-SERVICE
41119750	GRET	SVC	12/31/2022	2005	RET ABN	UG-SERVICE
38305722	GRET	SVC	7/15/2021	2005	RET ABN	UG-SERVICE
41062428	GRET	SVC	12/14/2022	2005	RET ABN	UG-SERVICE
41186062	GRET	SVC	1/19/2023	2005	RET ABN	UG-SERVICE
41183048	GRET	SVC	1/19/2023	2005	RET ABN	UG-SERVICE
40394311	GRET	SVC	7/6/2022	2005	RET ABN	UG-SERVICE
35909730	GRET	SVC	1/12/2020	2005	RET ABN	UG-SERVICE
39548807	GRET	SVC	12/15/2021	2005	RET ABN	UG-SERVICE
42166505	GRET	SVC	10/17/2023	2005	RET ABN	UG-SERVICE
43611858	GRET	SVC	9/26/2024	2005	RET ABN	UG-SERVICE
43912027	GRET	SVC	12/9/2024	2005	RET ABN	UG-SERVICE
37999544	GRET	SVC	1/12/2021	2005	RET ABN	UG-SERVICE
38069924	GRET	SVC	1/25/2021	2005	RET ABN	UG-SERVICE
43021506	GRET	SVC	5/6/2024	2005	RET ABN	UG-SERVICE
42701523	GRET	SVC	2/13/2024	2005	RET ABN	UG-SERVICE
42896956	GRET	SVC	4/7/2024	2005	RET ABN	UG-SERVICE
40395626	GRET	SVC	6/30/2022	2005	RET ABN	UG-SERVICE
43449545	GRET	SVC	8/20/2024	2005	RET ABN	UG-SERVICE
41594544	GRET	SVC	5/4/2023	2005	RET ABN	UG-SERVICE
41223068	GRET	SVC	1/31/2023	2005	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40462862	GRET	SVC	7/14/2022	2005	RET ABN	UG-SERVICE
38671323	GRET	SVC	6/24/2021	2005	RET ABN	UG-SERVICE
36009163	GRET	SVC	2/12/2020	2005	RET ABN	UG-SERVICE
41186313	GRET	SVC	1/19/2023	2005	RET ABN	UG-SERVICE
38693632	GRET	SVC	7/2/2021	2005	RET ABN	UG-SERVICE
41183049	GRET	SVC	1/19/2023	2005	RET ABN	UG-SERVICE
40843791	GRET	SVC	10/20/2022	2005	RET ABN	UG-SERVICE
41309567	GRET	SVC	2/20/2023	2005	RET ABN	UG-SERVICE
43963333	GRET	SVC	12/20/2024	2006	RET ABN	UG-SERVICE
41141838	GRET	SVC	1/9/2023	2006	RET ABN	UG-SERVICE
42670806	GRET	SVC	2/6/2024	2006	RET ABN	UG-SERVICE
38260816	GRET	SVC	3/22/2021	2006	RET ABN	UG-SERVICE
38522085	GRET	SVC	5/21/2021	2006	RET ABN	UG-SERVICE
43988607	GRET	SVC	11/15/2024	2006	RET ABN	UG-SERVICE
39704501	GRET	SVC	1/18/2022	2006	RET ABN	UG-SERVICE
37834464	GRET	SVC	11/30/2020	2006	RET ABN	UG-SERVICE
43341174	GRET	SVC	7/22/2024	2006	RET ABN	UG-SERVICE
41955449	GRET	SVC	7/29/2023	2006	RET ABN	UG-SERVICE
39294222	GRET	SVC	10/22/2021	2006	RET ABN	UG-SERVICE
41408151	GRET	SVC	4/2/2024	2006	RET ABN	UG-SERVICE
38813115	GRET	SVC	7/28/2021	2006	RET ABN	UG-SERVICE
41498362	GRET	SVC	4/12/2023	2006	RET ABN	UG-SERVICE
43806038	GRET	SVC	11/9/2024	2006	RET ABN	UG-SERVICE
42407800	GRET	SVC	11/26/2023	2006	RET ABN	UG-SERVICE
37848585	GRET	SVC	8/14/2020	2006	RET ABN	UG-SERVICE
40863773	GRET	SVC	11/2/2022	2006	RET ABN	UG-SERVICE
42177175	GRET	SVC	10/11/2023	2006	RET ABN	UG-SERVICE
42806286	GRET	SVC	3/11/2024	2006	RET ABN	UG-SERVICE
39823211	GRET	SVC	2/24/2022	2006	RET ABN	UG-SERVICE
41414101	GRET	SVC	3/20/2023	2006	RET ABN	UG-SERVICE
43880122	GRET	SVC	12/2/2024	2006	RET ABN	UG-SERVICE
39301611	GRET	SVC	10/15/2021	2006	RET ABN	UG-SERVICE
37958745	GRET	SVC	12/30/2020	2006	RET ABN	UG-SERVICE
40407299	GRET	SVC	7/11/2022	2006	RET ABN	UG-SERVICE
37390631	GRET	SVC	11/9/2020	2006	RET ABN	UG-SERVICE
42177707	GRET	SVC	10/3/2023	2006	RET ABN	UG-SERVICE
40660400	GRET	SVC	10/22/2022	2006	RET ABN	UG-SERVICE
38813117	GRET	SVC	3/28/2022	2006	RET ABN	UG-SERVICE
43529722	GRET	SVC	12/12/2024	2006	RET ABN	UG-SERVICE
40050319	GRET	SVC	4/27/2022	2006	RET ABN	UG-SERVICE
41119419	GRET	SVC	1/3/2023	2006	RET ABN	UG-SERVICE
40137222	GRET	SVC	5/11/2022	2006	RET ABN	UG-SERVICE
41831517	GRET	SVC	8/2/2023	2006	RET ABN	UG-SERVICE
43204005	GRET	SVC	6/18/2024	2006	RET ABN	UG-SERVICE
42816064	GRET	SVC	3/11/2024	2006	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43610733	GRET	SVC	11/20/2024	2006	RET ABN	UG-SERVICE
39463481	GRET	SVC	11/24/2021	2006	RET ABN	UG-SERVICE
38603475	GRET	SVC	6/10/2021	2006	RET ABN	UG-SERVICE
43481198	GRET	SVC	10/26/2024	2006	RET ABN	UG-SERVICE
40264988	GRET	SVC	6/8/2022	2006	RET ABN	UG-SERVICE
41348986	GRET	SVC	3/8/2023	2006	RET ABN	UG-SERVICE
42491871	GRET	SVC	12/19/2023	2006	RET ABN	UG-SERVICE
42283675	GRET	SVC	10/23/2023	2006	RET ABN	UG-SERVICE
39387615	GRET	SVC	11/5/2021	2006	RET ABN	UG-SERVICE
43640145	GRET	SVC	10/21/2024	2006	RET ABN	UG-SERVICE
43015590	GRET	SVC	5/6/2024	2006	RET ABN	UG-SERVICE
40870520	GRET	SVC	11/11/2022	2006	RET ABN	UG-SERVICE
42205155	GRET	SVC	10/19/2023	2006	RET ABN	UG-SERVICE
40395845	GRET	SVC	7/7/2022	2006	RET ABN	UG-SERVICE
40375048	GRET	SVC	7/2/2022	2006	RET ABN	UG-SERVICE
39665816	GRET	SVC	8/3/2022	2006	RET ABN	UG-SERVICE
38934707	GRET	SVC	8/18/2021	2006	RET ABN	UG-SERVICE
39213492	GRET	SVC	9/27/2021	2006	RET ABN	UG-SERVICE
39386292	GRET	SVC	11/4/2021	2006	RET ABN	UG-SERVICE
43324187	GRET	SVC	7/31/2024	2006	RET ABN	UG-SERVICE
43825012	GRET	SVC	11/22/2024	2006	RET ABN	UG-SERVICE
43141717	GRET	SVC	6/5/2024	2006	RET ABN	UG-SERVICE
40283218	GRET	SVC	6/10/2022	2006	RET ABN	UG-SERVICE
43730825	GRET	SVC	11/12/2024	2006	RET ABN	UG-SERVICE
42411040	GRET	SVC	11/28/2023	2006	RET ABN	UG-SERVICE
42414850	GRET	SVC	11/28/2023	2006	RET ABN	UG-SERVICE
41482813	GRET	SVC	4/14/2023	2006	RET ABN	UG-SERVICE
40283362	GRET	SVC	7/7/2022	2006	RET ABN	UG-SERVICE
37021085	GRET	SVC	10/22/2020	2007	RET ABN	UG-SERVICE
41328009	GRET	SVC	2/27/2023	2007	RET ABN	UG-SERVICE
37489727	GRET	SVC	11/13/2020	2007	RET ABN	UG-SERVICE
41767990	GRET	SVC	6/19/2023	2007	RET ABN	UG-SERVICE
38806234	GRET	SVC	7/29/2021	2007	RET ABN	UG-SERVICE
38786374	GRET	SVC	7/16/2021	2007	RET ABN	UG-SERVICE
36558770	GRET	SVC	7/1/2020	2007	RET ABN	UG-SERVICE
41101937	GRET	SVC	1/4/2023	2007	RET ABN	UG-SERVICE
42299743	GRET	SVC	10/26/2023	2007	RET ABN	UG-SERVICE
37425453	GRET	SVC	11/10/2020	2007	RET ABN	UG-SERVICE
41169124	GRET	SVC	1/18/2023	2007	RET ABN	UG-SERVICE
42619921	GRET	SVC	1/26/2024	2007	RET ABN	UG-SERVICE
39522293	GRET	SVC	12/13/2021	2007	RET ABN	UG-SERVICE
43512388	GRET	SVC	8/28/2024	2007	RET ABN	UG-SERVICE
43481123	GRET	SVC	11/1/2024	2007	RET ABN	UG-SERVICE
39380043	GRET	SVC	11/30/2021	2007	RET ABN	UG-SERVICE
35996870	GRET	SVC	2/10/2020	2007	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41964412	GRET	SVC	8/5/2023	2007	RET ABN	UG-SERVICE
43957833	GRET	SVC	12/17/2024	2007	RET ABN	UG-SERVICE
39857550	GRET	SVC	3/9/2022	2007	RET ABN	UG-SERVICE
43707751	GRET	SVC	10/18/2024	2007	RET ABN	UG-SERVICE
39582342	GRET	SVC	12/27/2021	2007	RET ABN	UG-SERVICE
43481125	GRET	SVC	11/1/2024	2007	RET ABN	UG-SERVICE
43481126	GRET	SVC	10/28/2024	2007	RET ABN	UG-SERVICE
40744624	GRET	SVC	9/15/2022	2007	RET ABN	UG-SERVICE
40498165	GRET	SVC	7/28/2022	2007	RET ABN	UG-SERVICE
39817269	GRET	SVC	2/21/2022	2007	RET ABN	UG-SERVICE
43481196	GRET	SVC	10/22/2024	2007	RET ABN	UG-SERVICE
38496694	GRET	SVC	5/17/2021	2007	RET ABN	UG-SERVICE
38333410	GRET	SVC	4/7/2021	2007	RET ABN	UG-SERVICE
40578829	GRET	SVC	8/16/2022	2007	RET ABN	UG-SERVICE
42506032	GRET	SVC	1/25/2024	2007	RET ABN	UG-SERVICE
38955853	GRET	SVC	8/23/2021	2007	RET ABN	UG-SERVICE
42409561	GRET	SVC	12/1/2023	2007	RET ABN	UG-SERVICE
43481124	GRET	SVC	11/1/2024	2007	RET ABN	UG-SERVICE
38886044	GRET	SVC	8/17/2021	2007	RET ABN	UG-SERVICE
37286086	GRET	SVC	11/17/2020	2007	RET ABN	UG-SERVICE
39524056	GRET	SVC	12/16/2021	2007	RET ABN	UG-SERVICE
41769563	GRET	SVC	6/19/2023	2007	RET ABN	UG-SERVICE
42526243	GRET	SVC	12/30/2023	2007	RET ABN	UG-SERVICE
43318027	GRET	SVC	8/15/2024	2007	RET ABN	UG-SERVICE
36379239	GRET	SVC	6/1/2020	2007	RET ABN	UG-SERVICE
40035079	GRET	SVC	4/27/2022	2007	RET ABN	UG-SERVICE
38424653	GRET	SVC	4/27/2021	2007	RET ABN	UG-SERVICE
38060234	GRET	SVC	1/27/2021	2007	RET ABN	UG-SERVICE
40265835	GRET	SVC	6/6/2022	2007	RET ABN	UG-SERVICE
43619269	GRET	SVC	9/26/2024	2007	RET ABN	UG-SERVICE
38677464	GRET	SVC	6/19/2021	2007	RET ABN	UG-SERVICE
41411296	GRET	SVC	4/2/2024	2007	RET ABN	UG-SERVICE
42434178	GRET	SVC	12/4/2023	2007	RET ABN	UG-SERVICE
41088619	GRET	SVC	1/12/2023	2007	RET ABN	UG-SERVICE
41464744	GRET	SVC	4/3/2023	2007	RET ABN	UG-SERVICE
39772297	GRET	SVC	2/8/2022	2007	RET ABN	UG-SERVICE
41470722	GRET	SVC	8/9/2023	2007	RET ABN	UG-SERVICE
39665140	GRET	SVC	4/28/2022	2007	RET ABN	UG-SERVICE
41606248	GRET	SVC	5/30/2023	2007	RET ABN	UG-SERVICE
37286897	GRET	SVC	11/2/2020	2007	RET ABN	UG-SERVICE
38671327	GRET	SVC	6/24/2021	2007	RET ABN	UG-SERVICE
42155781	GRET	SVC	9/27/2023	2007	RET ABN	UG-SERVICE
39340651	GRET	SVC	10/26/2021	2007	RET ABN	UG-SERVICE
42098400	GRET	SVC	9/13/2023	2007	RET ABN	UG-SERVICE
36779225	GRET	SVC	8/26/2020	2007	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36645610	GRET	SVC	7/17/2020	2007	RET ABN	UG-SERVICE
42201919	GRET	SVC	10/10/2023	2007	RET ABN	UG-SERVICE
39435286	GRET	SVC	11/18/2021	2007	RET ABN	UG-SERVICE
43237027	GRET	SVC	6/28/2024	2007	RET ABN	UG-SERVICE
42612663	GRET	SVC	1/24/2024	2007	RET ABN	UG-SERVICE
40668633	GRET	SVC	9/10/2022	2007	RET ABN	UG-SERVICE
43930806	GRET	SVC	12/13/2024	2008	RET ABN	UG-SERVICE
42069706	GRET	SVC	9/18/2023	2008	RET ABN	UG-SERVICE
39550222	GRET	SVC	12/17/2021	2008	RET ABN	UG-SERVICE
36014715	GRET	SVC	2/13/2020	2008	RET ABN	UG-SERVICE
38709766	GRET	SVC	8/9/2021	2008	RET ABN	UG-SERVICE
36183404	GRET	SVC	4/22/2020	2008	RET ABN	UG-SERVICE
42224049	GRET	SVC	10/12/2023	2008	RET ABN	UG-SERVICE
40277356	GRET	SVC	6/13/2022	2008	RET ABN	UG-SERVICE
41418736	GRET	SVC	3/22/2023	2008	RET ABN	UG-SERVICE
41222213	GRET	SVC	1/30/2023	2008	RET ABN	UG-SERVICE
37096589	GRET	SVC	10/21/2020	2008	RET ABN	UG-SERVICE
40961898	GRET	SVC	11/21/2022	2008	RET ABN	UG-SERVICE
39944269	GRET	SVC	3/28/2022	2008	RET ABN	UG-SERVICE
39084337	GRET	SVC	9/9/2021	2008	RET ABN	UG-SERVICE
40505927	GRET	SVC	8/3/2022	2008	RET ABN	UG-SERVICE
43488867	GRET	SVC	8/28/2024	2008	RET ABN	UG-SERVICE
42370897	GRET	SVC	11/12/2023	2008	RET ABN	UG-SERVICE
38335991	GRET	SVC	4/16/2021	2008	RET ABN	UG-SERVICE
40282852	GRET	SVC	6/9/2022	2008	RET ABN	UG-SERVICE
40119196	GRET	SVC	6/14/2022	2008	RET ABN	UG-SERVICE
36095960	GRET	SVC	3/10/2020	2008	RET ABN	UG-SERVICE
43970938	GRET	SVC	12/23/2024	2008	RET ABN	UG-SERVICE
41144401	GRET	SVC	1/9/2023	2008	RET ABN	UG-SERVICE
42549392	GRET	SVC	1/2/2024	2008	RET ABN	UG-SERVICE
39202978	GRET	SVC	9/27/2021	2008	RET ABN	UG-SERVICE
41408242	GRET	SVC	3/22/2023	2008	RET ABN	UG-SERVICE
43712063	GRET	SVC	10/15/2024	2008	RET ABN	UG-SERVICE
38260769	GRET	SVC	12/17/2021	2008	RET ABN	UG-SERVICE
36561319	GRET	SVC	7/6/2020	2008	RET ABN	UG-SERVICE
43560442	GRET	SVC	9/14/2024	2008	RET ABN	UG-SERVICE
43151062	GRET	SVC	6/6/2024	2008	RET ABN	UG-SERVICE
43343193	GRET	SVC	7/16/2024	2008	RET ABN	UG-SERVICE
41287923	GRET	SVC	2/24/2023	2008	RET ABN	UG-SERVICE
38625200	GRET	SVC	6/24/2021	2008	RET ABN	UG-SERVICE
42691748	GRET	SVC	2/9/2024	2008	RET ABN	UG-SERVICE
36775157	GRET	SVC	7/30/2020	2008	RET ABN	UG-SERVICE
43499910	GRET	SVC	9/11/2024	2008	RET ABN	UG-SERVICE
43173058	GRET	SVC	6/13/2024	2008	RET ABN	UG-SERVICE
36878398	GRET	SVC	9/9/2020	2008	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42131095	GRET	SVC	9/18/2023	2008	RET ABN	UG-SERVICE
41142226	GRET	SVC	1/10/2023	2008	RET ABN	UG-SERVICE
41090671	GRET	SVC	1/23/2023	2008	RET ABN	UG-SERVICE
43861747	GRET	SVC	11/30/2024	2008	RET ABN	UG-SERVICE
38287715	GRET	SVC	3/30/2021	2008	RET ABN	UG-SERVICE
41430052	GRET	SVC	9/12/2023	2008	RET ABN	UG-SERVICE
38472032	GRET	SVC	5/11/2021	2008	RET ABN	UG-SERVICE
42656640	GRET	SVC	2/10/2024	2008	RET ABN	UG-SERVICE
35316597	GRET	SVC	1/22/2021	2008	RET ABN	UG-SERVICE
41408202	GRET	SVC	10/19/2023	2008	RET ABN	UG-SERVICE
37005519	GRET	SVC	9/29/2020	2008	RET ABN	UG-SERVICE
38137996	GRET	SVC	2/17/2021	2008	RET ABN	UG-SERVICE
36893329	GRET	SVC	9/8/2020	2008	RET ABN	UG-SERVICE
43712064	GRET	SVC	10/15/2024	2008	RET ABN	UG-SERVICE
39992560	GRET	SVC	4/12/2022	2008	RET ABN	UG-SERVICE
39720312	GRET	SVC	3/4/2022	2008	RET ABN	UG-SERVICE
38478322	GRET	SVC	5/6/2021	2008	RET ABN	UG-SERVICE
41322605	GRET	SVC	2/28/2023	2008	RET ABN	UG-SERVICE
42942046	GRET	SVC	4/13/2024	2008	RET ABN	UG-SERVICE
38202903	GRET	SVC	3/9/2021	2008	RET ABN	UG-SERVICE
41204527	GRET	SVC	1/25/2023	2008	RET ABN	UG-SERVICE
41296497	GRET	SVC	4/12/2023	2008	RET ABN	UG-SERVICE
39713420	GRET	SVC	1/21/2022	2009	RET ABN	UG-SERVICE
43481259	GRET	SVC	11/22/2024	2009	RET ABN	UG-SERVICE
40352820	GRET	SVC	6/28/2022	2009	RET ABN	UG-SERVICE
40318814	GRET	SVC	6/20/2022	2009	RET ABN	UG-SERVICE
41411489	GRET	SVC	4/2/2024	2009	RET ABN	UG-SERVICE
43605022	GRET	SVC	10/2/2024	2009	RET ABN	UG-SERVICE
38084194	GRET	SVC	2/3/2021	2009	RET ABN	UG-SERVICE
41277502	GRET	SVC	2/13/2023	2009	RET ABN	UG-SERVICE
40667896	GRET	SVC	9/26/2022	2009	RET ABN	UG-SERVICE
43529733	GRET	SVC	12/6/2024	2009	RET ABN	UG-SERVICE
39884636	GRET	SVC	4/23/2022	2009	RET ABN	UG-SERVICE
43651758	GRET	SVC	10/15/2024	2009	RET ABN	UG-SERVICE
41088773	GRET	SVC	12/21/2022	2009	RET ABN	UG-SERVICE
43459229	GRET	SVC	8/19/2024	2009	RET ABN	UG-SERVICE
40951751	GRET	SVC	12/2/2022	2009	RET ABN	UG-SERVICE
41750998	GRET	SVC	6/10/2023	2009	RET ABN	UG-SERVICE
42524186	GRET	SVC	12/28/2023	2009	RET ABN	UG-SERVICE
38594189	GRET	SVC	6/7/2021	2009	RET ABN	UG-SERVICE
38034059	GRET	SVC	1/20/2021	2009	RET ABN	UG-SERVICE
37960957	GRET	SVC	12/28/2020	2009	RET ABN	UG-SERVICE
42407316	GRET	SVC	11/22/2023	2009	RET ABN	UG-SERVICE
42258901	GRET	SVC	10/25/2023	2009	RET ABN	UG-SERVICE
41232154	GRET	SVC	2/20/2023	2009	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42235258	GRET	SVC	11/28/2023	2009	RET ABN	UG-SERVICE
35871725	GRET	SVC	1/4/2020	2009	RET ABN	UG-SERVICE
42524581	GRET	SVC	12/28/2023	2009	RET ABN	UG-SERVICE
38657089	GRET	SVC	6/16/2021	2009	RET ABN	UG-SERVICE
43119125	GRET	SVC	6/3/2024	2009	RET ABN	UG-SERVICE
43904545	GRET	SVC	12/4/2024	2009	RET ABN	UG-SERVICE
38173384	GRET	SVC	3/1/2021	2009	RET ABN	UG-SERVICE
41224539	GRET	SVC	1/30/2023	2009	RET ABN	UG-SERVICE
36878399	GRET	SVC	8/29/2020	2009	RET ABN	UG-SERVICE
40888112	GRET	SVC	11/3/2022	2009	RET ABN	UG-SERVICE
38956799	GRET	SVC	8/16/2021	2009	RET ABN	UG-SERVICE
41430207	GRET	SVC	9/13/2023	2009	RET ABN	UG-SERVICE
43481127	GRET	SVC	11/20/2024	2009	RET ABN	UG-SERVICE
43506447	GRET	SVC	9/9/2024	2009	RET ABN	UG-SERVICE
42484655	GRET	SVC	12/14/2023	2009	RET ABN	UG-SERVICE
42462283	GRET	SVC	12/6/2023	2009	RET ABN	UG-SERVICE
40513128	GRET	SVC	8/3/2022	2009	RET ABN	UG-SERVICE
41843448	GRET	SVC	7/10/2023	2009	RET ABN	UG-SERVICE
42391577	GRET	SVC	11/14/2023	2009	RET ABN	UG-SERVICE
36811300	GRET	SVC	8/24/2020	2009	RET ABN	UG-SERVICE
40903887	GRET	SVC	11/10/2022	2009	RET ABN	UG-SERVICE
37897122	GRET	SVC	12/11/2020	2009	RET ABN	UG-SERVICE
38231096	GRET	SVC	3/16/2021	2009	RET ABN	UG-SERVICE
43324505	GRET	SVC	10/25/2024	2009	RET ABN	UG-SERVICE
40728687	GRET	SVC	9/27/2022	2009	RET ABN	UG-SERVICE
39900986	GRET	SVC	3/16/2022	2009	RET ABN	UG-SERVICE
43481128	GRET	SVC	11/20/2024	2009	RET ABN	UG-SERVICE
37016098	GRET	SVC	9/28/2020	2009	RET ABN	UG-SERVICE
42114053	GRET	SVC	9/11/2023	2009	RET ABN	UG-SERVICE
40283360	GRET	SVC	6/9/2022	2009	RET ABN	UG-SERVICE
40395852	GRET	SVC	7/6/2022	2009	RET ABN	UG-SERVICE
41205872	GRET	SVC	1/21/2023	2009	RET ABN	UG-SERVICE
37915191	GRET	SVC	12/18/2020	2009	RET ABN	UG-SERVICE
42070602	GRET	SVC	11/19/2023	2009	RET ABN	UG-SERVICE
39875959	GRET	SVC	3/10/2022	2009	RET ABN	UG-SERVICE
39719888	GRET	SVC	2/4/2022	2009	RET ABN	UG-SERVICE
35993663	GRET	SVC	2/7/2020	2009	RET ABN	UG-SERVICE
36393452	GRET	SVC	6/4/2020	2009	RET ABN	UG-SERVICE
41755630	GRET	SVC	6/10/2023	2009	RET ABN	UG-SERVICE
40492811	GRET	SVC	8/3/2022	2009	RET ABN	UG-SERVICE
39603680	GRET	SVC	1/5/2022	2009	RET ABN	UG-SERVICE
41976754	GRET	SVC	9/5/2023	2009	RET ABN	UG-SERVICE
43151638	GRET	SVC	7/15/2024	2009	RET ABN	UG-SERVICE
42520179	GRET	SVC	12/27/2023	2009	RET ABN	UG-SERVICE
36009289	GRET	SVC	2/11/2020	2009	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36199839	GRET	SVC	4/30/2020	2010	RET ABN	UG-SERVICE
36652216	GRET	SVC	7/11/2020	2010	RET ABN	UG-SERVICE
43324507	GRET	SVC	10/25/2024	2010	RET ABN	UG-SERVICE
41513275	GRET	SVC	4/16/2023	2010	RET ABN	UG-SERVICE
43318357	GRET	SVC	8/14/2024	2010	RET ABN	UG-SERVICE
41381455	GRET	SVC	3/13/2023	2010	RET ABN	UG-SERVICE
39269783	GRET	SVC	10/11/2021	2010	RET ABN	UG-SERVICE
43427487	GRET	SVC	8/23/2024	2010	RET ABN	UG-SERVICE
41711815	GRET	SVC	6/6/2023	2010	RET ABN	UG-SERVICE
41514001	GRET	SVC	4/16/2023	2010	RET ABN	UG-SERVICE
37958744	GRET	SVC	12/27/2020	2010	RET ABN	UG-SERVICE
41274151	GRET	SVC	2/24/2023	2010	RET ABN	UG-SERVICE
41520903	GRET	SVC	4/26/2023	2010	RET ABN	UG-SERVICE
37033139	GRET	SVC	10/7/2020	2010	RET ABN	UG-SERVICE
40407526	GRET	SVC	7/11/2022	2010	RET ABN	UG-SERVICE
38481836	GRET	SVC	5/11/2021	2010	RET ABN	UG-SERVICE
41520494	GRET	SVC	4/25/2023	2010	RET ABN	UG-SERVICE
38747521	GRET	SVC	7/7/2021	2010	RET ABN	UG-SERVICE
40049852	GRET	SVC	4/26/2022	2010	RET ABN	UG-SERVICE
41513267	GRET	SVC	4/15/2023	2010	RET ABN	UG-SERVICE
41513271	GRET	SVC	4/15/2023	2010	RET ABN	UG-SERVICE
40113656	GRET	SVC	5/2/2022	2010	RET ABN	UG-SERVICE
41513278	GRET	SVC	4/16/2023	2010	RET ABN	UG-SERVICE
40655359	GRET	SVC	9/8/2022	2010	RET ABN	UG-SERVICE
36342461	GRET	SVC	5/21/2020	2010	RET ABN	UG-SERVICE
40120303	GRET	SVC	5/4/2022	2010	RET ABN	UG-SERVICE
41279873	GRET	SVC	2/15/2023	2010	RET ABN	UG-SERVICE
42404945	GRET	SVC	11/22/2023	2010	RET ABN	UG-SERVICE
39386488	GRET	SVC	11/5/2021	2010	RET ABN	UG-SERVICE
40318189	GRET	SVC	6/17/2022	2010	RET ABN	UG-SERVICE
41429980	GRET	SVC	9/13/2023	2010	RET ABN	UG-SERVICE
41646069	GRET	SVC	5/17/2023	2010	RET ABN	UG-SERVICE
38086943	GRET	SVC	2/3/2021	2010	RET ABN	UG-SERVICE
43807761	GRET	SVC	11/15/2024	2010	RET ABN	UG-SERVICE
41514005	GRET	SVC	4/17/2023	2010	RET ABN	UG-SERVICE
41514003	GRET	SVC	4/17/2023	2010	RET ABN	UG-SERVICE
41585567	GRET	SVC	5/2/2023	2010	RET ABN	UG-SERVICE
43529742	GRET	SVC	12/13/2024	2010	RET ABN	UG-SERVICE
42672732	GRET	SVC	2/9/2024	2010	RET ABN	UG-SERVICE
37035464	GRET	SVC	10/7/2020	2010	RET ABN	UG-SERVICE
41424227	GRET	SVC	10/18/2023	2010	RET ABN	UG-SERVICE
42580209	GRET	SVC	1/17/2024	2010	RET ABN	UG-SERVICE
42376980	GRET	SVC	5/9/2024	2010	RET ABN	UG-SERVICE
36760383	GRET	SVC	8/10/2020	2010	RET ABN	UG-SERVICE
41514004	GRET	SVC	4/17/2023	2010	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36142342	GRET	SVC	3/17/2020	2010	RET ABN	UG-SERVICE
41508103	GRET	SVC	4/10/2023	2011	RET ABN	UG-SERVICE
40813628	GRET	SVC	10/20/2022	2011	RET ABN	UG-SERVICE
40282630	GRET	SVC	6/7/2022	2011	RET ABN	UG-SERVICE
41528289	GRET	SVC	4/27/2023	2011	RET ABN	UG-SERVICE
41520915	GRET	SVC	4/18/2023	2011	RET ABN	UG-SERVICE
38065680	GRET	SVC	2/22/2021	2011	RET ABN	UG-SERVICE
38332060	GRET	SVC	4/3/2021	2011	RET ABN	UG-SERVICE
41528290	GRET	SVC	4/21/2023	2011	RET ABN	UG-SERVICE
43318340	GRET	SVC	8/12/2024	2011	RET ABN	UG-SERVICE
43520224	GRET	SVC	8/28/2024	2011	RET ABN	UG-SERVICE
41347944	GRET	SVC	3/6/2023	2011	RET ABN	UG-SERVICE
38333227	GRET	SVC	4/7/2021	2011	RET ABN	UG-SERVICE
40391600	GRET	SVC	7/5/2022	2011	RET ABN	UG-SERVICE
36682175	GRET	SVC	7/27/2020	2011	RET ABN	UG-SERVICE
39860392	GRET	SVC	3/22/2022	2011	RET ABN	UG-SERVICE
40358503	GRET	SVC	7/28/2022	2011	RET ABN	UG-SERVICE
41770076	GRET	SVC	6/19/2023	2011	RET ABN	UG-SERVICE
41520907	GRET	SVC	4/14/2023	2011	RET ABN	UG-SERVICE
41284362	GRET	SVC	3/1/2023	2011	RET ABN	UG-SERVICE
41520918	GRET	SVC	4/18/2023	2011	RET ABN	UG-SERVICE
40855539	GRET	SVC	10/24/2022	2011	RET ABN	UG-SERVICE
41209116	GRET	SVC	1/24/2023	2011	RET ABN	UG-SERVICE
38716142	GRET	SVC	7/7/2021	2011	RET ABN	UG-SERVICE
40208622	GRET	SVC	5/31/2022	2011	RET ABN	UG-SERVICE
42300544	GRET	SVC	10/30/2023	2011	RET ABN	UG-SERVICE
43208316	GRET	SVC	6/22/2024	2011	RET ABN	UG-SERVICE
41528621	GRET	SVC	4/23/2023	2011	RET ABN	UG-SERVICE
41204523	GRET	SVC	1/25/2023	2011	RET ABN	UG-SERVICE
40399903	GRET	SVC	7/11/2022	2011	RET ABN	UG-SERVICE
40037443	GRET	SVC	5/24/2022	2011	RET ABN	UG-SERVICE
43506836	GRET	SVC	10/4/2024	2011	RET ABN	UG-SERVICE
41528442	GRET	SVC	4/23/2023	2011	RET ABN	UG-SERVICE
42909568	GRET	SVC	4/10/2024	2011	RET ABN	UG-SERVICE
41287748	GRET	SVC	3/19/2023	2011	RET ABN	UG-SERVICE
39533060	GRET	SVC	12/14/2021	2011	RET ABN	UG-SERVICE
41521121	GRET	SVC	4/21/2023	2011	RET ABN	UG-SERVICE
39318350	GRET	SVC	10/22/2021	2011	RET ABN	UG-SERVICE
41528292	GRET	SVC	4/26/2023	2011	RET ABN	UG-SERVICE
43318492	GRET	SVC	8/12/2024	2011	RET ABN	UG-SERVICE
43615032	GRET	SVC	9/24/2024	2011	RET ABN	UG-SERVICE
43151847	GRET	SVC	6/10/2024	2011	RET ABN	UG-SERVICE
41528622	GRET	SVC	4/23/2023	2011	RET ABN	UG-SERVICE
42432713	GRET	SVC	12/2/2023	2011	RET ABN	UG-SERVICE
43514600	GRET	SVC	9/4/2024	2011	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41184951	GRET	SVC	1/19/2023	2011	RET ABN	UG-SERVICE
41520909	GRET	SVC	4/14/2023	2011	RET ABN	UG-SERVICE
36037166	GRET	SVC	2/17/2020	2011	RET ABN	UG-SERVICE
43900063	GRET	SVC	12/4/2024	2011	RET ABN	UG-SERVICE
42619515	GRET	SVC	1/29/2024	2011	RET ABN	UG-SERVICE
41528620	GRET	SVC	4/27/2023	2011	RET ABN	UG-SERVICE
41528443	GRET	SVC	4/23/2023	2011	RET ABN	UG-SERVICE
41520910	GRET	SVC	4/14/2023	2011	RET ABN	UG-SERVICE
42370750	GRET	SVC	11/15/2023	2011	RET ABN	UG-SERVICE
36420955	GRET	SVC	6/8/2020	2011	RET ABN	UG-SERVICE
41571943	GRET	SVC	4/26/2023	2011	RET ABN	UG-SERVICE
39402149	GRET	SVC	11/8/2021	2011	RET ABN	UG-SERVICE
41514008	GRET	SVC	4/17/2023	2011	RET ABN	UG-SERVICE
36707975	GRET	SVC	7/30/2020	2011	RET ABN	UG-SERVICE
41520919	GRET	SVC	4/18/2023	2011	RET ABN	UG-SERVICE
42950627	GRET	SVC	4/18/2024	2011	RET ABN	UG-SERVICE
38414555	GRET	SVC	5/4/2021	2011	RET ABN	UG-SERVICE
41440600	GRET	SVC	3/27/2023	2011	RET ABN	UG-SERVICE
38497724	GRET	SVC	5/12/2021	2011	RET ABN	UG-SERVICE
36090333	GRET	SVC	3/5/2020	2011	RET ABN	UG-SERVICE
38240748	GRET	SVC	3/23/2021	2011	RET ABN	UG-SERVICE
40365304	GRET	SVC	6/29/2022	2011	RET ABN	UG-SERVICE
40112218	GRET	SVC	5/5/2022	2012	RET ABN	UG-SERVICE
41207527	GRET	SVC	1/26/2023	2012	RET ABN	UG-SERVICE
40247521	GRET	SVC	6/2/2022	2012	RET ABN	UG-SERVICE
42747783	GRET	SVC	2/16/2024	2012	RET ABN	UG-SERVICE
39435562	GRET	SVC	11/16/2021	2012	RET ABN	UG-SERVICE
41436378	GRET	SVC	3/25/2023	2012	RET ABN	UG-SERVICE
38107359	GRET	SVC	2/8/2021	2012	RET ABN	UG-SERVICE
41787195	GRET	SVC	6/19/2023	2012	RET ABN	UG-SERVICE
41479988	GRET	SVC	4/6/2023	2012	RET ABN	UG-SERVICE
41279860	GRET	SVC	2/12/2023	2012	RET ABN	UG-SERVICE
43749667	GRET	SVC	10/28/2024	2012	RET ABN	UG-SERVICE
42446591	GRET	SVC	12/5/2023	2012	RET ABN	UG-SERVICE
43139671	GRET	SVC	9/19/2024	2012	RET ABN	UG-SERVICE
42911793	GRET	SVC	4/9/2024	2012	RET ABN	UG-SERVICE
40974642	GRET	SVC	11/29/2022	2012	RET ABN	UG-SERVICE
41279354	GRET	SVC	3/8/2023	2012	RET ABN	UG-SERVICE
40137490	GRET	SVC	5/11/2022	2012	RET ABN	UG-SERVICE
42188672	GRET	SVC	10/2/2023	2012	RET ABN	UG-SERVICE
36121539	GRET	SVC	11/5/2020	2012	RET ABN	UG-SERVICE
40870058	GRET	SVC	11/9/2022	2012	RET ABN	UG-SERVICE
42637733	GRET	SVC	1/29/2024	2012	RET ABN	UG-SERVICE
41116474	GRET	SVC	12/29/2022	2012	RET ABN	UG-SERVICE
36112258	GRET	SVC	10/12/2020	2012	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40310333	GRET	SVC	6/13/2022	2012	RET ABN	UG-SERVICE
41279862	GRET	SVC	2/12/2023	2012	RET ABN	UG-SERVICE
40214147	GRET	SVC	5/26/2022	2012	RET ABN	UG-SERVICE
38551598	GRET	SVC	6/2/2021	2012	RET ABN	UG-SERVICE
35928399	GRET	SVC	1/20/2020	2012	RET ABN	UG-SERVICE
36875127	GRET	SVC	9/28/2020	2012	RET ABN	UG-SERVICE
40472871	GRET	SVC	7/20/2022	2012	RET ABN	UG-SERVICE
43883373	GRET	SVC	12/2/2024	2012	RET ABN	UG-SERVICE
36301100	GRET	SVC	5/27/2020	2012	RET ABN	UG-SERVICE
43481131	GRET	SVC	11/22/2024	2012	RET ABN	UG-SERVICE
40802820	GRET	SVC	10/10/2022	2012	RET ABN	UG-SERVICE
42183152	GRET	SVC	10/4/2023	2012	RET ABN	UG-SERVICE
39493267	GRET	SVC	12/6/2021	2012	RET ABN	UG-SERVICE
40864616	GRET	SVC	10/27/2022	2012	RET ABN	UG-SERVICE
43481130	GRET	SVC	11/2/2024	2012	RET ABN	UG-SERVICE
38612023	GRET	SVC	6/11/2021	2012	RET ABN	UG-SERVICE
40516837	GRET	SVC	8/5/2022	2012	RET ABN	UG-SERVICE
41127758	GRET	SVC	1/4/2023	2012	RET ABN	UG-SERVICE
42432669	GRET	SVC	11/29/2023	2012	RET ABN	UG-SERVICE
41279559	GRET	SVC	2/12/2023	2012	RET ABN	UG-SERVICE
40610967	GRET	SVC	8/25/2022	2012	RET ABN	UG-SERVICE
40691272	GRET	SVC	9/15/2022	2012	RET ABN	UG-SERVICE
38612024	GRET	SVC	6/11/2021	2012	RET ABN	UG-SERVICE
40744548	GRET	SVC	9/29/2022	2012	RET ABN	UG-SERVICE
41033839	GRET	SVC	12/8/2022	2012	RET ABN	UG-SERVICE
37919251	GRET	SVC	12/16/2020	2012	RET ABN	UG-SERVICE
37148988	GRET	SVC	11/2/2020	2012	RET ABN	UG-SERVICE
41436442	GRET	SVC	3/25/2023	2012	RET ABN	UG-SERVICE
36915183	GRET	SVC	9/11/2020	2012	RET ABN	UG-SERVICE
38409143	GRET	SVC	4/27/2021	2012	RET ABN	UG-SERVICE
40667760	GRET	SVC	9/23/2022	2012	RET ABN	UG-SERVICE
42837555	GRET	SVC	3/19/2024	2012	RET ABN	UG-SERVICE
36921493	GRET	SVC	9/14/2020	2012	RET ABN	UG-SERVICE
38534040	GRET	SVC	5/23/2021	2012	RET ABN	UG-SERVICE
42014238	GRET	SVC	8/19/2023	2012	RET ABN	UG-SERVICE
43596477	GRET	SVC	9/26/2024	2012	RET ABN	UG-SERVICE
38386356	GRET	SVC	4/18/2021	2012	RET ABN	UG-SERVICE
40609439	GRET	SVC	8/25/2022	2012	RET ABN	UG-SERVICE
40439933	GRET	SVC	7/13/2022	2012	RET ABN	UG-SERVICE
43586149	GRET	SVC	9/24/2024	2012	RET ABN	UG-SERVICE
41971175	GRET	SVC	8/8/2023	2012	RET ABN	UG-SERVICE
40418097	GRET	SVC	7/13/2022	2012	RET ABN	UG-SERVICE
39459228	GRET	SVC	11/22/2021	2012	RET ABN	UG-SERVICE
41183640	GRET	SVC	1/19/2023	2012	RET ABN	UG-SERVICE
40160583	GRET	SVC	6/6/2022	2012	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40360826	GRET	SVC	6/30/2022	2012	RET ABN	UG-SERVICE
41317819	GRET	SVC	3/2/2023	2013	RET ABN	UG-SERVICE
37093462	GRET	SVC	10/29/2020	2013	RET ABN	UG-SERVICE
40360191	GRET	SVC	6/30/2022	2013	RET ABN	UG-SERVICE
41425203	GRET	SVC	3/22/2023	2013	RET ABN	UG-SERVICE
38580713	GRET	SVC	6/9/2021	2013	RET ABN	UG-SERVICE
40880752	GRET	SVC	10/31/2022	2013	RET ABN	UG-SERVICE
41420721	GRET	SVC	3/24/2023	2013	RET ABN	UG-SERVICE
39581521	GRET	SVC	1/15/2022	2013	RET ABN	UG-SERVICE
43053907	GRET	SVC	5/8/2024	2013	RET ABN	UG-SERVICE
37960327	GRET	SVC	1/2/2021	2013	RET ABN	UG-SERVICE
41540776	GRET	SVC	4/20/2023	2013	RET ABN	UG-SERVICE
40813747	GRET	SVC	10/15/2022	2013	RET ABN	UG-SERVICE
43330334	GRET	SVC	7/17/2024	2013	RET ABN	UG-SERVICE
41330769	GRET	SVC	3/3/2023	2013	RET ABN	UG-SERVICE
38463324	GRET	SVC	5/11/2021	2013	RET ABN	UG-SERVICE
42248449	GRET	SVC	10/19/2023	2013	RET ABN	UG-SERVICE
41430964	GRET	SVC	3/29/2023	2013	RET ABN	UG-SERVICE
40359841	GRET	SVC	7/1/2022	2013	RET ABN	UG-SERVICE
41423634	GRET	SVC	3/22/2023	2013	RET ABN	UG-SERVICE
38053528	GRET	SVC	3/20/2021	2013	RET ABN	UG-SERVICE
40860638	GRET	SVC	11/9/2022	2013	RET ABN	UG-SERVICE
41573968	GRET	SVC	5/1/2023	2013	RET ABN	UG-SERVICE
41418704	GRET	SVC	3/22/2023	2013	RET ABN	UG-SERVICE
43481096	GRET	SVC	10/13/2024	2013	RET ABN	UG-SERVICE
40974224	GRET	SVC	11/29/2022	2013	RET ABN	UG-SERVICE
41423359	GRET	SVC	3/21/2023	2013	RET ABN	UG-SERVICE
39453245	GRET	SVC	8/1/2022	2013	RET ABN	UG-SERVICE
41277762	GRET	SVC	2/24/2023	2013	RET ABN	UG-SERVICE
39965045	GRET	SVC	4/5/2022	2013	RET ABN	UG-SERVICE
41423632	GRET	SVC	3/22/2023	2013	RET ABN	UG-SERVICE
40457109	GRET	SVC	7/14/2022	2013	RET ABN	UG-SERVICE
38953988	GRET	SVC	8/15/2021	2013	RET ABN	UG-SERVICE
41425691	GRET	SVC	3/26/2023	2013	RET ABN	UG-SERVICE
43481092	GRET	SVC	10/31/2024	2013	RET ABN	UG-SERVICE
41485311	GRET	SVC	4/14/2023	2013	RET ABN	UG-SERVICE
36834777	GRET	SVC	8/26/2020	2013	RET ABN	UG-SERVICE
41224005	GRET	SVC	2/2/2023	2013	RET ABN	UG-SERVICE
41529147	GRET	SVC	4/18/2023	2013	RET ABN	UG-SERVICE
38143972	GRET	SVC	2/18/2021	2013	RET ABN	UG-SERVICE
40354109	GRET	SVC	6/28/2022	2013	RET ABN	UG-SERVICE
43531082	GRET	SVC	9/16/2024	2013	RET ABN	UG-SERVICE
38330556	GRET	SVC	4/6/2021	2013	RET ABN	UG-SERVICE
38679328	GRET	SVC	7/12/2021	2013	RET ABN	UG-SERVICE
38240751	GRET	SVC	3/23/2021	2013	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41430968	GRET	SVC	3/29/2023	2013	RET ABN	UG-SERVICE
41194463	GRET	SVC	1/23/2023	2013	RET ABN	UG-SERVICE
39903467	GRET	SVC	3/15/2022	2013	RET ABN	UG-SERVICE
40325388	GRET	SVC	6/20/2022	2013	RET ABN	UG-SERVICE
41425201	GRET	SVC	3/22/2023	2013	RET ABN	UG-SERVICE
38749423	GRET	SVC	7/9/2021	2013	RET ABN	UG-SERVICE
41423628	GRET	SVC	3/21/2023	2013	RET ABN	UG-SERVICE
41423357	GRET	SVC	3/22/2023	2013	RET ABN	UG-SERVICE
41425205	GRET	SVC	3/24/2023	2013	RET ABN	UG-SERVICE
43026757	GRET	SVC	5/5/2024	2013	RET ABN	UG-SERVICE
40974647	GRET	SVC	11/29/2022	2013	RET ABN	UG-SERVICE
41277764	GRET	SVC	2/24/2023	2013	RET ABN	UG-SERVICE
41214158	GRET	SVC	12/11/2023	2013	RET ABN	UG-SERVICE
41301399	GRET	SVC	2/20/2023	2013	RET ABN	UG-SERVICE
39354698	GRET	SVC	10/28/2021	2013	RET ABN	UG-SERVICE
38154421	GRET	SVC	2/22/2021	2013	RET ABN	UG-SERVICE
42484242	GRET	SVC	12/14/2023	2013	RET ABN	UG-SERVICE
40850375	GRET	SVC	10/23/2022	2013	RET ABN	UG-SERVICE
36270420	GRET	SVC	4/27/2020	2013	RET ABN	UG-SERVICE
41031318	GRET	SVC	12/10/2022	2013	RET ABN	UG-SERVICE
39453243	GRET	SVC	8/1/2022	2013	RET ABN	UG-SERVICE
41871392	GRET	SVC	7/12/2023	2013	RET ABN	UG-SERVICE
41775028	GRET	SVC	6/21/2023	2013	RET ABN	UG-SERVICE
36106559	GRET	SVC	3/9/2020	2013	RET ABN	UG-SERVICE
43146620	GRET	SVC	6/3/2024	2013	RET ABN	UG-SERVICE
39734316	GRET	SVC	1/27/2022	2013	RET ABN	UG-SERVICE
42526299	GRET	SVC	1/2/2024	2013	RET ABN	UG-SERVICE
42556757	GRET	SVC	1/10/2024	2013	RET ABN	UG-SERVICE
36223775	GRET	SVC	4/23/2020	2013	RET ABN	UG-SERVICE
42789280	GRET	SVC	3/4/2024	2013	RET ABN	UG-SERVICE
41423622	GRET	SVC	3/21/2023	2013	RET ABN	UG-SERVICE
41927480	GRET	SVC	8/1/2023	2013	RET ABN	UG-SERVICE
36170376	GRET	SVC	3/23/2020	2013	RET ABN	UG-SERVICE
40990758	GRET	SVC	11/26/2022	2013	RET ABN	UG-SERVICE
41317244	GRET	SVC	3/4/2023	2013	RET ABN	UG-SERVICE
42169009	GRET	SVC	10/2/2023	2013	RET ABN	UG-SERVICE
41065074	GRET	SVC	12/12/2022	2013	RET ABN	UG-SERVICE
42475083	GRET	SVC	12/9/2023	2013	RET ABN	UG-SERVICE
42502373	GRET	SVC	12/15/2023	2013	RET ABN	UG-SERVICE
40744737	GRET	SVC	9/21/2022	2013	RET ABN	UG-SERVICE
43533814	GRET	SVC	9/16/2024	2013	RET ABN	UG-SERVICE
41482779	GRET	SVC	4/13/2023	2013	RET ABN	UG-SERVICE
39118131	GRET	SVC	9/14/2021	2013	RET ABN	UG-SERVICE
39434873	GRET	SVC	11/18/2021	2013	RET ABN	UG-SERVICE
41036615	GRET	SVC	12/15/2022	2013	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
35926324	GRET	SVC	1/17/2020	2013	RET ABN	UG-SERVICE
40360387	GRET	SVC	6/30/2022	2013	RET ABN	UG-SERVICE
40949360	GRET	SVC	11/19/2022	2013	RET ABN	UG-SERVICE
38064547	GRET	SVC	1/27/2021	2013	RET ABN	UG-SERVICE
41420301	GRET	SVC	3/24/2023	2013	RET ABN	UG-SERVICE
39827667	GRET	SVC	3/8/2022	2013	RET ABN	UG-SERVICE
40850368	GRET	SVC	10/23/2022	2013	RET ABN	UG-SERVICE
40681869	GRET	SVC	9/14/2022	2013	RET ABN	UG-SERVICE
38194542	GRET	SVC	3/10/2021	2013	RET ABN	UG-SERVICE
41418844	GRET	SVC	3/22/2023	2013	RET ABN	UG-SERVICE
41423925	GRET	SVC	3/20/2023	2013	RET ABN	UG-SERVICE
39899440	GRET	SVC	3/15/2022	2013	RET ABN	UG-SERVICE
36902011	GRET	SVC	9/8/2020	2013	RET ABN	UG-SERVICE
41273859	GRET	SVC	3/16/2023	2013	RET ABN	UG-SERVICE
43341295	GRET	SVC	7/29/2024	2013	RET ABN	UG-SERVICE
36984582	GRET	SVC	9/24/2020	2013	RET ABN	UG-SERVICE
41317494	GRET	SVC	3/3/2023	2013	RET ABN	UG-SERVICE
41846824	GRET	SVC	7/13/2023	2013	RET ABN	UG-SERVICE
43480652	GRET	SVC	10/6/2024	2013	RET ABN	UG-SERVICE
42226860	GRET	SVC	10/18/2023	2013	RET ABN	UG-SERVICE
41330770	GRET	SVC	3/3/2023	2013	RET ABN	UG-SERVICE
36200626	GRET	SVC	4/22/2020	2013	RET ABN	UG-SERVICE
39453241	GRET	SVC	8/1/2022	2013	RET ABN	UG-SERVICE
39118126	GRET	SVC	9/14/2021	2013	RET ABN	UG-SERVICE
40359850	GRET	SVC	6/30/2022	2013	RET ABN	UG-SERVICE
40400416	GRET	SVC	7/11/2022	2013	RET ABN	UG-SERVICE
38608321	GRET	SVC	6/10/2021	2013	RET ABN	UG-SERVICE
36974527	GRET	SVC	9/22/2020	2013	RET ABN	UG-SERVICE
41425210	GRET	SVC	3/24/2023	2013	RET ABN	UG-SERVICE
38745160	GRET	SVC	7/20/2021	2013	RET ABN	UG-SERVICE
41483270	GRET	SVC	4/12/2023	2013	RET ABN	UG-SERVICE
41428824	GRET	SVC	3/27/2023	2013	RET ABN	UG-SERVICE
40324313	GRET	SVC	6/20/2022	2013	RET ABN	UG-SERVICE
40955979	GRET	SVC	12/5/2022	2013	RET ABN	UG-SERVICE
42185202	GRET	SVC	10/2/2023	2013	RET ABN	UG-SERVICE
42921977	GRET	SVC	4/15/2024	2013	RET ABN	UG-SERVICE
41427493	GRET	SVC	3/28/2023	2013	RET ABN	UG-SERVICE
41423932	GRET	SVC	3/21/2023	2013	RET ABN	UG-SERVICE
42182406	GRET	SVC	10/11/2023	2013	RET ABN	UG-SERVICE
43481094	GRET	SVC	10/13/2024	2013	RET ABN	UG-SERVICE
40744891	GRET	SVC	9/21/2022	2013	RET ABN	UG-SERVICE
36995577	GRET	SVC	9/28/2020	2013	RET ABN	UG-SERVICE
42910239	GRET	SVC	4/8/2024	2013	RET ABN	UG-SERVICE
37024316	GRET	SVC	10/30/2020	2013	RET ABN	UG-SERVICE
38708694	GRET	SVC	7/7/2021	2013	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38934445	GRET	SVC	9/15/2021	2013	RET ABN	UG-SERVICE
42981231	GRET	SVC	4/29/2024	2013	RET ABN	UG-SERVICE
43330439	GRET	SVC	7/3/2024	2013	RET ABN	UG-SERVICE
40659934	GRET	SVC	10/21/2022	2013	RET ABN	UG-SERVICE
43957371	GRET	SVC	12/16/2024	2013	RET ABN	UG-SERVICE
43480654	GRET	SVC	10/6/2024	2013	RET ABN	UG-SERVICE
42796609	GRET	SVC	3/13/2024	2013	RET ABN	UG-SERVICE
40849836	GRET	SVC	10/23/2022	2013	RET ABN	UG-SERVICE
38344248	GRET	SVC	4/12/2021	2014	RET ABN	UG-SERVICE
42671071	GRET	SVC	2/3/2024	2014	RET ABN	UG-SERVICE
41576474	GRET	SVC	3/21/2023	2014	RET ABN	UG-SERVICE
40487925	GRET	SVC	7/25/2022	2014	RET ABN	UG-SERVICE
40353053	GRET	SVC	6/26/2022	2014	RET ABN	UG-SERVICE
40561839	GRET	SVC	8/18/2022	2014	RET ABN	UG-SERVICE
43318351	GRET	SVC	8/26/2024	2014	RET ABN	UG-SERVICE
40982965	GRET	SVC	11/28/2022	2014	RET ABN	UG-SERVICE
41482811	GRET	SVC	4/14/2023	2014	RET ABN	UG-SERVICE
39674319	GRET	SVC	1/12/2022	2014	RET ABN	UG-SERVICE
36096185	GRET	SVC	6/9/2020	2014	RET ABN	UG-SERVICE
42003636	GRET	SVC	8/16/2023	2014	RET ABN	UG-SERVICE
40468017	GRET	SVC	7/14/2022	2014	RET ABN	UG-SERVICE
43402925	GRET	SVC	8/7/2024	2014	RET ABN	UG-SERVICE
39338926	GRET	SVC	11/5/2021	2014	RET ABN	UG-SERVICE
36314549	GRET	SVC	5/11/2020	2014	RET ABN	UG-SERVICE
40708511	GRET	SVC	9/19/2022	2014	RET ABN	UG-SERVICE
40488329	GRET	SVC	7/28/2022	2014	RET ABN	UG-SERVICE
36838641	GRET	SVC	8/29/2020	2014	RET ABN	UG-SERVICE
36164864	GRET	SVC	3/25/2020	2014	RET ABN	UG-SERVICE
41791692	GRET	SVC	6/27/2023	2014	RET ABN	UG-SERVICE
38953221	GRET	SVC	8/23/2021	2014	RET ABN	UG-SERVICE
40492810	GRET	SVC	7/28/2022	2014	RET ABN	UG-SERVICE
38059756	GRET	SVC	1/27/2021	2014	RET ABN	UG-SERVICE
41674280	GRET	SVC	5/22/2023	2014	RET ABN	UG-SERVICE
40983621	GRET	SVC	11/28/2022	2014	RET ABN	UG-SERVICE
43318167	GRET	SVC	8/14/2024	2014	RET ABN	UG-SERVICE
39853612	GRET	SVC	3/8/2022	2014	RET ABN	UG-SERVICE
41513818	GRET	SVC	4/17/2023	2014	RET ABN	UG-SERVICE
36096181	GRET	SVC	6/9/2020	2014	RET ABN	UG-SERVICE
36058957	GRET	SVC	2/22/2020	2014	RET ABN	UG-SERVICE
43506828	GRET	SVC	10/4/2024	2014	RET ABN	UG-SERVICE
36366545	GRET	SVC	5/27/2020	2014	RET ABN	UG-SERVICE
36401305	GRET	SVC	5/31/2020	2014	RET ABN	UG-SERVICE
38359928	GRET	SVC	4/12/2021	2014	RET ABN	UG-SERVICE
41472671	GRET	SVC	4/10/2023	2014	RET ABN	UG-SERVICE
42057086	GRET	SVC	8/30/2023	2014	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42036565	GRET	SVC	8/30/2023	2014	RET ABN	UG-SERVICE
41334615	GRET	SVC	3/6/2023	2014	RET ABN	UG-SERVICE
37901089	GRET	SVC	12/11/2020	2014	RET ABN	UG-SERVICE
41860704	GRET	SVC	7/10/2023	2014	RET ABN	UG-SERVICE
43814800	GRET	SVC	11/15/2024	2014	RET ABN	UG-SERVICE
41508049	GRET	SVC	4/23/2023	2014	RET ABN	UG-SERVICE
41174819	GRET	SVC	1/18/2023	2014	RET ABN	UG-SERVICE
35663480	GRET	SVC	2/5/2020	2014	RET ABN	UG-SERVICE
42468689	GRET	SVC	12/13/2023	2014	RET ABN	UG-SERVICE
41497872	GRET	SVC	4/24/2023	2014	RET ABN	UG-SERVICE
40611930	GRET	SVC	8/21/2022	2014	RET ABN	UG-SERVICE
35663482	GRET	SVC	2/5/2020	2014	RET ABN	UG-SERVICE
40473671	GRET	SVC	7/26/2022	2014	RET ABN	UG-SERVICE
36152899	GRET	SVC	3/17/2020	2014	RET ABN	UG-SERVICE
37148982	GRET	SVC	11/2/2020	2014	RET ABN	UG-SERVICE
38959229	GRET	SVC	10/8/2021	2014	RET ABN	UG-SERVICE
36095742	GRET	SVC	3/7/2020	2014	RET ABN	UG-SERVICE
41031826	GRET	SVC	12/9/2022	2014	RET ABN	UG-SERVICE
41483271	GRET	SVC	4/12/2023	2014	RET ABN	UG-SERVICE
38220966	GRET	SVC	3/14/2021	2014	RET ABN	UG-SERVICE
38059752	GRET	SVC	1/25/2021	2014	RET ABN	UG-SERVICE
41938001	GRET	SVC	8/2/2023	2014	RET ABN	UG-SERVICE
41485312	GRET	SVC	4/19/2023	2014	RET ABN	UG-SERVICE
41584132	GRET	SVC	5/2/2023	2014	RET ABN	UG-SERVICE
39713737	GRET	SVC	1/25/2022	2014	RET ABN	UG-SERVICE
39424443	GRET	SVC	11/16/2021	2014	RET ABN	UG-SERVICE
39264072	GRET	SVC	10/6/2021	2014	RET ABN	UG-SERVICE
41508041	GRET	SVC	4/23/2023	2014	RET ABN	UG-SERVICE
43279916	GRET	SVC	11/27/2024	2014	RET ABN	UG-SERVICE
43953977	GRET	SVC	12/21/2024	2014	RET ABN	UG-SERVICE
38241888	GRET	SVC	3/18/2021	2014	RET ABN	UG-SERVICE
40105476	GRET	SVC	5/3/2022	2014	RET ABN	UG-SERVICE
40561707	GRET	SVC	8/12/2022	2014	RET ABN	UG-SERVICE
40090194	GRET	SVC	5/7/2022	2014	RET ABN	UG-SERVICE
41182819	GRET	SVC	1/20/2023	2014	RET ABN	UG-SERVICE
39776960	GRET	SVC	2/9/2022	2014	RET ABN	UG-SERVICE
40360820	GRET	SVC	6/27/2022	2014	RET ABN	UG-SERVICE
40561718	GRET	SVC	8/18/2022	2014	RET ABN	UG-SERVICE
40468018	GRET	SVC	7/15/2022	2014	RET ABN	UG-SERVICE
41497879	GRET	SVC	4/21/2023	2014	RET ABN	UG-SERVICE
40487933	GRET	SVC	7/26/2022	2014	RET ABN	UG-SERVICE
38397761	GRET	SVC	4/20/2021	2014	RET ABN	UG-SERVICE
41516369	GRET	SVC	4/24/2023	2014	RET ABN	UG-SERVICE
41514328	GRET	SVC	4/15/2023	2014	RET ABN	UG-SERVICE
43330432	GRET	SVC	7/17/2024	2014	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42036111	GRET	SVC	8/18/2023	2014	RET ABN	UG-SERVICE
36919391	GRET	SVC	9/17/2020	2014	RET ABN	UG-SERVICE
41485316	GRET	SVC	4/13/2023	2014	RET ABN	UG-SERVICE
38536241	GRET	SVC	5/27/2021	2014	RET ABN	UG-SERVICE
41723280	GRET	SVC	6/6/2023	2014	RET ABN	UG-SERVICE
41497637	GRET	SVC	4/12/2023	2014	RET ABN	UG-SERVICE
40685319	GRET	SVC	9/12/2022	2014	RET ABN	UG-SERVICE
40493086	GRET	SVC	7/28/2022	2014	RET ABN	UG-SERVICE
40879395	GRET	SVC	11/11/2022	2014	RET ABN	UG-SERVICE
38785519	GRET	SVC	7/16/2021	2014	RET ABN	UG-SERVICE
41146281	GRET	SVC	2/4/2023	2014	RET ABN	UG-SERVICE
41173975	GRET	SVC	1/18/2023	2014	RET ABN	UG-SERVICE
42973877	GRET	SVC	4/21/2024	2014	RET ABN	UG-SERVICE
41051915	GRET	SVC	1/12/2023	2014	RET ABN	UG-SERVICE
43115135	GRET	SVC	5/28/2024	2014	RET ABN	UG-SERVICE
43703182	GRET	SVC	10/17/2024	2014	RET ABN	UG-SERVICE
36472178	GRET	SVC	6/22/2020	2014	RET ABN	UG-SERVICE
39996609	GRET	SVC	4/16/2022	2014	RET ABN	UG-SERVICE
40500330	GRET	SVC	8/10/2022	2014	RET ABN	UG-SERVICE
41223070	GRET	SVC	1/28/2023	2014	RET ABN	UG-SERVICE
40303323	GRET	SVC	6/14/2022	2014	RET ABN	UG-SERVICE
43505782	GRET	SVC	9/10/2024	2014	RET ABN	UG-SERVICE
38178559	GRET	SVC	3/2/2021	2014	RET ABN	UG-SERVICE
40113467	GRET	SVC	5/11/2022	2014	RET ABN	UG-SERVICE
36153333	GRET	SVC	3/14/2020	2014	RET ABN	UG-SERVICE
38097060	GRET	SVC	9/2/2021	2014	RET ABN	UG-SERVICE
43974003	GRET	SVC	12/28/2024	2014	RET ABN	UG-SERVICE
36867567	GRET	SVC	8/29/2020	2014	RET ABN	UG-SERVICE
37113291	GRET	SVC	10/21/2020	2014	RET ABN	UG-SERVICE
40573500	GRET	SVC	8/18/2022	2014	RET ABN	UG-SERVICE
43610676	GRET	SVC	10/10/2024	2014	RET ABN	UG-SERVICE
43010357	GRET	SVC	4/28/2024	2014	RET ABN	UG-SERVICE
40513296	GRET	SVC	8/10/2022	2014	RET ABN	UG-SERVICE
42183130	GRET	SVC	10/3/2023	2014	RET ABN	UG-SERVICE
40762241	GRET	SVC	10/3/2022	2014	RET ABN	UG-SERVICE
40782678	GRET	SVC	10/6/2022	2014	RET ABN	UG-SERVICE
39801066	GRET	SVC	2/12/2022	2014	RET ABN	UG-SERVICE
42487738	GRET	SVC	7/18/2024	2014	RET ABN	UG-SERVICE
39280846	GRET	SVC	10/12/2021	2014	RET ABN	UG-SERVICE
40750114	GRET	SVC	9/29/2022	2014	RET ABN	UG-SERVICE
42565080	GRET	SVC	1/6/2024	2014	RET ABN	UG-SERVICE
40558508	GRET	SVC	8/12/2022	2014	RET ABN	UG-SERVICE
41480832	GRET	SVC	4/8/2023	2014	RET ABN	UG-SERVICE
36156980	GRET	SVC	5/4/2020	2014	RET ABN	UG-SERVICE
40513444	GRET	SVC	8/10/2022	2014	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40493091	GRET	SVC	7/28/2022	2014	RET ABN	UG-SERVICE
40487932	GRET	SVC	7/20/2022	2014	RET ABN	UG-SERVICE
39970252	GRET	SVC	4/5/2022	2014	RET ABN	UG-SERVICE
42691183	GRET	SVC	2/13/2024	2014	RET ABN	UG-SERVICE
41414816	GRET	SVC	3/20/2023	2014	RET ABN	UG-SERVICE
40468015	GRET	SVC	7/15/2022	2014	RET ABN	UG-SERVICE
40487105	GRET	SVC	7/23/2022	2014	RET ABN	UG-SERVICE
40890259	GRET	SVC	11/21/2022	2014	RET ABN	UG-SERVICE
38179283	GRET	SVC	3/1/2021	2014	RET ABN	UG-SERVICE
40988639	GRET	SVC	1/6/2023	2014	RET ABN	UG-SERVICE
41808563	GRET	SVC	6/22/2023	2014	RET ABN	UG-SERVICE
38711101	GRET	SVC	7/7/2021	2014	RET ABN	UG-SERVICE
40275012	GRET	SVC	6/21/2022	2014	RET ABN	UG-SERVICE
42975502	GRET	SVC	5/1/2024	2014	RET ABN	UG-SERVICE
38429030	GRET	SVC	6/16/2021	2015	RET ABN	UG-SERVICE
40316317	GRET	SVC	7/5/2022	2015	RET ABN	UG-SERVICE
43521336	GRET	SVC	9/10/2024	2015	RET ABN	UG-SERVICE
43600865	GRET	SVC	9/23/2024	2015	RET ABN	UG-SERVICE
40371592	GRET	SVC	7/6/2022	2015	RET ABN	UG-SERVICE
39876680	GRET	SVC	3/7/2022	2015	RET ABN	UG-SERVICE
43480996	GRET	SVC	11/1/2024	2015	RET ABN	UG-SERVICE
41482056	GRET	SVC	3/29/2023	2015	RET ABN	UG-SERVICE
43480934	GRET	SVC	10/5/2024	2015	RET ABN	UG-SERVICE
41483267	GRET	SVC	4/13/2023	2015	RET ABN	UG-SERVICE
42560256	GRET	SVC	1/8/2024	2015	RET ABN	UG-SERVICE
41064671	GRET	SVC	12/15/2022	2015	RET ABN	UG-SERVICE
40395632	GRET	SVC	7/7/2022	2015	RET ABN	UG-SERVICE
40406164	GRET	SVC	7/12/2022	2015	RET ABN	UG-SERVICE
41064583	GRET	SVC	12/16/2022	2015	RET ABN	UG-SERVICE
41117387	GRET	SVC	1/9/2023	2015	RET ABN	UG-SERVICE
39875677	GRET	SVC	3/9/2022	2015	RET ABN	UG-SERVICE
42247462	GRET	SVC	11/10/2023	2015	RET ABN	UG-SERVICE
41036614	GRET	SVC	12/10/2022	2015	RET ABN	UG-SERVICE
35924508	GRET	SVC	1/23/2020	2015	RET ABN	UG-SERVICE
41821844	GRET	SVC	7/1/2023	2015	RET ABN	UG-SERVICE
38665719	GRET	SVC	8/2/2021	2015	RET ABN	UG-SERVICE
38160999	GRET	SVC	2/22/2021	2015	RET ABN	UG-SERVICE
40359847	GRET	SVC	6/28/2022	2015	RET ABN	UG-SERVICE
39710753	GRET	SVC	1/26/2022	2015	RET ABN	UG-SERVICE
42524203	GRET	SVC	1/5/2024	2015	RET ABN	UG-SERVICE
41483028	GRET	SVC	4/14/2023	2015	RET ABN	UG-SERVICE
42937515	GRET	SVC	4/15/2024	2015	RET ABN	UG-SERVICE
40360823	GRET	SVC	6/26/2022	2015	RET ABN	UG-SERVICE
40612350	GRET	SVC	8/23/2022	2015	RET ABN	UG-SERVICE
38778278	GRET	SVC	7/15/2021	2015	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43529801	GRET	SVC	12/12/2024	2015	RET ABN	UG-SERVICE
38200830	GRET	SVC	3/15/2021	2015	RET ABN	UG-SERVICE
41064590	GRET	SVC	12/8/2022	2015	RET ABN	UG-SERVICE
37123589	GRET	SVC	10/28/2020	2015	RET ABN	UG-SERVICE
40352829	GRET	SVC	6/26/2022	2015	RET ABN	UG-SERVICE
39358682	GRET	SVC	10/26/2021	2015	RET ABN	UG-SERVICE
41117038	GRET	SVC	2/8/2023	2015	RET ABN	UG-SERVICE
36349905	GRET	SVC	5/27/2020	2015	RET ABN	UG-SERVICE
41106886	GRET	SVC	12/27/2022	2015	RET ABN	UG-SERVICE
35924321	GRET	SVC	1/16/2020	2015	RET ABN	UG-SERVICE
42004793	GRET	SVC	10/11/2023	2015	RET ABN	UG-SERVICE
39996625	GRET	SVC	4/11/2022	2015	RET ABN	UG-SERVICE
42520520	GRET	SVC	12/29/2023	2015	RET ABN	UG-SERVICE
39318771	GRET	SVC	10/27/2021	2015	RET ABN	UG-SERVICE
43480933	GRET	SVC	10/5/2024	2015	RET ABN	UG-SERVICE
39257539	GRET	SVC	11/10/2021	2015	RET ABN	UG-SERVICE
41253456	GRET	SVC	2/6/2023	2015	RET ABN	UG-SERVICE
41485313	GRET	SVC	4/20/2023	2015	RET ABN	UG-SERVICE
43717837	GRET	SVC	10/19/2024	2015	RET ABN	UG-SERVICE
43866221	GRET	SVC	12/16/2024	2015	RET ABN	UG-SERVICE
43618891	GRET	SVC	9/21/2024	2015	RET ABN	UG-SERVICE
42570263	GRET	SVC	2/20/2024	2015	RET ABN	UG-SERVICE
39768304	GRET	SVC	2/7/2022	2015	RET ABN	UG-SERVICE
41479075	GRET	SVC	4/10/2023	2015	RET ABN	UG-SERVICE
39950430	GRET	SVC	3/31/2022	2015	RET ABN	UG-SERVICE
41585804	GRET	SVC	4/30/2023	2015	RET ABN	UG-SERVICE
41508053	GRET	SVC	4/17/2023	2015	RET ABN	UG-SERVICE
41277501	GRET	SVC	2/24/2023	2015	RET ABN	UG-SERVICE
43480995	GRET	SVC	11/1/2024	2015	RET ABN	UG-SERVICE
41485317	GRET	SVC	4/14/2023	2015	RET ABN	UG-SERVICE
42006927	GRET	SVC	8/10/2023	2015	RET ABN	UG-SERVICE
41482806	GRET	SVC	4/4/2023	2015	RET ABN	UG-SERVICE
42281589	GRET	SVC	10/22/2023	2015	RET ABN	UG-SERVICE
38456261	GRET	SVC	5/4/2021	2015	RET ABN	UG-SERVICE
43506883	GRET	SVC	9/23/2024	2015	RET ABN	UG-SERVICE
42253894	GRET	SVC	10/20/2023	2015	RET ABN	UG-SERVICE
41364435	GRET	SVC	3/13/2023	2015	RET ABN	UG-SERVICE
41064593	GRET	SVC	12/8/2022	2015	RET ABN	UG-SERVICE
41016200	GRET	SVC	12/13/2022	2015	RET ABN	UG-SERVICE
40384604	GRET	SVC	6/24/2022	2015	RET ABN	UG-SERVICE
36366078	GRET	SVC	8/24/2020	2015	RET ABN	UG-SERVICE
39869439	GRET	SVC	3/10/2022	2015	RET ABN	UG-SERVICE
41508055	GRET	SVC	4/17/2023	2015	RET ABN	UG-SERVICE
41223587	GRET	SVC	2/15/2023	2015	RET ABN	UG-SERVICE
36751508	GRET	SVC	8/11/2020	2015	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41483035	GRET	SVC	4/14/2023	2015	RET ABN	UG-SERVICE
37896188	GRET	SVC	12/8/2020	2015	RET ABN	UG-SERVICE
42328558	GRET	SVC	11/7/2023	2015	RET ABN	UG-SERVICE
41016203	GRET	SVC	12/13/2022	2015	RET ABN	UG-SERVICE
41226272	GRET	SVC	1/28/2023	2015	RET ABN	UG-SERVICE
41032258	GRET	SVC	12/4/2022	2015	RET ABN	UG-SERVICE
41498364	GRET	SVC	4/12/2023	2015	RET ABN	UG-SERVICE
38200828	GRET	SVC	3/17/2021	2015	RET ABN	UG-SERVICE
43318355	GRET	SVC	8/6/2024	2015	RET ABN	UG-SERVICE
38416177	GRET	SVC	4/29/2021	2015	RET ABN	UG-SERVICE
40291546	GRET	SVC	6/13/2022	2015	RET ABN	UG-SERVICE
41016206	GRET	SVC	12/13/2022	2015	RET ABN	UG-SERVICE
41032543	GRET	SVC	12/4/2022	2015	RET ABN	UG-SERVICE
37880365	GRET	SVC	12/8/2020	2015	RET ABN	UG-SERVICE
42263863	GRET	SVC	10/23/2023	2015	RET ABN	UG-SERVICE
43707637	GRET	SVC	10/28/2024	2015	RET ABN	UG-SERVICE
41937753	GRET	SVC	7/24/2023	2015	RET ABN	UG-SERVICE
43224594	GRET	SVC	6/26/2024	2015	RET ABN	UG-SERVICE
41128151	GRET	SVC	12/31/2022	2015	RET ABN	UG-SERVICE
35865601	GRET	SVC	1/7/2020	2015	RET ABN	UG-SERVICE
41273578	GRET	SVC	2/16/2023	2015	RET ABN	UG-SERVICE
41032250	GRET	SVC	12/6/2022	2015	RET ABN	UG-SERVICE
40395522	GRET	SVC	7/6/2022	2015	RET ABN	UG-SERVICE
36286881	GRET	SVC	6/13/2020	2015	RET ABN	UG-SERVICE
43250929	GRET	SVC	6/29/2024	2015	RET ABN	UG-SERVICE
40593818	GRET	SVC	8/22/2022	2015	RET ABN	UG-SERVICE
43379780	GRET	SVC	8/1/2024	2015	RET ABN	UG-SERVICE
41274837	GRET	SVC	2/15/2023	2015	RET ABN	UG-SERVICE
41106618	GRET	SVC	12/28/2022	2015	RET ABN	UG-SERVICE
37903754	GRET	SVC	12/16/2020	2015	RET ABN	UG-SERVICE
40578571	GRET	SVC	8/16/2022	2015	RET ABN	UG-SERVICE
41114622	GRET	SVC	12/29/2022	2015	RET ABN	UG-SERVICE
36675999	GRET	SVC	7/28/2020	2015	RET ABN	UG-SERVICE
41036613	GRET	SVC	12/10/2022	2015	RET ABN	UG-SERVICE
38200825	GRET	SVC	3/10/2021	2015	RET ABN	UG-SERVICE
42784177	GRET	SVC	3/5/2024	2015	RET ABN	UG-SERVICE
37045736	GRET	SVC	10/21/2020	2015	RET ABN	UG-SERVICE
41482801	GRET	SVC	4/4/2023	2015	RET ABN	UG-SERVICE
41082582	GRET	SVC	12/19/2022	2015	RET ABN	UG-SERVICE
41572132	GRET	SVC	5/6/2023	2015	RET ABN	UG-SERVICE
41721648	GRET	SVC	6/6/2023	2015	RET ABN	UG-SERVICE
41032549	GRET	SVC	12/16/2022	2015	RET ABN	UG-SERVICE
43207843	GRET	SVC	6/22/2024	2015	RET ABN	UG-SERVICE
39394745	GRET	SVC	11/12/2021	2015	RET ABN	UG-SERVICE
41128156	GRET	SVC	12/31/2022	2015	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41064594	GRET	SVC	12/13/2022	2015	RET ABN	UG-SERVICE
41771847	GRET	SVC	6/27/2023	2016	RET ABN	UG-SERVICE
40216937	GRET	SVC	6/5/2022	2016	RET ABN	UG-SERVICE
41768170	GRET	SVC	6/17/2023	2016	RET ABN	UG-SERVICE
42745597	GRET	SVC	2/19/2024	2016	RET ABN	UG-SERVICE
41187062	GRET	SVC	1/18/2023	2016	RET ABN	UG-SERVICE
40644721	GRET	SVC	9/16/2022	2016	RET ABN	UG-SERVICE
36818926	GRET	SVC	9/4/2020	2016	RET ABN	UG-SERVICE
37013965	GRET	SVC	10/14/2020	2016	RET ABN	UG-SERVICE
43329965	GRET	SVC	7/18/2024	2016	RET ABN	UG-SERVICE
41284192	GRET	SVC	2/21/2023	2016	RET ABN	UG-SERVICE
35956609	GRET	SVC	1/27/2020	2016	RET ABN	UG-SERVICE
35929651	GRET	SVC	1/23/2020	2016	RET ABN	UG-SERVICE
42512725	GRET	SVC	12/26/2023	2016	RET ABN	UG-SERVICE
38635511	GRET	SVC	6/21/2021	2016	RET ABN	UG-SERVICE
42276953	GRET	SVC	10/25/2023	2016	RET ABN	UG-SERVICE
43170486	GRET	SVC	6/17/2024	2016	RET ABN	UG-SERVICE
41690367	GRET	SVC	5/30/2023	2016	RET ABN	UG-SERVICE
40846767	GRET	SVC	10/29/2022	2016	RET ABN	UG-SERVICE
37256532	GRET	SVC	11/9/2020	2016	RET ABN	UG-SERVICE
37064079	GRET	SVC	11/16/2020	2016	RET ABN	UG-SERVICE
36152449	GRET	SVC	3/19/2020	2016	RET ABN	UG-SERVICE
38869778	GRET	SVC	8/5/2021	2016	RET ABN	UG-SERVICE
40555890	GRET	SVC	8/25/2022	2016	RET ABN	UG-SERVICE
41568589	GRET	SVC	4/27/2023	2016	RET ABN	UG-SERVICE
36371110	GRET	SVC	6/19/2020	2016	RET ABN	UG-SERVICE
41918683	GRET	SVC	7/25/2023	2016	RET ABN	UG-SERVICE
43169821	GRET	SVC	6/10/2024	2016	RET ABN	UG-SERVICE
36643846	GRET	SVC	7/20/2020	2016	RET ABN	UG-SERVICE
41284197	GRET	SVC	2/15/2023	2016	RET ABN	UG-SERVICE
36834291	GRET	SVC	8/26/2020	2016	RET ABN	UG-SERVICE
40779653	GRET	SVC	10/26/2022	2016	RET ABN	UG-SERVICE
39613255	GRET	SVC	12/29/2021	2016	RET ABN	UG-SERVICE
42744596	GRET	SVC	2/19/2024	2016	RET ABN	UG-SERVICE
36596483	GRET	SVC	8/12/2020	2016	RET ABN	UG-SERVICE
43071571	GRET	SVC	5/17/2024	2016	RET ABN	UG-SERVICE
40691986	GRET	SVC	9/13/2022	2016	RET ABN	UG-SERVICE
42226914	GRET	SVC	10/16/2023	2016	RET ABN	UG-SERVICE
41284198	GRET	SVC	2/14/2023	2016	RET ABN	UG-SERVICE
43013381	GRET	SVC	5/4/2024	2016	RET ABN	UG-SERVICE
35953732	GRET	SVC	1/27/2020	2016	RET ABN	UG-SERVICE
36948624	GRET	SVC	9/18/2020	2016	RET ABN	UG-SERVICE
41568561	GRET	SVC	4/27/2023	2016	RET ABN	UG-SERVICE
39257781	GRET	SVC	10/12/2021	2016	RET ABN	UG-SERVICE
43831245	GRET	SVC	11/26/2024	2016	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43741075	GRET	SVC	10/28/2024	2016	RET ABN	UG-SERVICE
41673901	GRET	SVC	5/22/2023	2016	RET ABN	UG-SERVICE
41405833	GRET	SVC	3/20/2023	2016	RET ABN	UG-SERVICE
40230340	GRET	SVC	5/31/2022	2016	RET ABN	UG-SERVICE
43526642	GRET	SVC	9/5/2024	2016	RET ABN	UG-SERVICE
41279556	GRET	SVC	2/12/2023	2016	RET ABN	UG-SERVICE
36021124	GRET	SVC	2/12/2020	2016	RET ABN	UG-SERVICE
40780619	GRET	SVC	10/10/2022	2016	RET ABN	UG-SERVICE
42975777	GRET	SVC	6/3/2024	2016	RET ABN	UG-SERVICE
38092844	GRET	SVC	2/4/2021	2016	RET ABN	UG-SERVICE
39668880	GRET	SVC	1/10/2022	2016	RET ABN	UG-SERVICE
43225267	GRET	SVC	6/26/2024	2016	RET ABN	UG-SERVICE
41287538	GRET	SVC	3/18/2023	2016	RET ABN	UG-SERVICE
39773244	GRET	SVC	2/9/2022	2016	RET ABN	UG-SERVICE
38568981	GRET	SVC	6/7/2021	2016	RET ABN	UG-SERVICE
40874774	GRET	SVC	10/29/2022	2016	RET ABN	UG-SERVICE
38200983	GRET	SVC	3/10/2021	2016	RET ABN	UG-SERVICE
36650025	GRET	SVC	7/18/2020	2016	RET ABN	UG-SERVICE
42706729	GRET	SVC	2/13/2024	2016	RET ABN	UG-SERVICE
40558481	GRET	SVC	8/21/2022	2016	RET ABN	UG-SERVICE
41609017	GRET	SVC	5/6/2023	2016	RET ABN	UG-SERVICE
42995589	GRET	SVC	4/30/2024	2016	RET ABN	UG-SERVICE
38941812	GRET	SVC	8/18/2021	2016	RET ABN	UG-SERVICE
41286301	GRET	SVC	3/17/2023	2016	RET ABN	UG-SERVICE
42921106	GRET	SVC	3/30/2024	2016	RET ABN	UG-SERVICE
43345805	GRET	SVC	7/26/2024	2016	RET ABN	UG-SERVICE
40976086	GRET	SVC	11/28/2022	2016	RET ABN	UG-SERVICE
38596272	GRET	SVC	6/8/2021	2016	RET ABN	UG-SERVICE
42788300	GRET	SVC	3/11/2024	2016	RET ABN	UG-SERVICE
43862725	GRET	SVC	11/25/2024	2016	RET ABN	UG-SERVICE
37986309	GRET	SVC	1/5/2021	2016	RET ABN	UG-SERVICE
36682911	GRET	SVC	7/27/2020	2016	RET ABN	UG-SERVICE
41919955	GRET	SVC	8/7/2023	2016	RET ABN	UG-SERVICE
43883122	GRET	SVC	12/9/2024	2016	RET ABN	UG-SERVICE
39149347	GRET	SVC	9/16/2021	2016	RET ABN	UG-SERVICE
39316996	GRET	SVC	10/25/2021	2016	RET ABN	UG-SERVICE
40672066	GRET	SVC	10/1/2022	2016	RET ABN	UG-SERVICE
39249723	GRET	SVC	10/11/2021	2016	RET ABN	UG-SERVICE
39215340	GRET	SVC	11/1/2021	2016	RET ABN	UG-SERVICE
41439586	GRET	SVC	3/27/2023	2016	RET ABN	UG-SERVICE
42707431	GRET	SVC	2/11/2024	2016	RET ABN	UG-SERVICE
36196116	GRET	SVC	4/21/2020	2016	RET ABN	UG-SERVICE
41769393	GRET	SVC	6/17/2023	2016	RET ABN	UG-SERVICE
37896786	GRET	SVC	12/9/2020	2016	RET ABN	UG-SERVICE
39352877	GRET	SVC	10/19/2021	2016	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43822621	GRET	SVC	11/8/2024	2016	RET ABN	UG-SERVICE
40746028	GRET	SVC	9/23/2022	2017	RET ABN	UG-SERVICE
43683503	GRET	SVC	10/14/2024	2017	RET ABN	UG-SERVICE
40375096	GRET	SVC	7/2/2022	2017	RET ABN	UG-SERVICE
43060531	GRET	SVC	5/13/2024	2017	RET ABN	UG-SERVICE
43668851	GRET	SVC	10/8/2024	2017	RET ABN	UG-SERVICE
40499691	GRET	SVC	8/1/2022	2017	RET ABN	UG-SERVICE
41639188	GRET	SVC	5/19/2023	2017	RET ABN	UG-SERVICE
41389385	GRET	SVC	3/13/2023	2017	RET ABN	UG-SERVICE
41283637	GRET	SVC	2/18/2023	2017	RET ABN	UG-SERVICE
39930409	GRET	SVC	3/28/2022	2017	RET ABN	UG-SERVICE
41904186	GRET	SVC	7/25/2023	2017	RET ABN	UG-SERVICE
43364928	GRET	SVC	12/2/2024	2017	RET ABN	UG-SERVICE
43481247	GRET	SVC	11/22/2024	2017	RET ABN	UG-SERVICE
41274584	GRET	SVC	2/13/2023	2017	RET ABN	UG-SERVICE
43752069	GRET	SVC	11/16/2024	2017	RET ABN	UG-SERVICE
40319102	GRET	SVC	6/20/2022	2017	RET ABN	UG-SERVICE
43480992	GRET	SVC	11/10/2024	2017	RET ABN	UG-SERVICE
41803122	GRET	SVC	6/27/2023	2017	RET ABN	UG-SERVICE
38349990	GRET	SVC	4/14/2021	2017	RET ABN	UG-SERVICE
43370930	GRET	SVC	7/30/2024	2017	RET ABN	UG-SERVICE
36602821	GRET	SVC	7/9/2020	2017	RET ABN	UG-SERVICE
36168225	GRET	SVC	3/23/2020	2017	RET ABN	UG-SERVICE
39880011	GRET	SVC	3/14/2022	2017	RET ABN	UG-SERVICE
38222416	GRET	SVC	3/17/2021	2017	RET ABN	UG-SERVICE
39324294	GRET	SVC	10/27/2021	2017	RET ABN	UG-SERVICE
40383953	GRET	SVC	7/5/2022	2017	RET ABN	UG-SERVICE
38067901	GRET	SVC	1/25/2021	2017	RET ABN	UG-SERVICE
40091708	GRET	SVC	5/2/2022	2017	RET ABN	UG-SERVICE
38364543	GRET	SVC	4/14/2021	2017	RET ABN	UG-SERVICE
37115386	GRET	SVC	11/2/2020	2017	RET ABN	UG-SERVICE
43642980	GRET	SVC	10/7/2024	2017	RET ABN	UG-SERVICE
38880692	GRET	SVC	8/6/2021	2017	RET ABN	UG-SERVICE
38526701	GRET	SVC	4/11/2021	2017	RET ABN	UG-SERVICE
41893698	GRET	SVC	7/21/2023	2017	RET ABN	UG-SERVICE
41534326	GRET	SVC	5/8/2023	2017	RET ABN	UG-SERVICE
38174775	GRET	SVC	2/27/2021	2017	RET ABN	UG-SERVICE
42181125	GRET	SVC	10/4/2023	2017	RET ABN	UG-SERVICE
39873510	GRET	SVC	3/15/2022	2017	RET ABN	UG-SERVICE
41484577	GRET	SVC	4/18/2023	2017	RET ABN	UG-SERVICE
43905526	GRET	SVC	12/9/2024	2017	RET ABN	UG-SERVICE
42257455	GRET	SVC	10/23/2023	2017	RET ABN	UG-SERVICE
39878839	GRET	SVC	3/14/2022	2017	RET ABN	UG-SERVICE
42653746	GRET	SVC	2/5/2024	2017	RET ABN	UG-SERVICE
41083717	GRET	SVC	12/20/2022	2017	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41750989	GRET	SVC	6/13/2023	2017	RET ABN	UG-SERVICE
40204785	GRET	SVC	5/23/2022	2017	RET ABN	UG-SERVICE
43957196	GRET	SVC	12/18/2024	2017	RET ABN	UG-SERVICE
39550414	GRET	SVC	12/16/2021	2017	RET ABN	UG-SERVICE
43459323	GRET	SVC	8/19/2024	2017	RET ABN	UG-SERVICE
40878242	GRET	SVC	11/7/2022	2017	RET ABN	UG-SERVICE
43715117	GRET	SVC	10/22/2024	2017	RET ABN	UG-SERVICE
42914394	GRET	SVC	4/11/2024	2017	RET ABN	UG-SERVICE
41175051	GRET	SVC	1/20/2023	2017	RET ABN	UG-SERVICE
41566183	GRET	SVC	4/25/2023	2017	RET ABN	UG-SERVICE
41560897	GRET	SVC	4/20/2023	2017	RET ABN	UG-SERVICE
42222135	GRET	SVC	10/12/2023	2017	RET ABN	UG-SERVICE
39275116	GRET	SVC	10/15/2021	2017	RET ABN	UG-SERVICE
40928808	GRET	SVC	11/15/2022	2017	RET ABN	UG-SERVICE
42939579	GRET	SVC	4/17/2024	2017	RET ABN	UG-SERVICE
42594903	GRET	SVC	1/24/2024	2017	RET ABN	UG-SERVICE
40853685	GRET	SVC	10/24/2022	2017	RET ABN	UG-SERVICE
43219490	GRET	SVC	6/25/2024	2017	RET ABN	UG-SERVICE
43506824	GRET	SVC	10/3/2024	2017	RET ABN	UG-SERVICE
41424768	GRET	SVC	10/18/2023	2017	RET ABN	UG-SERVICE
36486890	GRET	SVC	6/25/2020	2017	RET ABN	UG-SERVICE
41926528	GRET	SVC	7/29/2023	2017	RET ABN	UG-SERVICE
36152268	GRET	SVC	3/16/2020	2017	RET ABN	UG-SERVICE
39713217	GRET	SVC	1/12/2022	2017	RET ABN	UG-SERVICE
36366992	GRET	SVC	5/26/2020	2017	RET ABN	UG-SERVICE
41279548	GRET	SVC	2/12/2023	2017	RET ABN	UG-SERVICE
42907196	GRET	SVC	4/7/2024	2017	RET ABN	UG-SERVICE
41588281	GRET	SVC	5/3/2023	2017	RET ABN	UG-SERVICE
43582912	GRET	SVC	9/18/2024	2017	RET ABN	UG-SERVICE
42762981	GRET	SVC	2/29/2024	2017	RET ABN	UG-SERVICE
42967786	GRET	SVC	4/25/2024	2017	RET ABN	UG-SERVICE
36200532	GRET	SVC	4/23/2020	2017	RET ABN	UG-SERVICE
41955802	GRET	SVC	8/5/2023	2017	RET ABN	UG-SERVICE
39081127	GRET	SVC	9/10/2021	2017	RET ABN	UG-SERVICE
36199243	GRET	SVC	5/14/2020	2017	RET ABN	UG-SERVICE
42277126	GRET	SVC	10/12/2023	2017	RET ABN	UG-SERVICE
43481120	GRET	SVC	10/29/2024	2017	RET ABN	UG-SERVICE
42096936	GRET	SVC	9/12/2023	2017	RET ABN	UG-SERVICE
36347808	GRET	SVC	5/19/2020	2017	RET ABN	UG-SERVICE
41958783	GRET	SVC	8/7/2023	2018	RET ABN	UG-SERVICE
37844120	GRET	SVC	12/1/2020	2018	RET ABN	UG-SERVICE
40092393	GRET	SVC	4/27/2022	2018	RET ABN	UG-SERVICE
38428372	GRET	SVC	4/28/2021	2018	RET ABN	UG-SERVICE
39194846	GRET	SVC	9/27/2021	2018	RET ABN	UG-SERVICE
40035889	GRET	SVC	4/20/2022	2018	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40694162	GRET	SVC	9/15/2022	2018	RET ABN	UG-SERVICE
36598693	GRET	SVC	7/25/2020	2018	RET ABN	UG-SERVICE
38741237	GRET	SVC	7/27/2021	2018	RET ABN	UG-SERVICE
43489146	GRET	SVC	8/26/2024	2018	RET ABN	UG-SERVICE
40860204	GRET	SVC	10/25/2022	2018	RET ABN	UG-SERVICE
36643845	GRET	SVC	7/20/2020	2018	RET ABN	UG-SERVICE
41205724	GRET	SVC	1/27/2023	2018	RET ABN	UG-SERVICE
41286322	GRET	SVC	2/20/2023	2018	RET ABN	UG-SERVICE
36019879	GRET	SVC	2/12/2020	2018	RET ABN	UG-SERVICE
43481045	GRET	SVC	11/1/2024	2018	RET ABN	UG-SERVICE
38312793	GRET	SVC	4/7/2021	2018	RET ABN	UG-SERVICE
43571069	GRET	SVC	9/17/2024	2018	RET ABN	UG-SERVICE
36066842	GRET	SVC	2/28/2020	2018	RET ABN	UG-SERVICE
40782757	GRET	SVC	10/7/2022	2018	RET ABN	UG-SERVICE
43147157	GRET	SVC	6/3/2024	2018	RET ABN	UG-SERVICE
40812314	GRET	SVC	10/30/2022	2018	RET ABN	UG-SERVICE
43058936	GRET	SVC	5/15/2024	2018	RET ABN	UG-SERVICE
42944771	GRET	SVC	4/16/2024	2018	RET ABN	UG-SERVICE
39657980	GRET	SVC	1/30/2022	2018	RET ABN	UG-SERVICE
42906048	GRET	SVC	4/10/2024	2018	RET ABN	UG-SERVICE
43752226	GRET	SVC	11/27/2024	2018	RET ABN	UG-SERVICE
42078595	GRET	SVC	5/9/2023	2018	RET ABN	UG-SERVICE
39242836	GRET	SVC	10/4/2021	2018	RET ABN	UG-SERVICE
39120028	GRET	SVC	9/14/2021	2018	RET ABN	UG-SERVICE
43370808	GRET	SVC	11/4/2024	2018	RET ABN	UG-SERVICE
42470302	GRET	SVC	12/11/2023	2018	RET ABN	UG-SERVICE
40274919	GRET	SVC	6/13/2022	2018	RET ABN	UG-SERVICE
40118393	GRET	SVC	5/4/2022	2018	RET ABN	UG-SERVICE
43023019	GRET	SVC	5/6/2024	2018	RET ABN	UG-SERVICE
38089275	GRET	SVC	2/2/2021	2018	RET ABN	UG-SERVICE
41883655	GRET	SVC	7/15/2023	2018	RET ABN	UG-SERVICE
39484987	GRET	SVC	11/26/2021	2018	RET ABN	UG-SERVICE
43948489	GRET	SVC	12/19/2024	2018	RET ABN	UG-SERVICE
37560374	GRET	SVC	11/5/2020	2018	RET ABN	UG-SERVICE
36914331	GRET	SVC	9/17/2020	2018	RET ABN	UG-SERVICE
40333089	GRET	SVC	6/21/2022	2018	RET ABN	UG-SERVICE
41585923	GRET	SVC	5/2/2023	2018	RET ABN	UG-SERVICE
39776979	GRET	SVC	2/9/2022	2018	RET ABN	UG-SERVICE
40545980	GRET	SVC	1/3/2023	2018	RET ABN	UG-SERVICE
38257670	GRET	SVC	3/20/2021	2018	RET ABN	UG-SERVICE
43861748	GRET	SVC	12/9/2024	2018	RET ABN	UG-SERVICE
40883589	GRET	SVC	11/9/2022	2018	RET ABN	UG-SERVICE
43648281	GRET	SVC	10/22/2024	2018	RET ABN	UG-SERVICE
37358765	GRET	SVC	10/29/2020	2018	RET ABN	UG-SERVICE
40645570	GRET	SVC	8/31/2022	2018	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36999957	GRET	SVC	10/5/2020	2018	RET ABN	UG-SERVICE
38528019	GRET	SVC	5/24/2021	2018	RET ABN	UG-SERVICE
38820995	GRET	SVC	7/27/2021	2018	RET ABN	UG-SERVICE
41699139	GRET	SVC	5/30/2023	2018	RET ABN	UG-SERVICE
42250456	GRET	SVC	10/16/2023	2018	RET ABN	UG-SERVICE
38301277	GRET	SVC	7/30/2021	2018	RET ABN	UG-SERVICE
43330270	GRET	SVC	7/15/2024	2018	RET ABN	UG-SERVICE
43466685	GRET	SVC	9/16/2024	2018	RET ABN	UG-SERVICE
39890608	GRET	SVC	3/28/2022	2018	RET ABN	UG-SERVICE
39266340	GRET	SVC	10/11/2021	2018	RET ABN	UG-SERVICE
41913462	GRET	SVC	7/24/2023	2018	RET ABN	UG-SERVICE
40593804	GRET	SVC	8/16/2022	2018	RET ABN	UG-SERVICE
43654922	GRET	SVC	10/2/2024	2018	RET ABN	UG-SERVICE
40949361	GRET	SVC	12/9/2022	2018	RET ABN	UG-SERVICE
41030771	GRET	SVC	12/7/2022	2018	RET ABN	UG-SERVICE
38706201	GRET	SVC	7/7/2021	2018	RET ABN	UG-SERVICE
43493904	GRET	SVC	9/4/2024	2018	RET ABN	UG-SERVICE
41224142	GRET	SVC	1/28/2023	2018	RET ABN	UG-SERVICE
42177006	GRET	SVC	9/29/2023	2018	RET ABN	UG-SERVICE
38838961	GRET	SVC	7/20/2021	2018	RET ABN	UG-SERVICE
36114268	GRET	SVC	3/11/2020	2018	RET ABN	UG-SERVICE
41669294	GRET	SVC	5/25/2023	2018	RET ABN	UG-SERVICE
43141728	GRET	SVC	6/1/2024	2018	RET ABN	UG-SERVICE
36820287	GRET	SVC	8/25/2020	2018	RET ABN	UG-SERVICE
40062841	GRET	SVC	5/14/2022	2018	RET ABN	UG-SERVICE
36577459	GRET	SVC	7/8/2020	2018	RET ABN	UG-SERVICE
40558804	GRET	SVC	8/11/2022	2018	RET ABN	UG-SERVICE
41612016	GRET	SVC	5/8/2023	2018	RET ABN	UG-SERVICE
36685504	GRET	SVC	7/27/2020	2018	RET ABN	UG-SERVICE
38534654	GRET	SVC	5/27/2021	2018	RET ABN	UG-SERVICE
38397595	GRET	SVC	4/21/2021	2018	RET ABN	UG-SERVICE
41397335	GRET	SVC	3/16/2023	2018	RET ABN	UG-SERVICE
41398471	GRET	SVC	3/14/2023	2018	RET ABN	UG-SERVICE
40506220	GRET	SVC	8/2/2022	2018	RET ABN	UG-SERVICE
39850142	GRET	SVC	3/4/2022	2018	RET ABN	UG-SERVICE
37008451	GRET	SVC	11/12/2020	2018	RET ABN	UG-SERVICE
43519323	GRET	SVC	9/10/2024	2018	RET ABN	UG-SERVICE
41480834	GRET	SVC	4/8/2023	2018	RET ABN	UG-SERVICE
38330664	GRET	SVC	4/6/2021	2018	RET ABN	UG-SERVICE
39996896	GRET	SVC	4/25/2022	2018	RET ABN	UG-SERVICE
36793151	GRET	SVC	8/17/2020	2018	RET ABN	UG-SERVICE
39245797	GRET	SVC	10/6/2021	2018	RET ABN	UG-SERVICE
43669822	GRET	SVC	10/11/2024	2018	RET ABN	UG-SERVICE
41480226	GRET	SVC	4/9/2023	2018	RET ABN	UG-SERVICE
41897722	GRET	SVC	7/22/2023	2018	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38466250	GRET	SVC	5/11/2021	2018	RET ABN	UG-SERVICE
36916483	GRET	SVC	9/11/2020	2018	RET ABN	UG-SERVICE
41916572	GRET	SVC	8/22/2023	2018	RET ABN	UG-SERVICE
39166343	GRET	SVC	9/29/2021	2018	RET ABN	UG-SERVICE
43654684	GRET	SVC	10/21/2024	2018	RET ABN	UG-SERVICE
42903351	GRET	SVC	4/10/2024	2018	RET ABN	UG-SERVICE
38534655	GRET	SVC	5/24/2021	2018	RET ABN	UG-SERVICE
42409830	GRET	SVC	11/28/2023	2018	RET ABN	UG-SERVICE
42078302	GRET	SVC	9/5/2023	2019	RET ABN	UG-SERVICE
36282719	GRET	SVC	6/15/2020	2019	RET ABN	UG-SERVICE
37739212	GRET	SVC	11/23/2020	2019	RET ABN	UG-SERVICE
38719485	GRET	SVC	7/12/2021	2019	RET ABN	UG-SERVICE
40418554	GRET	SVC	7/13/2022	2019	RET ABN	UG-SERVICE
43676776	GRET	SVC	10/15/2024	2019	RET ABN	UG-SERVICE
36283381	GRET	SVC	6/15/2020	2019	RET ABN	UG-SERVICE
36671815	GRET	SVC	7/24/2020	2019	RET ABN	UG-SERVICE
36192819	GRET	SVC	4/15/2020	2019	RET ABN	UG-SERVICE
36598689	GRET	SVC	7/25/2020	2019	RET ABN	UG-SERVICE
39233803	GRET	SVC	10/15/2021	2019	RET ABN	UG-SERVICE
36282718	GRET	SVC	6/15/2020	2019	RET ABN	UG-SERVICE
42425970	GRET	SVC	11/27/2023	2019	RET ABN	UG-SERVICE
39150591	GRET	SVC	9/20/2021	2019	RET ABN	UG-SERVICE
39892549	GRET	SVC	3/15/2022	2019	RET ABN	UG-SERVICE
42476344	GRET	SVC	12/7/2023	2019	RET ABN	UG-SERVICE
43353626	GRET	SVC	11/4/2024	2019	RET ABN	UG-SERVICE
41334869	GRET	SVC	3/6/2023	2019	RET ABN	UG-SERVICE
43915732	GRET	SVC	12/16/2024	2019	RET ABN	UG-SERVICE
36270018	GRET	SVC	4/28/2020	2019	RET ABN	UG-SERVICE
38361202	GRET	SVC	4/14/2021	2019	RET ABN	UG-SERVICE
43882980	GRET	SVC	11/30/2024	2019	RET ABN	UG-SERVICE
36192180	GRET	SVC	4/24/2020	2019	RET ABN	UG-SERVICE
43218663	GRET	SVC	6/25/2024	2019	RET ABN	UG-SERVICE
40368480	GRET	SVC	6/29/2022	2019	RET ABN	UG-SERVICE
35986290	GRET	SVC	2/4/2020	2019	RET ABN	UG-SERVICE
38514856	GRET	SVC	8/5/2021	2019	RET ABN	UG-SERVICE
43492522	GRET	SVC	9/18/2024	2019	RET ABN	UG-SERVICE
37773047	GRET	SVC	11/24/2020	2019	RET ABN	UG-SERVICE
41402091	GRET	SVC	3/15/2023	2019	RET ABN	UG-SERVICE
39550753	GRET	SVC	12/17/2021	2019	RET ABN	UG-SERVICE
41114425	GRET	SVC	1/7/2023	2019	RET ABN	UG-SERVICE
36760770	GRET	SVC	8/11/2020	2019	RET ABN	UG-SERVICE
40050472	GRET	SVC	4/26/2022	2019	RET ABN	UG-SERVICE
43066566	GRET	SVC	5/20/2024	2019	RET ABN	UG-SERVICE
39233714	GRET	SVC	10/11/2021	2019	RET ABN	UG-SERVICE
37914673	GRET	SVC	12/13/2020	2019	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42519503	GRET	SVC	12/21/2023	2019	RET ABN	UG-SERVICE
36927894	GRET	SVC	9/14/2020	2019	RET ABN	UG-SERVICE
38808394	GRET	SVC	7/17/2021	2019	RET ABN	UG-SERVICE
36598690	GRET	SVC	7/25/2020	2019	RET ABN	UG-SERVICE
38373952	GRET	SVC	5/3/2021	2019	RET ABN	UG-SERVICE
36740314	GRET	SVC	8/17/2020	2019	RET ABN	UG-SERVICE
36572213	GRET	SVC	6/30/2020	2019	RET ABN	UG-SERVICE
40939061	GRET	SVC	12/6/2022	2019	RET ABN	UG-SERVICE
36837899	GRET	SVC	9/1/2020	2019	RET ABN	UG-SERVICE
38373081	GRET	SVC	4/14/2021	2019	RET ABN	UG-SERVICE
42833098	GRET	SVC	7/22/2024	2019	RET ABN	UG-SERVICE
42166610	GRET	SVC	9/26/2023	2019	RET ABN	UG-SERVICE
43709853	GRET	SVC	10/21/2024	2019	RET ABN	UG-SERVICE
40711628	GRET	SVC	9/18/2022	2019	RET ABN	UG-SERVICE
43318029	GRET	SVC	7/25/2024	2019	RET ABN	UG-SERVICE
39895678	GRET	SVC	3/14/2022	2019	RET ABN	UG-SERVICE
40318183	GRET	SVC	6/22/2022	2019	RET ABN	UG-SERVICE
41401436	GRET	SVC	3/24/2023	2019	RET ABN	UG-SERVICE
36696973	GRET	SVC	7/29/2020	2019	RET ABN	UG-SERVICE
40268707	GRET	SVC	6/7/2022	2019	RET ABN	UG-SERVICE
40607289	GRET	SVC	8/24/2022	2019	RET ABN	UG-SERVICE
41768694	GRET	SVC	6/17/2023	2019	RET ABN	UG-SERVICE
41114388	GRET	SVC	12/28/2022	2019	RET ABN	UG-SERVICE
36833931	GRET	SVC	8/26/2020	2019	RET ABN	UG-SERVICE
36598694	GRET	SVC	7/25/2020	2019	RET ABN	UG-SERVICE
43798465	GRET	SVC	11/9/2024	2019	RET ABN	UG-SERVICE
43345694	GRET	SVC	7/26/2024	2019	RET ABN	UG-SERVICE
41989647	GRET	SVC	8/11/2023	2019	RET ABN	UG-SERVICE
36470400	GRET	SVC	6/22/2020	2019	RET ABN	UG-SERVICE
40020074	GRET	SVC	5/23/2022	2019	RET ABN	UG-SERVICE
43480650	GRET	SVC	10/2/2024	2019	RET ABN	UG-SERVICE
38873032	GRET	SVC	8/1/2021	2019	RET ABN	UG-SERVICE
38242133	GRET	SVC	3/16/2021	2019	RET ABN	UG-SERVICE
36283380	GRET	SVC	6/15/2020	2019	RET ABN	UG-SERVICE
39776976	GRET	SVC	2/11/2022	2019	RET ABN	UG-SERVICE
39350824	GRET	SVC	10/28/2021	2019	RET ABN	UG-SERVICE
38865013	GRET	SVC	8/3/2021	2019	RET ABN	UG-SERVICE
42150648	GRET	SVC	9/25/2023	2019	RET ABN	UG-SERVICE
40018465	GRET	SVC	4/16/2022	2019	RET ABN	UG-SERVICE
42184977	GRET	SVC	10/5/2023	2019	RET ABN	UG-SERVICE
42164208	GRET	SVC	11/30/2023	2019	RET ABN	UG-SERVICE
39821358	GRET	SVC	2/21/2022	2019	RET ABN	UG-SERVICE
41649339	GRET	SVC	5/19/2023	2019	RET ABN	UG-SERVICE
38954719	GRET	SVC	8/31/2021	2019	RET ABN	UG-SERVICE
41402227	GRET	SVC	3/15/2023	2019	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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42386950	GRET	SVC	11/14/2023	2019	RET ABN	UG-SERVICE
42837761	GRET	SVC	3/19/2024	2019	RET ABN	UG-SERVICE
43697688	GRET	SVC	10/12/2024	2019	RET ABN	UG-SERVICE
41089225	GRET	SVC	12/22/2022	2019	RET ABN	UG-SERVICE
39020762	GRET	SVC	8/30/2021	2019	RET ABN	UG-SERVICE
38942234	GRET	SVC	8/23/2021	2019	RET ABN	UG-SERVICE
43759459	GRET	SVC	10/29/2024	2019	RET ABN	UG-SERVICE
43481044	GRET	SVC	11/1/2024	2019	RET ABN	UG-SERVICE
41772175	GRET	SVC	6/19/2023	2019	RET ABN	UG-SERVICE
36270003	GRET	SVC	4/29/2020	2019	RET ABN	UG-SERVICE
36627611	GRET	SVC	7/11/2020	2019	RET ABN	UG-SERVICE
40515683	GRET	SVC	8/2/2022	2019	RET ABN	UG-SERVICE
38514348	GRET	SVC	5/24/2021	2019	RET ABN	UG-SERVICE
37944918	GRET	SVC	12/22/2020	2019	RET ABN	UG-SERVICE
41049460	GRET	SVC	2/21/2023	2019	RET ABN	UG-SERVICE
37019195	GRET	SVC	10/6/2020	2019	RET ABN	UG-SERVICE
36734668	GRET	SVC	9/2/2020	2019	RET ABN	UG-SERVICE
39719594	GRET	SVC	1/25/2022	2019	RET ABN	UG-SERVICE
39461568	GRET	SVC	11/22/2021	2019	RET ABN	UG-SERVICE
41286748	GRET	SVC	2/20/2023	2019	RET ABN	UG-SERVICE
39950252	GRET	SVC	3/30/2022	2019	RET ABN	UG-SERVICE
43112291	GRET	SVC	5/26/2024	2020	RET ABN	UG-SERVICE
42392613	GRET	SVC	11/20/2023	2020	RET ABN	UG-SERVICE
42842213	GRET	SVC	3/18/2024	2020	RET ABN	UG-SERVICE
36545679	GRET	SVC	6/30/2020	2020	RET ABN	UG-SERVICE
43281677	GRET	SVC	7/6/2024	2020	RET ABN	UG-SERVICE
40584450	GRET	SVC	8/18/2022	2020	RET ABN	UG-SERVICE
40432776	GRET	SVC	7/13/2022	2020	RET ABN	UG-SERVICE
41389717	GRET	SVC	3/16/2023	2020	RET ABN	UG-SERVICE
41925433	GRET	SVC	7/30/2023	2020	RET ABN	UG-SERVICE
42461810	GRET	SVC	12/9/2023	2020	RET ABN	UG-SERVICE
39671443	GRET	SVC	1/10/2022	2020	RET ABN	UG-SERVICE
40840380	GRET	SVC	10/18/2022	2020	RET ABN	UG-SERVICE
41425425	GRET	SVC	5/1/2023	2020	RET ABN	UG-SERVICE
43496215	GRET	SVC	9/10/2024	2020	RET ABN	UG-SERVICE
38258599	GRET	SVC	3/24/2021	2020	RET ABN	UG-SERVICE
42327735	GRET	SVC	11/3/2023	2020	RET ABN	UG-SERVICE
38461048	GRET	SVC	5/7/2021	2020	RET ABN	UG-SERVICE
43488609	GRET	SVC	9/6/2024	2020	RET ABN	UG-SERVICE
43083117	GRET	SVC	5/22/2024	2020	RET ABN	UG-SERVICE
38852427	GRET	SVC	7/29/2021	2020	RET ABN	UG-SERVICE
43903567	GRET	SVC	12/26/2024	2020	RET ABN	UG-SERVICE
41379500	GRET	SVC	3/14/2023	2020	RET ABN	UG-SERVICE
37809334	GRET	SVC	11/24/2020	2020	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41330551	GRET	SVC	3/1/2023	2020	RET ABN	UG-SERVICE
39506088	GRET	SVC	12/7/2021	2020	RET ABN	UG-SERVICE
41833025	GRET	SVC	7/6/2023	2020	RET ABN	UG-SERVICE
43615938	GRET	SVC	9/23/2024	2020	RET ABN	UG-SERVICE
36191044	GRET	SVC	6/27/2020	2020	RET ABN	UG-SERVICE
41018278	GRET	SVC	12/6/2022	2020	RET ABN	UG-SERVICE
42165550	GRET	SVC	9/22/2023	2020	RET ABN	UG-SERVICE
40247822	GRET	SVC	6/25/2022	2020	RET ABN	UG-SERVICE
36809602	GRET	SVC	8/21/2020	2020	RET ABN	UG-SERVICE
41399247	GRET	SVC	3/17/2023	2020	RET ABN	UG-SERVICE
42164914	GRET	SVC	9/26/2023	2020	RET ABN	UG-SERVICE
42274276	GRET	SVC	10/20/2023	2020	RET ABN	UG-SERVICE
38153367	GRET	SVC	2/23/2021	2020	RET ABN	UG-SERVICE
40699906	GRET	SVC	9/14/2022	2020	RET ABN	UG-SERVICE
43952089	GRET	SVC	12/17/2024	2020	RET ABN	UG-SERVICE
40837918	GRET	SVC	10/15/2022	2020	RET ABN	UG-SERVICE
40177191	GRET	SVC	5/16/2022	2020	RET ABN	UG-SERVICE
43713255	GRET	SVC	10/15/2024	2020	RET ABN	UG-SERVICE
42697535	GRET	SVC	2/14/2024	2020	RET ABN	UG-SERVICE
42702437	GRET	SVC	2/15/2024	2020	RET ABN	UG-SERVICE
39607683	GRET	SVC	12/27/2021	2020	RET ABN	UG-SERVICE
40273956	GRET	SVC	6/20/2022	2020	RET ABN	UG-SERVICE
42563288	GRET	SVC	1/10/2024	2020	RET ABN	UG-SERVICE
40633657	GRET	SVC	8/29/2022	2020	RET ABN	UG-SERVICE
41317152	GRET	SVC	3/1/2023	2020	RET ABN	UG-SERVICE
39451541	GRET	SVC	11/22/2021	2020	RET ABN	UG-SERVICE
42137985	GRET	SVC	9/18/2023	2020	RET ABN	UG-SERVICE
39524195	GRET	SVC	12/12/2021	2020	RET ABN	UG-SERVICE
40563520	GRET	SVC	8/15/2022	2020	RET ABN	UG-SERVICE
42816657	GRET	SVC	3/13/2024	2020	RET ABN	UG-SERVICE
42581343	GRET	SVC	1/18/2024	2020	RET ABN	UG-SERVICE
40607513	GRET	SVC	8/20/2022	2020	RET ABN	UG-SERVICE
41401967	GRET	SVC	3/9/2023	2020	RET ABN	UG-SERVICE
43178294	GRET	SVC	6/11/2024	2020	RET ABN	UG-SERVICE
43594940	GRET	SVC	9/16/2024	2020	RET ABN	UG-SERVICE
43710737	GRET	SVC	10/17/2024	2020	RET ABN	UG-SERVICE
42407128	GRET	SVC	12/18/2023	2020	RET ABN	UG-SERVICE
43087440	GRET	SVC	5/20/2024	2020	RET ABN	UG-SERVICE
42355274	GRET	SVC	11/13/2023	2020	RET ABN	UG-SERVICE
43800060	GRET	SVC	11/9/2024	2020	RET ABN	UG-SERVICE
43100872	GRET	SVC	8/14/2024	2020	RET ABN	UG-SERVICE
42104225	GRET	SVC	9/11/2023	2020	RET ABN	UG-SERVICE
39814000	GRET	SVC	2/28/2022	2020	RET ABN	UG-SERVICE
43709155	GRET	SVC	10/17/2024	2020	RET ABN	UG-SERVICE
40665225	GRET	SVC	9/8/2022	2020	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43516005	GRET	SVC	9/5/2024	2020	RET ABN	UG-SERVICE
43066420	GRET	SVC	5/17/2024	2020	RET ABN	UG-SERVICE
43241292	GRET	SVC	7/29/2024	2020	RET ABN	UG-SERVICE
43826001	GRET	SVC	11/18/2024	2020	RET ABN	UG-SERVICE
43330505	GRET	SVC	7/17/2024	2020	RET ABN	UG-SERVICE
40272425	GRET	SVC	6/8/2022	2020	RET ABN	UG-SERVICE
43139809	GRET	SVC	6/3/2024	2020	RET ABN	UG-SERVICE
41429977	GRET	SVC	9/13/2023	2020	RET ABN	UG-SERVICE
43005903	GRET	SVC	4/30/2024	2020	RET ABN	UG-SERVICE
40926493	GRET	SVC	11/14/2022	2021	RET ABN	UG-SERVICE
40667659	GRET	SVC	9/12/2022	2021	RET ABN	UG-SERVICE
40383925	GRET	SVC	7/5/2022	2021	RET ABN	UG-SERVICE
40250913	GRET	SVC	6/7/2022	2021	RET ABN	UG-SERVICE
39733562	GRET	SVC	1/27/2022	2021	RET ABN	UG-SERVICE
43903134	GRET	SVC	12/2/2024	2021	RET ABN	UG-SERVICE
42379188	GRET	SVC	11/15/2023	2021	RET ABN	UG-SERVICE
43205162	GRET	SVC	6/12/2024	2021	RET ABN	UG-SERVICE
42856378	GRET	SVC	3/27/2024	2021	RET ABN	UG-SERVICE
40128902	GRET	SVC	5/8/2022	2021	RET ABN	UG-SERVICE
43184786	GRET	SVC	6/12/2024	2021	RET ABN	UG-SERVICE
42594066	GRET	SVC	1/24/2024	2021	RET ABN	UG-SERVICE
40518877	GRET	SVC	8/5/2022	2021	RET ABN	UG-SERVICE
40036551	GRET	SVC	4/20/2022	2021	RET ABN	UG-SERVICE
43676217	GRET	SVC	11/4/2024	2021	RET ABN	UG-SERVICE
42683548	GRET	SVC	2/13/2024	2021	RET ABN	UG-SERVICE
42165919	GRET	SVC	9/19/2023	2021	RET ABN	UG-SERVICE
40978225	GRET	SVC	11/23/2022	2021	RET ABN	UG-SERVICE
43081678	GRET	SVC	5/21/2024	2021	RET ABN	UG-SERVICE
41588398	GRET	SVC	5/1/2023	2021	RET ABN	UG-SERVICE
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39836180	GRET	SVC	3/2/2022	2021	RET ABN	UG-SERVICE
41981422	GRET	SVC	8/16/2023	2021	RET ABN	UG-SERVICE
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41081809	GRET	SVC	12/17/2022	2021	RET ABN	UG-SERVICE
40387113	GRET	SVC	7/6/2022	2021	RET ABN	UG-SERVICE
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43864422	GRET	SVC	11/25/2024	2021	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40359084	GRET	SVC	6/28/2022	2021	RET ABN	UG-SERVICE
42284942	GRET	SVC	10/23/2023	2021	RET ABN	UG-SERVICE
42225311	GRET	SVC	10/11/2023	2021	RET ABN	UG-SERVICE
42051354	GRET	SVC	8/29/2023	2021	RET ABN	UG-SERVICE
43506839	GRET	SVC	10/4/2024	2021	RET ABN	UG-SERVICE
42096879	GRET	SVC	9/13/2023	2021	RET ABN	UG-SERVICE
43877243	GRET	SVC	12/18/2024	2021	RET ABN	UG-SERVICE
41974954	GRET	SVC	9/7/2023	2021	RET ABN	UG-SERVICE
39419348	GRET	SVC	11/4/2021	2021	RET ABN	UG-SERVICE
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42476013	GRET	SVC	12/8/2023	2021	RET ABN	UG-SERVICE
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40589919	GRET	SVC	8/17/2022	2021	RET ABN	UG-SERVICE
41821807	GRET	SVC	7/3/2023	2021	RET ABN	UG-SERVICE
43027221	GRET	SVC	5/17/2024	2021	RET ABN	UG-SERVICE
39837038	GRET	SVC	2/28/2022	2021	RET ABN	UG-SERVICE
41417314	GRET	SVC	3/20/2023	2021	RET ABN	UG-SERVICE
40481487	GRET	SVC	7/25/2022	2021	RET ABN	UG-SERVICE
43736054	GRET	SVC	10/17/2024	2021	RET ABN	UG-SERVICE
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39968191	GRET	SVC	4/6/2022	2021	RET ABN	UG-SERVICE
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39419359	GRET	SVC	11/4/2021	2021	RET ABN	UG-SERVICE
43364870	GRET	SVC	12/4/2024	2021	RET ABN	UG-SERVICE
40099804	GRET	SVC	5/2/2022	2021	RET ABN	UG-SERVICE
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39419355	GRET	SVC	11/4/2021	2021	RET ABN	UG-SERVICE
39940284	GRET	SVC	3/29/2022	2021	RET ABN	UG-SERVICE
43341451	GRET	SVC	7/22/2024	2021	RET ABN	UG-SERVICE
41693187	GRET	SVC	6/1/2023	2021	RET ABN	UG-SERVICE
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40572170	GRET	SVC	8/16/2022	2021	RET ABN	UG-SERVICE
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40727970	GRET	SVC	9/23/2022	2021	RET ABN	UG-SERVICE
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42202874	GRET	SVC	10/10/2023	2022	RET ABN	UG-SERVICE
40659650	GRET	SVC	9/7/2022	2022	RET ABN	UG-SERVICE
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43480984	GRET	SVC	10/13/2024	2022	RET ABN	UG-SERVICE
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40903511	GRET	SVC	11/7/2022	2022	RET ABN	UG-SERVICE
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40812853	GRET	SVC	11/4/2022	2022	RET ABN	UG-SERVICE
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order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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43352875	GRET	SVC	7/12/2024	2024	RET ABN	UG-SERVICE
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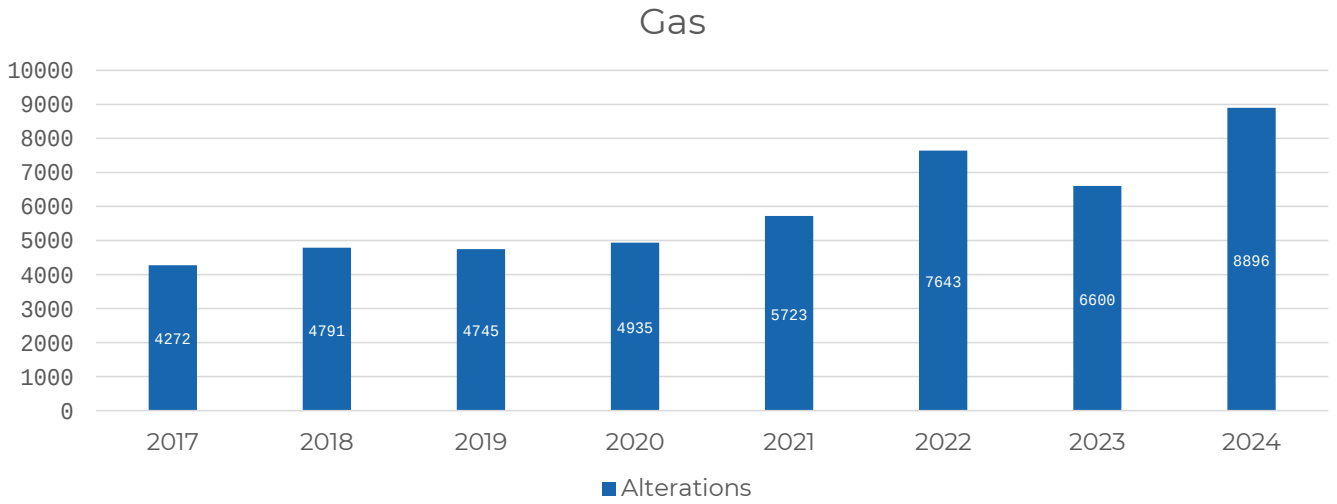
Customer Requested Alterations



2017 to 2024 (8 years) 108% increase in alteration requests

Alterations = Upgrades, Relocates, etc.

Cost of Gas Construction

New Business

2023

Luther Bonner

Customer Energy Management Process, Performance & Technology Lead

Consumers Energy

Count on Us®

Per Foot Rates and Excess Service Costs

2021/2022 Rates

Residential	Service		2" Main		4" Main		6" Main
Gas Only	$ 29.47		$ 17.13		$ 54.01		$ 61.58
Joint	$ 25.60		$ 22.49		$ 68.13		$ 44.66
Directional Bore	Addl $8.80/ft		$ 53.15		$ 104.21		$ 182.17
Non-Residential							
Gas Only	$ 42.90		$ 17.13		$ 54.01		$ 61.58
Joint	$ 25.60		$ 22.49		$ 68.13		$ 44.66
Directional Bore	Addl $8.80/ft		$ 53.15		$ 104.21		$ 182.17

2023 Rates

36% increase **in 2" Plastic** Main

Residential	**Service**		**2" Main**		**4" Main**		**6" Main**
Gas Only	$36.82		$23.36		$79.90		$110.22
Joint	$29.23		$29.46		$100.83		$124.34
Directional Bore	Addl $8.80/ft		$67.31		$105.03		$185.67
Non-Residential							
Gas Only	$47.01		$23.36		$79.90		$110.22
Joint	$29.23		$29.46		$100.83		$124.34
Directional Bore	Addl $8.80/ft		$67.31		$105.03		$185.67

Free Footage Allowances

2021/2022

Residential	Allowable Footage		
Category	Gas Only		Joint
Primary 250	158		227
Primary 425	544		672
Primary 800	1071		1278
Seasonal	0		24
Mobile Home	52		105

- **Seasonal**
  - **No specific data field available to segment seasonal loads**
  - **Consumptions 40mcf annually or lower equate to 10% of Customer Base, removal does not change average**
- **Mobile**
  - **No specific data field available to segment mobile loads**
  - **Modular homes are less efficient then stick built, makes sense to offer and include within the overall average**
- **425 & 800**
  - **Consumptions 400 and greater annually equate to .001% of Customer Base, removal does not change average**
  - **13% of the 10,500 new meters installed in 2021 were 425/800. 10,500/1,300,000 = .008% - .001% = .007%/.008% = 12.5% of the 13% consume the annual MCF allotted, 87.5% of 425/800 meters installed in 2021 fall within the average of 97 annually**
- **Apartments (Apt)**
  - **Including Apts changes average from 97 to 93, 10% of customer base, already use the same service line limits**

2023

Category	Allowable Footage		
	Gas Only		Joint
Residential	92		138

Residential Annual MCF Revenue

Average Installation Count				
	2020	2021	2022	3 Year
No	1,325,721	1,330,227	1,325,163	1,327,037
Yes	136,706	136,417	131,448	134,857

Average Consumption by Heating Season (Oct-May)				
	APT	Consumption	Premise Count	Ave Consumption
2020/21	NO	113,348,851.50	1,327,974	85
2020/21	YES	6,356,449.70	136,562	47
2021/22	NO	121,234,436.20	1,327,695	91
2021/22	YES	6,773,597.70	133,932	51

Average Consumption Non-Heating Season (Jun-Sep)				
	APT	Consumption	Premise Count	Ave Consumption
2021	NO	11,704,567.30	1,330,227	9
2021	YES	581,704.20	136,417	4
2022	NO	10,979,509.60	1,325,163	8
2022	YES	530,665.20	131,448	4

Average Consumption Previous Full Seasons (Jul-Jun)				
	APT	Consumption	Premise Count	Ave Consumption
2020/21	NO	125,236,446.30	1,327,974	94
2020/21	YES	6,951,819.50	136,562	51
2021/22	NO	132,371,784.00	1,327,695	100
2021/22	YES	7,321,306.40	133,932	55
2 Year	NO	128,804,115.15	1,327,037	97
2 Year	YES	7,136,562.95	134,857	53

Prior Years

Class	Description	Meter	MCF
250	Permanent Structure	250	150
Apt	Apartments, Condos	250	85
Mobile	Modular Homes	250	84
Season	250/Mobile used Seasonally	250	40
425	Permanent Structure	425	400
800	Permanent Structure	800	750

New 2yr Average – Decrease of 65%

Class	Description	Meter	MCF
Res	Permanent Structures, Modular, Seasonal	Any	97
Apt	Apartments, Condos (Multi Unit Buildings)	Any	53

Customer Impacts

- **38% of NBS Customers & 27% of NJS Customers with longer service requirements will see higher costs due to excess service charges per ft after the service line limit**

- **Average residential customer will see $736.40 increase based on average service length**
  - **62% of NBS customers within the past 3 years would have had no impact**
  - **73% of NJS customer within the past 3 years would have had no impact**

- **20 lot Subdivision scenario –**
  - **$86,196.39 increase using the service line limit 92'**
  - **$88,783.94 increase using the average service length of 112'**
  - **$78,174.94 Typical Subdivisions have an average of 30' services for subdivisions**

- **Developments with larger lots & longer service requirements will see increase in upfront costs**
- **Customers requiring larger meters will only see increase in costs if service length exceeds limit**
- **Company is truing up recovery of costs of service based on current consumption data (2-year average) and current construction costs (3-year average)**

Customer Impacts Development Scenario

2021/2022 Rates

- **5000’ Normal trench 2” plastic**
- **20 lot development – NEW service limit 92’**
- **Original MCF – 150 annually**
- **Costs**

Year 1 Construction Costs	
Main	$85,650.00
Service	$22,258.85
Meter	$1,129.50
Direct Charge	$0.00
Permit Costs	$0.00
Total	**$109,038.35**
Customer Costs	
Main	$85,650.00
Service	$89,035.40
Meter	$4,518.00
Conn Fee	$0.00
Direct Charge	$0.00
Permit Costs	$0.00
Rev Cred/Op Exp	($117,089.12)
Total	**$62,114.28**

2023 Rates

- **5000’ Normal trench 2” plastic**
- **20 lot development – NEW service limit 92’**
- **NEW MCF – 97 annually**
- **Costs**

Year 1 Construction Costs	
Main	$116,600.00
Service	$24,802.30
Meter	$1,129.50
Direct Charge	$0.00
Permit Costs	$0.00
Total	**$142,731.80**
Customer Costs	
Main	$116,800.00
Service	$99,209.20
Meter	$4,518.00
Conn Fee	$0.00
Direct Charge	$0.00
Permit Costs	$0.00
Rev Cred/Op Exp	($72,216.53)
Total	**$148,310.67**

Gem Billables Summary

Year 1 Main Cost	Year 1 Service Cost	Year 1 Meter Cost	Year 1 Direct Cost
116800.00	24802.30	1129.50	0.00
Total Main Cost	**Total Service Cost**	**Total Meter Cost**	**Total Additional Cost**
116800.00	99209.20	4517.99	0.00
Net Present Value Cost	**Net Present Value Revenue**	**Net Present Value Difference**	
237211.91	100624.85	136587.06	
Net Present Value Gross Up			
148310.66			
Total Customer Cost	**Status**		
148310.66	Billed		

Customer Impacts Development Scenario

2021/2022 Rates

- **5000’ Normal trench 2” plastic**
- **20 lot development – service limit 112’**
- **Original MCF – 150 annually**
- **Costs**

Year 1 Construction Costs	
Main	$85,650.00
Service	$24,568.85
Meter	$1,129.50
Direct Charge	$0.00
Permit Costs	$0.00
Total	**$111,348.35**
Customer Costs	
Main	$85,650.00
Service	$98,275.40
Meter	$4,518.00
Conn Fee	$0.00
Direct Charge	$0.00
Permit Costs	$0.00
Rev Cred/Op Exp	($116,400.10)
Total	**$72,043.30**

2023 Rates

- **5000’ Normal trench 2” plastic**
- **20 lot development – NEW service limit 112’**
- **NEW MCF – 97 annually**
- **Costs**

Year 1 Construction Costs	
Main	$116,800.00
Service	$27,714.30
Meter	$1,129.50
Direct Charge	$0.00
Permit Costs	$0.00
Total	**$145,643.80**
Customer Costs	
Main	$116,800.00
Service	$110,857.20
Meter	$4,518.00
Conn Fee	$0.00
Direct Charge	$0.00
Permit Costs	$0.00
Rev Cred/Op Exp	($71,347.96)
Total	**$160,827.24**

Gem Billables Summary

Year 1 Main Cost	Year 1 Service Cost	Year 1 Meter Cost	Year 1 Direct Cost
116800.00	27714.30	1129.50	0.00
Total Main Cost	**Total Service Cost**	**Total Meter Cost**	**Total Additional Cost**
116800.00	110857.20	4517.99	0.00
Net Present Value Cost	**Net Present Value Revenue**	**Net Present Value Difference**	
248739.09	100624.05	148114.23	
Net Present Value Gross Up			
160827.24			
Total Customer Cost	**Status**		
160827.24	Billed		

Customer Impacts Development Scenario

2021/2022 Rates

- **5000’ Normal trench 2” plastic**
- **20 lot development – service limit 30’**
- **Original MCF – 150 annually**
- **Costs**

Year 1 Construction Costs	
Main	$85,650.00
Service	$15,097.85
Meter	$1,129.50
Direct Charge	$0.00
Permit Costs	$0.00
Total	**$101,877.35**
Customer Costs	
Main	$85,650.00
Service	$60,391.40
Meter	$4,518.00
Conn Fee	$0.00
Direct Charge	$0.00
Permit Costs	$0.00
Rev Cred/Op Exp	($119,225.07)
Total	**$31,334.33**

2023 Rates

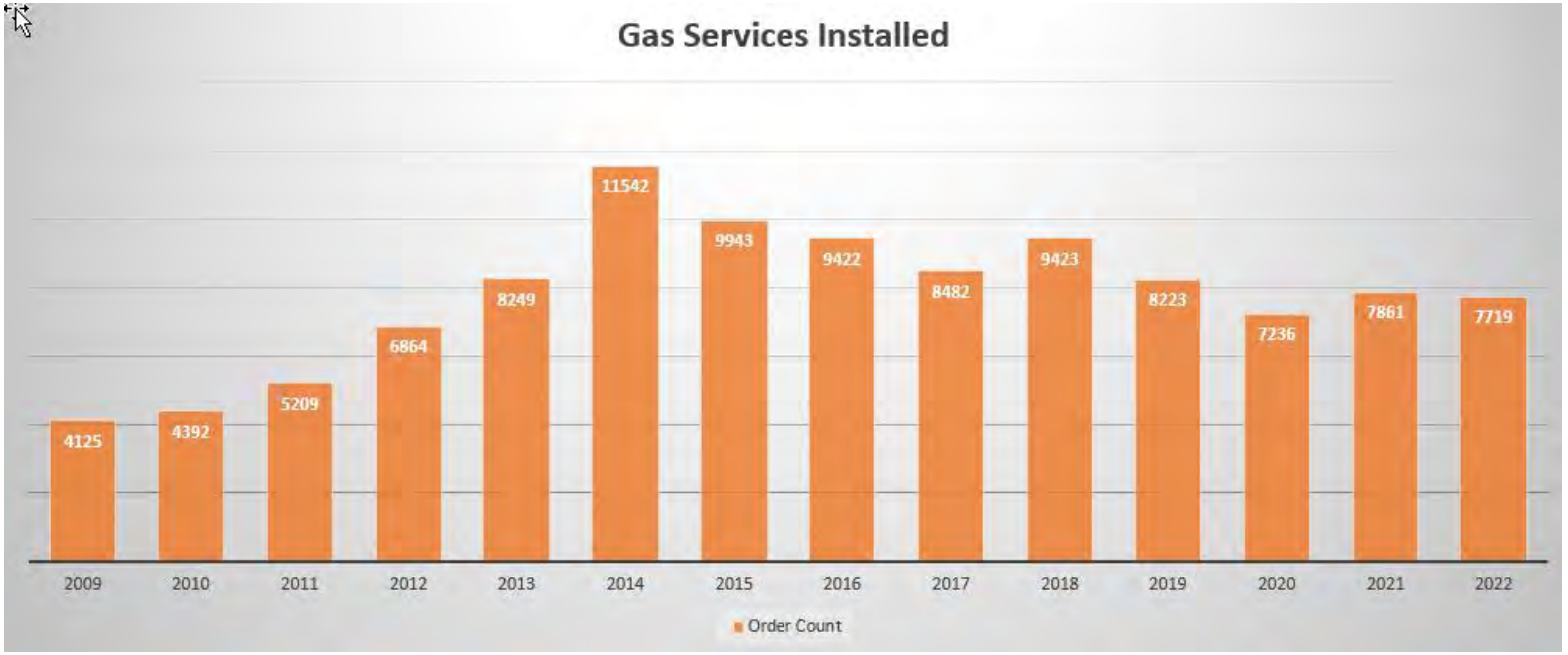
- **5000’ Normal trench 2” plastic**
- **20 lot development – NEW service limit 30’**
- **NEW MCF – 97 annually**
- **Costs**

Year 1 Construction Costs	
Main	$116,800.00
Service	$15,775.10
Meter	$1,129.50
Direct Charge	$0.00
Permit Costs	$0.00
Total	**$133,704.60**
Customer Costs	
Main	$116,800.00
Service	$63,100.40
Meter	$4,518.00
Conn Fee	$0.00
Direct Charge	$0.00
Permit Costs	$0.00
Rev Cred/Op Exp	($74,909.13)
Total	**$109,509.27**

Gem Billables Summary

Year 1 Main Cost	Year 1 Service Cost	Year 1 Meter Cost	Year 1 Direct Cost
116800.00	15775.10	1129.50	0.00
Total Main Cost	Total Service Cost	Total Meter Cost	Total Additional Cost
116800.00	65180.39	4517.99	0.00
Net Present Value Cost	Net Present Value Revenue	Net Present Value Difference	
201477.67	100624.85	100852.82	
Net Present Value Gross Up			
109509.27			
Total Customer Cost	Status		
109509.27	Billed		

New Business Gas Connections



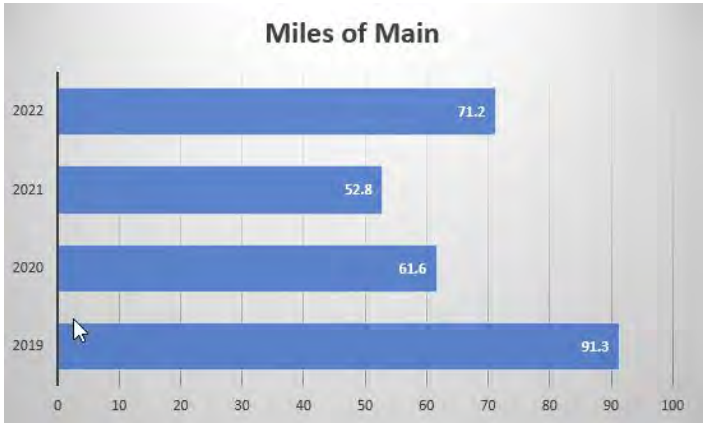
2023 New Business Review

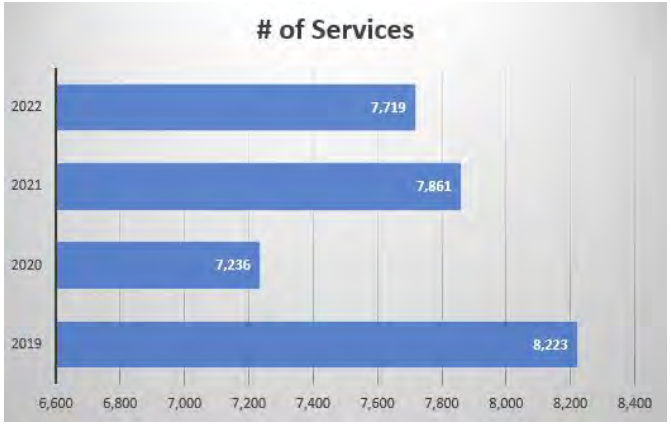
Gas Main Installation

- 2022 = 71.2 miles
- 2021 = 52.8 miles
- 2020 = 61.6 miles
- 2019 = 91.3 miles

Gas Service Installation

- 2022 = 7,719 services
- 2021 = 7,861 services
- 2020 = 7,236 services
- 2019 = 8,223 services





Questions?

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

REBUTTAL TESTIMONY

OF

ANN E. BULKLEY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Ann E. Bulkley. My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108. I am a Principal at The Brattle Group ("Brattle"), a consulting firm that advises clients on regulatory finance and ratemaking issues.

Q. Are you the same Ann E. Bulkley that previously filed direct testimony in this proceeding?

A. Yes. I previously submitted direct testimony before the Michigan Public Service Commission ("MPSC" or the "Commission") in this proceeding on behalf of Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the issues raised in the testimonies of Kirk D. Megginson on behalf of the Commission Staff ("Staff"),[1] Sebastian Coppola on behalf of the Attorney General,[2] Matthew J. Bandyk on behalf of Citizens Utility Board of Michigan ("CUB"),[3] and Christopher Walters on behalf of the Association of Businesses Advocating Tariff Equity ("ABATE"),[4] regarding the just and reasonable return on equity ("ROE") for the Company in this proceeding. To the extent that I do not address a

[1] Michigan Public Service Commission, Case No. U-21806, Testimony of Kirk D. Megginson, April 23, 2025 ("Megginson Direct").

[2] Michigan Public Service Commission, Case No. U-21806, Testimony of Sebastian Coppola, April 23, 2025 ("Coppola Direct").

[3] Michigan Public Service Commission, Case No. U-21806, Testimony of Matthew J. Bandyk, April 23, 2025 ("Bandyk Direct").

[4] Michigan Public Service Commission, Case No. U-21806, Testimony of Christopher W. Walters, April 23, 2025 ("Walters Direct").

particular issue raised by these witnesses in my rebuttal testimony should not be viewed as acceptance of that issue.

Q. Are you sponsoring any exhibits in support of your rebuttal testimony?

A. I am sponsoring the following exhibits:

Exhibit A-127 (AEB-2) Cost of Common Shareholder's Equity; and

Exhibit A-128 (AEB-3) Jurisdictions Using ECAPM.

Q. Was this exhibit prepared by you or under your supervision?

A. Yes.

Q. Have you updated the cost of equity analyses that you presented in your direct testimony to reflect current market conditions?

A. Yes. As discussed in more detail herein, I have updated my cost of equity analyses based on market data through April 30, 2025. These results provide continual support for my recommended ROE range of 10.25% to 11.25% and the Company's requested ROE of 10.25%. While the analytical results of the cost of equity estimation models provide a starting point, I continue to base my recommendation on consideration of not only the results of multiple cost of equity models, but also other factors, including capital market conditions, the capital attraction and comparable return standards, and Company-specific risks.

Q. How is the remainder of your rebuttal testimony organized?

A. The remainder of my rebuttal testimony is organized as follows:

- Section II provides a summary and overview of my rebuttal testimony and the important factors to be considered in establishing the authorized ROE for the Company.

- Section III provides cost of equity analyses based on market data as of April 25, 2025.

- Section IV discusses the changes in capital market conditions since my direct testimony and their effect on the cost of equity and authorized ROEs for comparable utilities nationwide relative to the witnesses' ROE recommendations in this proceeding.

- Section V provides my response to the issues raised by the parties regarding the proxy group.

- Section VI provides my response to the issues raised by the parties regarding the Discounted Cash Flow ("DCF") model.

- Section VII provides my response to the issues raised by the parties regarding the Capital Asset Pricing Model ("CAPM") analysis.

- Section VIII provides my response to the issues raised by the parties regarding the Empirical CAPM ("ECAPM") analysis.

- Section IX provides my response to the issues raised by the parties regarding the Bond Yield Plus Risk Premium analysis.

- Section X provides the adjusted results of the cost of equity analyses of Mr. Megginson, Mr. Coppola, Mr. Bandyk, and Mr. Walters based on the issues that I have identified with their respective analyses.

- Section XI provides my response to the issues raised by the parties regarding the Company's business risks.

II. SUMMARY OF ANALYSES AND CONCLUSIONS

Q. What factors should be considered in evaluating the results of the cost of equity analyses and establishing the authorized ROE?

A. The primary factors that should be considered are: (1) the importance of providing a return that is comparable to returns on alternative investments with commensurate risk; (2) the need for a return that supports a utility's ability to attract needed capital at reasonable terms; (3) the effect of current and expected capital market conditions; and (4) achieving a reasonable balance between the interests of investors and customers.

Q. Please summarize the ROE recommendations of the parties in this proceeding.

A. Figure 1 below summarizes the results of the cost of equity analyses presented by Mr. Megginson, Mr. Coppola, Mr. Bandyk, and Mr. Walters in this proceeding and each of their final ROE recommendations. As shown, the ROE recommendations of Mr. Megginson and Mr. Coppola are 9.75%, Mr. Bandyk recommends 9.24%, and Mr. Walters recommends 9.45%. Despite a significant increase in interest rates since the Company's last rate proceeding suggesting a higher overall cost of capital, all intervening witnesses recommend an ROE for the Company lower than the Company's currently authorized ROE of 9.90 percent. None of their recommendations are reasonable or appropriate based on changes in the cost of equity as reflected in current market conditions and the Company's overall risk profile.

Figure 1: Summary of Cost of Equity Analyses Results and ROE Recommendations of Mr. Megginson, Mr. Coppola, Mr. Bandyk, and Mr. Walters

Methods	Megginson	Coppola	Bandyk	Walters
DCF				
Constant DCF	9.40%	9.11%	-	8.38-8.70% and 10.74%-13.54%[5]
Two-Stage DCF	-	-	9.22%	-
Multi-Stage DCF	-	-	-	8.47%-9.26%
CAPM	8.25%-9.93%	10.66%	7.95%	8.72%-10.74%
Risk Premium	9.46%-9.72%	9.20%	-	9.73%-10.23%
Current Authorized ROE	-	-	9.90%	-
Recommended ROE Range	9.25%-10.25%	-	-	9.00%-9.90%
Recommended ROE	**9.75%**	**9.75%**	**9.24%**	**9.45%**

[5] Mr. Walters's results of 8.37% - 8.70% use a "sustainable growth" rate, and the results of 10.74% – 13.54% use analyst earnings growth projections.

Q. What are your key conclusions and recommendations regarding the appropriate ROE for the Company?

A. Nothing in the direct testimonies of Mr. Megginson, Mr. Coppola, Mr. Bandyk, or Mr. Walters has caused me to change my conclusions or recommendations. My key conclusions regarding a reasonable ROE for the Company in this proceeding are as follows:

Cost of Equity

- Updated cost of equity analyses based on data through April 25, 2025 continue to support the reasonableness of the Company's proposed ROE of 10.25%.
- Changes in market conditions and heightened uncertainty in the macro environment support a higher ROE than the Company's last proceeding, and Mr. Megginson, Mr. Coppola, Mr. Bandyk, and Mr. Walters do not adequately consider current capital market conditions.
- Mr. Bandyk recommends an ROE that is more than a *65-basis point decrease* relative to the Company's currently authorized ROE, which is primarily a function of his CAPM estimate that is substantially below any authorized ROE for a natural gas or electric utility since at least 1980.
- When reasonable adjustments are reflected to the cost of equity analyses prepared by Mr. Megginson, Mr. Coppola, Mr. Bandyk, and Mr. Walters to update and correct their analyses, it demonstrates that the Company's proposed ROE is reasonable.
    - The adjusted results of Mr. Megginson's, Mr. Coppola's, Mr. Bandyk's and Mr. Walters's analyses indicate a cost of equity in the range of 10.50% to 10.70%, which is higher than the Company's proposed ROE of 10.25%.
- There is no basis to Mr. Bandyk's claim that regulators have incorrectly authorized ROEs substantially higher than the cost of equity for decades.
- No intervening witness has independently evaluated the comparative risk of the Company relative to their respective proxy groups. Therefore, there is no basis to conclude that the risk factors that I evaluated in my direct testimony should not be considered.

III. COST OF EQUITY ANALYSES

Q. Have you prepared cost of equity analyses to support your rebuttal testimony?

A. Yes. I updated the results of the cost of equity analyses conducted in my direct testimony based on market data through April 25, 2025, to rebut the outdated cost of equity analyses provided by Mr. Megginson, Mr. Coppola, Mr. Bandyk, and Mr. Walters. To develop my updated cost of equity analyses, I relied on the same methodologies used in my direct testimony except for one modification. In my direct testimony, I relied on projected earnings per share ("EPS") growth rates provided by *Yahoo! Finance* as one of the estimates of long-term growth in my constant growth DCF model; however, *Yahoo! Finance* no longer reports consensus projected three to five-year EPS growth rates. As a result, in my rebuttal testimony, I am now instead relying on the consensus projected three to five-year EPS growth rates reported by *S&P Capital IQ Pro* in my constant growth DCF model.

Q. What are the updated results of your cost of equity analyses?

A. Figure 2 summarizes the results of my updated analyses, which are also presented in Exhibit A-127 (AEB-2), pages 1 through 42.

Figure 2: Cost of Equity Model Results

Constant Growth DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.99%	10.86%	11.68%
90-Day Avg. Stock Price	10.09%	10.97%	11.78%
180-Day Avg. Stock Price	10.17%	11.05%	11.86%
Average	10.08%	10.96%	11.77%
Median Results:			
30-Day Avg. Stock Price	9.78%	10.91%	12.14%
90-Day Avg. Stock Price	9.92%	11.06%	12.28%
180-Day Avg. Stock Price	10.10%	11.24%	12.47%
Average	9.93%	11.07%	12.30%

CAPM / ECAPM / Bond Yield Risk Premium

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.25%	11.23%	11.22%
Current Bloomberg Beta	10.11%	10.05%	10.02%
Long-term Avg. *Value Line* Beta	10.23%	10.18%	10.14%
ECAPM:			
Current *Value Line* Beta	11.42%	11.40%	11.39%
Current Bloomberg Beta	10.56%	10.52%	10.49%
Long-term Avg. *Value Line* Beta	10.65%	10.61%	10.59%
Bond Yield Risk Premium	10.55%	10.41%	10.33%

Q. Do the updated results support the Company's requested ROE of 10.25% in this proceeding?

A. Yes. The results of each of the DCF analyses have increased since the filing of my direct testimony, while the results of my CAPM and ECAPM analyses are generally consistent

with those filed in my direct testimony (i.e. the results of some scenarios have slightly increased while others have slightly decreased). The results of the Bond Yield Risk Premium have generally increased modestly since the filing of my direct testimony. Therefore, as shown, the results of the cost of equity analyses continue to support my direct testimony and exhibits and the Company's proposed ROE of 10.25% in this proceeding.

IV. CAPITAL MARKET CONDITIONS AND A COMPARABLE RETURN

Q. Do any parties analyze capital market conditions and its impact on the Company's ROE?

A. Only Mr. Walters addresses capital market conditions in the context of setting an ROE,[6] while Mr. Coppola discusses interest rates in the context of mortgages, housing starts, and service connections.[7] Mr. Megginson and Mr. Bandyk do not discuss capital markets in any context.

Q. What do Mr. Walters and Mr. Coppola say about capital market conditions?

A. Mr. Walters believes that "economic activity is expanding solidly, with solid labor market conditions though inflation remains somewhat elevated," and cites a Federal Reserve Board statement from March 19, 2025 in support of this view.[8] Mr. Walters observes that there have been more credit downgrades than upgrades to utilities due to higher capital expenditures, wildfire risk, and uneven regulatory outcomes,[9] and he further observes that utility stocks have outperformed the broader market since the second half of 2021 due to a

[6] Walters Direct, at 11-21.
[7] Coppola Direct, at 20.
[8] Walters Direct, at 13.
[9] *Id*., at 17.

macro environment with "elevated inflation, rising interest rates, and uncertainty because of geopolitical events around the world."[10]

Mr. Coppola acknowledges that "persistently high inflation rates and other economic factors have prevented the Federal Reserve Bank from lowering interest rates with no clear expectation currently of further declines in 2025."[11] To account for "uncertainty of the timing in the decline in interest rates," Mr. Coppola arbitrarily adds 23 basis points to his cost of capital results of 9.52% to reach his recommended 9.75%.[12]

Q. Do changes in capital market conditions since the Company's last rate proceeding continue to indicate an increase in the cost of equity?

A. Yes. Changes in long-term bond yields since the Company's last rate proceeding, as well as since the filing of the Company's direct testimony in this proceeding, demonstrate an increase in the cost of capital. Specifically, as shown in Figure 3, although the federal funds rate has declined since the filing of the Company's direct testimony in this proceeding, long-term interest rates have increased 20 basis points over this period, which is indicative of an increase in the cost of equity. Core inflation has declined since the last rate proceeding and the filing of the direct testimony; although, it remains above the Federal Reserve's long-term target of 2.00%. The VIX, which is a measure of volatility, has increased significantly since both the Company's previous rate case and the Company's direct testimony in this proceeding, indicating heightened uncertainty in capital markets.

[10] *Id.*, at 20-21.
[11] Coppola Direct, at 20.
[12] *Id.*, at 153.

Figure 3: Change in Market Conditions Since Consumers Energy's Last Rate Proceeding[13]

Docket	Date	Federal Funds Rate	30-Day Avg 30 Year Treasury Bond Yield	Core Inflation Rate	30-Day Avg VIX Index
Previous Case: U-21490	7/23/2024	5.33%	4.44%	3.23%	13.04
Current Case: U-21806					
Direct	12/16/2024	4.58%	4.50%	3.21%	14.77
Rebuttal	4/30/2025	4.33%	4.70%	2.81%	28.20
Increase / (Decrease):					
Previous Case to Direct		-0.75%	0.05%	-0.01%	1.74
Previous Case to Rebuttal		-1.00%	0.26%	-0.42%	15.16

Q. Do you agree with Mr. Coppola's assessment of his recommended ROE in the context of current and projected interest rates?

A. Although I appreciate that Mr. Coppola attempts to consider the uncertainty in the direction of interest rate policy, his recommended ROE, which includes an arbitrary adjustment to his model results of 23 basis points is inadequate.[14] Current market conditions demonstrate that there is no basis for a reduction in the Company's currently authorized ROE of 9.90%, and further demonstrate that there has been an increase in interest rates and uncertainty that suggests that the investor-required return has increased since the Company's last rate proceeding.

Q. Do you agree with Mr. Walters's assessment of capital market conditions and its impact on the ROE?

A. No. While I agree with Mr. Walters's summary of macroeconomic conditions, I disagree with his contention that utilities have been performing well since the second half of 2021.[15]

[13] St. Louis Federal Reserve Bank; Bureau of Labor Statistics; Bloomberg Professional.

[14] Coppola Direct, at 153.

[15] Walters Direct, at 20-22.

In addition, Mr. Walters fails to sufficiently discuss the heightened uncertainty in the economy that has an impact on capital investments.

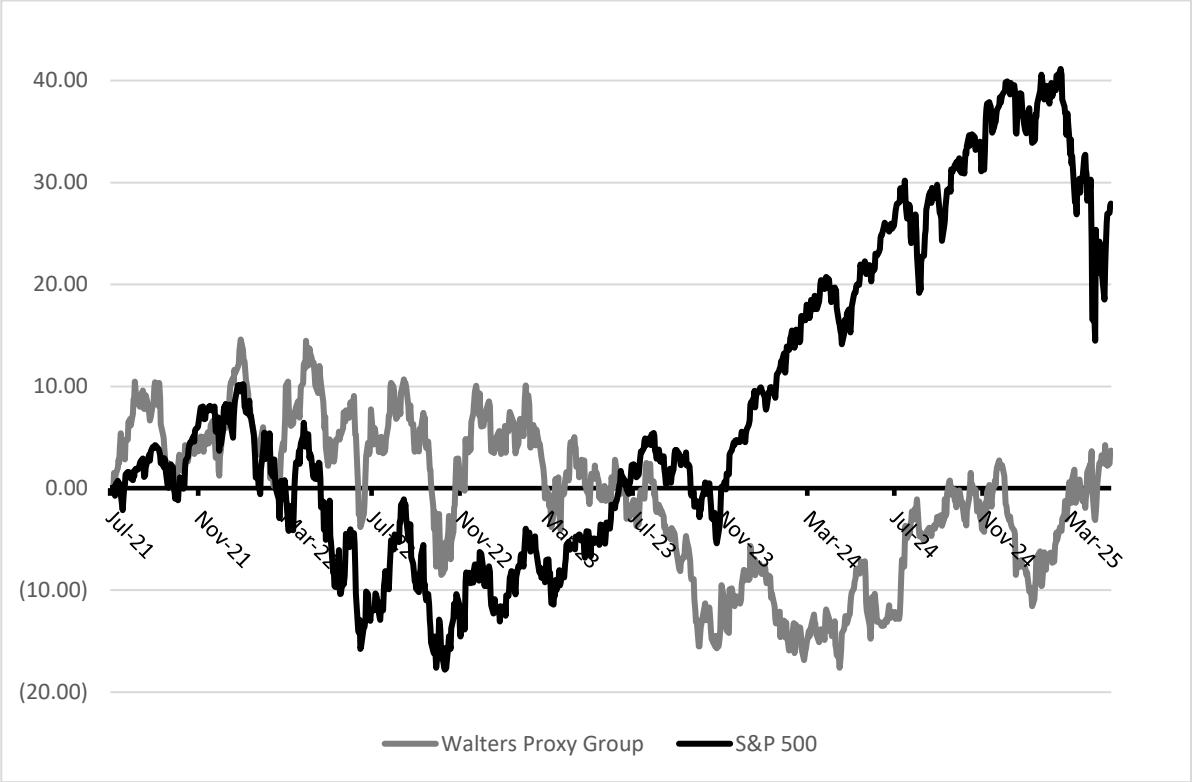
First, Mr. Walters's Figure CCW-4 provides misleading conclusions that the natural gas utility sector has outperformed the broader market in the recent period characterized by "elevated inflation, rising interest rates, and uncertainty because of geopolitical events around the world."[16] Specifically:

- Mr. Walters chooses to begin his analysis in the second half of 2021.
- Mr. Walters's S&P 500 Gas Utilities Sub Ind Index is misleading because there are only two gas utilities in the S&P 500, Atmos and NiSource, which is not representative of the entire natural gas industry.
- Mr. Walters does not show how water companies performed during this time, which is important considering he includes water companies in his proxy group, implying that he believes they have comparable risk profiles to natural gas utilities.

Figure 4 below shows the returns of the S&P 500 and Mr. Walters' proxy group since the second half of 2021, the same starting time-period Mr. Walters selects in his Figure CCW-4.[17] Because Mr. Walters views his proxy group as comparable to Consumers Energy, an index consisting of his proxy group companies is the appropriate benchmark to compare to the overall market. As shown in Figure 4, the S&P 500 significantly outperforms his proxy group; therefore, his conclusion that utilities have had "positive and relatively stable returns" is misleading.[18]

[16] *Id.*, at 21.
[17] Capital IQ Market Charts created a market capitalization weighted index.
[18] *Id*.

Figure 4: Mr. Walters' Weighted Proxy Group Return and S&P 500 Index Price Index July 2021 through April 2025[19]



In addition, despite mentioning it in passing, Mr. Walters does not sufficiently discuss uncertainty in macro conditions and its impact on capital markets and the cost of equity. He does not present any data on elevated volatility or market uncertainty. A recent article from *The Wall Street Journal* reports that companies are delaying investments and projects due to heightened uncertainty driven by the recent Trump tariffs.[20] Increased uncertainty means increased risk, which, all else equal, increases the cost of equity.

[19] *S&P Capital IQ*. Proxy group return is market capitalization weighted.

[20] Chip Cutter, "America Inc. Slashes Spending as Tariff Uncertainty Swirls," *The Wall Street Journal*, April 27, 2025.

Q. What are the expectations for inflation and monetary policy over the near-term?

A. At the March 2025 Federal Open Market Committee ("FOMC") meeting, Chairman Powell noted that labor market conditions are "solid" and while inflation has declined it remains above the Federal Reserve's target of 2.00%, as a result, the FOMC decided to maintain the current federal fund rate range of 4.25% to 4.50%.[21]

Regarding the possible path of monetary policy, Chairman Powell continued to reiterate that policy is "not on any preset course"; but he acknowledged increased uncertainly due to the implementation of significant policy changes (i.e. trade, immigration, fiscal policy, and regulation) by the Trump administration.[22] Mr. Walters' citation from the Federal Reserve notes that "[u]ncertainty around the economic outlook has increased."[23] Chairman Powell noted that the FOMC will continue to analyze incoming data to determine the effect of such policy changes and was in a good position to adjust the course of monetary policy if needed.[24] Thus, the FOMC's forecast of the federal funds rate remained unchanged from the December 2024 meeting, forecasting just two rate cuts before the end of 2025.[25]

More recently, during an event at the Economic Club in Chicago, Chairman Powell acknowledged that the recent tariff policy of the Trump Administration has caused volatility and uncertainty in the market, but that policy was currently well positioned and that the Federal Reserve could rely on incoming economic data to gain greater clarity on

[21] Transcript of Chair Powell's Press Conference, March 19, 2025.
[22] *Id.*
[23] Walters Direct, at 13.
[24] *Id.*
[25] Federal Reserve, Summary of Economic Projections, March 19, 2025, at 2.

the economic effects of the tariffs before considering changes to policy.[26] Further, in regard to economic conditions, Chairman Powell reiterated that the labor market was "in solid condition" but he did acknowledge that tariffs would cause temporary inflation that could be more persistent depending on how long it takes the tariffs to fully flow through to prices which the Federal Reserve is monitoring.[27]

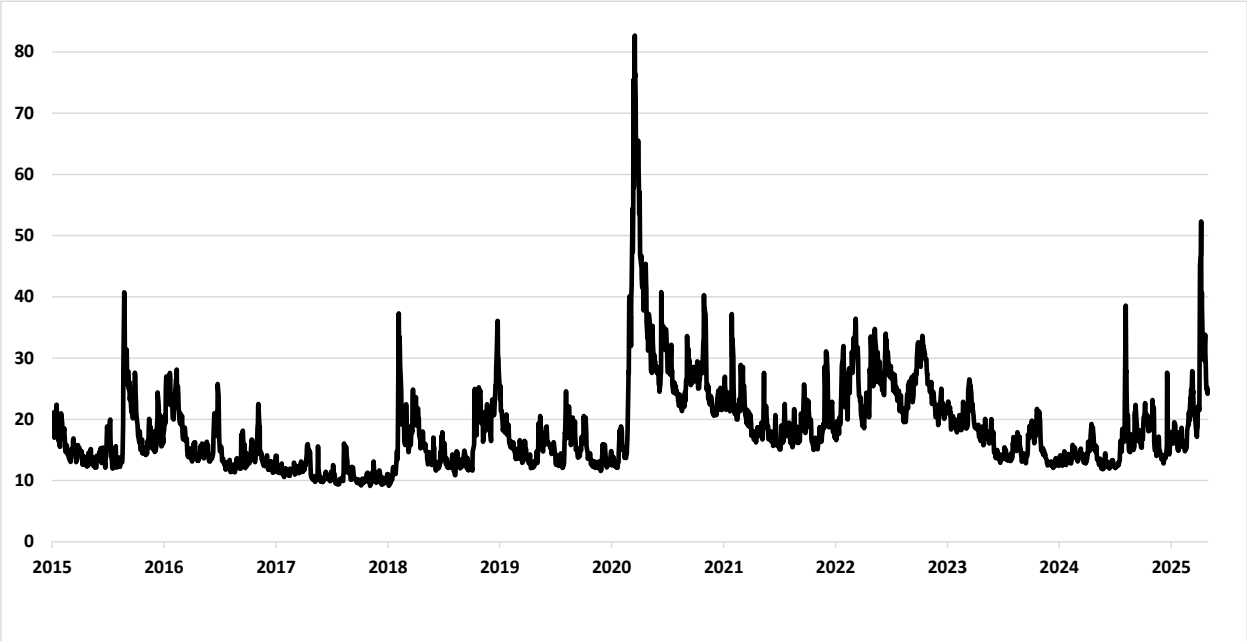
Q. Has the recent tariff policy of the Trump Administration resulted in increased volatility in financial markets?

A. Yes, financial markets have been extremely volatile since President Trump announced a significant set of tariffs on April 2, 2025. For example, as shown in Figure 5, the VIX, which measures investors' expectation of volatility in the S&P 500 over the next 30 days, has remained elevated since April 2, 2025, and peaked at 52.33 on April 8, 2025. The VIX has not reached 50.00 since April 2020 during the height of the COVID-19 pandemic. The high level of uncertainty associated with the economic effects of the Trump Administration's tariff policy has resulted in significant volatility increasing the risk of holding equity investments and implying an increase in the cost of equity.

[26] Howard Schneider and Ann Saphir, "Powell says Fed remains in wait-and-see mode; markets processing policy shifts," *Reuters*, April 16, 2025.

[27] *Id*.

Figure 5: CBOE VIX, January 2015 – April 2025[28]



Q. Have you reviewed any other indicators that show that the Trump Administration's tariff policy has resulted in increased uncertainty?

A. Yes. In addition to the recent high volatility as measured by the VIX, the University of Michigan's consumer sentiment index indicates consumer sentiment is at its second lowest point since 1952 and that inflation expectations are at the highest levels in 44 years.[29] Furthermore, a recent Bank of America Global Fund Manager Survey conducted in April 2025, shows investor sentiment at its 5th lowest point since the study began in 2001.[30]

[28] Bloomberg Professional Services.

[29] Harriet Torry, "'From anxious to petrified': Consumer sentiment plunges further," *Wall Street Journal*, April 11, 2025.

[30] Michael Hartnett, *et al*., "Global Fund Manager Survey: The Bear Necessities," *BoA Global Research*, April 15, 2025.

Q. What are investors' expectations for the yields on long-term government bonds given the sustained elevated levels of inflation and the Federal Reserve's restrictive monetary policy?

A. Economists and analysts are expecting elevated rates. *Blue Chip Financial Forecasts* provides a forecast from economists on the 30-year Treasury bond. In the most recently published *Blue Chip Financial Forecasts* report, economists projected the 30-year Treasury bond yield to remain relatively stable and decrease only slightly from 4.60% in Q2/2025 to 4.40% in Q2/2026.[31] Additionally, the most consensus estimate over the longer-term (i.e. 2026-2030) is 4.30%.[32] This is important because it means that long-term interest rates are expected to remain elevated during the period that the Company's rates will be in effect.

Q. What are your conclusions regarding current market conditions?

A. Although the federal funds rate and core inflation have decreased since the Company's last rate proceeding, the 30-year Treasury bond yield remains elevated and the VIX has significantly increased as a result of tariffs and the uncertainty related to the current administration's policies. Chairman Powell has indicated that the Federal Reserve is in wait-and-see mode and will rely on incoming data to determine when it is appropriate to adjust the federal funds rate. Furthermore, there are economic indicators that suggest both consumer and investor sentiment is weakening. With elevated expected interest rates, borrowing is more expensive, which in turn raises the cost of capital. As a result, investors demand higher returns on equity, leading to an increase in the cost of equity.

[31] *Blue Chip Financial Forecasts*, Vol. 44, No. 5, May 1, 2025, at 2.
[32] *Blue Chip Financial Forecasts*, Vol. 43, No. 12, November 27, 2024, at 14.

Q. What is Mr. Megginson's view on recently authorized ROEs?

A. Mr. Megginson provides the average authorized ROE for 2022, 2023, and 2024, which recognizes that the authorized ROEs have been increasing, from 9.53% to 9.72%. Mr. Megginson suggests that the three-year average is 9.63%, which he concludes is "well below" Staff's ROE recommendation of 9.75%.[33]

Q. Do you agree with Mr. Megginson's analysis of authorized ROEs?

A. No. As discussed in more detail in the remainder of my testimony, the relationship between the cost of equity and interest rates is important to consider. In averaging data for the three-year period from 2022 through 2024, Mr. Megginson fails to consider the interest rate environment over this time-period. As shown in Figure 4 of my direct testimony, in 2022, the yield on the 10-year Treasury bond was significantly lower than in current market conditions, beginning at 1.50% and increasing over the year, reaching approximately 4.25% by year end. Given the lag associated with the regulatory process, it is reasonable to expect that many of the ROEs that were authorized in 2022 were based on 2021 data or data as of the beginning of 2022; a time-period that does not reflect the current interest rate environment. Including data from 2022 in the average return that he uses to benchmark his proposed ROE in the current interest rate environment, is not an appropriate comparison.

[33] Megginson Direct, at 35.

Q. Have you reviewed more current authorized ROEs data than Mr. Megginson presented?

A. Yes. I reviewed the range of authorized ROEs in 2024 and the averages. While I agree with Mr. Megginson that the average authorized ROE in 2024 for natural gas utilities was 9.71%, the high end of the range was 11.88%.

Q. What is Mr. Bandyk's position regarding previously authorized ROEs?

A. Mr. Bandyk claims that the Commission, as well as all other regulatory commissions across the United States, have incorrectly authorized ROEs for decades. Mr. Bandyk cites three sources to support his claim. Specifically, Mr. Bandyk contends that regulated utilities have "been awarded ROEs above market return," and that "regulatory commissions have tended to accept estimates for ROE that are above fair, market-based ROE estimates."[34] Based on this assumption, Mr. Bandyk suggests that previously authorized ROEs should not be considered for purposes of establishing the ROE for the Company in this proceeding. Furthermore, Mr. Bandyk claims that the Commission's goal is to help maintain a utility's "financial integrity":

> But a return sufficient to maintain "financial integrity" only implies that the utility be able to attract capital – not that it can attract capital on the terms that it currently does. A utility can still attract capital with a lower ROE. For example, if a lower ROE causes the stock price to drop, that lower price will attract new investors.[35]

[34] Bandyk Direct, at 7.

[35] *Id*., at 8.

Q. Is Mr. Bandyk's position consistent with Mr. Megginson's, Mr. Coppola's, or Mr. Walters' testimony?

A. No, Mr. Bandyk is alone in his position. Mr. Megginson specifically considers previously authorized ROEs for natural gas utilities in developing his recommended ROE in this proceeding, Mr. Coppola also references previously authorized ROEs as support for his recommended ROE, and Mr. Walters analyzes trends in authorized ROEs when reviewing capital markets and his Risk Premium analysis. [36]

Q. Based on his position that regulators have consistently incorrectly authorized ROEs in the past, what is Mr. Bandyk's ROE recommendation for the Company?

A. Mr. Bandyk states that the average of his cost of equity model results suggests a market-based cost of equity for Consumers Energy that is lower than his recommended ROE of 9.24%. However, Mr. Bandyk acknowledges that there is uncertainty in any financial model and there is a need "not to create unnecessary instability in the company's market value, which is based to a great degree on the outcomes of regulatory proceedings like this one."[37] Therefore, Mr. Bandyk states that his ROE recommendation represents "gradualism" in moving from the Company's currently authorized ROE to his recommended ROE, despite his claim that his recommendation is higher than the market-based cost of equity for Consumers Energy.[38]

[36] Megginson Direct, at 35-36; Coppola Direct, at 146-147; Walters Direct, at 4-5, and 44.
[37] Bandyk Direct, at 12.
[38] *Id*.

Q. Does Mr. Bandyk indicate the point or range to which he believes the Company's ROE should transition to over time?

A. No. Mr. Bandyk has not defined where he believes the ultimate end point is of his proposed "gradualism."

Q. Do you agree with Mr. Bandyk's position?

A. No. Mr. Bandyk and I have a fundamental disagreement regarding his claim that regulators have incorrectly authorized ROEs substantially higher than the cost of equity for decades. I agree with him that: (1) there is a distinction between the cost of equity and the ROE authorized by regulatory commissions in setting just and reasonable rates; (2) the cost of equity cannot be definitively determined and therefore must be estimated by analysts; and (3) there is significant disagreement as to the way in which to estimate the cost of equity. However, he has provided no evidence that supports his position that regulatory commissions, including this Commission, have consistently erred for decades in establishing utilities' ROEs.

Q. Why is this disagreement with Mr. Bandyk so fundamental?

A. Regulatory commissions have an obligation to establish rates that balance the interests of customers and shareholders and that are just and reasonable. There is no evidence that Mr. Bandyk's estimate of the cost of equity, which includes the results of his CAPM analysis that is substantially lower than any ROE that has been authorized by a regulatory commission in the past, is in fact reasonable and that regulatory commissions have been consistently approving unjust and unreasonable rates.

Q. As a threshold matter, are you aware of any other regulatory jurisdiction in the United States that has adopted Mr. Bandyk's views?

A. No. I am not aware of any regulatory commission in the United States – state or Federal – that has adopted Mr. Bandyk's position.

Q. Are you aware of any regulatory commissions that have specifically disagreed with Mr. Bandyk's notion that there is and has been a substantial difference between authorized ROEs and the cost of equity for utilities?

A. Yes. For example, when the same argument was made by the Minnesota Department of Commerce, Division of Energy Resources, the Minnesota Public Utilities Commission clearly stated in a recent decision that it did not agree that utility ROEs have exceeded the cost of equity historically:

> The Department's recommended cost of equity of 9.30% is informed by an underlying assumption that the cost of equity and the return on equity are distinct concepts in the sense that utility earnings exceed the cost of equity over time. This understanding, according to the Department, undermines the reliability of earnings' estimates in predicting long-term growth and instead justifies the use of a multi-stage DCF analysis that uses GDP to forecast the long-term cost of equity. ***The Commission does not share this concern***.[39]

Q. Are you aware of examples where capital attraction and willingness to invest have been hampered when a regulatory jurisdiction is perceived as not being credit supportive?

A. Yes. Connecticut and Illinois are two recent examples. In Illinois, market reactions to regulatory decisions in December 2023 for Ameren Illinois Co. and Commonwealth

[39] Minnesota Public Utilities Commission, Docket No. E-015/GR-21-335, Findings of Fact, Conclusions, and Order, February 28, 2023, at 45; emphasis added.

Edison Co. were universally negative and both utilities considered shifting investment to their other utility operating subsidiaries outside of Illinois.

Connecticut, which is viewed by research analysts, equity analysts, and investors as among the least credit supportive jurisdictions in the United States for utilities, is the most recent example of where capital attraction and a willingness to invest have been hampered. For example:

- The two major utility holding companies operating in Connecticut (i.e. Eversource Energy ("Eversource") and Avangrid Inc. ("Avangrid")) have announced their unwillingness to continue discretionary investment in the state until the regulatory environment and cost recovery outcomes change.
- Avangrid's utility operating subsidiaries in Connecticut (i.e. Connecticut Natural Gas Corporation ("CNG") and Southern Connecticut Gas Company ("SCG")) have recently experienced difficulty fully subscribing bond issuances, and while able to do so, the premiums were higher than anticipated.

Specifically, in May 2024, Eversource, which owns Connecticut Light & Power and Aquarion Water in Connecticut, announced on its earnings call that it would be cutting investment by its utilities within the state due to "unreasonable, arbitrary decisions by the regulator," (i.e. the Public Utilities Regulatory Authority ("PURA")), and that the company had "grave concerns" regarding the Connecticut regulatory environment.[40] Eversource executives stated that the company is unwilling to place capital at risk within Connecticut given that the state's regulatory policy discourages investment.[41] Driving the cut in utility investment is Eversource's view that utility regulators have been slow to approve the recovery of $635 million in storm costs incurred from 2018 through 2021, $400 million in

[40] Mark Pazniokas, "Eversource escalates CT fight, saying it will cut investments," CT Mirror, May 2, 2024.

[41] Jared Anderson, "Eversource cutting investment in Connecticut by up to $500 million over 5 years," S&P Capital IQ Pro, May 3, 2024.

uncollected bills from ratepayers, a rate reduction imposed on Aquarion Water in its most recent rate proceeding, and elimination of a program supporting electric vehicles.[42] Consequently, Eversource stated that it is taking a "hard look" at its capital deployment priorities in Connecticut and plans to reduce its capital investment in Connecticut by $500 million over the next five years, which will likely come from reliability areas until "Connecticut's regulatory decisions come back into alignment with law and state policy."[43] Eversource indicated that it will not reduce safety spending, but that it has made significant investments in reliability over the past decade but is unwilling to continue doing so without a secure and predictable cost recovery path.[44] Moreover, since that time, Eversource has entered into an agreement to sell Aquarion Water.[45]

Similarly, Avangrid, which owns United Illuminating, CNG, and SCG in Connecticut, has also announced that its planned $191 million in capital investment in the state hinges on the regulatory decisions associated with the pending rate cases of CNG and SCG, and the resolution of Avangrid's ongoing legal appeal of PURA's August 2023 order whereby United Illuminating's rate request was reduced from $131 million to $23 million, which the utility says will require it to operate at a loss.

In addition, Avangrid has indicated that it experienced difficulties in attracting adequate subscription levels for debt issuances by its Connecticut utilities that closed in

[42] Mark Pazniokas, "Eversource escalates CT fight, saying it will cut investments," CT Mirror, May 2, 2024.

[43] Jared Anderson, "Eversource cutting investment in Connecticut by up to $500 million over 5 years," S&P Capital IQ Pro, May 3, 2024.

[44] *Id*.

[45] "Eversource Energy Announces Sale of Aquarion Water Company," Business Wire, January 27, 2025.

December 2023, and the bonds priced at a higher coupon rate than anticipated.[46] Specifically, as stated in its currently pending rate proceeding:

> The debt issuance was a private offering in which four banks served as lead placement agents and worked with the Company to market the transaction to investors in advance of pricing. On the day of pricing, November 15th, the subscriptions sought for CNG and SCG were only 65% and 50% fulfilled, respectively. This compares to the offering for one of the other Avangrid utilities which was more than two-times subscribed. After some additional negotiation, the banks were able to get one investor to fill the remaining portions of the issuance sought for CNG and SCG and the full transaction priced on the following day; however, the credit spreads were wider than anticipated across the Avangrid Connecticut utilities, raising the financing cost by approximately 10-15 basis points. *The bankers informed Avangrid that the difficulty in fulfilling the necessary subscription levels and the wider credit spreads attracted were caused in part by the limited interest to invest in Connecticut utilities due to concerns over the regulatory environment and potential impacts to current ratings*.[47]

Q. Have utilities shifted investment outside of a jurisdiction that is viewed as unsupportive?

A. Yes. After Eversource's announcement to curtail investment in Connecticut, Guggenheim Partners analyst Shahriar Pourreza noted that the threats to reduce investment should be taken seriously and that it has happened in other states, most recently in Illinois. Because utilities are capital intensive and inherently cash-flow negative, Mr. Pourreza stated that he has seen utilities that operate in multiple jurisdictions shift capital to where the return is more predictable.[48]

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[46] Public Utilities Regulatory Authority, Docket No. 23-11-02, Response of Connecticut Natural Gas Corporation to data request RRU-402, February 27, 2024.

[47] *Id*., emphasis added.

[48] Mark Pazniokas, "Eversource escalates CT fight, saying it will cut investments," CT Mirror, May 2, 2024.

Q. What three sources does Mr. Bandyk cite to claim that awarded ROEs are too high and why are they not credible sources to support his conclusions?

A. The three sources that Mr. Bandyk cites are: (1) a paper published by Rode and Fischbeck (2019) on the growing market risk premium; (2) an Energy Institute *working paper* that Mr. Bandyk claims is published to presumably lend it more credibility; and (3) an op-ed article from *Fortnightly Magazine* from 2016 by a lawyer.[49] None of these sources credibly support Mr. Bandyk's claim that "public regulatory commissions on average have tended to set electric utility ROEs above what economists would arrive at using the widely-accepted methods for estimating ROE."[50]

Rode and Fischbeck (2019) is the only peer-reviewed published academic article, and it studies the spread between *electric* ROEs and risk-free rates. As a threshold matter, this paper does not look at *natural gas* ROEs. The paper does not use causal empirical techniques to support a conclusion that ROEs are too high. The paper only considers the CAPM model, and it does not evaluate the DCF and other considerations that may impact ROEs such as capital market conditions. Most strikingly, the authors conclude that "[o]ur research does not necessarily imply that the rates of return authorized by regulators are too high, or otherwise necessarily inappropriate for utilities."[51] Therefore the paper does not support Mr. Bandyk's conclusion that a "market-based ROE" should be lower than recently authorized ROEs.

[49] Bandyk Direct, at 5-6.

[50] *Id*., at 5.

[51] David Rode and Paul Fischbeck, "Regulated equity returns: A puzzle," *Energy Policy*, October 2019.

The working paper by Werner and Jarvis suffers from several limitations. First, the study, which benchmarks authorized returns to corporate bond yields and Treasury bond yields, incorrectly assumes that a 1.00 percentage point change in the yield on Treasury bonds will result in a 1.00 percentage point change in the authorized returns. However, the authors provide no references to studies or other information to support their assumption. Further, when the authors calculated an alternative scenario that assumed the authorized return would change at only half the rate of change in the Treasury yield (i.e. a 100 basis point increase in the Treasury yield would result in a 50 basis point increase in the authorized ROE), the spread between the estimated benchmark returns and the authorized returns decreased significantly and did not show an increasing trend over the study period, which suggests that their initial 1-to-1 relationship between the change in the yield on Treasury bonds and the change in authorized ROEs is flawed.[52]

Second, the authors acknowledged that their analysis, which compares authorized returns to the cost of equity estimates resulting from the CAPM, is highly dependent on the assumptions used to calculate the CAPM. Further, their analyses demonstrated the sensitivity of their results to the assumptions relied on in the CAPM. The authors used two CAPM analyses, with significantly different assumptions and demonstrated that the spread between the cost of equity results of these models and authorized returns were dramatically different. For example, the first CAPM analysis resulted in a spread between the estimated cost of equity and the authorized return of 3.89 percentage points in 2022, while the second

[52] Karl Dunkle Werner and Stephen Jarvis, "Rate of Return Regulation Revisited," Working Paper, Energy Institute, University of California at Berkeley, 2024, at 20.

CAPM analysis produced a spread of only 1.19 percentage points.[53] Therefore, this test demonstrated that their analysis was highly dependent on the assumptions used in the CAPM and did not support a conclusion that authorized ROEs were systematically higher than the cost of equity:

> Bolstering the financial expertise of regulators is another promising path forward. Seemingly objective methods like the capital asset pricing model cannot provide a definitive answer on the cost of equity. As we have documented, a range of plausible input assumptions can lead to widely divergent estimates of the cost of equity. When incorporating evidence from these methods regulators need to have the expertise to understand their limitations and push back on the assumptions utilities put forward when using them.[54]

Finally, the authors acknowledge that "there are many differences between the utility sector and investor environment in the US and UK," and these differences in the risk factors between utility operations in the United States and the United Kingdom ought to be addressed but are not addressed in their work.[55] Given that the authors acknowledge there are differences in the regulatory environments, yet have not considered the effect of those differences on the cost of equity for the electric and natural gas utilities in either the UK or US, it is not reasonable to conclude that the authorized ROEs in the US are too high based on a comparison to the returns authorized for utilities in the UK. As a result, the limitations of the Werner and Jarvis (2024) study do not support Mr. Bandyk's contention that US state regulatory commissions have consistently authorized ROEs in excess of the cost of equity.

[53] *Id*., at Appendix B.2 page 12.
[54] *Id*., at 39.
[55] *Id*., at 21.

The third source cited by Mr. Bandyk is an op-ed from *Public Utilities Fortnightly* from 2016 by Steve Huntoon, a utility attorney who claims that commissions set authorized ROEs at rates that are higher and not consistent to utilities' risk level.[56] As a threshold matter, although Mr. Huntoon has a background in energy, he is not a cost of capital expert, and this article is merely his opinion. Mr. Huntoon recommends individuals invest in Vanguard's utility ETF, VPU, because there have been periods where regulated utilities have outperformed the broader market. However, since the article's publication in August 2016, the VPU has significantly lagged the S&P 500 Index through April 30, 2025, with the VPU returning approximately 94% over this period, while the S&P 500 has returned approximately 199%.[57] Clearly, this refutes Mr. Bandyk's claims that utilities violate "the economic reality that lower risk means lower return."[58]

Q. Does Mr. Bandyk define "financial integrity" or at what point a utility will struggle to attract capital with a low ROE?

A. No. Mr. Bandyk believes that a utility can attract capital and new investors under any circumstances, regardless of a low ROE leading to a stock price decline.[59] This ignores the opportunity cost principle in finance. As discussed in my direct testimony, utilities compete for capital with other investments of similar risk.[60] If both ROE and stock price decrease, investors' required returns would increase as the perceived Company's risk increases. Mr. Bandyk does not suggest at what low ROE level it becomes infeasible to

[56] Steve Huntoon, "Nice Work If You Can Get It," *Fortnightly*, August 2016; Mr. Bandyk did not provide the article as the article is behind a paywall, and only two pages of the article is accessible.

[57] *S&P Capital IQ* from August 1, 2016 – April 30, 2025.

[58] Bandyk Direct, at 6.

[59] Bandyk Direct, at 8.

[60] *Id*., at 7.

attract capital, nor does he describe the difficulty Consumers Energy would face to fund its operations with a lower ROE and lower stock price.

In conclusion, I strongly disagree with Mr. Bandyk's suggestion that authorized ROEs have been set too high by regulatory commissions across the United States, including this Commission, and that ROEs of any level can attract adequate capital even with resulting lower stock price.

V. PROXY GROUP

Q. How have Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk specified their respective proxy groups?

A. To estimate the cost of equity for Consumers Energy, Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk develop their respective proxy groups as follows:

- Mr. Megginson utilizes a proxy group of eight companies, six of which overlap with my proxy group. Relative to my proxy group, Mr. Megginson includes two additional companies: New Jersey Resources ("NJR") and DTE Energy ("DTE"). While DTE did not meet the screening criteria applied by Mr. Megginson, he includes DTE because it is the "primary comparison utility" to Consumers Energy in Michigan.[61]

- Mr. Coppola relies on a proxy group of eight companies, six of which are the companies in my proxy group. The two additional companies in Mr. Coppola's proxy group are: Black Hills Corp. ("BKH") and Chesapeake Utilities ("Chesapeake").[62]

- Mr. Walters starts with the same proxy group that I have utilized, but excludes NiSource since, in early 2024, the company completed the sale of a 20% ownership interest in Northern Indiana Public Service Company ("NIPSCO"). In addition, Mr. Walters states that since there are only five companies remaining in the proxy group once he excludes NiSource, he includes six

[61] Megginson Direct, at 20.
[62] Coppola Direct, at 131.

additional water utilities in his proxy group in order to expand the proxy group.[63]

- Mr. Bandyk relies on the same proxy group for his cost of equity analyses as I have utilized.

Q. Do you have any concerns with the screening criteria relied upon by Mr. Megginson?

A. Yes, I disagree with Mr. Megginson's screen that ensures the companies included in the proxy group derive a certain portion of their operations from regulated natural gas distribution operations for two reasons. First, Mr. Megginson's screen relies on revenue instead of operating income. However, operating income is the more appropriate screening criterion because it better reflects the contribution of each business segment to the corporation's earnings. For regulated utilities that collect the cost of purchased gas, fuel, and/or power on a pass-through basis through rates, regulated revenue can fluctuate materially with changes in weather without affecting the corporation's earnings or financial position. In contrast, operating income, which excludes purchased commodity costs, more closely represents the effect of each business segment on the corporation's overall risk profile.

Second, Mr. Megginson requires that a company derive at least 50% of revenues from regulated natural gas distribution operations; however, the required percentage should be greater than 50% because Mr. Megginson's screen could result in a company being included in the proxy group that derives 50% of total revenue from unregulated operations. It is unreasonable to conclude that a company that derives 50% of total revenue from

[63] Walter Direct, at 30.

unregulated operations would be considered comparable to a company that derives 100% of revenue from regulated natural gas distribution operations such as Consumers Energy.

Q. Would the composition of Mr. Megginson's proxy group change had he relied on an operating income screen as opposed to a revenue screen?

A. Yes. If Mr. Megginson correctly relied on an operating income screen as opposed to a revenue screen, he would have excluded NJR from his proxy. As shown in Exhibit A-127 (AEB-2), page 25, NJR derived only 50.02% of its total operating income from regulated natural gas distribution operations for the three-year period of 2022-2024. While NJR would meet an operating income screen that, similar to Mr. Megginson's screen, required a company to have greater than 50% of total operating income derived from natural gas operations; as also shown in Exhibit A-127 (AEB-2), page 25, NJR derives only 56.48% of total operating income from regulated operations for the three-year period of 2022-2024. Therefore, NJR has significant unregulated operations and should have been excluded from Mr. Megginson's proxy group.

Q. Do you agree with Mr. Megginson's inclusion of DTE in his proxy group?

A. No. While I do not agree with the screening criteria developed by Mr. Megginson, he developed the criteria to select companies that would be viewed by investors as comparable to Consumers Energy's natural gas operations. However, as Mr. Megginson acknowledges, DTE did not meet his screening criteria. Furthermore, DTE is classified by *Value Line* as an electric utility because DTE provides electric service to approximately 2.3 million customers across Michigan and owns and operates approximately 12,000 MW

of electric generation.[64] As shown in Exhibit A-127 (AEB-2), page 25, DTE derived only 22.49% of total operating income from regulated natural gas operations for the three-year period of 2022-2024 whereas DTE derived 65.83% of total operating income from regulated electric operations. Given DTE's substantial electric operations, it is clear that DTE is not comparable to Consumers Energy's natural gas operations and should have been excluded from Mr. Megginson's proxy group. It is not reasonable to conclude as Mr. Megginson has that a company such as DTE should be included in the proxy group if the company operates in the same state as the subject company.

Q. Do any of the other witnesses include either NJR or DTE in their respective proxy groups?

A. No. Neither Mr. Coppola, Mr. Walters, nor Mr. Bandyk have included NJR or DTE in their respective proxy groups. Further, Mr. Coppola specifically notes that he excluded NJR because "it earns less than 50% of its income from the utility business".[65]

Q. Have you identified any errors in Mr. Coppola's application of his "utility business" screen?

A. Yes. Mr. Coppola appears to rely on a screen that requires a company to derive approximately 50% of its operations (as measured by either revenue, operating income or net income) from its utility business (i.e. regulated electric and natural gas operations) to be included in his proxy group.[66] However, Mr. Coppola incorrectly calculated the percentage of total operating income derived from regulated electric and natural gas

[64] DTE, 2024 Form 10-K, at 7-8.
[65] Coppola Direct, at 131.
[66] *Id*.

operations, which resulted in the erroneous inclusion of Chesapeake in Mr. Coppola's proxy group. Specifically, Mr. Coppola incorrectly classified the operating income associated with Chesapeake's natural gas transmission assets as operating income associated with its "utility business." Further, as shown in Exhibit AG-46, this classification is in direct conflict with his calculation for Atmos Energy where he excluded the pipeline business from its "utility business". As a result, as shown in Exhibit AG-46, Mr. Coppola incorrectly concluded that Chesapeake derived 86 percent of their total operating income from utility operations. However, as shown in Exhibit A-127 (AEB-2), page 25, excluding the operating income derived from natural gas transmission operations, Chesapeake derived only 44.03% of its total operating income from regulated electric and natural gas operations (i.e. "utility business") for the three-year period of 2022-2024. Further, excluding both the operating income from natural gas transmission operations and electric operations, Chesapeake only derived 39.52% of its total operating income from regulated natural gas operations, which, as shown in Exhibit A-127 (AEB-2), page 25, is less than NJR, a company that Mr. Coppola excluded from his proxy group. It is clear that Mr. Coppola should have excluded Chesapeake from his proxy group.

Q. Do you agree with Mr. Coppola's decisions to include BKH in his proxy group?

A. No. As Mr. Coppola acknowledges, BKH is classified by *Value Line* as an electric utility. Further, while I agree with Mr. Coppola that approximately 50% of the company's operating income is from natural gas utility operation, the reason that *Value Line* classifies BKH as an electric utility is that the company provides electric service to approximately 222,000 customers across four states and owns and operates approximately 1,400 MW of

electric generation.[67] The fact that the company has substantial vertically-integrated electric utility operations makes it not comparable to Consumers Energy's natural gas utility operations in Michigan.

Q. Do any of the other witnesses include either Chesapeake or BKH in their respective proxy groups?

A. No. Neither Mr. Megginson, Mr. Walters, nor Mr. Bandyk have included either Chesapeake or BKH in their respective proxy groups.

Q. Do you have any concerns with Mr. Walters's proxy group?

A. Yes. My primary concern with Mr. Walters's proxy group is that he excludes NiSource because he contends the company was engaged in a transformative transaction.

Q. Do you agree that companies engaged in transformative transactions should be excluded from the proxy group?

A. Yes. As noted in the proxy group screening criteria discussed in my direct testimony, I agree with Mr. Walters that significant merger and acquisition ("M&A") activity that materially affects a company's finances should be excluded from use in a proxy. The purpose of applying an M&A screen is to isolate companies that are involved in transformative transactions that cause a fundamental change in a company and its financials. The larger the size of the transaction, the greater the likelihood that the transaction will have a significant effect on the share prices of the firms involved. Thus, it is important to exclude the companies involved in transformative transactions from the proxy group so that the temporary effect of the transaction does not affect the inputs to the

[67] S&P Capital IQ Pro.

cost of equity analyses. However, excluding companies based on non-transformative transactions unnecessarily reduces the size of the proxy group and eliminates companies that investors would consider alternatives.

Q. Was the NiSource transaction transformative?

A. No. As Mr. Walters notes, NiSource announced the sale of a minority ownership interest in one of its subsidiary utilities (i.e. a 19.9% noncontrolling interest in NIPSCO) on June 20, 2023. However, this sale of a noncontrolling interest in NIPSCO did not affect the stock price of NiSource when the transaction was announced, and thus there is no reason to exclude it from the proxy group. Specifically, in the 10 trading days prior to the transaction announcement, NiSource's stock price traded between $25.76 and $26.36. Likewise, in the 10 trading days after the transaction announcement, NiSource's stock traded between $25.71 and $26.82 – or effectively the same range.[68] Thus, there is no evidence to suggest that NiSource's sale of a noncontrolling interest in NIPSCO was transformative, and thus, there is no basis to exclude NiSource from the proxy group.

Q. Are there other reasons that this transaction should not be the reason that NiSource is excluded from a proxy group at this time?

A. Yes. The transaction occurred in June 2023, which means that it is prior to the analytical period that was used by any of the witnesses in this proceeding. Since the transaction preceded the analytical period that is being used in this case, it cannot have an effect on the current market data, which is the reason that we eliminate transformative transactions. For

[68] Stock prices reflect the adjusted closing price for NiSource as reported by *Yahoo! Finance*.

this reason, it is unreasonable to exclude NiSource from the proxy group based on this transaction.

Q. Have the other witnesses included NiSource in their respective proxy groups?

A. Yes. Mr. Megginson, Mr. Coppola, and Mr. Bandyk have each included NiSource in their respective proxy groups.

Q. What is your conclusion regarding the appropriate proxy group for Consumers Energy?

A. I continue to support the use of the screening criteria outlined in my direct testimony to develop the proxy group for Consumers Energy.

VI. DCF ANALYSIS

Q. Please summarize the DCF analyses of these witnesses.

A. Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk have each conducted a form of the DCF analysis. Specifically:

- Mr. Megginson conducts a constant growth DCF, and for each of his proxy group companies relies on (1) an average of closing monthly stock prices as of January 1, February 1, and March 1, 2025; (2) annualized dividends that reflect one-half of the estimated growth rate; and (3) projected EPS growth rates from *Value Line* and *Zacks Investment Research* ("*Zacks*"). The average cost of equity resulting from Mr. Megginson's constant growth DCF analysis is 9.40%.[69]

- Mr. Coppola conducts a constant growth DCF, and for each of his proxy group companies relies on (1) an average of the 30-day high and low stock prices; (2) projected dividends as reported by *Value Line*; and (3) analysts' projected EPS growth rates as published by *Value Line* and *Zacks* as his growth rates.[70] Mr. Coppola does not rely on the projected EPS growth rates published by *Value Line*, but instead calculates projected EPS growth rates using the actual

[69] Megginson Direct, at 24.
[70] Coppola Direct, Exhibit AG-43.

EPS for 2024 and projected EPS for 2029 as published by *Value Line*. The average cost of equity from Mr. Coppola's constant growth DCF analysis is 9.11%.

- Mr. Walters conducts three DCF analyses: two constant growth DCF models (i.e. one version that relies on analysts' projected EPS growth rates and the other that relies on estimated sustainable growth rates), and a multi-stage DCF model. Mr. Walters' multi-stage DCF model relies on analysts' projected EPS growth rates in Stage 1 (years 1-5) and a growth rate of 4.14% in Stage 3 (year 11 onward) to represent projected long-term gross domestic product ("GDP") growth, while the growth rate in Stage 2 (years 6-10) transitions between the Stage 1 and Stage 3 growth rates.[71] The results of these analyses range from 8.38% to 13.54%.[72]

- Mr. Bandyk conducts a two-stage DCF analysis whereby he relies on: (1) an average of the 30-day high and low stock prices; (2) annualized dividends that I relied on in my direct testimony; (3) projected EPS growth rates that I relied on in my direct testimony; and (4) a projected nominal GDP growth rate of 3.80%. To calculate the growth rate, Mr. Bandyk applies a weighting of 80% to the average of the analysts' projected EPS growth rates and a weighting of 20% to his long-term growth rate of 3.80%.[73] The resulting cost of equity of Mr. Bandyk's constant growth DCF is 9.22%.

Q. What is your primary area of disagreement with the constant growth DCF analyses conducted by Mr. Megginson?

A. I have two primary concerns with Mr. Megginson's constant growth DCF model. First, as noted previously, I disagree with Mr. Megginson's inclusion of DTE and NJR in the proxy group. NJR has substantial unregulated operations and DTE has substantial vertically integrated electric utility operations; thus, neither company is comparable to Consumers Energy.

[71] Walters Direct, at 37-38.

[72] *Id.,* at 43.

[73] Bandyk Direct, at 23 and Exhibit CUB-18.

Second, while Mr. Megginson contends that he has relied on projected EPS growth rates from *Zacks* as of March 12, 2025, the projected EPS growth rates he relies on for each of the companies included in his proxy group do not appear to tie to the projected EPS growth rates reported by *Zacks*. For example, while I do not have access to the projected EPS report by *Zacks* on March 12, 2025, I did download from *Zacks* the projected EPS growth rates for each of the companies included in Mr. Megginson's proxy group as of February 28, 2025, and March 31, 2025. As shown in Figure 6 below, for seven of the eight companies included in Mr. Megginson's proxy group, the projected EPS growth rate from *Zacks* did not change from February 28, 2025 to March 31, 2025. However, of the seven companies that did not have a change in the projected EPS growth rate, Mr. Megginson reported a different growth rate for six out of the seven companies. Therefore, while the source of Mr. Megginson's projected EPS growth rates appears unclear, it is reasonable to conclude that they do not represent the projected EPS growth rates reported by *Zacks* on March 12, 2025.

Figure 6: Projected EPS Growth Rates – Zacks

Company	Ticker	Megginson (March 12, 2025)	Zacks (Feb. 28, 2025)	Zacks (March 31, 2025)
Atmos Energy Corporation	ATO	7.10%	7.10%	7.10%
DTE Energy Company	DTE	n/a	7.60%	7.60%
New Jersey Resources Corporation	NJR	6.00%	n/a	n/a
NiSource Inc.	NI	6.00%	8.20%	8.20%
Northwest Natural Gas Company	NWN	3.70%	n/a	n/a
ONE Gas, Inc.	OGS	3.98%	4.70%	4.70%
Southwest Gas Corporation	SWX	5.00%	6.60%	6.60%
Spire, Inc.	SR	5.62%	5.80%	6.50%

Q. Did you adjust Mr. Megginson's constant growth DCF analysis to reflect the issues you have identified?

A. Yes. Specifically, I adjusted Mr. Megginson's constant growth DCF analysis to: (1) exclude NJR and DTE from his proxy group; (2) rely on projected EPS growth rates from *Zacks* as of March 31, 2025. As shown in Exhibit A-127 (AEB-2), page 27, applying these reasonable adjustments and corrections to Mr. Megginson's constant growth DCF increases his constant growth DCF result 95 basis points from 9.40% to 10.34%.

Q. Did you also update Mr. Megginson's constant growth DCF analysis to reflect more recent market data?

A. Yes. Given the recent changes in market conditions referenced in Section IV, I updated Mr. Megginson's constant growth DCF analysis to reflect market data through April 30, 2025. As shown in Exhibit A-127 (AEB-2), page 28, when Mr. Megginson's analysis is updated with current data and DTE and NJR are excluded from his proxy group, the mean cost of equity results is 10.58%.

Q. What are your primary disagreements with Mr. Coppola's application of the constant growth DCF model?

A. In addition to the adjustment to Mr. Coppola's proxy group discussed in Section V above, I also disagree with Mr. Coppola's reliance on the projected EPS growth rates from *Zacks* that I relied on in my direct testimony which were as of September 30, 2024. The projected EPS growth rate from *Zacks* as of September 30, 2024 are clearly outdated and should have been updated by Mr. Coppola considering his constant growth DCF analysis relies on share prices through March 17, 2025.

Q. Have you adjusted Mr. Coppola's constant growth DCF analyses to address the issues you just discussed?

A. Yes, I have. I modified Mr. Coppola's constant growth DCF analysis to: (1) remove CPK and BKH from his proxy group, and (2) reflect market data (i.e. share prices, dividends, and growth rates) through April 30, 2025. As shown in Exhibit A-127 (AEB-2), page 30, by making these reasonable adjustments to Mr. Coppola's constant growth DCF analysis, the mean ROE result increases by 68 basis points from 9.11% to 9.79%.

Q. How does Mr. Walters use the results of his DCF models to establish his ROE recommendation?

A. While his specification of the DCF analyses have not changed, Mr. Walters's use of the DCF model results to establish his ROE range has changed over time. Specifically, Mr. Walters has gone from primarily weighting his constant growth DCF using projected EPS growth rates, to generally weighting all three of his DCF analyses equally, to now in the current proceeding, stating that he gives primary weight to his constant growth DCF using sustainable growth rates and his multi-stage DCF.[74]

[74] See, e.g., Oklahoma Corporation Commission, Case No. 2021-00164, Responsive Testimony of Christopher C. Walters, April 22, 2022, at 35, 38 and Exhibit CCW-3; Oklahoma Corporation Commission, Case No. 2022-000093, Responsive Testimony of Christopher C. Walters, March 7, 2023, at 35, 38 and Exhibit CCW-3; Wyoming Public Service Commission, Docket No. 20000-633-ER-23, Direct Testimony of Christopher C. Walters, August 14, 2023 at 41, 43 and WOCA Exhibit No. 602.5; Michigan Public Service Commission, Case No. U-21389, Direct Testimony of Christopher C. Walters, August 29, 2023, at 39, 42 and Exhibit AB-14.

Q. Why does Mr. Walters contend that primary weight should be placed on the results of his constant growth DCF model that relies on sustainable growth rates and his multi-stage DCF analyses?

A. Mr. Walters states that he supports placing less weight on his constant growth DCF that relies on analysts' projected EPS growth rates because the average projected EPS growth rate exceeds his projected GDP growth rate.[75]

Q. Is this rationale for the change in his approach credible?

A. No. While Mr. Walters offers this as his current rationale for limiting the weight on his DCF models that rely on EPS growth rates, the fact is that the average projected EPS growth rates that he has relied on in prior cases referenced previously have exceeded his projected GDP growth rates in each of those cases.

Q. Are the results of Mr. Walters' constant growth DCF using sustainable growth rates reasonable?

A. No. As a threshold matter, Mr. Walters' constant growth DCF results using the sustainable growth rate, which range from 8.38% to 8.70%, are not reasonable as they are either below or at the very low-end of the range of comparable authorized returns for natural gas utilities in the last 40 years, including even the lowest interest rate environments. The *Hope* and *Bluefield* decisions[76], which Mr. Walters acknowledges are standards to be followed in setting a just and reasonable return, require the authorized return to be comparable to other

[75] Walters Direct, at 42.

[76] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("Hope"); *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ("Bluefield").

returns available to investors in companies with similar risk. Mr. Walters' constant growth DCF results using the sustainable growth rate do not meet this standard.

Q. Why do you disagree with Mr. Walters's constant growth DCF analysis that relies on sustainable growth rates?

A. The use of a sustainable growth rate in the DCF suggests there is a positive relationship between future earnings and the retention ratio; however, the amount of earnings retained and not paid as dividends varies as a result of management decisions as opposed to earnings that are largely market driven. For example, management may decide to: (1) conserve cash for capital investments; (2) manage the dividend payout for the purpose of minimizing future dividend reductions; (3) manage its capital structure; or (4) signal future earnings prospects. These decisions can and do influence the amount of earnings retained versus paid out as dividends, and such decisions have been seen recently in the market. For example, due to the economic effects of COVID-19, more than 40 S&P 500 companies temporarily suspended their dividends.[77]

Q. Is there academic research that supports your conclusion?

A. Yes. Zhou and Ruland (2006), Gwilym, et. al. (2006) and Vivian (2006) discussed the theory that high dividend payouts (i.e. low retention ratios) are associated with low future earnings growth.[78] Each of these studies also cited Arnott and Asness (2003) that found,

[77] Karen Langley, "U.S. Companies Slashed Dividends at Fastest Pace in More Than a Decade," *The Wall Street Journal*, July 8, 2020.

[78] Ping Zhou and William Ruland, "Dividend Payout and Future Earnings Growth," *Financial Analysts Journal*, Vol. 62, No. 3, 2006; Owain Gwilym, James Seaton, Karina Suddason, and Stephen Thomas, "International Evidence on the Payout Ratio, Earnings, Dividends and Returns," *Financial Analysts Journa*l, Vol. 62, No. 1, 2006; Andrew Vivian, "The Payout Ratio, Earnings Growth Returns: UK Industry Evidence," Working Paper, School of Economics, Finance and Business, University of Durham, 2006.

over the course of 130 years of data, future earnings growth is associated with high, rather than low payout ratios.[79] Specifically, Arnott and Asness (2003) concluded:

> Unlike optimistic new-paradigm advocates, we found that low payout ratios (high retention rates) historically precede low earnings growth. This relationship is statistically strong and robust. We found that the empirical facts conform to a world in which managers possess private information that causes them to pay out a large share of earnings when they are optimistic that dividend cuts will not be necessary and to pay out a small share when they are pessimistic, perhaps so that they can be confident of maintaining the dividend payouts. Alternatively, the facts also fit a world in which low payout ratios lead to, or come with, inefficient empire building and the funding of less than-ideal projects and investments, leading to poor subsequent growth, whereas high payout ratios lead to more carefully chosen projects. The empire-building story also fits the initial macroeconomic evidence quite well. At this point, these explanations are conjectures; more work on discriminating among competing stories is appropriate.[80]

All four studies found that there is a negative, not a positive, relationship between earnings growth rates and retention ratios. As such, Mr. Walters's reliance on retention growth rates in the constant growth DCF model is not appropriate.

Q. Are there other reasons why you believe that sustainable growth rates should not be used in the DCF model?

A. Yes. First, the use of the sustainable or retention growth rates involves estimating investor expectations for four separate variables over the near-term: (1) the retention ratio, reflected as the "b" variable; (2) the expected return on book equity, reflected as the "r" variable;

[79] Robert Arnott and Clifford Asness, "Surprise: Higher Dividends = Higher Earnings Growth," *Financial Analysts Journal*, Vol. 59, No. 1, January/February 2003. Since the payout ratio is the inverse of the retention ratio, the authors found that future earnings growth is negatively related to the retention ratio.

[80] *Id*.

(3) the growth in the number of share of common equity, reflected as the "s" variable; and (4) the portion of the market-to-book ratio that exceeds unity, reflected as the "v" variable. This means that the growth estimate includes the forecasting error of the four separate variables.

Second, Mr. Walters relies on two growth rates that he suggests represent the long-term growth of the proxy group (i.e. the sustainable growth rate assumed in his constant growth DCF analysis and the long-term growth rate assumed in his multi-stage DCF analysis); however, these assumed growth rates are significantly different from one another and affect the results of his DCF analyses. The average long-term "sustainable" growth rate that Mr. Walters relies on in a constant growth DCF model is 5.32%.[81] Mr. Walters states that the sustainable growth rate is limited by the projected long-term GDP growth rate as that reflects the projected long-term growth in the economy as a whole, yet this growth rate is inconsistent with the long-term growth rate that he assumes in his multi-stage DCF model (i.e. 4.14%).[82]

Finally, the use of sustainable growth rates ignores the extensive academic research demonstrating that EPS growth rates are most relevant in stock price valuation.[83]

[81] Walters Direct, at Exhibit AB-11, pg. 1.

[82] *Id*., at 40.

[83] See, e.g., Robert S. Harris, "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return," *Financial Management*, Spring 1986, at 66; James H. Vander Weide and Willard T. Carleton, "Investor growth expectations: Analysts vs. history," *The Journal of Portfolio Management*, Spring, 1988; Robert S. Harris and Felicia C. Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Financial Management*, Summer, 1992; Advanced Research Center, "Investor Growth Expectations," Summer 2004; Eugene F. Brigham, Dilip K. Shome and Steve R. Vinson, "The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Financial Management*, Vol. 14, No. 1, Spring, 1985; Dr. Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., 2006, at 299-303; Jing Liu, *et. al*., "Equity Valuation Using Multiples," *Journal of Accounting Research*, Vol. 40 No. 1, March 2002; C. A. Gleason, *et. al*., "Valuation Model Use and the Price Target Performance of Sell-Side Equity Analysts," *Contemporary Accounting Research*, September 2011; Bochun Jung, *et.. al*., "Do financial analysts' long-term growth forecasts matter? Evidence from stock

Continued on next page

Q. Do you agree with Mr. Walters' and Mr. Bandyk's use of multi-stage DCF analyses to estimate the ROE for the Company?

A. No, I do not. The utility industry is considered a mature industry due to its regulated status and relatively stable demand. Thus, financial projections such as earnings growth rate projections are also likely to be relatively stable over the long-term. The relative stability of the financial forecasts for utilities supports the use of a constant growth DCF model to estimate the cost of equity for a mature industry like utilities. As noted, both Mr. Megginson and Mr. Coppola also conduct constant growth DCF analyses and do not rely on a multi-stage DCF model. For these reasons, the constant growth DCF model is the more appropriate model to estimate the cost of equity for the Company rather than the multi-stage analyses conducted by Mr. Walters and Mr. Bandyk.

Q. Do the two-stage and multi-stage forms of the DCF model increase the number of subjective inputs required to estimate the DCF model?

A. Yes. The multi-stage DCF model introduces additional assumptions and potential analyst bias. Specifically, the multi-stage DCF models presented by Mr. Walters and Mr. Bandyk in this proceeding resulted in the following additional assumptions that require subjective judgment:

- Specification of the Model: In this case, Mr. Bandyk and Mr. Walters present two different specifications of the model (i.e. Mr. Bandyk presents a two-stage growth DCF which is a form of the constant growth DCF model but relies on a blended growth rate calculated using a weighted average of short-term and long-term growth, and Mr. Walters presents a multi-stage DCF with three stages of growth).

recommendations and career outcomes," *Journal of Accounting and Economics*, Vol. 53 Issues 1-2, February-April 2012.

- Selection of the Growth Rates: Mr. Bandyk's DCF that relies on a blended growth rate requires selecting a short-term and long-term growth rate, while Mr. Walters's multi-stage DCF with three stages of growth requires the additional selection of an intermediate growth rate.

- Weighting Factors for the Blended Growth Rate: Mr. Bandyk places 80% weight on the short-term growth rate and 20% on the long-term growth rate when calculating his blended growth rate, which is consistent with the Federal Energy Regulatory Commission ("FERC") methodology.[84] The selection of the weighting factor will have a direct effect on the result produced by Mr. Bandyk's two-stage DCF model.

- Duration of Each Stage of the Multi-Stage DCF Model: For his multi-stage DCF model with three stages of growth, Mr. Walters assumes stage 1 growth is years 1-5, stage 2 growth is years 6-10, and stage 3 growth is year 11 and after.

Given the number of additional subjective assumptions required, it is reasonable to conclude that a multi-stage DCF analysis creates greater opportunity for an analyst to influence the results of the DCF model.

Q. How do you respond to Mr. Walters' and Mr. Bandyk's contention that the use of projected EPS growth rates is not consistent with the infinite time horizon in the DCF model?

A. There are multiple reasons why there is no basis to Mr. Walters's and Mr. Bandyk's claims.

First, both Mr. Bandyk[85] and Mr. Walters[86] appear to support their conclusion by comparing the projected EPS growth rates to their respective projected GDP growth rates, noting that it is not reasonable to assume that utilities can grow at a rate that is greater than

[84] FERC Opinion No. 569-A, issued May 21, 2020, at P57.
[85] Bandyk Direct, at 22-23.
[86] Walters Direct, at 64-65.

the economy over the long-term. However, this comparison relies entirely on the accuracy of Mr. Bandyk's and Mr. Walters' estimate of the long-term GDP growth rate.

Second, considering the empirical studies comparing the total factor productivity ("TFP") growth of the utility industry relative to the economy, it is not unreasonable to assume that earnings growth for utilities could exceed GDP growth over the long term. In a study filed as part of the Rate Regulation Initiative of the Alberta Utilities Commission, the authors calculated TFP growth[87] for 72 U.S. electric and combination electric and natural gas utilities and for the U.S. economy for the period of 1972 through 2009. For the U.S. utility group, TFP growth averaged 0.96% over the period of 1972 to 2009,[88] while TFP growth for the U.S. economy was 0.91%,[89] indicating that electric and combination electric and natural gas utilities were approximately 5% more productive than the U.S. economy over the study period. Therefore, the authors demonstrated that utility growth exceeded growth for the U.S. economy for approximately 40 years.

Q. Is there academic research that refutes Mr. Bandyk's and Mr. Walters' contention that the use of analysts' projected EPS growth rates is not consistent with a long-term growth rate that matches investors' expectations of the domestic economy as a whole.

A. Yes. Both Mr. Walters and Mr. Bandyk support their conclusion that a multi-stage DCF is necessary by comparing the analysts' projected EPS growth rates to their respective projected GDP growth rates and suggests that it is not reasonable to assume that utilities

[87] TFP growth is a measure of productivity calculated as the difference between output growth and input growth. Higher TFP growth indicates that a company is converting inputs into higher levels of output growth (i.e. increased productivity).

[88] Alberta Utilities Commission, Jeff Makholm and Agustin Ros, "Update, Reply and PBR Plan Review for AUC Proceeding 566 – Rate Regulation Initiative", February 22, 2012, at 5.

[89] *Id*., at 19.

can grow at a rate that is greater than the economy over the long term. However, as noted above, there is significant academic literature that supports the use of earnings growth rates in the DCF analysis and texts that challenge the assumption of GDP growth used in a multi-stage DCF model. For example, in a recent publication, Dr. Roger Morin notes the following:

> One central assumption in Multi-Stage DCF models, and a potential Achilles' heel, in my view, is that utility growth rates will eventually match the growth of the macroeconomy usually measured by the growth of the Gross Domestic Product (GDP). I am not aware of any financial literature supporting the notion that utility earnings per share are expected to grow at the average growth of the economy, or GDP.
>
> As discussed in Chapter 10, based upon the wealth of empirical and academic literature that supports the superiority of analyst's forecasts as a measure of investor expectations for the use of such forecasts in the DCF model, current earnings growth forecasts are the appropriate growth rates to use in a DCF analysis. Besides, to the extent that economic trends influence growth, it is reasonable to assume that they are already captured in analysts' growth estimates for utilities.
>
> Multi-stage DCF applications appear somewhat disconnected from the assumptions of the method and the consensus expectations of investors. The investment community does not look to GDP growth over the next several decades when evaluating an investment in utility stocks, nor does it anticipate a series of discrete muti-stage decennial stages. I am not aware of any evidence that investors evaluate the future based on the assumptions and data sources required to apply the two-stage or three-stage DCF model.[90]

[90] Roger A. Morin, *Modern Regulatory Finance*, Public Utilities Reports, Inc., 2021, at 486.

Q. How do Mr. Bandyk and Mr. Walters develop their projected GDP growth rates?

A. Mr. Bandyk relies on the projected nominal GDP growth rate over the period of 2028-2035 from the Congressional Budget Office ("CBO") of 3.80%.[91] Mr. Walters relies on a projected nominal GDP of 4.14% as reported by *Blue Chip Economic Indicators*.[92]

Q. Do you agree with Mr. Bandyk's and Mr. Walters's projected GDP growth rate?

A. No. Mr. Bandyk relies on a projected nominal GDP growth rate from CBO for the period of 2028 to 2035. However, Mr. Bandyk's two-stage DCF analysis relies on a blended growth rate that continues into perpetuity. Therefore, the projected nominal GDP growth rate from CBO would only reflect growth for the seven-year period of 2028 through 2035, even though his two-stage DCF model extends into perpetuity. In other words, his assumed long-term growth rate only covers a small portion of the long-term period to which it is being applied in his DCF analyses. As a result, the projected GDP growth rates from CBO may not be indicative of the expected growth in GDP over the long term, and therefore, cannot be used as the basis to conclude that the projected EPS growth rate for my proxy group will not be sustained in perpetuity.

Mr. Walters relies on a projected nominal GDP growth rate of 4.14% as reported by *Blue Chip Economic Indicators,* which is only for the next 5 to 10 years. As a result, similar to the growth rate of CBO relied on by Mr. Bandyk, the projected GDP growth rate from *Blue Chip Economic Indicators* may not be indicative of the expected growth in GDP over the long term and therefore cannot be used to conclude that my projected EPS growth rates are not sustainable.

[91] Bandyk Direct, at Exhibit CUB-19.
[92] Walters Direct, at 40.

Q. Is Mr. Walters's assumed long-term growth rate in his multi-stage DCF consistent with the analyst literature that he relies on?

A. No. Mr. Walters's assumed long-term growth rate in his multi-stage DCF of 4.14% is inconsistent with the analyst literature he cites in his testimony. When discussing the long-term growth rate for his multi-stage DCF, Mr. Walters references the following quote from the *Ibbotson* SBBI 2013 Valuation Yearbook:

> Another approach to estimating long-term growth rates is to focus on estimating the overall economic growth rate. Again, this is the approach used in the *Ibbotson Cost of Capital Yearbook*. To obtain the economic growth rate, a forecast is made of the growth rate's component parts. Expected growth can be broken into two main parts: expected inflation and expected real growth. By analyzing these components separately, it is easier to see the factors that drive growth.[93]

However, Mr. Walters cites only a portion of the quote and omits the remainder of the discussion, which indicates that his assumed long-term growth rate is inconsistent with the approach recommended by *Ibbotson* for establishing a long-term growth rate:

> Once the long-term expected inflation rate is estimated, the real growth rate must be determined. The growth rate in real Gross Domestic Product (GDP) for the period 1929 to 2012 was approximately 3.22 percent. Growth in real GDP (with only a few exceptions) has been reasonably stable over time; therefore, its historical performance is a good estimate of expected long-term (future) performance.
>
> By combining the inflation estimate with the real growth rate estimate, a long-term estimate of nominal growth is formed.[94]

[93] *Id.,* at 39.

[94] *Morningstar, Inc*., Ibbotson SBBI 2013 Valuation Yearbook, at 52.

The *Ibbotson* SBBI 2013 Valuation Yearbook recommends that the long-term growth rate reflect the sum of the long-term historical average real GDP growth rate and the expected inflation rate. As shown in Exhibit A-127 (AEB-2), page 31, had Mr. Walters used the *Ibbotson* approach, based on the full citation, taking into consideration the real GDP growth rate and expected inflation, the resulting long-term growth is 5.45%. As a result, Mr. Walters understates the long-term growth rate consistent with *Ibbotson's* methodology that he cites in his testimony.

Q. If Mr. Walters had appropriately included NiSource in his proxy group and placed primary weight on the results of his constant growth DCF model that relies on analysts' EPS growth rates consistent with his approach in prior proceedings, what is the resulting cost of equity?

A. As shown in Exhibit A-127 (AEB-2), page 33, when Mr. Walters' constant growth DCF relying on analysts' projected EPS growth rates is updated to rely on a proxy group including NiSource, the median cost of equity result is 11.05%.[95]

Q. Did you also adjust Mr. Bandyk's DCF analysis?

A. Yes. I modified Mr. Bandyk's DCF analysis to: (1) rely on the constant growth DCF model as opposed to the two-stage DCF model; and (2) reflect market data (i.e. share prices, dividends, and growth rates) through April 30, 2025, because Mr. Bandyk was relying on the annualized dividends and projected EPS growth rates that I relied on in my direct

[95] The mean was not considered due to a projected EPS growth rate for California Water Service Group of approximately 42 percent from Zacks, S&P and I/B/E/S, which has a significant effect on the average. It is more appropriate to rely on the median which is not affected to a large degree by the presence of outliers.

testimony which are outdated.[96] As shown in Exhibit A-127 (AEB-2), page 35, by making these reasonable adjustments to Mr. Bandyk's DCF analysis, the mean ROE result increases by from 9.22% to 10.99%.

VII. CAPM ANALYSIS

Q. Please summarize the CAPM analyses prepared by Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk.

A. Mr. Megginson conducts three CAPM analyses, one using a historical market risk premium, and two additional scenarios using different implied projected market risk premia, one based on the trailing 12-month cash yield and the other based on the average cash yield over the past 10 years.[97] For all three of his CAPM analyses, Mr. Megginson relies on (1) a risk-free rate of 4.25%, which is based on a weighted average of projected 30-year Treasury bond yields for 2025 and 2026 as reported by S&P Global Market and *econforecasting.com*; and (2) current betas for each of the proxy group companies as published by *Value Line*. Mr. Megginson calculates his historical market risk premium, which is 6.94%, as the arithmetic mean realized return on large company stocks over the period 1928-2024 minus the income-only total return on long-term government bonds over that same period. For each of his CAPM scenarios relying on a projected market risk premium, Mr. Megginson relies on data reported by Professor Damodaran. The average cost of equity result of Mr. Megginson's CAPM analyses are 10.63% (historical market

[96] In my direct testimony, I relied on projected EPS growth rates from *Yahoo! Finance*; however, *Yahoo! Finance* is no longer reporting projected EPS growth rates. Therefore, when updating my constant growth DCF analysis in my rebuttal testimony, I instead relied on projected EPS growth rates from S&P Capital IQ Pro. Thus, when adjusting Mr. Bandyk's DCF analysis, I relied on projected EPS growth rates from S&P Capital IQ Pro in addition to the projected EPS growth rates from *Zacks* and *Value Line*.

[97] Megginson Direct, Exhibit No. S-4, Schedule D-5, at 8-9.

risk premium), 8.25% (12-month trailing projected market risk premium), and 9.93% (10-year projected market risk premium).[98]

Mr. Coppola conducts a CAPM analysis that relies on (1) a risk-free rate of 4.00%, based on the near-term projected 30-year Treasury bond yield as reported by *Blue Chip Financial Forecasts* as of October 1, 2024; (2) current betas for each of the proxy group companies as published by *Value Line*; and (3) a market risk premium of 7.30%, which is the historical market return of large company stocks minus the income-only return on long-term government bonds from 1926 through 2023 as published by *Kroll*.[99] The cost of equity resulting from Mr. Coppola's CAPM analysis is 10.66%.

Mr. Walters produces 12 different cost of equity estimates from his CAPM analysis, relying on different estimates of the risk-free rate, beta, and market risk premium. Specifically, for the risk-free rate, Mr. Walters relies on a projected 30-year Treasury yield in eight scenarios, and a *Kroll* "normalized" risk-free rate in the remaining four scenarios. For beta, Mr. Walters relies on four estimates for the proxy group companies: (1) current five-year betas published by *Value Line*; (2) historical average betas published by *Value Line*; (3) current beta estimates from S&P Market Intelligence's Beta Generator ("Market Intelligence"); and (4) current three-year raw betas published by Market Intelligence and then applying the Blume adjustment similar to *Value Line's* adjustment. For the market risk premium, Mr. Walters also relies on three estimates: (1) the long-term historical arithmetic average real return on the S&P 500 plus an expected inflation rate, less the risk-free rate; (2) a constant growth DCF-derived return on the S&P 500, averaging the

[98] Megginson Direct, at 27-30 and Exhibit S-4, Schedule D-5, at 7-9.
[99] Coppola Direct, at 134-136 and Exhibit AG-44.

method prescribed by FERC in Order No. 569-A with an alternative where all the companies in the S&P 500 are used rather than just the dividend-paying companies, less the risk-free rate; and (3) a "normalized" market risk premium published by *Kroll*. Mr. Walters's CAPM results produce a cost of equity range from 8.19% to 11.44%.[100]

Mr. Bandyk's CAPM analysis relies on (1) a risk-free rate of 4.41%; (2) current betas for each of the proxy group companies as published by *Value Line* and Bloomberg, but adjusted to remove the Blume adjustment reflected in those betas such that he relies on the raw betas; and (3) an estimated market risk premium that is an average of three sources: Professor Damodaran; the IESE Business School survey; and *Kroll*.[101]

A. Risk-Free Rate

Q. Is the risk-free rate that Mr. Coppola relies on in his CAPM analysis reasonable?

A. No. Mr. Coppola's risk-free rate is outdated and does not reflect current expectations and therefore should not be relied upon. Specifically, Mr. Coppola relies on a risk-free rate of 4.00% based on the *Blue Chip Financial Forecasts* as of October 1, 2024, and states that his 4.00% risk-free rate is "forecasted for the first quarter of 2026, which is about the mid-point of the projected test year."[102] However, the *Blue Chip Financial Forecast* is a monthly publication, and thus Mr. Coppola's analysis should have been based on the most recent data available. It is unclear why Mr. Coppola relies on an outdated risk-free rate that is more than six months old given the availability of more current data prior to the filing of his testimony on April 23, 2025.

[100] Walters Direct, at 49-58 and Exhibit AB-20.
[101] Bandyk Direct, Exhibits CUB-15, CUB-16, and CUB-17.
[102] Coppola Direct, at 140.

Q. Is the current consensus estimate of the 30-year Treasury bond yield significantly different than assumed in Mr. Coppola's CAPM analysis?

A. Yes. As reported in the most recent publication of the *Blue Chip Financial Forecasts*, the consensus estimate of the 30-year Treasury bond yield for the first quarter of 2026 as relied on by Mr. Coppola is 4.50%.[103]

Q. Is Mr. Megginson's calculation of the risk-free rate similarly understated?

A. Yes, at least in part. As noted, Mr. Megginson relies on two projections of the 30-year Treasury bond yield for his risk-free rate: a projection published by S&P Global Market Intelligence from IHS Markit and a projection published by *econforecasting.com*. While I do not have access to the source of Mr. Megginson's risk-free rate published by S&P Global Market Intelligence from IHS Markit, the current projections from *econforecasting.com* indicate a projected 30-year Treasury bond yield for the remainder of 2025 of 4.69%, and for calendar year 2026 of 4.12%.[104] Even assuming no change in Mr. Megginson's S&P Global Market Intelligence data, the resulting risk-free rate, when updating the *econforecasting.com* data and weighting the sources in the same manner as Mr. Megginson has in his testimony, results in a risk-free rate of 4.38% as compared to Mr. Megginson's assumed 4.25%.

[103] *Blue Chip Financial Forecasts*, Vol. 44, No. 4, April 1, 2025, at 2.

[104] *econforecasting.com*; data accessed as of April 28, 2025.

B. Market Risk Premium

Q. What is the primary criticism that you have of the development of the market risk premium used by each of the witnesses recommending an ROE for the Company in this proceeding?

A. Each of the other witnesses in this proceeding develop their market risk premium independent from the risk-free rate that they are using in their CAPM analyses, which ignores the academic research that there is an inverse relationship between the risk-free rate and the market risk premium.[105] As I will discuss, this misalignment of the risk-free rate and market risk premium in their respective CAPM analyses serves to underestimate the cost of equity.

Q. Do you disagree with other aspects of the market risk premium assumptions developed by the witnesses in this proceeding?

A. Yes. I also disagree with the use of the historical market risk premium, as applied by Mr. Megginson and Mr. Coppola, and I disagree with the projected market risk premium developed by Mr. Megginson and find the methodologies that he uses in this case to develop the market risk premia to be inconsistent with his prior testimony and the prior testimony of other staff members.

[105] See e.g., S. Keith Berry, "Interest Rate Risk and Utility Risk Premia during 1982-93," *Managerial and Decision Economics*, Vol. 19, No. 2, March, 1998. *See also*, Robert S. Harris, "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return," *Financial Management*, Spring 1986, at 66.

Q. Please explain why you disagree with Mr. Megginson's and Mr. Coppola's use of a historical market risk premium for estimating the CAPM.

A. Fundamentally, the market return and market risk premium should be forward-looking. Neither Mr. Megginson nor Mr. Coppola have provided any evidence that the historical averages that they calculate for the market return or the market risk premium reflect the expected market conditions during the period in which the Company's proposed rates will be in effect. As *Morningstar* has observed, the market risk premium is a forward-looking concept, not a historical analysis:

> It is important to note that the expected equity risk premium, as it is used in discount rates and the cost of capital analysis, is a forward-looking concept. That is, the equity risk premium that is used in the discount rate should be reflective of what investors think the risk premium will be going forward.[106]

Interest rates have increased significantly since historical lows and are expected to remain elevated over at least the next year. Inflation remains above the Federal Reserve's target level, and uncertainty (i.e. overall higher risk) in the market has increased because of the effect of the current administration's policies with respect to tariffs, immigration, and taxes on the economy. All of these conditions affect the current and projected equity risk premium and should be considered in establishing the ROE in this proceeding.

[106] *Morningstar Inc*., 2010 Ibbotson SBBI Valuation Yearbook, at 55.

Q. Are there other reasons why using a historical market risk premium for estimating the forward-looking cost of equity is not appropriate in the calculation of the CAPM based on current market conditions?

A. Yes. As noted previously, Mr. Megginson's and Mr. Coppola's use of the historical market risk premium disregards the demonstrated relationship between interest rates and the market risk premium. Both Mr. Megginson and Mr. Coppola calculate the cost of equity using the CAPM by relying on a long-term historical average market risk premia and a near-term projected risk-free rate. However, in Mr. Megginson's and Mr. Coppola's specification of the CAPM, their respective near-term projected risk-free rates bear no relationship to the historical average interest rates underlying the historical average market risk premia on which they rely. Therefore, the use of assumptions from different time periods fails to account for the inverse relationship that exists between the risk-free rate and the equity risk premium. Both academic literature and market evidence indicate that the equity risk premium is inversely related to the level of interest rates (i.e. as interest rates increase, the equity risk premium decreases, and vice versa), and given that current interest rates on long-term government bonds are below the historical average interest rate of those same bonds, the market risk premium should be *greater than* the long-term historical average market risk premium – which is not the case for either Mr. Megginson's or Mr. Coppola's CAPM analyses.

Q. Can you illustrate the inconsistency between Mr. Megginson's and Mr. Coppola's risk-free rate and equity risk premium?

A. Yes. Mr. Megginson's estimate of the historical market risk premium, relies on the arithmetic average market risk premium for the period of 1928-2023 (i.e. 6.94%), which is

based on the difference between the historical average return on large company stocks (i.e. 11.79%) and the historical average income-only return on long-term government bonds (i.e. 4.85%) over this period.[107] However, Mr. Megginson relies on a near-term projected risk-free rate on long-term government bonds of 4.25% to estimate the cost of equity in the CAPM, which is *lower than* the historical average return on long-term government bonds (i.e., 4.85%) that he relies on to estimate the market risk premium. Considering the academic research that demonstrates the inverse relationship between interest rates and the market risk premium, since Mr. Megginson's current return on long-term government bonds is *less than* the historical average return on those same bonds, the current market risk premium should be *greater than* the long-term historical average of 6.94% that Mr. Megginson assumes. Consequently, Mr. Megginson's use of a historical market risk premium understates the market risk premium in the current market environment when interest rates are below the long-term average. This flaw in Mr. Coppola's analysis is even more pronounced given that he uses the same historical average return on long-term government bonds that Mr. Megginson relies on (i.e. 4.85%) to estimate the equity risk premium, but relies on an even lower forward-looking risk-free rate of 4.00%.[108] Therefore, Mr. Coppola's CAPM analysis also understates the cost of equity.

[107] Megginson Direct, Exhibit No. S-4, Schedule D-5, at 7.
[108] Coppola Direct, Exhibit AG-44.

Q. Has *Kroll*, the publisher of the historical data on which Mr. Megginson and Mr. Coppola rely to estimate the historical market risk premium, highlighted a potential inconsistency with relying on historical data for a forward-looking analysis such as the CAPM?

A. Yes. *Kroll* has stated that, "[i]n using a historical measure of the equity risk premium, one assumes that what has happened in the past is representative of what might be expected in the future."[109] However, because the near-term projected long-term government bond yields are currently below those that Mr. Megginson and Mr. Coppola have relied on in their historical average market risk premium estimates, the market risk premium based on long-term historical average data is certainly not representative of what is expected in the future. Given the inverse relationship between the market risk premium and interest rates, since the projected interest rate is lower than the historical average, it is reasonable to expect that the market risk premium would be higher than the historical average.

Q. Is there also evidence that the use of a historical market premium can produce counter-intuitive results?

A. Yes. Figure 7 illustrates the problem with relying on the historical market risk premium such as Mr. Megginson and Mr. Coppola have done. Specifically, the figure shows that from 2007-2009, the historical market risk premium decreased even as market volatility (the primary statistical measure of risk) significantly increased. Further, this figure demonstrates the significant swings in the annual equity risk premium that are averaged into the long-term historical average calculations. As shown, in 2008, the annual equity

[109] *Kroll*, 2022 SBBI Yearbook, at 198.

"premium" was actually negative, which implies a discount for equity holders relative to the cost of debt. It is incomprehensible that the perceived risk for equity was negative (implying a lower required return) in the height of the financial market collapse when the overall market return was a negative 37%. As shown, this individual observation alone, which runs counter to the theory of the equity risk premium, reduces the historical average market risk premium for the prior 80 years by 60 basis points.

Figure 7: Historical Market Risk Premium and Market Volatility

	Market Volatility	Market Return	Annual Equity Premium	Long-term Average Historical Market Risk Premium[110]
2007	17.54	5.49%	0.63%	7.10%
2008	32.69	-37.00%	-41.45%	6.50%
2009	31.48	26.46%	3.47%	6.70%

The assumption that investors would expect or require a lower equity risk premium during periods of increased volatility is counter-intuitive and leads to unreliable analytical results. As noted earlier, the relevant objective in the application of the CAPM is to ensure that all three components of the model (i.e. the risk-free rate, the beta, and the market risk premium) are consistent with market conditions and investor perceptions. The forecasted market risk premium estimates used in my original and rebuttal CAPM analyses specifically address that concern.

[110] Ibbotson SBBI Yearbook. *Morningstar Inc*. 2008, at 28. *Ibbotson SBBI Yearbook. Morningstar Inc*. 2009, at 23; Ibbotson SBBI Yearbook. *Morningstar Inc*. 2010, at 23. The historical market risk premium equals the total return on large company stocks less the income-only return on long-term government securities.

Q. Is the method that Mr. Megginson relies on for purposes of estimating his historical market risk premium consistent with Staff's prior methodology?

A. No. The calculation of the historical average market risk premium that Mr. Megginson relies on is inconsistent with the method that Staff utilized previously in another recent proceeding. As noted, Mr. Megginson relies on a historical average market risk premium of 6.94%, which is based on a subset of the historical data reported by *Kroll*, from 1928 through 2023, plus data for 2023 and 2024 obtained from other market sources since *Kroll* has discontinued publishing the SBBI Yearbook. However, in Case No. U-21461, the Staff witness also relied on a historical market risk premium based on the data published by *Kroll*, however they used the full analytical period that *Kroll* publishes from 1926 through the current year – not arbitrarily starting in 1928 as Mr. Megginson has done in this proceeding.[111]

Q. What is the effect of relying on a shorter historical data set than what Staff has relied on in prior cases?

A. Relying on data starting in 1928 rather than the full data set understates the long-term market return and market risk premium. Mr. Megginson calculates a market return of 11.79% and a market risk premium of 6.94% using the truncated data set. However, on their online Cost of Capital Navigator, *Kroll* reports that the historical long-term market return for 1926 through 2024 is 12.17% and that the long-term income-only return on long-term government bonds over the same period is 4.86%, and thus the long-term

[111] Michigan Public Service Commission, Case No. U-21461, Qualifications and Direct Testimony of Joseph E. Ufolla, January 18, 2024, at 13.

historical average equity risk premium over this period is 7.31%.[112] This historical calculation is higher than Mr. Megginson's market risk premium and is consistent with the historical market risk premium on which Mr. Coppola relies for this CAPM analysis.[113] Therefore, while Mr. Megginson's and Mr. Coppola's use of a historical average market risk premium in their CAPM analyses understates the market risk premium and thus understates the cost of equity by failing to account for current market conditions and the inverse relationship between interest rates and the market risk premium, Mr. Megginson has further understated the historical average market risk premium, and thus cost of equity, by arbitrarily not relying on the entire historical data set published by *Kroll*.

Q. Mr. Megginson also calculates two CAPM analyses using projected market risk premia. Are these analyses reasonable?

A. No. First, as a threshold matter, the first of Mr. Megginson's CAPM analyses that relies on the 12-month trailing market risk premium of 4.35% results in a cost of equity of 8.25%, which is unreasonable,[114] as it is well below the low end of any authorized ROE in a comparable regulatory jurisdiction for a natural gas utility since at least 1980. Moreover, his CAPM scenarios that rely on projected market risk premia are also inconsistent with the inverse relationship between the risk-free rate and the market risk premium, and, as a result, significantly understate the cost of equity. Specifically, Mr. Megginson relies on a risk-free rate of 4.25%, which is well below the historical average return on long-term government bonds (i.e. 4.85%), which means that one would expect Mr. Megginson's

[112] *Kroll*, Cost of Capital Navigator, Historical Long-Term (1926-2024) equity risk premium; https://costofcapital.kroll.com/coc-inputs/rfr-and-erp.

[113] Coppola Direct, Exhibit AG-44; see "Sources, column (d)."

[114] Megginson Direct, Exhibit No S-4, Schedule D-5, at 8.

projected market risk premia to be *greater than* the long-term historical average market risk premium of 7.31%; however, Mr. Megginson's projected market risk premia are nearly 300 basis points and more than 110 basis points, respectively, below the long-term historical average.[115]

Q. Is Mr. Megginson's projected market risk premium consistent with his prior testimony?

A. No. In the recent Michigan Gas Utilities proceeding in Case No. U-21540, Mr. Megginson relied on a projected market risk premium as calculated in the same manner as I have done in my direct testimony (i.e. the projected return on the S&P 500 less the assumed risk-free rate).[116] In addition, in the Company's last electric division rate proceeding in Case No. U-21585, Mr. Megginson also relied on a similar approach, although he used an outdated market risk premium based on data filed more than 16 months prior in another rate proceeding.[117] Mr. Megginson has provided no basis for his change in approach in this proceeding.

[115] *Id*., at 8-9.

[116] Qualifications and Direct Testimony of Kirk D. Megginson, Case No. U-21540, July 1, 2024, Exhibit No. S-4, Schedule D-5, at 6 of 11. Note, the heading in column (e) of this exhibit mistakenly refers to the market risk premium as a "historical market risk premium;" however, the exhibit is clear that the market risk premium assumed by Mr. Megginson is a projected market risk premium consistent with the method relied on by the company in that proceeding.

[117] Direct Testimony of Kirk D. Megginson, Case No. U-21585, September 27, 2024, Exhibit No. S-4, Schedule D-5, at 8, whereby Mr. Megginson referenced and relied on the market risk premium in the Direct Testimony of Todd A. Wehner, Case No. U-21389, May 1, 2023, Exhibit No. A-14, Schedule D-5, page 10 of 12.

Q. Does this change in Mr. Megginson's approach when using a projected market risk premium produce a significantly different result for his projected market risk premium?

A. Yes. If Mr. Megginson had calculated the market risk premium in a manner consistent with his prior testimony in Case No. U-21540, his projected market risk premium would be 7.79% (i.e. the market return of 12.04% as shown in my direct testimony in Exhibit No. A-14, Schedule D-5, page 16, minus Mr. Megginson's assumed risk-free rate in this proceeding of 4.25%), or *nearly 350 basis points higher* than the 4.35% that he assumes for his projected market risk premium in the current proceeding.

Q. Do the market risk premia relied on by Mr. Walters and Mr. Bandyk suffer from the same failure to appropriately reflect the inverse relationship between interest rates and the market risk premium as you previously discussed in your response to Mr. Megginson and Mr. Coppola?

A. Yes. As shown in Figure 8, Mr. Walters' four CAPM analyses that rely on his *Kroll* "normalized" market risk premium, as well as the assumed market risk premium in Mr. Bandyk's CAPM analysis, which reflects an average of his three sources (i.e. Professor Damodaran; the IESE Business School survey; and *Kroll*), are also inconsistent with the inverse relationship between interest rates and the market risk premium and thus understates the cost of equity. Specifically, the risk-free rate assumptions used in their CAPM analyses are either below or consistent with the long-term average risk-free rate, and yet contrary to the inverse relationship between interest rates and the market risk premium, their respective market risk premia are well below the long-term term average market risk premium.

Figure 8: Misalignment of Market Risk Premia Relied on by Mr. Walters and Mr. Bandyk[118]

Witness	Source	Market Risk Premium	Amount Below Long-Term Avg.	Risk-Free Rate	Amount Below Long-Term Avg.
	Long-Term Historical Avg.	**7.31%**		**4.86%**	
Walters	*Kroll* - Normalized	5.00%	-2.31%	4.78%	-0.08%
Bandyk	Damodaran (TTM sustainable payout)	4.43%	-2.88%	4.24%	-0.62%
Bandyk	Damodaran (TTM)	4.61%	-2.70%	4.24%	-0.62%
Bandyk	Damodaran (smoothed)	5.91%	-1.40%	4.24%	-0.62%
Bandyk	Damodaran (normalized)	4.07%	-3.24%	4.24%	-0.62%
Bandyk	Damodaran (net cash yield)	4.33%	-2.98%	4.24%	-0.62%
Bandyk	IESE Survey	5.70%	-1.61%	4.10%	-0.76%
Bandyk	*Kroll*	5.00%	-2.31%	4.88%	0.02%

Q. Are there other issues with the data used by Mr. Walters and Mr. Bandyk?

A. Yes. Both Mr. Walters and Mr. Bandyk rely on outdated estimates of the market risk premium. Both witnesses use a *Kroll* projected risk premium of 5.00% as part of their respective CAPM analyses; however, the current forecasted market risk premium by *Kroll* is 5.50%.[119] Furthermore, as shown in Figure 8 above, Mr. Bandyk relies on five different estimates from Professor Damodaran for purposes of deriving an average market risk premium; however, these data are from September 2024, and are therefore more than eight months old and do not reflect current market conditions.[120]

[118] *Kroll*, Cost of Capital Navigator, Historical Long-Term (1926-2024) equity risk premium; https://costofcapital.kroll.com/coc-inputs/rfr-and-erp.

[119] *Kroll*, Cost of Capital Navigator, https://costofcapital.kroll.com/coc-inputs/rfr-and-erp. Mr. Bandyk also states on page 16 of his testimony that he relies on data from September 2024 for estimating his market risk premium; however, it appears that is in error as Exhibit CUB-16 indicates that the data was accessed as of April 2025.

[120] Bandyk Direct, at 16.

Q. Are the results of either Mr. Walters's CAPM analyses that rely on the *Kroll* "normalized" market risk premium or Mr. Bandyk's CAPM reasonable?

A. No. The cost of equity results from their CAPM analyses are unreasonable. Specifically, the results of Mr. Walters's *Kroll* "normalized" market risk premium CAPM scenarios are 8.19%, 8.57%, 8.72%, and 9.17%,[121] while the results of Mr. Bandyk's CAPM analysis is 7.95%. Due to their misspecification of the market risk premium in these scenarios, all of these results are either at or well below the low end of any authorized ROE in a comparable regulatory jurisdiction for a natural gas utility in nearly half a century. I recognize that Mr. Bandyk believes it is not appropriate to compare his CAPM result to previously authorized ROEs given that he claims that regulatory commissions have consistently authorized ROEs well in excess of the cost of equity for decades; however, as I have discussed, his position is unsupported and unfounded given the obligation of regulatory commissions to authorize just and reasonable rates.

Q. What are your concerns with Mr. Walters' "forward-looking" risk premium-derived market return and thus market risk premium?

A. I disagree with what Mr. Walters considers a "forward-looking" estimate of the market return. Mr. Walters calculates what he terms a "forward-looking" estimate of the market return, which reflects the long-term historical arithmetic average real return of the S&P 500 from 1926 through 2023 of 9.02% plus a projected inflation rate based on the Consumer Price Index of 2.50% as reported by *Blue Chip Financial Forecasts* as of February 28, 2025.[122] From this market return of 11.75%, Mr. Walters then subtracts his

[121] Walters Direct, Exhibit AB-20, at 1.
[122] Walters Direct, at 53.

projected risk-free rate of 4.60% to estimate a market risk premium that he then uses in four of his 12 CAPM scenarios.[123]

Q. Why do you disagree with Mr. Walter's "forward-looking" risk premium-based estimate of the market return?

A. Mr. Walters's risk premium-derived estimate of the market return is neither "forward-looking" nor does it reflect the current and expected market conditions during which the Company's rates will be in effect. First, while Mr. Walters characterizes his market return as "forward-looking," which presumably is to recognize that the market return estimate of the CAPM should be forward-looking, simply applying a projected inflation rate to a long-term historical average market return does not produce a "forward-looking" market return. Second, while Mr. Walters' use of the average real return of the S&P 500 from 1926 through 2023 is reflective of the returns realized by investors under different market and economic conditions, it is not necessarily reflective of the market return required by investors in the current and expected market environment. Mr. Walters provides no evidence that the historical average market return is reflective of the expected market conditions during the period in which the Company's proposed rates will be in effect.

Q. Have you identified inconsistencies in the analyses prepared by Mr. Bandyk?

A. Yes. The assumptions used in Mr. Bandyk's CAPM are inconsistent with the results of his DCF analyses. As shown in Figure 9, in four of the five estimates of the market risk premium on which Mr. Bandyk relies from Professor Damodaran, the market risk premium

[123] *Id*.

reflects an implied *market* return that ranges from 8.31% to 8.35%, which are all lower than his average DCF result for his proxy group of natural gas distribution companies of 9.22%.[124] This result is counterintuitive, as it is reasonable to expect that the return on the overall market, with a presumed beta of 1.0, would be higher than the return on Mr. Bandyk's proxy group of natural gas utilities, which he assumes have an average beta coefficient of 0.81 (*Value Line*) and 0.64 (*Bloomberg*) in his CAPM analysis. However, as shown in Figure 9, the results of Mr. Bandyk's analyses indicate the exact opposite of the expected risk/return trade off. As shown in Figure 9, Mr. Bandyk's overall market return is lower than the return he estimates for the natural gas utility proxy group, despite the expectation that this proxy group has lower overall risk than the market.

Figure 9: Mr. Bandyk's Implied Market Return in the CAPM Analysis as Compared to His DCF Results

	Mr. Bandyk CAPM Assumptions				Mr. Bandyk
Source	Market Risk Premium	Risk-Free Rate	Implied Return for the *Market*		DCF Return for *Gas Utilities*
Damodaran (TTM sust. payout)	4.43%	4.24%	8.67%		9.21%
Damodaran (TTM)	4.61%	4.24%	8.85%		9.21%
Damodaran (normalized)	4.07%	4.24%	8.31%	v.	9.21%
Damodaran (net cash yield)	4.33%	4.24%	8.57%		9.21%

Q. Is it reasonable for Mr. Bandyk to have relied on the IESE Business School survey as an estimate of the market risk premium?

A. No. It specifically states in the IESE Business School survey that the average of the distribution of the required equity premium from the survey, which Mr. Bandyk relies on,

[124] Bandyk Direct, at 12 and Exhibit CUB-18.

cannot be interpreted as the required equity premium of the market nor of a representative investor.[125]

Further, there are several other academic sources that caution against the use of survey data:

- The drawbacks of survey data include biased responses and biased sampling as noted by Brigham, Shome, and Vinson (1985).[126]
- Professor Damodaran, who Mr. Bandyk also relies on for his other market risk premium estimate, noted that survey results were affected by how the questions were asked in the survey and on recent stock price movements.[127]
- The response rates to surveys can be limited, as Graham and Harvey (2018) noted in their CFO survey where the response rate was only 5% to 8%.[128]

C. Beta Coefficients

Q. What are the primary areas where you disagree with the betas used by the witnesses in this case?

A. I disagree with Mr. Bandyk's reliance on raw betas, and Mr. Walters' reliance on betas from S&P Market Intelligence that reflect a Vasicek adjustment whereby the raw beta is adjusted to assume that a company's beta coefficient will trend toward the *industry* average as opposed to the *market* average of 1.0.

[125] Pablo Fernandez, Diego Garcia de la Garza, and Lucia Fernandez Acin, "Survey: Market Risk Premium and Risk-Free Rate used for 96 countries in 2024," IESE Business School, March 11, 2024, at 11; emphasis added.

[126] Eugene F. Brigham, Dilip K.Shome, and Steve R. Vinson, "The Risk Premium Approach to Measuring Utility's Cost of Equity," *Financial Management*, Vol. 14, No. 1, 1985, at 33.

[127] Aswath Damodaran, "Equity Risk Premiums (ERP): Determinants, Estimation, and Implications," March 23, 2023, at 28.

[128] John R. Graham and Campbell R Harvey, "The Equity Risk Premium in 2018," *Social Science Research Network*, March 27, 2018.

Q. Why you do you disagree with these betas relied on by Mr. Bandyk and Mr. Walters?

A. The use of either raw betas as Mr. Bandyk has utilized or the Vasicek-adjusted betas that Mr. Walters has utilized is not appropriate for regulated utilities because these beta coefficients likely understate the true beta of utility stocks given that the utility sector is not only correlated to the broader market, but is also sensitive to changes in interest rates, which are *not* factored into either the raw beta or Vasicek-adjusted beta calculations. Therefore, neither of Mr. Bandyk's raw beta coefficients nor Mr. Walters's Vasicek-adjusted betas consider interest rate risk and likely understate the actual risk, which in turn understates the result of the CAPM analysis. Conversely, the Blume adjustment applied by *Value Line* and *Bloomberg* adjusts the raw beta coefficients toward the market average of 1.0, thus likely better reflecting the true beta of the utility sector inclusive of interest rate risk.

Q. Do any of the other witnesses in this proceeding rely on the raw beta coefficients that Mr. Bandyk has relied on for his CAPM analysis?

A. No. Mr. Megginson, Mr. Coppola, Mr. Walters, and I have all relied on beta coefficients that have been adjusted using the Blume adjustment for purposes of our CAPM analyses, and as discussed, Mr. Walters has also relied on betas in one scenario adjusted using the Vasicek adjustment.

D. <u>Response to Intervenor Positions</u>

Q. What are the positions of Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk regarding your CAPM analysis?

A. These witnesses offer the following positions regarding my CAPM analyses:

- Mr. Coppola alleges that my use of multiple risk-free rates "seems to be a hunt for an approach that will result in a higher ROE rate."[129]

- Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk contend that my market risk premium is excessive, with Mr. Walters and Mr. Bandyk suggesting that I should have considered multiple methodologies to estimate the expected market return and market risk premium.[130]

- Mr. Coppola also contends that a problem with my calculation of the market return is that there are many companies with dividend yields and long-term growth estimates that are omitted.[131]

Q. Is your use of three different risk-free rates an intentional attempt to achieve a higher CAPM result as Mr. Coppola alleges?

A. No. There is no basis to Mr. Coppola's claim that I have intentionally selected three risk-free rates in an attempt to increase the resulting cost of equity from the CAPM. The Company's authorized ROE should be a forward-looking estimate of the cost of equity, and, as stated in my direct testimony, I have relied on a current risk-free rate, a near-projected risk-free rate, and a longer-term risk-free rate consistent with estimating a forward-looking cost of equity. While Mr. Coppola suggests my use of a longer-term projected risk-free rate is used to achieve a specific result, it is important to note that the long-term risk-free rate is the lowest of the three risk-free rates that I have relied upon in my analyses. Therefore, it is inconceivable that I would have relied on this projection to increase the results of my analyses.

[129] Coppola Direct, at 140.
[130] Megginson Direct, at 23; Bandyk Direct, at 17-18; Walters Direct, at 67.
[131] Coppola Direct, at 141.

Q. Is there any basis to the claims by Mr. Megginson, Mr. Walters, or Mr. Bandyk regarding your market return and thus market risk premium?

A. No. There are multiple reasons why there is no basis to their contention regarding the market return and thus market risk premia used in my CAPM analyses. As discussed, the market return used in my CAPM analyses is reasonable, consistent with the range established by historical market return data,[132] and has been relied upon in other regulatory jurisdictions.

First, as shown in Figure 7 of my direct testimony, an expected market return of 12.04% is reasonable given that the realized total equity return was at least at this level or greater in 52 out of the past 98 years (i.e. 53% of the observations). In addition, as reflected in Exhibit A-127 (AEB-2), pages 15-20, the forward-looking market return has declined slightly since the filing of my direct testimony and is currently 11.92%.

Second, in a cost of capital proceeding for the electric utilities in California, the California Public Utilities Commission ("California PUC") noted that all parties recognized historical market returns, and economically logical projections, fall within the range of 12%.[133]

Third, various state utility regulatory commissions have supported the use of a constant growth DCF model to estimate the market return in the CAPM such as I have done. As shown in Figure 10, the Staff of the Illinois Commerce Commission ("ICC"), the Bureau of Investigation and Enforcement ("I&E") of the Pennsylvania Public Utility

[132] Bulkley Direct, at 42-43.

[133] California Public Utilities Commission, Application No. 22-04-008, Decision No. 22-12-031, December 15, 2022, at 23.

Commission ("Pennsylvania PUC"), and the Staff of the Maine Public Utilities Commission ("Maine PUC") have each supported the forward-looking market risk premium, and the market return estimates using the constant growth DCF model. In each of these cases, the respective regulatory commission relied on the estimated CAPM results by these parties to determine the authorized ROE and did not dispute the use of the constant growth DCF model to calculate the market return.

Figure 10: Examples of Jurisdictions Where Market Return Estimated Using the Constant Growth DCF Model

Intervening Party	Applicant	Docket No.	Approach of Intervening Party to Calculating the Market Return	Date of Order	Did the Commission Rely on the Intervening Party's CAPM?
Staff of the ICC	North Shore Gas Company	20-0810	Constant growth DCF of the dividend-paying companies in the S&P 500 (11.95%)[134]	9/8/21	Yes[135]
I&E	Aqua Pennsylvania, Inc.	R-2021-3027385	CGDCF of the Value Line Universe and S&P 500 (12.14%)[136]	5/12/22	Yes, the regulator placed primary weight on I&E's CAPM[137]
Staff of the Maine PUC	Northern Utilities, Inc.	2019-00092	CGDCF of the dividend-paying companies in the S&P 500 (11.33%-13.49%)[138]	4/1/20	Yes[139]

Fourth, the Federal Reserve Bank of New York published an analysis in 2015 that reviewed 20 methodologies over the period 1960 through 2013 for estimating the market risk premium. The result of this study demonstrates that my market risk premium

134 Illinois Commerce Commission, Docket No. 20-0810, Order, September 8, 2021, at 71.

135 *Id*., at 86-87.

136 Pennsylvania Public Utility Commission, Docket No. R-2021-3027385, Opinion and Order, May 16, 2022, at 147.

137 *Id*. at 178.

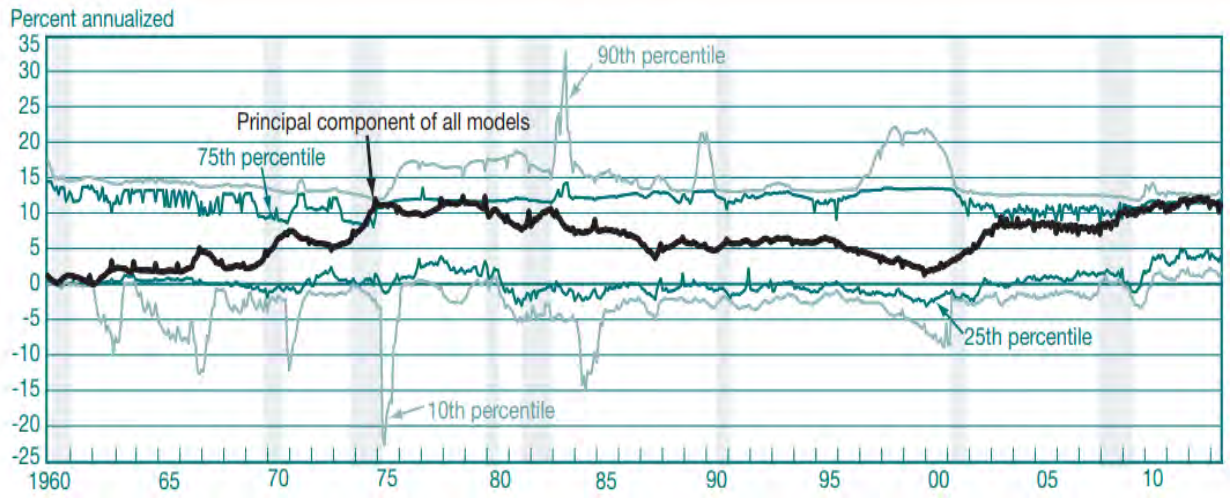
138 Maine Public Utilities Commission, Docket No. 2019-00092, Bench Analysis, October 29, 2019, at 21.

139 *Id*., Order Part II, April 1, 2020, at 58.

estimates, which, as shown on Exhibit A-127 (AEB-2), pages 5-13, of my rebuttal cost of equity analyses, are in the range of 7.24% to 7.62%, are reasonable. Specifically, the key conclusions from this study are:

- The 20 methodologies reviewed reflected a range for the market risk premium of between -1.0% to 14.5%.
- As shown in Figure 11, the principal component analysis of the 20 models (i.e. the bold black line) produced a range for the market risk premium of approximately 0% to over 10% from 1960 through 2013.
- The one-year-ahead market risk premium was consistently greater than 10% following the financial crisis of 2008/09.

Figure 11: The Federal Reserve Bank of New York, One-Year-Ahead Market Risk Premium[140]



Further, the Federal Reserve Bank of New York also noted the following:

> Chart 2 shows the first principal component of all twenty models in black (the black line is the same principal component shown in black in each of the panels of Chart 1). ***As expected, the principal component tends to peak during financial turmoil, recessions, and periods of low real GDP growth or high inflation***. It tends to bottom out after periods

[140] Fernando Duarte and Carla Rosa, "The Equity Risk Premium: A Review of Models," Federal Reserve Bank of New York, 2015, at 50.

> of sustained bullish stock markets and high real GDP growth. Evaluated by the first principal component, the one-year ahead ERP [*equity risk premium*] reaches a local peak in June 2012 at 12.2 percent. The surrounding months have ERP estimates of similar magnitude, with the most recent estimate in June 2013 at 11.2 percent. This behavior is not so clearly seen by simply looking at the collection of individual models in Chart 1, a finding that highlights the usefulness of principal component analysis. Similarly high levels were observed in the mid- and late 1970s, during a period of stagflation, while the recent financial crisis had slightly lower ERP estimates, closer to 10 percent.[141]

Thus, the Federal Reserve Bank of New York noted that the market risk premium is higher during periods of increased inflation. As discussed at length in my direct testimony as well as herein, inflation remains well above the Federal Reserve's target of 2% and is expected to remain elevated over the near term. Given the results of the analysis conducted by the Federal Reserve Bank of New York, it is clear that my estimates of the market risk premium are reasonable.

Lastly, it is also important to note that, despite their criticisms:

- Mr. Walters calculates a market risk premium using a forward-looking single stage DCF analysis in this proceeding (which are both higher than in my direct testimony).[142]

- As discussed previously, Mr. Megginson has conducted a CAPM scenario using a forward-looking single stage DCF analysis in prior cases and offers no discussion as to why he has changed his methodology in this proceeding.

- Mr. Coppola relies on a historically based market risk premium of 7.30%, which is not materially different than the market risk premium of 7.74% in my direct testimony. In fact, while Mr. Coppola inappropriately compares the results of his CAPM analysis to the highest result of my CAPM analysis, the resulting

[141] *Id*.; emphasis and clarification added.

[142] As shown in Exhibit AB-20, the market return in his analysis is 12.48% and the market risk premium is 7.90%, which are both higher

cost of equity from Mr. Coppola's CAPM is 10.66%, which is higher than the average of all of my CAPM analyses in my direct testimony of 10.43%.[143]

Therefore, for all of the reasons just discussed, the market return, and thus market risk premium, in my CAPM analyses are reasonable and consistent with the findings of the Federal Reserve and other utility regulatory commissions, and there is no basis for the claims that the market return, and thus market risk premium, in my CAPM analyses is excessive.

Q. Have courts addressed these witnesses' assertion that your forward-looking market return is inflated?

A. Yes. In its review of FERC Opinion No. 569-B, the U.S. State Court of Appeals for the District of Columbia addressed the concern regarding the use of projected EPS growth rates in a constant growth DCF model to estimate the market return. In the Court's decision, it acknowledged that FERC has relied on the use of projected EPS growth rates in the calculation of the market return on the S&P 500 because the S&P 500 is regularly updated to include companies with high market capitalization and it includes companies at all stages of growth, including lower and higher growth potential. The Court determined that FERC's rationale for using projected EPS growth rates was sufficient and did not accept the challenge to this assumption.[144]

[143] Coppola Direct, at 139 and Exhibit AG-44; Bulkley Direct, at 48.

[144] United States Court of Appeals, District of Columbia Circuit, Opinion, Docket No. 16-1325, August 9, 2022, at 19.

Q. Mr. Coppola also suggests that there is a concern with your market return in that certain companies have been omitted. Is there any merit to Mr. Coppola's contention?

A. No. Mr. Coppola's suggestion that my calculation of the market return on the S&P 500 Index results in a modified population of companies that is inconsistent with the S&P 500 Index or the equity markets is incorrect. As shown on Exhibit A-14, Schedule D-5, of my direct testimony, companies in the S&P 500 Index are only excluded from my constant growth DCF analysis if their projected EPS growth rate was either negative or greater than 20%. While I believe that the calculation of the weighted projected earnings growth rate for the S&P 500 Index should include all of the companies in the index, my calculation of the market return for the CAPM and ECAPM excludes companies in the S&P 500 Index that have a long-term earnings growth rate that is negative or greater than 20% to address previously raised concerns by parties regarding the use of a constant growth DCF model relying on projected EPS growth rates.

E. <u>Adjusted CAPM Results</u>

Q. Have you recalculated the CAPM analyses of Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk to address your concerns with their reliance on a historical market risk premium?

A. Yes, I have adjusted their respective CAPM analyses to address the issues that I have discussed:

- As noted, Mr. Megginson relies on both a historical market risk premium and projected market risk premia for his CAPM analysis.
  - First, rather than relying on the historical market risk premium for the reasons discussed, I have adjusted Mr. Megginson's CAPM analysis to

calculate the market risk premium as the historical arithmetic average market return from 1926 through 2023 minus his estimate of the risk-free rate. While I do not agree with the use of the historical market return as the estimate of the forward-looking market return for the reasons discussed, a calculation that at least derives the market risk premium from the risk-free rate that is being used in the CAPM to estimate the cost of equity is more appropriate than the calculation performed by Mr. Megginson. This is because the derived market risk premium will reflect an inverse relationship between interest rates and the market risk premium that is established in the CAPM equation (i.e. because near-term interest rates are lower than the long-term historical average, the market risk premium should be greater than the historical average risk premium). As shown on Exhibit A-127 (AEB-2), page 37, when the market risk premium is adjusted as just discussed, the average cost of equity for Mr. Megginson's CAPM analysis is 11.53%, which is an increase of 90 basis points from his as-filed position.

- Second, given that Mr. Megginson's approach for his projected market risk premia is inconsistent with his prior testimony, I have updated his CAPM analysis to rely on a projected market risk premium consistent with his prior approach. As shown on Exhibit A-127 (AEB-2), page 38, this results in a cost of equity of 11.41%.

- Therefore, whether using Mr. Megginson's historical market risk premium or his prior approach of a projected market risk premium, the cost of equity results support the reasonableness of the Company's proposed ROE in this proceeding.

- I have also adjusted the market risk premium for Mr. Coppola's CAPM analysis in the same manner as I just discussed regarding Mr. Megginson's CAPM analysis, and I have also updated Mr. Coppola's risk-free rate through April 30, 2025. As shown on Exhibit A-127 (AEB-2), page 40, this results in a cost of equity of 11.50%, which fully supports the reasonableness of the Company's proposed ROE in this proceeding.

- As discussed, four of Mr. Walters's 12 CAPM scenarios rely on a *Kroll* "normalized" market risk premium that does not properly reflect the inverse relationship between interest rates and the market risk premium. When those scenarios of Mr. Walters's CAPM analyses are excluded for this reason, the average result of his remaining eight CAPM scenarios is 10.38%, which

supports the reasonableness of the Company's proposed ROE in this proceeding.

- Mr. Bandyk's projected market risk premium also is inconsistent with the inverse relationship between interest rates and the market risk premium. As a result, I have adjusted Mr. Bandyk's CAPM analysis to rely on the projected market return of 12.04% that I relied on in my direct testimony, which is a more reasonable estimate of the market return than the implied market return based on the market risk premia in his CAPM analysis. As shown on Exhibit A-127 (AEB-2), page 42, making this adjustment produces a cost of equity result of 9.99%, or approximately 200 basis points higher than Mr. Bandyk's as-filed position. At a minimum, this supports the reasonableness of an increase in the Company's ROE for this proceeding. I also do not agree with Mr. Bandyk's use of raw betas for the reasons discussed; however, I have not adjusted his betas for purposes of the analysis shown on Exhibit A-127 (AEB-2), page 42.

VIII. ECAPM ANALYSIS

Q. Please summarize the positions of Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk regarding your ECAPM analyses.

A. Mr. Megginson, Mr. Coppola, and Mr. Walters suggest that the use of an adjusted beta in the ECAPM analysis is duplicative, as the weighting adjustments applied in the ECAPM are mathematically the same as adjusting beta, and thus the ECAPM produces a result that is overstated.[145] In addition, Mr. Megginson and Mr. Coppola also claim that the use of long-term interest rates as the risk-free rate is inconsistent with the ECAPM.[146] Mr. Bandyk states that he has not conducted an ECAPM since the Staff has historically declined using an ECAPM and the Commission has not previously recognized the ECAPM as a valid methodology.[147]

[145] Megginson Direct, at 31-33; Coppola Direct, at 142-143; Walters Direct, at 68-71.
[146] Megginson Direct, at 31; Coppola Direct, at 142-143.
[147] Bandyk Direct, at 21.

Q. Is it appropriate to use adjusted betas in the ECAPM?

A. Yes, it is entirely appropriate to use adjusted betas in the ECAPM, and doing so is consistent with academic literature and the estimation of the ECAPM in this manner has been accepted by various regulatory commissions. There is no merit to any of these witnesses' contentions regarding the ECAPM.

Q. What is the purpose of using adjusted betas in the ECAPM?

A. The purpose of adjusting beta in the CAPM is to account for the tendency of beta to trend back over time to the market beta of 1.00. As noted by Mr. Megginson, the betas published by *Value Line* include this adjustment,[148] which was first proposed by Marshall E. Blume in 1975.[149] The use of adjusted betas in the CAPM is important because if beta trends towards 1.00, as Blume noted, then the adjusted beta will be more reflective of the beta that can be expected over the near-term. This is equally important in the specification of the CAPM in this case since the cost of equity for the Company is being estimated over the near term.

The ECAPM does not account for the tendency of beta to trend toward 1.00. The purpose of the ECAPM is to account for the fact that the risk-return relationship is flatter than what is estimated by the CAPM, ***even when using adjusted betas***. While beta is not observable and must be estimated, the theory behind the ECAPM is that even if the true value of a stock's beta were observable, the CAPM would understate the results for stocks with betas less than 1.00 and overstate the results for stocks with betas greater than 1.00.

[148] Megginson Direct, at 32.

[149] Marshall E. Blume, "Betas And Their Regression Tendencies," *The Journal of Finance*, Vol. 30, No. 3, 1975, at 785-795.

Therefore, contrary to the assertions of Mr. Megginson, Mr. Coppola, and Mr. Walters, the purpose of each adjustment is different and thus applying both adjustments in the ECAPM is not duplicative.

Q. Mr. Coppola cites a chapter in Dr. Morin's text *New Regulatory Finance* to support his view that there is academic disagreement with the studies that led to the use of the ECAPM.[150] Do you agree with Mr. Coppola's conclusion from this text?

A. No. Reviewing the excerpt provided by Mr. Coppola, it is clear that, while Dr. Morin identifies some who have argued that the use of ECAPM is inconsistent with the use of adjusted betas, Dr. Morin further explains that the argument that has been used to support this concern is erroneous. Importantly, Dr. Morin's text fully supports the use of adjusted betas in the ECAPM and explains why it is appropriate:

> Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such a trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprise two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated…***Both adjustments are necessary. Moreover, recall from Chapter 3 that the use of adjusted betas compensates for interest***

[150] Coppola Direct, at 142-143.

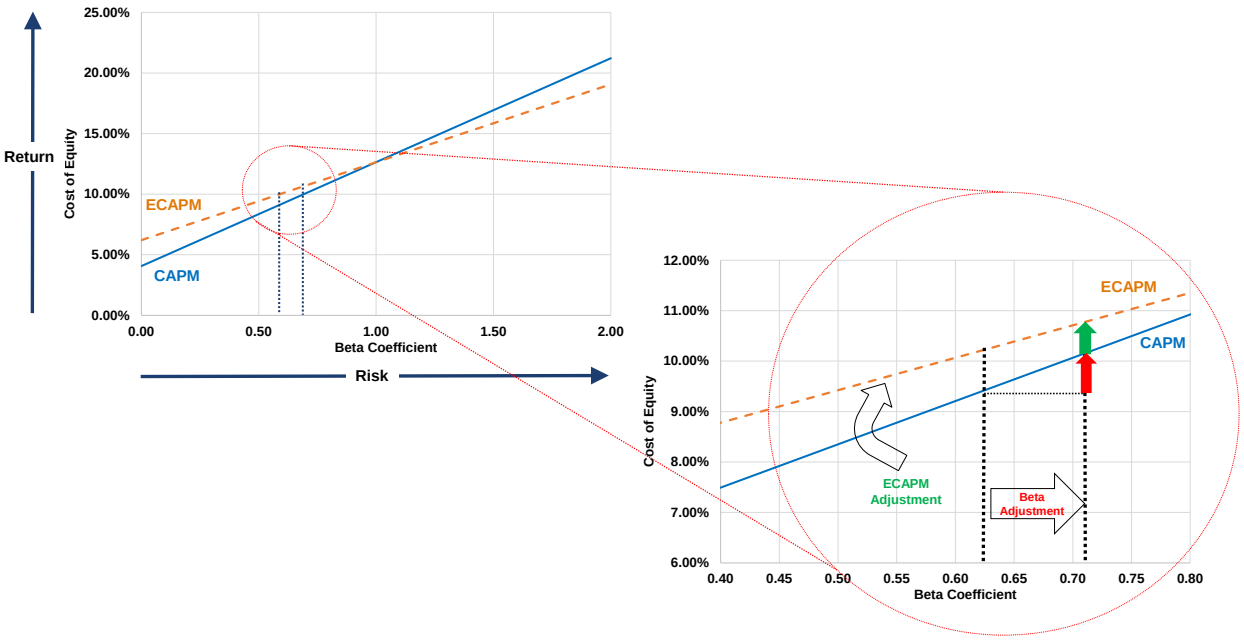
rate sensitivity of utility stocks not captured by unadjusted betas.[151]

Q. Can you demonstrate that using adjusted betas in the CAPM and relying on the ECAPM are two distinct adjustments to the CAPM?

A. Yes. Figure 12 demonstrates the point that adjusting betas and adjusting the slope of the risk/return relationship through the ECAPM are two distinct adjustments and are not duplicative as alleged by Mr. Megginson, Mr. Coppola, and Mr. Walters. As shown in Figure 12, when beta is adjusted to recognize that betas revert to the market mean of 1.0 over time and used in the CAPM, the resulting adjustment is shown by the red arrow in the lower right-hand corner. Separately, when the ECAPM is employed to recognize that the risk/return relationship is flatter than predicted by the CAPM, the resulting adjustment is shown by the green arrow in the lower right-hand corner. To the extent that a company with a beta greater than 1.0 is being evaluated, the same process of two separate adjustments would apply, albeit in the opposite direction from what is shown in Figure 12 and would result in a decrease in the cost of equity otherwise predicted by the CAPM.

[151] Dr. Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., 2006, at 191 (emphasis added).

Figure 12: Risk/Return Relationship between CAPM and ECAPM



Q. Are you aware of academic studies that have used adjusted betas to estimate the ECAPM?

A. Yes. For example, Litzenberger, Ramaswamy, Sosin (1980) studied the ability of the CAPM to estimate the returns for utilities, and found that the CAPM tends to understate the return for stocks such as utilities, which have a beta less than 1.0.[152] To develop the analysis, Litzenberger, *et al*. utilized both adjusted and raw betas, and in both cases, the CAPM understated the return for utilities with betas less than 1.0. In addition, Chrétien and Coggins (2011) studied the CAPM and its ability to estimate the risk premium for the utility industry in particular subgroups of utilities for a data set that included market data through the end of 2006.[153] Chrétien and Coggins considered the CAPM, the Fama-French

[152] Robert Litzenberger, *et al*., "On the CAPM Approach to the Estimation of A Public Utility's Cost of Equity Capital," *The Journal of Finance*, Vol. 35, No. 2, 1980, at 369-383.

[153] Stéphane Chrétien and Frank Coggins, "Cost Of Equity For Energy Utilities: Beyond The CAPM," *Energy Studies Review*, Vol. 18, No. 2, 2011.

three-factor model, and a model similar to the ECAPM. The study shows that the ECAPM significantly outperformed the traditional CAPM at predicting the observed risk premium for the various utility subgroups.

Additionally, Dr. Morin directly addresses the issue in his 2021 text *Modern Regulatory Finance* as follows:

> Because of this adjustment, some critics of the ECAPM argue that the use of Value Line adjusted betas in the traditional CAPM amounts to using an ECAPM. This is incorrect. The use of adjusted betas in a CAPM analysis is not equivalent to the ECAPM. Betas are adjusted because of the regression tendency of betas to converge towards 1.0 over time. We have seen that numerous empirical studies have determined that the SML [Security Market Line] described by the CAPM formula at *any given moment* in time is not as steeply sloped as the predicted SML. The slope of the SML should not be confused with Beta. On the point, Eugene F. Brigham, finance professor and the author of many financial textbooks states:
>
> > The Slope of the SML (5% in Figure 6-16) reflects the degree of risk aversion in the economy. The greater the average investor's aversion to risk, then (a) the steeper the slope of the line, (b) the greater the risk premium for all stocks, and (c) the higher required rate of return on all stocks. Students sometimes confuse beta with the slope of the SML. This is a mistake.
>
> The use of an adjusted beta by Value Line is correcting for a different problem than the ECAPM. The adjusted beta captures the fact that betas regress towards one over time. The ECAPM corrects for the fact that the CAPM under-predicts observed returns when beta is less than one and over-predicts observed returns when beta is greater than one.[154]

[154] Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., 2006, at 223-224 (emphasis added).

Q. Do you agree with Mr. Megginson and Mr. Coppola that your ECAPM is flawed because of the use of a long-term risk-free rate as opposed to a short-term risk-free rate?

A. No. While Mr. Megginson does not explain his disagreement on this issue, Mr. Coppola contends that Dr. Morin concluded in *New Regulatory Finance* that the use of the ECAPM was not required if long-term interest rates were used as the risk-free rate as opposed to short-term interest rates.[155] However, Mr. Coppola misquotes Dr. Morin and, thus, misrepresents Dr. Morin's conclusion regarding the ECAPM. Specifically, Dr. Morin states the following:

> ***An alpha range of 1%-2% is somewhat lower than estimated empirically. The use of a lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. That is because the use of a long-term risk-free rate rather than a short-term risk-free rate already incorporates some of the desired effect of using the ECAPM. That is, the long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free rate version which has been tested. Thus, it is reasonable to apply a conservative alpha adjustment***. Moreover, the lowering of the tax burden on capital gains and dividend income enacted in 2002 may have decreased the required return for taxable investors, steepening the slope of the ECAPM risk-return trade-off and bring it closer to the CAPM predicted returns.[156]

Thus, Dr. Morin developed the ECAPM based on a conservative estimate of alpha (i.e. 1% to 2%) relative to the range of alphas estimated empirically to account for the effect of using a long-term risk-free rate as opposed to a short-term risk-free rate. Figure 13 provides the list of studies summarized by Dr. Morin. As shown, six of the eight studies

[155] Coppola Direct, at 142-143.

[156] Dr. Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., 2006, at 191; emphasis added.

estimated positive values of the constant term, and among the six studies that estimate only positive values of the constant term, the range of the constant term was 1.63% to 13.56%. It is evident that Dr. Morin's use of an alpha in the range of 1% to 2% to develop the 0.25 and 0.75 factors included in the ECAPM is conservative. The ECAPM was developed to be used with a long-term risk-free rate, and thus the use of a long-term risk-free rate is not a substitute for the ECAPM as suggested by Mr. Megginson and Mr. Coppola.

Figure 13: Empirical Evidence on the Alpha Factor (Constant Term)[157]

Author	Range of Alpha
Fischer (1993)	-3.6% to 3.6%
Fischer, Jensen and Scholes (1972)	-9.61% to 12.24%
Fama and McBeth (1972)	4.08% to 9.36%
Fama and French (1992)	10.08% to 13.56%
Litzenberger and Ramaswamy (1979)	5.32% to 8.17%
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 5.04%
Pettengill, Sundaram and Mathur (1995)	4.6%
Morin (1989)	2.0%

[157] Roger A. Morin, *Modern Regulatory Finance*, Public Utilities Reports, Inc., 2021, at 222.

Q. While Mr. Megginson and Mr. Bandyk state that the Commission has not previously considered the merits of the ECAPM,[158] and Mr. Coppola states that the ECAPM is not widely accepted by state regulatory commissions,[159] are you aware of state regulatory commissions that have accepted the use of the ECAPM in the manner as you have conducted?

A. Yes. While Mr. Coppola references a Company data response from a proceeding filed in 2017 as support for his position,[160] there are various regulatory commissions that have supported the use of the ECAPM in establishing an authorized ROE and have done so when adjusted betas are used in the ECAPM analysis. For example, the New York Public Service Commission ("NYPSC"), the Montana Public Service Commission ("Montana PSC"), and North Carolina Utilities Commission ("NCUC") have accepted the ECAPM analysis with the use of adjusted beta coefficients in establishing the authorized ROE for regulated utilities. Specifically, the NYPSC gives equal weight to the CAPM and ECAPM (which it refers to as the "Zero Beta" CAPM) results,[161] the Montana PSC has expressed preference for the ECAPM analysis,[162] and the NCUC has recently found that both the adjustment to beta in the CAPM and the adjustment in the ECAPM were needed because they correct for different things.[163] Exhibit A-128 (AEB-3).

158 Megginson Direct, at 33; Bandyk Direct, at 21.

159 Coppola Direct, at 143-144.

160 *Id*., at 143.

161 New York Public Service Commission Case No. 20-G-0101, Order, May 19, 2021, at 44-46.

162 Montana Public Service Commission, Docket No. D2017.9.80, Order No. 7575c, September 26, 2018, at 40.

163 North Carolina Utilities Commission, Docket No. E-2, SUB 1300, Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Public Notice, August 18, 2023, at 162-63.

IX. BOND YIELD RISK PREMIUM ANALYSIS

Q. Do any of the witnesses conduct a Risk Premium analysis?

A. Yes. Mr. Megginson, Mr. Coppola, and Mr. Walters have each conducted a Risk Premium analysis. Specifically:

- Mr. Megginson conducts two forms of a Risk Premium analysis: one reflecting the historical equity risk premium of gas utility stock returns less utility bond yields over the period 1954 to 2024 plus a projected utility bond yield on A-rated rated utility bonds ("Utility Bond Approach"); and another reflecting the historical equity risk premium of gas utility stock returns less 30-year Treasury bond yields over the period 1954 to 2024 plus a projected 30-year Treasury bond yield ("Treasury Bond Approach"). The cost of equity resulting from Mr. Megginson's Utility Bond Approach is 9.56%, respectively, while the cost of equity from his Treasury Bond Approach is 9.46%.[164]

- Mr. Coppola's Risk Premium analysis is similar to Mr. Megginson's Utility Bond Approach, as Mr. Coppola's analysis reflects the historical equity risk premium of gas utility stock returns less A-rated utility bond yields over the period 1954 to 2023 plus a projected average yield on A-rated/BBB-rated utility bonds. Mr. Coppola calculates his projected utility yield by averaging the 2024 spreads between A-rated utility bonds and the 30-year Treasury, and BBB-rated utility bonds and the 30-year Treasury. He adds this average spread to the 4.00% 30-year Treasury rate from his CAPM. Mr. Coppola's risk premium model produces a cost of equity of 9.20%.[165]

- Similarly, Mr. Walters develops five cost of equity estimates based on two forms of a Risk Premium analysis: one reflecting the risk premium relative to yields on 30-year Treasury by subtracting the average 30-year Treasury yield from the average authorized Gas ROE over the period 1986-2024 plus a projected 30-year Treasury yield ("Treasury Bond Approach") to produce a 10.23% cost of equity; and four based on the utility equity risk premium relative to yields on both the Moody's A-rated and Baa-rated utility bonds both using

[164] Megginson Direct, at 33-34 and Exhibit S-4, Schedule D-5.

[165] Coppola Direct, at 137 and Exhibit AG-45.

3-month average yield data and 6-month yield data ("Utility Bond Approach") to produce a cost of capital estimate ranging from 9.73% to 9.98%.[166]

Q. Do you agree with Mr. Megginson's, Mr. Coppola's, and Mr. Walters' Risk Premium analyses?

A. No. The key issue, as previously discussed, is that their analyses apply a historical risk premium to a projected interest rate which fails to consider the inverse relationship between interest rates and the market risk premium. Specifically, the witnesses' risk premium methods add a current or projected yield (i.e. a utility bond yield or a Treasury bond yield) that differs from the historical average rate used to estimate the risk premium. There is an interest rate mismatch in their calculation. Consequently, their Bond Yield to Risk Premium ("BYRP") results do not reflect what it would be if the historical rate had been used consistently, resulting in ROEs that fail to appropriately account for the dynamic, inverse relationship between risk premiums and interest rates. Because historical bond yields are higher than the bond yields utilized by the witnesses in their analyses, and given inverse relationship between risk premiums and interest rates, their analyses, which utilize a historical risk premium, understate the cost of equity.

For example, in his Treasury Bond Approach, Mr. Megginson adds a near-term projected Treasury bond yield of 4.25% to his historical average Treasury bond risk premium of 5.21%, resulting in his estimated cost of equity of 9.46%.[167] However, as shown on Mr. Megginson's Exhibit S-4, Schedule D-5, the average 30-year Treasury bond yield over the 1954-2024 period was 5.73%, *or more than 145 basis points higher* than the

[166] Walters Direct, at 43-47.
[167] Megginson Direct, at 34.

near-term projected Treasury bond yield of 4.25% that he relies on to calculate the cost of equity for this version of his Risk Premium analysis.

Q. Can you show the impact to ROE estimates by mismatching historical and projected interest rates?

A. Figure 14 shows how the witnesses' mismatching of the historical and projected interest rates leads to understated cost of capital estimates. All witnesses projected interest rates are less than the historical interest rates that were used for their risk premium calculation. When adding the historical interest rate to the risk premium for consistency, estimates for the cost of capital are significantly higher by at least 54 basis points[168] in all cases and on average 115 basis points higher.[169] Please note that I do not endorse this method, but simply demonstrate how the witnesses materially understate the ROE by being inconsistent with their interest rates usage in their risk premium models.

[168] Mr. Walters' adjusted 10.77% less his 10.23% ROE result.

[169] Average spread between ROE using only historical bond yield less ROE as reported from Figure 14.

Figure 14: Update of Mr. Megginson's, Mr. Coppola's, and Mr. Walters' Risk Premium Analyses[170]

	Historical Bond Yield	Current or Projected Bond Yield	Historical Risk Premium as Reported	ROE as Reported	ROE Using Only Historical Bond Yield
Mr. Megginson					
Utility Bond Approach (A-Rated)	7.14%	5.76%	3.80%	9.56%	10.94%
Treasury Bond Approach	5.73%	4.25%	5.21%	9.46%	10.94%
Mr. Coppola Utility Bond Approach	7.14%	5.40%	3.80%	9.20%	10.94%
Mr. Walters					
Treasury Bond Approach	5.14%	4.60%	5.63%	10.23%	10.77%
3-Month Average Yields					
Utility Bond Approach (A-Rated)	6.50%	5.51%	4.27%	9.78%	10.77%
Utility Bond Approach (Baa-Rated)	6.70%	5.71%	4.27%	9.98%	10.97%
6-Month Average Yields					
Utility Bond Approach (A-Rated)	6.50%	5.46%	4.27%	9.73%	10.77%
Utility Bond Approach (Baa-Rated)	6.70%	5.67%	4.27%	9.94%	10.97%

Q. Do you have any additional concerns with the Risk Premium analysis conducted by Mr. Coppola?

A. Yes. As discussed previously in my response to Mr. Coppola's CAPM analysis, he relies on an outdated near-term projected risk-free rate as of October 2024 from the *Blue Chip Financial Forecasts* when more current data is available, particularly when his testimony was filed on April 23, 2025.[171]

[170] Megginson Exhibit S-4, Schedule D-5; Coppola workpapers; Walters Exhibit AB-15, Exhibit AB-16, and Exhibit AB-18. Mr. Walters uses the same risk premium derived from A-rated utility bonds as he does for Baa-rated utility bonds. As a result, the 6.70% historical Baa-rated bond is implied.

[171] Coppola Exhibit AG-44 and Exhibit AG-45.

Q. What are the positions offered by Mr. Megginson, Mr. Coppola, Mr. Bandyk, and Mr. Walters regarding your Risk Premium analyses?

A. The following summarizes the reasons offered by each of these witnesses to suggest that my Risk Premium approach should be given little weight or not be relied upon:[172]

- Mr. Megginson and Mr. Coppola claim that my Risk Premium analyses reflect a simplistic inverse relationship between equity risk premiums and interest rates and contend that this relationship can be influenced by factors other than interest rates.[173]

- Mr. Megginson and Mr. Coppola oppose the use of my Risk Premium analysis because they contend that authorized ROEs are not market behavior but rather a reflection of regulator behavior.[174]

- Mr. Coppola objects that interest rates of up to 12.10% in the late 1980s are not comparable to today's environment, and therefore should not be included in a BYRP analysis.[175]

- Mr. Walters believes that my BYRP analysis uses electric utilities and uses overstated equity risk premiums.[176]

- Mr. Bandyk believes that authorized ROEs used as an input in my BYRP have been "excessive." Mr. Bandyk rejects my BYRP and does not perform one himself.[177]

- Mr. Walters believes that my BYRP analysis is predicated on an overstated risk premium.[178]

[172] Megginson Direct, at 35. Walters Direct, at 73. Coppola Direct, at 138. Bandyk Direct, at 24.
[173] Megginson Direct, at 34-35; Coppola Direct, at 138.
[174] *Id*.
[175] Coppola Direct, at 138.
[176] Walters Direct, at 72.
[177] Bandyk Direct, at 24-25.
[178] Walters Direct, at 73.

Q. Is there any validity to Mr. Megginson's or Mr. Coppola's claims regarding your Risk Premium analyses?

A. No. While authorized ROEs are not "market data," it is unreasonable to suggest that investors are not aware of authorized ROEs and do not consider them in their assessment of the value of a utility stock. Recent market data demonstrates that unconstructive ROEs have resulted in sharp declines in utility stock prices, as well as commentary from equity analysts and rating agencies. Accordingly, it is appropriate for the Commission to accept and consider the results of my Risk Premium analyses. In addition, while I disagree with his approach, Mr. Walters also relies on a risk premium-based methodology as one of the methodologies he uses to estimate the cost of equity.

Q. Do you agree with Mr. Megginson that it is more appropriate to use historical authorized ROEs for comparison as opposed to an input in your BYRP analysis?[179]

A. No. As discussed in my direct testimony, it is important to recognize that both academic literature and market evidence have identified a relationship between the equity risk premium and the level of interest rates (i.e. as interest rates increase, the equity risk premium decreases, and vice versa). Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. Accordingly, I have developed such an analysis based on a regression of the risk premium as a function of 30-year Treasury bond yields. As discussed, neither Mr. Megginson's nor Mr. Coppola's Risk Premium analyses appropriately account for this inverse relationship, and I have

[179] Megginson Direct at 35.

demonstrated that their use of an historical average market risk premium fails to account for this inverse relationship. Therefore, there is no basis to Mr. Megginson's suggestion that the results of my Risk Premium analysis do not appear to align simply because I do not utilize a historical market risk premium, but rather appropriately apply the regression results of the historical data to the current and projected interest rates.

Q. Do you agree with Mr. Megginson and Mr. Coppola that your Risk Premium results are invalid because you have not considered other factors in addition to interest rates in your regression analyses?

A. No. Mr. Megginson and Mr. Coppola fail to recognize the large body of research that supports the inverse relationship between equity risk premia and interest rates and have failed to present any research to support their positions. For example, Berry (1998) came to similar conclusions regarding the inverse relationship between interest rates and the risk premia.[180] Also, as summarized in *New Regulatory Finance*:

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates—rising when rates fell and declining when interest rates rose. The reason for this relationship is that when interest rates rise, bondholders suffer a capital loss. This is referred to as interest rate risk…. Conversely in low interest rate environments, when bondholders' interest rate fears subside and shareholders' fears of loss of earning power dominate, the risk differential will widen and hence the risk premium will increase.[181]

[180] S. Keith Berry, "Interest Rate Risk and Utility Risk Premia during 1982-93," *Managerial and Decision Economics*, Vol. 19, No. 2, March, 1998.

[181] Dr. Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., 2006, at 128.

In his more recent textbook, *Modern Regulatory Finance*, Dr. Morin outlines the issues and academic research and concludes the following with respect to the relationship between interest rates and the equity risk premium:

> This is particularly true in a high inflation environment. Interest rates rise as a result of accelerating inflation, and the interest rate risk of bonds intensifies more than the earnings of common stocks, which are partially hedged from the ravages of inflation. This phenomenon has been termed as a "lock-in" premium. Conversely, in low interest rate environments, when bondholders' interest rate fears subside and shareholders' fears of loss of earnings power dominate, the risk differential will widen and hence the risk premium will increase.
>
> Published empirical studies demonstrate that risk premiums vary inversely with the level of interest rates, rising when rates fell and declining when interest rates rose. Studies by Brigham, Shone, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), and Morin 2020), and others ***demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when rates rose***.[182]

These studies demonstrate that my Risk Premium analysis is consistent with academic and scholarly research. Mr. Megginson and Mr. Coppola do not present any academic studies that refute the bases and methodology that I have used in my Risk Premium analyses.

[182] Roger A. Morin, *Modern Regulatory Finance*, Public Utilities Reports, Inc., 2021, at 146; graphic referenced in cite and shown in text has been omitted.

Q. Does the regression analysis that you have conducted for your Risk Premium analysis demonstrate a strong inverse relationship between interest rates and the equity risk premium?

A. Yes. As shown both in my direct testimony on Exhibit A-14, Schedule D-5, page 22, and as updated herein on Exhibit A-127 (AEB-2), page 21, the regression equation for my Risk Premium analysis has an R^2 of approximately 0.86, which means that 86.00% of the variation in historical implied utility equity risk premia can be explained by changes in interest rates. The regression indicates that there indeed exists a strong negative correlation between utility equity risk premia and interest rates, and that the regression equation is an effective tool for predicting authorized ROEs at specified interest rate levels, whether current or projected interest rates. Mr. Megginson and Mr. Coppola fail to address this strong relationship demonstrated by the data in my Risk Premium analysis, which invalidates the critiques offered by Mr. Megginson that there are "numerous" factors that are unaccounted for in my analyses and by Mr. Coppola that regulators establish "ROEs based on many factors" that are not in lock-step with interest rates.[183]

Q. Do you agree with Mr. Megginson and Mr. Coppola that your Risk Premium methodology does not measure investor behavior and is therefore invalid?

A. No. As noted previously, it is unquestionable that both credit rating agencies and investors consider the authorized ROE data in their determination of the valuation of utility stocks. As I discussed both earlier in this rebuttal testimony and in my direct testimony, both credit rating agencies and investors have responded negatively to authorized ROEs deemed to be

[183] Megginson Direct, at 35; Coppola Direct, at 138.

too low.[184] Therefore, the relationship between recently authorized ROEs and the prevailing interest rates at the time that the ROE was authorized is reasonable to consider when setting the ROE in the context of a rate proceeding.

Moreover, it is important to recognize the inconsistency in both Mr. Megginson's and Mr. Coppola's position regarding the reliance of authorized ROEs in the Risk Premium analysis. Each of these witnesses suggest that my Risk Premium approach cannot be relied upon because the authorized ROEs reflect regulatory commission behavior and not investor behavior. However, despite that claim, both Mr. Megginson and Mr. Coppola evaluate the same authorized ROE and 30-year Treasury bond yield data that I use in my Risk Premium analyses in their own testimony as support for their recommended ROEs for the Company in this proceeding.[185] Therefore, Mr. Megginson and Mr. Coppola are inconsistent in their positions on the use of this information, seeking only to rely on it in establishing their own ROE recommendations while disregarding the historical relationship developed in my Risk Premium approach.

Q. Please respond to Mr. Coppola's concern that interest rates of the 1980s are not comparable to today's interest rates.

A. The high interest rates of the 1980s correspond with high authorized natural gas ROEs. Therefore, as seen in Exhibit A-14, Schedule D-5, page 23, of my direct testimony, the individual risk premium data points from the 1980s are comparable, if not lower than risk premiums in recent quarters.

[184] Bulkley Direct, at 39-47.

[185] Megginson Direct, at 34-35; Coppola Direct, at 146, Exhibit AG-45, and Exhibit AG-48.

Mr. Coppola undermines his own methods with his critique by relying on the very type of data he dismisses. While he takes issue with my use of data from the 1980s in the BYRP, he has no problem using historical equity and bond data, not only from the same period, but going as far back as 1952 in his Risk Premium approach.[186]

Q. Please respond to Mr. Walters' claim that your risk premium is overstated.

A. As a threshold matter, I use natural gas authorized ROEs in my BYRP analysis, not electric authorized ROEs as Mr. Walters states.[187]

Mr. Walters' claim that my risk premium is overstated is based on his own long-term historical average risk premium. However, as discussed earlier, his long-term average risk premium does not reflect current market conditions and bond yields. As shown on Mr. Walters' Exhibit AB-15, Mr. Walters' long-term historical average risk premium over 30-year Treasury bond yields is 5.63%, but his long-term historical average 30-year Treasury bond yield is 5.14%. This is despite Mr. Walters acknowledging that current 30-year Treasury bond yields are lower at approximately 4.60%.[188] Therefore, based on the inverse relationship between interest rates and the equity risk premium, an interest rate that is lower than the historical average means that the equity risk premium should be higher than his historical average of 5.63% – which is the case for my analysis. Therefore, Mr. Walters's criticism of my BYRP analyses is unfounded.

[186] Coppola Direct, at 137.
[187] Walters Direct, at 72.
[188] Walters Direct, at 46.

Q. What is Mr. Bandyk's position regarding your Risk Premium analyses?

A. Mr. Bandyk states that the results of my Risk Premium analyses should be disregarded because it relies on the ROEs authorized by other commissions, which he argues is not objective data but rather reflects the fact that regulatory commissions have historically and consistently authorized excessive ROEs for utilities.[189]

Q. Is there any merit to Mr. Bandyk's position regarding your Risk Premium analyses?

A. No. As I discussed previously, there is no merit to Mr. Bandyk's claim that regulatory commissions have consistently authorized "excessive" ROEs.

Q. Do any witnesses use regression analysis?

A. No.

Q. What are some benefits of using regression analysis as opposed to reviewing simple averages?

A. The benefit of conducting a regression analysis is that the resulting predictive equation can be used to estimate a *forward-looking* equity risk premium corresponding to *any* interest rate one wishes to specify. By specifying the interest rate projected for the time period that the Company's rates from this proceeding will be in effect, one can estimate an equity risk premium (and thus an ROE) for the *forward-looking* time period that corresponds with the rates that are set in this proceeding.

While using average authorized ROEs can be useful starting point for analysis, regression analysis formalizes comparing previous ROEs in a systematic way that allows for forward-looking estimating. Regression analysis is a common forecasting tool.

[189] Bandyk Direct, at 24-25.

X. SUMMARY OF THE ADJUSTED RESULTS

Q. Have you considered how the ROE recommendations of Mr. Megginson, Mr. Coppola, Mr. Bandyk, and Mr. Walters would change if their cost of equity analyses were corrected for the issues you have identified with each of their analyses?

A. Yes, I evaluate how each of these witnesses' ROE recommendations would change once their analyses are updated and corrected.

Q. How do the results of Mr. Megginson's cost of equity analyses change if the issues that you have identified are addressed with each of his analyses?

A. Figure 15 presents the results of Mr. Megginson's cost of equity analyses based on the updates and corrections to those analyses that I have discussed. As shown, when the results of Mr. Megginson's cost of equity analyses based on the updates and corrections to those analyses that I have discussed are considered, the average cost of equity resulting from his analyses is 10.68%, which is greater than the Company's requested ROE of 10.25% in this proceeding.

Figure 15: Results of Mr. Megginson's as Filed and Adjusted Cost of Equity Analyses

		Mr. Megginson As Filed	Mr. Megginson As Adjusted
Constant Growth DCF	[1]	9.40%	10.58%
CAPM			
Historical MRP		10.63%	11.53%
Projected Market Risk Premium			
Proj. Retrun on S&P 500 Less Risk-free Rate		n/a	11.41%
Damodaran (4.35%)		8.25%	n/a
Damodaran (6.18%)		9.93%	n/a
Average	[2]	9.60%	11.47%
Risk Premium			
Utility Bond Risk Premium (A-rated)		9.56%	10.94%
Treasury Bond Risk Premium		9.46%	10.94%
Average	[3]	9.51%	10.94%
Authorized ROEs			
2024 Avg. Auth'd Gas ROE	[4]	9.72%	9.72%
Average of [1], [2], [3], [4]		**9.56%**	**10.68%**
Recommended ROE		9.75%	
Company's Proposed ROE			10.25%

Q. How do the results of Mr. Coppola's cost of equity analyses change if the issues that you have identified are addressed with each of his analyses?

A. Figure 16 presents the results of Mr. Coppola's cost of equity analyses based on the updates and corrections to his analyses that I have discussed. As shown, Mr. Coppola applies a 50% weighting to the result of his constant growth DCF and a 25% weighting each to the results of his CAPM and Risk Premium analyses. As shown in Figure 16, applying these same weightings to the updates and corrections to Mr. Coppola's analyses produces a cost

of equity of 10.51%, which supports the Company's requested ROE of 10.25% in this proceeding.

Figure 16: Results of Mr. Coppola's as Filed and Adjusted Cost of Equity Analyses

	Model Weighting	As Filed	As Adjusted
Constant Growth DCF	50.00%	9.11%	9.79%
CAPM	25.00%	10.66%	11.50%
Risk Premium	25.00%	9.20%	10.94%
Wgtd. Avg. Cost of Equity		**9.52%**	**10.51%**
Recommended ROE		9.75%	
Company's Proposed ROE			10.25%

Q. How do the results of Mr. Walters's cost of equity analyses change if the issues that you have identified are addressed with each of his analyses?

A. Figure 17 summarizes the results of Mr. Walters' cost of equity models based on the adjustments to his analyses that I have discussed. Based on these changes, the average results of each of Mr. Walters' three analyses range from 10.38% to 11.05%, with a midpoint of 10.72%, which supports the Company's proposed ROE of 10.25%, and is significantly greater than Mr. Walters' recommended ROE of 9.45%.

Figure 17: Results of Mr. Walters's As-Filed and Adjusted Cost of Equity Analyses[190]

	Mr. Walters As Filed		Mr. Walters As Adjusted	
	Mean	**Median**	**Mean**	**Median**
DCF				
Constant Growth (analyst growth rates)	13.54%	10.74%	n/a	11.05%
Constant Growth (sustainable growth rates)	8.70%	8.38%	n/a	n/a
Multi-Stage	9.26%	8.47%	n/a	n/a
Average	**9.85%**		**11.05%**	
Risk Premium				
Near-Term Projected Treasury Bond Yield	10.23%		10.77%	
3-Month Avg. A-rated Utility Bond Yield	9.78%		10.77%	
3-Month Avg. Baa-rated Utility Bond Yield	9.98%		10.97%	
6-Month Avg. A-rated Utility Bond Yield	9.73%		10.77%	
6-Month Avg. Baa-rated Utility Bond Yield	9.94%		10.97%	
Average	**9.93%**		**10.85%**	
CAPM				
Kroll Normalized Method:	8.66%		n/a	
Risk Premium Method:	10.11%		10.11%	
FERC DCF Method:	10.65%		10.65%	
Average	**9.81%**		**10.38%**	
Midpoint	**9.83%**		**10.72%**	
Recommended ROE	9.45%			
Company's Proposed ROE			10.25%	

Q. Lastly, how do the results of Mr. Bandyk's cost of equity analyses change if the issues that you have identified are addressed with each of his analyses?

A. Figure 18 presents the results of Mr. Bandyk's cost of equity analyses based on the updates and corrections to his analyses that I have discussed. As shown, Mr. Bandyk calculates his

[190] The mean constant growth DCF result using projected EPS growth rates was excluded due to a projected EPS growth rate for California Water Service Group of approximately 42% from *Zacks*, S&P and I/B/E/S, which has a significant effect on the average. It is more appropriate to rely on the median which is not affected to a large degree by the presence of outliers.

recommended ROE by taking the average of the results of his two cost of equity analyses, and then average that result with the Company's currently authorized ROE. I disagree with this approach for determining the ROE in this proceeding given that the existing authorized ROE is not representative of the current or projected capital market conditions during the period in which the rates established in this proceeding will be in effect. Therefore, a more appropriate ROE recommendation for the Company based on Mr. Bandyk's corrected cost of equity analyses would be the average of the results of his DCF and CAPM analyses, which is 10.48% and is greater than the Company's requested ROE of 10.25% in this proceeding. Nonetheless, even if the same approach that Mr. Bandyk applies for determining his recommended ROE is applied, the recommended ROE is still 10.19%, or substantially higher than the 9.24% that he reflects in his testimony.

Figure 18: Results of Mr. Bandyk's As-Filed and Adjusted Cost of Equity Analyses

	As Filed	As Adjusted
DCF	9.22%	10.99%
CAPM	7.95%	9.96%
Average	8.59%	10.48%
Consumers Existing ROE	9.90%	9.90%
Recommended ROE	**9.24%**	**10.19%**

XI. BUSINESS RISK

Q. What are Mr. Megginson's, Mr. Coppola's, Mr. Bandyk's, and Mr. Walters' positions regarding the business and financial risks of the Company relative to the ROE that should be authorized for the Company in this proceeding?

A. The witnesses have the following positions:

- Mr. Megginson testifies that: Consumers Energy experiences enhanced infrastructure replacement and decoupling, has experienced several years with positive net income growth,[191] and believes that the Commission's prior approval of the Company's main replacement program, as well as other programs and surcharge mechanisms to pay for those programs, "all but ensure recovery and reduces the Company's overall business and financial risk,"[192] and that Consumers Energy's filing every 12-months "borders on a 100% risk-free investment."[193]

- Mr. Coppola claims that his proxy group is riskier than Consumers Energy due to other non-regulated business operations and higher financial leverage.[194]

- Mr. Bandyk dismisses the use of commission rankings as a measure of regulatory risk,[195] and believes that the Company does not possess additional business risk as a result of large capital expenditures and having fewer mechanisms relative to my proxy group.[196]

- Mr. Walters cites an S&P stable outlook and a Barclays analyst who believes that Consumers Energy's parent CMS Energy has financially performed strongly, as evidence that the Company is financially healthy and a lower ROE is warranted.[197]

- None of the witnesses address flotation costs.

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191 Megginson Direct, at 6-10.
192 *Id*., at 37
193 *Id*.
194 Coppola Direct, at 145.
195 Bandyk Direct, at 9.
196 *Id*., at 27-32.
197 Walters Direct, at 28.

Q. Is Mr. Megginson correct about the mechanisms that Consumers Energy currently has available to facilitate timely recovery of costs?

A. Not entirely. As discussed in the testimony of Mr. Bleckman, Consumers Energy does not currently have a decoupling mechanism and currently does not have a surcharge for an Enhanced Infrastructure Replacement Program. Further, while Staff references the Company's Gas Cost Recovery Mechanism and Energy Waste Reduction programs, neither of these programs provides for the recovery of investments made to improve or replace the Company's infrastructure.

Q. Has Mr. Megginson conducted any analysis to support his position that Consumers Energy has less risk as a result of rate mechanisms?

A. No. As noted in the testimony of Mr. Bleckman, the mechanisms that Mr. Megginson references are not implemented by Consumers Energy, and therefore it is not possible for such mechanisms to be risk reducing factors. Further, even if Consumers Energy did have certain mechanisms, in order to determine whether or not the risk mitigation should be considered in setting the ROE, it is necessary to review what types of mechanisms have been implemented by the proxy group companies, and therefore are reflected in the market data that is used to estimate the ROE. Mr. Megginson has not done that analysis, nor could he, since the mechanisms that he references are not implemented by Consumers Energy, or the mechanisms do not recover infrastructure improvements. As discussed in my direct testimony, I evaluate Consumers Energy's business and regulatory risk relative to the operating utilities of the proxy group and, based on that analysis, demonstrate that Consumers Energy has moderately greater regulatory risk as compared to the operating

subsidiaries of the proxy group companies given the more-timely cost recovery of the proxy group companies.

Q. Please respond to Mr. Megginson's analysis of Consumers steady earnings.

A. Mr. Megginson's analysis is incomplete and inconclusive. Mr. Megginson reviews the Company's annual change in net income in complete isolation, without considering the changes in investment over time or the changes in rate base.[198] To the extent that the Company has invested in the system over the period from 2010 through 2024, its net income should increase. However, the analysis does nothing to demonstrate that the increases in net income are sufficient to satisfy the investor-required return on that investment, nor does it conclude anything meaningful about the Company's financial integrity. Accordingly, in its current form, this analysis cannot be used to conclude anything meaningful about the Company's earnings or its financial integrity and should be disregarded.

Q. Please respond to Mr. Megginson's claim that the frequency of Consumers Energy's rate filings "borders on a risk-free investment for the Company."[199]

A. No, filing a rate case is not akin to a risk-free investment. If Mr. Megginson's claim was correct, investors would flood Consumers Energy with capital and bid up its bond prices. The Company's bond yields would converge to risk-free government Treasury yields. Mr. Megginson's claim ignores principles of finance including the risk-reward tradeoff, opportunity cost, and regulatory risk, and he has provided no support for his claim.

[198] Megginson Direct, at 9.
[199] *Id*., at 37.

Q. Has Mr. Coppola performed an analysis that his proxy group is riskier than Consumers Energy?

A. No. Mr. Coppola simply claims this because some proxy group companies have non-regulated business segments.[200] He does not refer to specific companies nor does he attempt to measure any impact of non-regulated activities of his proxy group. On the other hand, my proxy screening criteria involves quantifying companies' non-regulated operating incomes. Companies in my proxy group who derive some operating income from non-regulated activities have similar cost of equity estimates to companies that derive 100% operating income from regulated operations. Furthermore, when discussing regulatory and business risk in my direct testimony, I only consider regulated business operations of my proxy group for comparability.[201] Therefore, Mr. Coppola's claim that his proxy group, or mine for that matter, is riskier than the Company is baseless.

Q. Is Mr. Bandyk's rejection of considering regulatory environment rankings reasonable?

A. No. Mr. Bandyk believes that the rankings "appear to be judgments for how generous utility commissions tend to be with the ROEs they tend to grant utilities."[202] This is incorrect. A recent publication that summarizes commission rankings from S&P Global Ratings states that:

> We assess all North America's regulatory jurisdictions as credit supportive or better, reflecting the industry's generally stable and predictable cash flows (see chart 16). Over the past decade much of the industry has implemented regulatory mechanisms such as decoupling, interim rates,

[200] Coppola Direct, at 145.
[201] Bulkley Direct, at 33-47.
[202] Bandyk Direct, at 9.

> capital trackers, formula rate plans, forward test years, muti-year rate case filings, and regulatory riders to significantly improve cash flow stability while minimizing regulatory lag.[203]

The statement emphasizes cash flow, not "how generous" commissions are towards awarding ROEs. The rankings are simply an additional input for the Commission to consider in their decision.

Q. Do you agree with Mr. Bandyk's assessment of the risk factors that you evaluated?

A. No. Mr. Bandyk rejects the notion that the Company has additional risk that should be considered. Rather, he believes that relative to the proxy group, the Company's lower capital expenditure and the absence of comparable rate mechanisms do not support my position that the Company faces more risk.[204]

To be clear, the capital investment analysis in my direct testimony concludes that Consumers Energy faces slightly higher risk than the proxy group because it has a significant capital spending plan and does not have a mechanism to recover those investments. In comparison, the majority of the proxy group companies have some form of capital tracking mechanism. Therefore, Consumers Energy has slightly higher risk than the proxy group on this basis.

Mr. Bandyk's alternative analysis confirms my conclusion that the Company has fewer mechanisms relative to the proxy company. Mr. Bandyk compares rate mechanisms between Consumers Energy and my proxy group using an alternative weighting. His alternative method equally weights proxy group companies instead of my equal weighting

[203] S&P Global Ratings. "North America Regulated Utilities: Capex and climate change pressures credit quality." Industry Credit Outlook 2025. January 14, 2025.

[204] Bandyk Direct, at 26-32.

to each subsidiary such that each of my six proxy group companies receive a 1/6th (i.e. an approximately 16.67%) weight. Although I disagree with Mr. Bandyk's method of limiting subsidiary weights by parent company in the proxy group, his results still show that most companies in my proxy group have more capital investment recovery mechanisms than Consumers Energy. [205]

Q. Do you agree with Mr. Megginson that a utility should not recover flotation costs if the equity is issued at the parent company level?

A. No. Mr. Megginson's position with respect to the recovery of flotation costs related to equity issuances is inconsistent with his position on the recovery of the costs associated with debt issuances.[206] Mr. Megginson acknowledges that the cost of debt issuances should be and are recovered by utilities; however, he suggests that the cost of issuing equity should be born at the parent company level because that is where equity is issued. I disagree entirely. The cost of equity capital that is raised on behalf of the operating company results in a permanent reduction in the overall capital that is received through an issuance and is properly reflected in the cost of equity for the operating company that is in receipt of the equity capital.

Q. Does this conclude your rebuttal testimony?

A. Yes.

[205] Bandyk Direct, at 28-29.
[206] Megginson Direct, at 25.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

EXHIBITS

OF

ANN E. BULKLEY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

COST OF EQUITY ANALYSES
SUMMARY OF RESULTS

Constant Growth DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.99%	10.86%	11.68%
90-Day Avg. Stock Price	10.09%	10.97%	11.78%
180-Day Avg. Stock Price	10.17%	11.05%	11.86%
Average	10.08%	10.96%	11.77%
Median Results:			
30-Day Avg. Stock Price	9.78%	10.91%	12.14%
90-Day Avg. Stock Price	9.92%	11.06%	12.28%
180-Day Avg. Stock Price	10.10%	11.24%	12.47%
Average	9.93%	11.07%	12.30%

CAPM / ECAPM / Bond Yield Risk Premium

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.25%	11.23%	11.22%
Current Bloomberg Beta	10.11%	10.05%	10.02%
Long-term Avg. *Value Line* Beta	10.23%	10.18%	10.14%
ECAPM:			
Current *Value Line* Beta	11.42%	11.40%	11.39%
Current Bloomberg Beta	10.56%	10.52%	10.49%
Long-term Avg. *Value Line* Beta	10.65%	10.61%	10.59%
Bond Yield Risk Premium	10.55%	10.41%	10.33%

30-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Capital IQ Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	$3.48	$152.74	2.28%	2.36%	6.00%	7.20%	7.47%	6.89%	8.35%	9.25%	9.83%
NiSource Inc.	NI	$1.12	$39.15	2.86%	2.98%	9.50%	7.90%	7.96%	8.45%	10.87%	11.43%	12.50%
Northwest Natural Gas Company	NWN	$1.96	$42.13	4.65%	4.82%	6.50%	n/a	8.25%	7.38%	11.30%	12.20%	13.09%
ONE Gas, Inc.	OGS	$2.68	$75.20	3.56%	3.65%	4.00%	5.60%	5.17%	4.92%	7.64%	8.57%	9.26%
Southwest Gas Corporation	SWX	$2.48	$72.58	3.42%	3.58%	10.00%	9.50%	n/a	9.75%	13.08%	13.33%	13.59%
Spire, Inc.	SR	$3.14	$76.80	4.09%	4.21%	4.50%	6.50%	7.54%	6.18%	8.68%	10.39%	11.78%
Mean		$2.48	$76.43	3.48%	3.60%	6.75%	7.34%	7.28%	7.26%	9.99%	10.86%	11.68%
Median		$2.58	$73.89	3.49%	3.62%	6.25%	7.20%	7.54%	7.13%	9.78%	10.91%	12.14%

Notes:
[1] Bloomberg Professional as of April 25, 2025
[2] Bloomberg Professional 30-day average as of April 25, 2025
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Zacks
[7] Capital IQ
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

90-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Capital IQ Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	3.48	$146.67	2.37%	2.45%	6.00%	7.20%	7.47%	6.89%	8.44%	9.34%	9.93%
NiSource Inc.	NI	1.12	$38.31	2.92%	3.05%	9.50%	7.90%	7.96%	8.45%	10.94%	11.50%	12.56%
Northwest Natural Gas Company	NWN	1.96	$40.98	4.78%	4.96%	6.50%	n/a	8.25%	7.38%	11.44%	12.33%	13.23%
ONE Gas, Inc.	OGS	2.68	$72.49	3.70%	3.79%	4.00%	5.60%	5.17%	4.92%	7.77%	8.71%	9.40%
Southwest Gas Corporation	SWX	2.48	$73.04	3.40%	3.56%	10.00%	9.50%	n/a	9.75%	13.06%	13.31%	13.57%
Spire, Inc.	SR	3.14	$73.02	4.30%	4.43%	4.50%	6.50%	7.54%	6.18%	8.90%	10.61%	12.00%
Mean		$2.48	$74.08	3.58%	3.71%	6.75%	7.34%	7.28%	7.26%	10.09%	10.97%	11.78%
Median		$2.58	$72.75	3.55%	3.67%	6.25%	7.20%	7.54%	7.13%	9.92%	11.06%	12.28%

Notes:
[1] Bloomberg Professional as of April 25, 2025
[2] Bloomberg Professional 90-day average as of April 25, 2025
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Zacks
[7] Capital IQ
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

180-DAY CONSTANT GROWTH DCF

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Projected EPS Growth Rate	[6] Zacks Projected EPS Growth Rate	[7] Capital IQ Projected EPS Growth Rate	[8] Average Projected EPS Growth Rate	[9] Cost of Equity: Minimum Growth Rate	[10] Cost of Equity: Mean Growth Rate	[11] Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	$3.48	$142.59	2.44%	2.52%	6.00%	7.20%	7.47%	6.89%	8.51%	9.41%	10.00%
NiSource Inc.	NI	$1.12	$36.47	3.07%	3.20%	9.50%	7.90%	7.96%	8.45%	11.09%	11.65%	12.72%
Northwest Natural Gas Company	NWN	$1.96	$40.67	4.82%	5.00%	6.50%	n/a	8.25%	7.38%	11.48%	12.37%	13.27%
ONE Gas, Inc.	OGS	$2.68	$72.35	3.70%	3.80%	4.00%	5.60%	5.17%	4.92%	7.78%	8.72%	9.41%
Southwest Gas Corporation	SWX	$2.48	$73.44	3.38%	3.54%	10.00%	9.50%	n/a	9.75%	13.04%	13.29%	13.55%
Spire, Inc.	SR	$3.14	$69.72	4.50%	4.64%	4.50%	6.50%	7.54%	6.18%	9.11%	10.82%	12.21%
Mean		$2.48	$72.54	3.65%	3.78%	6.75%	7.34%	7.28%	7.26%	10.17%	11.05%	11.86%
Median		$2.58	$71.03	3.54%	3.67%	6.25%	7.20%	7.54%	7.13%	10.10%	11.24%	12.47%

Notes:
[1] Bloomberg Professional as of April 25, 2025
[2] Bloomberg Professional 180-day average as of April 25, 2025
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Zacks
[7] Capital IQ
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND VALUE LINE BETA

$$K = Rf + \beta (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.68%	0.90	11.92%	7.24%	11.19%	11.37%
NiSource Inc.	NI	4.68%	0.95	11.92%	7.24%	11.55%	11.64%
Northwest Natural Gas Company	NWN	4.68%	0.90	11.92%	7.24%	11.19%	11.37%
ONE Gas, Inc.	OGS	4.68%	0.85	11.92%	7.24%	10.83%	11.10%
Southwest Gas Corporation	SWX	4.68%	0.95	11.92%	7.24%	11.55%	11.64%
Spire, Inc.	SR	4.68%	0.90	11.92%	7.24%	11.19%	11.37%
Mean						11.25%	11.42%
Median						11.19%	11.37%

Notes:
[1] Bloomberg Professional 30-day average as of April 25, 2025
[2] Value Line
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA

$$K = Rf + \beta\,(Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q3 2025 - Q3 2026)	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.44%	0.90	11.92%	7.48%	11.17%	11.35%
NiSource Inc.	NI	4.44%	0.95	11.92%	7.48%	11.54%	11.63%
Northwest Natural Gas Company	NWN	4.44%	0.90	11.92%	7.48%	11.17%	11.35%
ONE Gas, Inc.	OGS	4.44%	0.85	11.92%	7.48%	10.79%	11.07%
Southwest Gas Corporation	SWX	4.44%	0.95	11.92%	7.48%	11.54%	11.63%
Spire, Inc.	SR	4.44%	0.90	11.92%	7.48%	11.17%	11.35%
Mean						11.23%	11.40%
Median						11.17%	11.35%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 44, No. 5, May 1, 2025, at 2
[2] Value Line
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA

$$K = Rf + \beta (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2026 - 2030)	[2] Beta	[3] Market Return	[4] Market Risk Premium	[5] Cost of Equity: CAPM	[6] Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.30%	0.90	11.92%	7.62%	11.15%	11.34%
NiSource Inc.	NI	4.30%	0.95	11.92%	7.62%	11.53%	11.63%
Northwest Natural Gas Company	NWN	4.30%	0.90	11.92%	7.62%	11.15%	11.34%
ONE Gas, Inc.	OGS	4.30%	0.85	11.92%	7.62%	10.77%	11.06%
Southwest Gas Corporation	SWX	4.30%	0.95	11.92%	7.62%	11.53%	11.63%
Spire, Inc.	SR	4.30%	0.90	11.92%	7.62%	11.15%	11.34%
Mean						11.22%	11.39%
Median						11.15%	11.34%

Notes:

[1] Blue Chip Financial Forecasts, Vol. 43, No. 12, November 27, 2024, at 14

[2] Value Line

[3] Market Return

[4] Equals [3]-[1]

[5] Equals [1] + [2] x [4]

[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND BLOOMBERG BETA

$$K = Rf + \beta (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.68%	0.73	11.92%	7.24%	9.98%	10.46%
NiSource Inc.	NI	4.68%	0.78	11.92%	7.24%	10.33%	10.72%
Northwest Natural Gas Company	NWN	4.68%	0.68	11.92%	7.24%	9.62%	10.19%
ONE Gas, Inc.	OGS	4.68%	0.75	11.92%	7.24%	10.08%	10.54%
Southwest Gas Corporation	SWX	4.68%	0.82	11.92%	7.24%	10.59%	10.92%
Spire, Inc.	SR	4.68%	0.75	11.92%	7.24%	10.07%	10.53%
Mean						10.11%	10.56%
Median						10.08%	10.54%

Notes:
[1] Bloomberg Professional 30-day average as of April 25, 2025
[2] Bloomberg Professional
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR TERM PROJECTED RISK-FREE RATE AND BLOOMBERG BETA

$$K = Rf + \beta (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q3 2025 - Q3 2026)	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.44%	0.73	11.92%	7.48%	9.91%	10.41%
NiSource Inc.	NI	4.44%	0.78	11.92%	7.48%	10.28%	10.69%
Northwest Natural Gas Company	NWN	4.44%	0.68	11.92%	7.48%	9.54%	10.14%
ONE Gas, Inc.	OGS	4.44%	0.75	11.92%	7.48%	10.02%	10.49%
Southwest Gas Corporation	SWX	4.44%	0.82	11.92%	7.48%	10.54%	10.89%
Spire, Inc.	SR	4.44%	0.75	11.92%	7.48%	10.01%	10.49%
Mean						10.05%	10.52%
Median						10.01%	10.49%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 44, No. 5, May 1, 2025, at 2
[2] Bloomberg Professional
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK-FREE RATE AND BLOOMBERG BETA

$$K = Rf + \beta (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2026 - 2030)	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.30%	0.73	11.92%	7.62%	9.87%	10.38%
NiSource Inc.	NI	4.30%	0.78	11.92%	7.62%	10.24%	10.66%
Northwest Natural Gas Company	NWN	4.30%	0.68	11.92%	7.62%	9.50%	10.10%
ONE Gas, Inc.	OGS	4.30%	0.75	11.92%	7.62%	9.98%	10.46%
Southwest Gas Corporation	SWX	4.30%	0.82	11.92%	7.62%	10.52%	10.87%
Spire, Inc.	SR	4.30%	0.75	11.92%	7.62%	9.98%	10.46%
Mean						10.02%	10.49%
Median						9.98%	10.46%

Notes:

[1] Blue Chip Financial Forecasts, Vol. 43, No. 12, November 27, 2024, at 14

[2] Bloomberg Professional

[3] Market Return

[4] Equals [3]-[1]

[5] Equals [1] + [2] x [4]

[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND LONG-TERM VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.68%	0.76	11.92%	7.24%	10.20%	10.63%
NiSource Inc.	NI	4.68%	0.78	11.92%	7.24%	10.29%	10.69%
Northwest Natural Gas Company	NWN	4.68%	0.73	11.92%	7.24%	9.93%	10.42%
ONE Gas, Inc.	OGS	4.68%	0.75	11.92%	7.24%	10.11%	10.56%
Southwest Gas Corporation	SWX	4.68%	0.84	11.92%	7.24%	10.74%	11.03%
Spire, Inc.	SR	4.68%	0.75	11.92%	7.24%	10.14%	10.58%
Mean						10.23%	10.65%
Median						10.17%	10.60%

Notes:

[1] Bloomberg Professional 30-day average as of April 25, 2025

[2] Source: LT Beta

[3] Market Return

[4] Equals [3]-[1]

[5] Equals [1] + [2] x [4]

[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q3 2025 - Q3 2026)	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.44%	0.76	11.92%	7.48%	10.14%	10.58%
NiSource Inc.	NI	4.44%	0.78	11.92%	7.48%	10.23%	10.65%
Northwest Natural Gas Company	NWN	4.44%	0.73	11.92%	7.48%	9.86%	10.37%
ONE Gas, Inc.	OGS	4.44%	0.75	11.92%	7.48%	10.05%	10.51%
Southwest Gas Corporation	SWX	4.44%	0.84	11.92%	7.48%	10.70%	11.00%
Spire, Inc.	SR	4.44%	0.75	11.92%	7.48%	10.08%	10.54%
Mean						10.18%	10.61%
Median						10.11%	10.56%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 44, No. 5, May 1, 2025, at 2
[2] Source: LT Beta
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2026 - 2030)	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.30%	0.76	11.92%	7.62%	10.11%	10.56%
NiSource Inc.	NI	4.30%	0.78	11.92%	7.62%	10.20%	10.63%
Northwest Natural Gas Company	NWN	4.30%	0.73	11.92%	7.62%	9.82%	10.34%
ONE Gas, Inc.	OGS	4.30%	0.75	11.92%	7.62%	10.01%	10.49%
Southwest Gas Corporation	SWX	4.30%	0.84	11.92%	7.62%	10.68%	10.99%
Spire, Inc.	SR	4.30%	0.75	11.92%	7.62%	10.04%	10.51%
Mean						10.14%	10.59%
Median						10.07%	10.53%

Notes:

[1] Blue Chip Financial Forecasts, Vol. 43, No. 12, November 27, 2024, at 14

[2] Source: LT Beta

[3] Market Return

[4] Equals [3]-[1]

[5] Equals [1] + [2] x [4]

[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

HISTORICAL BETA

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
Company	Ticker	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021	12/31/2022	12/31/2023	12/31/2024	Average
Atmos Energy Corporation	ATO	0.80	0.80	0.80	0.70	0.70	0.60	0.60	0.80	0.80	0.80	0.85	0.90	0.76
NiSource Inc.	NI	0.85	0.85	NMF	NMF	0.60	0.50	0.55	0.85	0.85	0.85	0.90	0.95	0.78
Northwest Natural Gas Company	NWN	0.65	0.70	0.65	0.65	0.70	0.60	0.60	0.80	0.85	0.80	0.80	0.90	0.73
ONE Gas, Inc.	OGS				0.70	0.70	0.65	0.65	0.80	0.80	0.80	0.80	0.85	0.75
Southwest Gas Corporation	SWX	0.80	0.85	0.80	0.75	0.80	0.70	0.70	0.95	0.95	0.90	0.90	0.95	0.84
Spire, Inc.	SR	0.65	0.70	0.70	0.70	0.70	0.65	0.65	0.85	0.85	0.85	0.85	0.90	0.75
Mean		0.75	0.78	0.74	0.70	0.70	0.62	0.63	0.84	0.85	0.83	0.85	0.91	0.77

Notes:
[1] Value Line, dated December 26, 2013.
[2] Value Line, dated December 31, 2014.
[3] Value Line, dated December 30, 2015.
[4] Value Line, dated December 29, 2016.
[5] Value Line, dated December 28, 2017.
[6] Value Line, dated December 27, 2018.
[7] Value Line, dated December 26, 2019.
[8] Value Line, dated December 30, 2020.
[9] Value Line, dated December 29, 2021.
[10] Value Line, dated December 30, 2022.
[11] Value Line, Dated December 29, 2023.
[12] Value Line, Dated December 27, 2024.

MARKET RISK PREMIUM DERIVED FROM S&P 500 INDEX

[1] Estimate of the S&P 500 Dividend Yield	1.52%
[2] Estimate of the S&P 500 Growth Rate	10.32%
[3] S&P 500 Estimated Required Market Return	11.92%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
LyondellBasell Industries NV	LYB	321.40	59.44	19,104.02	0.05%	9.02%	0.00%	7.03%	0.00%
American Express Co	AXP	700.59	264.81	185,522.94	0.51%	1.24%	0.01%	14.77%	0.08%
Verizon Communications Inc	VZ	4216.25	41.91	176,703.24	0.49%	6.47%	0.03%	2.62%	0.01%
Texas Pacific Land Corp	TPL	22.98	1334.63	30,676.20		0.48%			
Broadcom Inc	AVGO	4701.95	192.31	904,231.76		1.23%		23.48%	
Boeing Co/The	BA	754.01	177.95	134,175.27				31.75%	
Solventum Corp	SOLV	173.00	66.07	11,430.30				-0.35%	
Caterpillar Inc	CAT	477.93	306.45	146,462.27		1.84%			
JPMorgan Chase & Co	JPM	2783.00	243.55	677,798.75	1.88%	2.30%	0.04%	4.54%	0.09%
Chevron Corp	CVX	1746.72	138.73	242,322.36	0.67%	4.93%	0.03%	11.52%	0.08%
Coca-Cola Co/The	KO	4303.57	71.91	309,469.49	0.86%	2.84%	0.02%	5.69%	0.05%
AbbVie Inc	ABBV	1768.98	186.06	329,136.10	0.91%	3.53%	0.03%	16.08%	0.15%
Walt Disney Co/The	DIS	1807.79	90.28	163,207.18	0.45%	1.11%	0.01%	11.36%	0.05%
Corpay Inc	CPAY	70.25	322.03	22,622.58	0.06%			11.73%	0.01%
Extra Space Storage Inc	EXR	212.23	141.05	29,934.39	0.08%	4.59%	0.00%	2.83%	0.00%
Exxon Mobil Corp	XOM	4325.29	108.57	469,597.13	1.30%	3.65%	0.05%	7.58%	0.10%
Phillips 66	PSX	407.44	103.97	42,361.25		4.62%		24.39%	
General Electric Co	GE	1066.39	198.43	211,603.10	0.59%	0.73%	0.00%	18.48%	0.11%
HP Inc	HPQ	942.70	25.28	23,831.53	0.07%	4.58%	0.00%	1.55%	0.00%
Home Depot Inc/The	HD	993.93	357.58	355,408.83	0.99%	2.57%	0.03%	5.11%	0.05%
Monolithic Power Systems Inc	MPWR	47.88	583.72	27,946.97		1.07%			
International Business Machines Corp	IBM	929.40	232.41	216,001.06	0.60%	2.87%	0.02%	3.70%	0.02%
Johnson & Johnson	JNJ	2406.07	154.58	371,930.81	1.03%	3.36%	0.03%	7.00%	0.07%
Lululemon Athletica Inc	LULU	115.52	267.9	30,948.14					
McDonald's Corp	MCD	715.07	316.74	226,491.94	0.63%	2.24%	0.01%	8.53%	0.05%
Merck & Co Inc	MRK	2516.39	82.74	208,206.45	0.58%	3.92%	0.02%	14.62%	0.08%
3M Co	MMM	538.18	137.32	73,903.06	0.20%	2.13%	0.00%	6.18%	0.01%
American Water Works Co Inc	AWK	195.01	143.97	28,075.73	0.08%	2.13%	0.00%	6.60%	0.01%
Bank of America Corp	BAC	7602.80	39.69	301,755.07		2.62%			
Pfizer Inc	PFE	5671.45	22.92	129,989.74		7.50%		-1.66%	
Procter & Gamble Co/The	PG	2344.54	161.02	377,518.16	1.05%	2.63%	0.03%	3.76%	0.04%
AT&T Inc	T	7178.18	26.81	192,447.09	0.53%	4.14%	0.02%	3.95%	0.02%
Travelers Cos Inc/The	TRV	226.57	259.16	58,717.57	0.16%	1.70%	0.00%	2.22%	0.00%
RTX Corp	RTX	1335.95	125.22	167,288.13	0.46%	2.01%	0.01%	7.41%	0.03%
Analog Devices Inc	ADI	495.98	194.59	96,512.06	0.27%	2.04%	0.01%	11.79%	0.03%
Walmart Inc	WMT	8000.89	95.09	760,804.34	2.11%	0.99%	0.02%	7.43%	0.16%
Cisco Systems Inc	CSCO	3978.29	56.71	225,608.96	0.63%	2.89%	0.02%	4.69%	0.03%
Intel Corp	INTC	4362.00	20.05	87,458.10	0.24%			15.96%	0.04%
General Motors Co	GM	966.28	47.11	45,521.47	0.13%	1.02%	0.00%	8.79%	0.01%
Microsoft Corp	MSFT	7433.98	391.85	2,913,005.94	8.07%	0.85%	0.07%	13.09%	1.06%
Dollar General Corp	DG	219.95	93.56	20,578.25	0.06%	2.52%	0.00%	5.74%	0.00%
Cigna Group/The	CI	271.11	335.36	90,918.81	0.25%	1.80%	0.00%	5.07%	0.01%
Kinder Morgan Inc	KMI	2222.07	26.85	59,662.55		4.36%			
Citigroup Inc	C	1882.16	68.43	128,796.21		3.27%		23.17%	
American International Group Inc	AIG	583.77	81.22	47,414.05	0.13%	1.97%	0.00%	14.08%	0.02%
Altria Group Inc	MO	1686.34	58.26	98,246.25	0.27%	7.00%	0.02%	4.48%	0.01%
HCA Healthcare Inc	HCA	246.20	327.92	80,734.99	0.22%	0.88%	0.00%	9.24%	0.02%
International Paper Co	IP	527.88	47.35	24,994.92		3.91%		55.66%	
Hewlett Packard Enterprise Co	HPE	1313.58	16.24	21,332.51	0.06%	3.20%	0.00%	4.02%	0.00%
Abbott Laboratories	ABT	1734.32	128.85	223,467.57	0.62%	1.83%	0.01%	9.85%	0.06%
Aflac Inc	AFL	545.81	107.94	58,915.23	0.16%	2.15%	0.00%	4.80%	0.01%
Air Products and Chemicals Inc	APD	222.48	267.11	59,425.48	0.16%	2.68%	0.00%	6.28%	0.01%
Super Micro Computer Inc	SMCI	596.75	36.47	21,763.54					
Royal Caribbean Cruises Ltd	RCL	271.51	211.97	57,551.83	0.16%	1.42%	0.00%	19.67%	0.03%
Hess Corp	HES	309.31	132.34	40,934.05		1.51%			
Lennox International Inc	LII	35.48	527.31	18,711.51		0.87%			
Archer-Daniels-Midland Co	ADM	480.16	48.25	23,167.51	0.06%	4.23%	0.00%	5.97%	0.00%
Automatic Data Processing Inc	ADP	406.87	291.76	118,708.65	0.33%	2.11%	0.01%	9.07%	0.03%
Verisk Analytics Inc	VRSK	139.94	286.05	40,031.16	0.11%	0.63%	0.00%	8.98%	0.01%
AutoZone Inc	AZO	16.73	3609.33	60,379.25	0.17%			9.56%	0.02%
Linde PLC	LIN	472.91	448.4	212,053.57	0.59%	1.34%	0.01%	6.94%	0.04%
Avery Dennison Corp	AVY	78.97	170.75	13,483.44	0.04%	2.20%	0.00%	6.53%	0.00%
Enphase Energy Inc	ENPH	131.21	46.83	6,144.42				42.49%	
MSCI Inc	MSCI	77.60	535.36	41,544.81	0.12%	1.34%	0.00%	9.94%	0.01%
Ball Corp	BALL	282.38	50.56	14,277.08	0.04%	1.58%	0.00%	9.72%	0.00%
Axon Enterprise Inc	AXON	77.85	603.78	47,003.16				27.80%	
Dayforce Inc	DAY	158.26	57.81	9,149.15					
Carrier Global Corp	CARR	863.99	60.06	51,891.09	0.14%	1.50%	0.00%	13.16%	0.02%
Bank of New York Mellon Corp/The	BK	717.97	78.65	56,468.65	0.16%	2.39%	0.00%	13.11%	0.02%
Otis Worldwide Corp	OTIS	394.68	92.93	36,677.30		1.81%			
Baxter International Inc	BAX	512.92	30.22	15,500.57	0.04%	2.25%	0.00%	14.67%	0.01%
Becton Dickinson & Co	BDX	287.14	205.08	58,885.73	0.16%	2.03%	0.00%	9.31%	0.02%
Berkshire Hathaway Inc	BRK/B	1339.91	530.96	711,436.30					
Best Buy Co Inc	BBY	211.37	67.71	14,311.84	0.04%	5.61%	0.00%	5.78%	0.00%
Boston Scientific Corp	BSX	1479.07	101.9	150,717.25	0.42%			12.56%	0.05%
Bristol-Myers Squibb Co	BMY	2035.08	47.9	97,480.37		5.18%		80.00%	
Brown-Forman Corp	BF/B	303.54	33.96	10,308.22		2.67%		-2.71%	
Coterra Energy Inc	CTRA	764.10	25.37	19,385.12		3.47%		32.16%	
Hilton Worldwide Holdings Inc	HLT	239.61	219.62	52,624.03	0.15%	0.27%	0.00%	11.85%	0.02%

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Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Carnival Corp	CCL	1166.61	18.6	21,698.89				22.81%	
Builders FirstSource Inc	BLDR	113.74	121.35	13,802.69	0.04%			4.59%	0.00%
UDR Inc	UDR	331.13	41.3	13,675.81	0.04%	4.16%	0.00%	1.98%	0.00%
Clorox Co/The	CLX	123.19	138.27	17,033.46	0.05%	3.53%	0.00%	8.97%	0.00%
Paycom Software Inc	PAYC	57.85	227.6	13,167.19	0.04%	0.66%	0.00%	7.40%	0.00%
CMS Energy Corp	CMS	299.12	72.18	21,590.75	0.06%	3.01%	0.00%	7.59%	0.00%
Colgate-Palmolive Co	CL	810.42	93.91	76,106.55	0.21%	2.21%	0.00%	5.69%	0.01%
EPAM Systems Inc	EPAM	57.27	159.12	9,112.83	0.03%			7.68%	0.00%
Conagra Brands Inc	CAG	477.36	24.45	11,671.51		5.73%		-3.22%	
Airbnb Inc	ABNB	440.00	122.51	53,904.66	0.15%			10.66%	0.02%
Consolidated Edison Inc	ED	360.20	110.45	39,784.12	0.11%	3.08%	0.00%	4.84%	0.01%
Corning Inc	GLW	856.78	44.18	37,852.41	0.10%	2.54%	0.00%	17.92%	0.02%
GoDaddy Inc	GDDY	142.44	183.4	26,122.67					
Cummins Inc	CMI	137.74	293.26	40,394.39	0.11%	2.48%	0.00%	8.31%	0.01%
Caesars Entertainment Inc	CZR	208.86	28.44	5,940.03				82.46%	
Danaher Corp	DHR	715.67	197.14	141,087.10	0.39%	0.65%	0.00%	8.67%	0.03%
Target Corp	TGT	455.58	96.58	43,999.57	0.12%	4.64%	0.01%	6.49%	0.01%
Williams-Sonoma Inc	WSM	123.51	151.19	18,673.40	0.05%	1.75%	0.00%	4.50%	0.00%
Deere & Co	DE	271.41	459.3	124,660.42		1.41%		-0.83%	
Dominion Energy Inc	D	852.22	52.95	45,124.79		5.04%		23.10%	
Dover Corp	DOV	137.10	169.01	23,172.01	0.06%	1.22%	0.00%	10.05%	0.01%
Alliant Energy Corp	LNT	256.87	60.74	15,602.48	0.04%	3.34%	0.00%	6.19%	0.00%
Steel Dynamics Inc	STLD	149.90	127.34	19,087.86	0.05%	1.57%	0.00%	14.00%	0.01%
Duke Energy Corp	DUK	777.02	119.85	93,126.05	0.26%	3.49%	0.01%	8.00%	0.02%
Regency Centers Corp	REG	181.53	71.42	12,964.58	0.04%	3.95%	0.00%	4.59%	0.00%
Eaton Corp PLC	ETN	391.77	288.82	113,150.83	0.31%	1.44%	0.00%	11.80%	0.04%
Ecolab Inc	ECL	283.63	238.14	67,544.26	0.19%	1.09%	0.00%	11.63%	0.02%
Revvity Inc	RVTY	120.15	94.29	11,328.69	0.03%	0.30%	0.00%	8.52%	0.00%
Dell Technologies Inc	DELL	358.71	94.89	34,038.03	0.09%	2.21%	0.00%	12.40%	0.01%
Emerson Electric Co	EMR	563.90	105.28	59,367.39	0.16%	2.00%	0.00%	8.02%	0.01%
EOG Resources Inc	EOG	551.54	113.07	62,363.13	0.17%	3.45%	0.01%	1.15%	0.00%
Aon PLC	AON	216.00	335.85	72,543.97	0.20%	0.89%	0.00%	10.68%	0.02%
Entergy Corp	ETR	446.34	84.61	37,764.90	0.10%	2.84%	0.00%	7.73%	0.01%
Equifax Inc	EFX	124.20	256.48	31,854.57	0.09%	0.78%	0.00%	12.80%	0.01%
EQT Corp	EQT	598.63	50.24	30,074.97		1.25%		51.24%	
IQVIA Holdings Inc	IQV	176.32	150.28	26,496.62	0.07%			8.49%	0.01%
Gartner Inc	IT	77.06	416.09	32,063.56					
FedEx Corp	FDX	239.60	211.56	50,689.55	0.14%	2.61%	0.00%	11.22%	0.02%
Brown & Brown Inc	BRO	286.63	114.44	32,801.66	0.09%	0.52%	0.00%	9.12%	0.01%
Ford Motor Co	F	3905.70	10.04	39,213.18	0.11%	1.49%	0.00%	0.18%	0.00%
NextEra Energy Inc	NEE	2058.63	66.09	136,054.93	0.38%	3.43%	0.01%	7.19%	0.03%
Franklin Resources Inc	BEN	525.40	18.72	9,835.45		6.84%			
Garmin Ltd	GRMN	192.64	198.96	38,327.90	0.11%	1.81%	0.00%	11.34%	0.01%
Freeport-McMoRan Inc	FCX	1437.07	37.35	53,674.68	0.15%	1.61%	0.00%	16.33%	0.02%
Expand Energy Corp	EXE	237.97	105.3	25,058.67		2.18%			
Dexcom Inc	DXCM	392.11	71.66	28,098.42	0.08%			19.18%	0.01%
General Dynamics Corp	GD	268.40	271.97	72,995.70	0.20%	2.21%	0.00%	13.82%	0.03%
General Mills Inc	GIS	547.60	56.14	30,742.29		4.28%		-2.42%	
Genuine Parts Co	GPC	138.79	116.64	16,188.42		3.53%			
Atmos Energy Corp	ATO	158.73	158.14	25,101.28	0.07%	2.20%	0.00%	7.27%	0.01%
WW Grainger Inc	GWW	48.17	1013.87	48,839.57	0.14%	0.81%	0.00%	5.89%	0.01%
Halliburton Co	HAL	859.72	20.85	17,925.06		3.26%		-2.39%	
L3Harris Technologies Inc	LHX	186.95	216.08	40,395.21	0.11%	2.22%	0.00%	12.47%	0.01%
Healthpeak Properties Inc	DOC	698.60	17.83	12,455.97	0.03%	6.84%	0.00%	4.91%	0.00%
Insulet Corp	PODD	70.23	260.71	18,308.65				24.42%	
Fortive Corp	FTV	339.88	68.92	23,424.27	0.06%	0.46%	0.00%	7.33%	0.00%
Hershey Co/The	HSY	147.95	163.28	24,157.19		3.36%		-9.26%	
Synchrony Financial	SYF	380.65	51.42	19,573.06	0.05%	2.33%	0.00%	17.55%	0.01%
Hormel Foods Corp	HRL	549.91	29.7	16,332.40	0.05%	3.91%	0.00%	5.97%	0.00%
Arthur J Gallagher & Co	AJG	255.73	322.3	82,423.33		0.81%			
Mondelez International Inc	MDLZ	1295.54	65.59	84,974.14	0.24%	2.87%	0.01%	0.40%	0.00%
CenterPoint Energy Inc	CNP	652.73	38.19	24,927.63	0.07%	2.30%	0.00%	8.05%	0.01%
Humana Inc	HUM	120.69	264.4	31,911.13	0.09%	1.34%	0.00%	6.88%	0.01%
Willis Towers Watson PLC	WTW	99.15	302.19	29,962.08	0.08%	1.22%	0.00%	6.91%	0.01%
Illinois Tool Works Inc	ITW	293.37	239.5	70,261.15	0.19%	2.51%	0.00%	1.21%	0.00%
CDW Corp/DE	CDW	131.77	157.95	20,812.55	0.06%	1.58%	0.00%	6.38%	0.00%
Trane Technologies PLC	TT	223.18	347.97	77,658.53	0.22%	1.08%	0.00%	9.79%	0.02%
Interpublic Group of Cos Inc/The	IPG	369.73	24.56	9,080.68		5.37%			
International Flavors & Fragrances Inc	IFF	255.74	76.24	19,497.24	0.05%	2.10%	0.00%	4.29%	0.00%
Generac Holdings Inc	GNRC	59.61	112.89	6,729.83	0.02%			19.54%	0.00%
NXP Semiconductors NV	NXPI	253.62	193.55	49,088.17	0.14%	2.10%	0.00%	4.62%	0.01%
Kellanova	K	345.22	82.62	28,521.74	0.08%	2.76%	0.00%	4.55%	0.00%
Broadridge Financial Solutions Inc	BR	117.02	237.72	27,817.68		1.48%			
Kimberly-Clark Corp	KMB	331.82	131.61	43,670.31	0.12%	3.83%	0.00%	3.40%	0.00%
Kimco Realty Corp	KIM	679.50	20.35	13,827.80	0.04%	4.91%	0.00%	3.40%	0.00%
Oracle Corp	ORCL	2804.23	138.49	388,358.37	1.08%	1.44%	0.02%	8.44%	0.09%
Kroger Co/The	KR	660.89	70	46,262.54	0.13%	1.83%	0.00%	6.11%	0.01%
Lennar Corp	LEN	232.18	107.63	24,990.01		1.86%		-4.18%	
Eli Lilly & Co	LLY	947.99	884.54	838,534.32		0.68%		21.00%	
Charter Communications Inc	CHTR	140.36	373.65	52,447.09	0.15%			19.22%	0.03%
Loews Corp	L	210.34	85.27	17,935.85		0.29%			
Lowe's Cos Inc	LOW	559.71	220.91	123,644.61	0.34%	2.08%	0.01%	6.05%	0.02%
Hubbell Inc	HUBB	53.57	359.84	19,277.84		1.47%			
IDEX Corp	IEX	75.54	173	13,069.13		1.60%			
Marsh & McLennan Cos Inc	MMC	492.73	219.24	108,025.63	0.30%	1.49%	0.00%	8.59%	0.03%
Masco Corp	MAS	210.94	60.42	12,745.12	0.04%	2.05%	0.00%	7.38%	0.00%
S&P Global Inc	SPGI	313.84	480	150,643.23	0.42%	0.80%	0.00%	14.39%	0.06%
Medtronic PLC	MDT	1282.54	84.16	107,938.86	0.30%	3.33%	0.01%	6.49%	0.02%

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Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Viatris Inc	VTRS	1193.69	8.13	9,704.69		5.90%		-3.79%	
CVS Health Corp	CVS	1262.38	65.32	82,458.91	0.23%	4.07%	0.01%	14.47%	0.03%
DuPont de Nemours Inc	DD	418.50	65.69	27,491.17	0.08%	2.50%	0.00%	5.58%	0.00%
Micron Technology Inc	MU	1117.57	79.78	89,159.86		0.58%			
Motorola Solutions Inc	MSI	166.96	430.22	71,831.06	0.20%	1.01%	0.00%	7.04%	0.01%
Cboe Global Markets Inc	CBOE	104.71	213.59	22,365.54	0.06%	1.18%	0.00%	9.71%	0.01%
Newmont Corp	NEM	1113.00	53.94	60,035.05	0.17%	1.85%	0.00%	14.18%	0.02%
NIKE Inc	NKE	1178.10	57.62	67,882.28		2.78%		-6.80%	
NiSource Inc	NI	470.61	39.45	18,565.38	0.05%	2.84%	0.00%	7.43%	0.00%
Norfolk Southern Corp	NSC	225.44	221.71	49,983.08	0.14%	2.44%	0.00%	11.89%	0.02%
Principal Financial Group Inc	PFG	224.97	73.46	16,526.42	0.05%	4.14%	0.00%	11.78%	0.01%
Eversource Energy	ES	367.08	57.86	21,239.36	0.06%	5.20%	0.00%	4.47%	0.00%
Northrop Grumman Corp	NOC	143.93	473.2	68,106.81	0.19%	1.74%	0.00%	4.19%	0.01%
Wells Fargo & Co	WFC	3265.16	69.73	227,679.53	0.63%	2.29%	0.01%	14.29%	0.09%
Nucor Corp	NUE	230.75	115.72	26,701.94		1.90%		20.02%	
Occidental Petroleum Corp	OXY	939.78	40.36	37,929.62		2.38%			
Omnicom Group Inc	OMC	195.11	74.92	14,617.60		3.74%			
ONEOK Inc	OKE	624.62	86.31	53,911.09	0.15%	4.77%	0.01%	0.13%	0.00%
Raymond James Financial Inc	RJF	204.91	137.37	28,148.49	0.08%	1.46%	0.00%	8.07%	0.01%
PG&E Corp	PCG	2675.43	17.14	45,856.85		0.58%			
Parker-Hannifin Corp	PH	128.76	598.02	77,003.95	0.21%	1.20%	0.00%	7.05%	0.02%
Rollins Inc	ROL	484.65	55.31	26,805.80		1.19%			
PPL Corp	PPL	739.05	35.93	26,554.12	0.07%	3.03%	0.00%	6.92%	0.01%
Aptiv PLC	APTV	229.45	55.93	12,832.94	0.04%			15.01%	0.01%
ConocoPhillips	COP	1264.17	91.72	115,949.25		3.40%			
PulteGroup Inc	PHM	200.43	101.88	20,419.52		0.86%		-1.13%	
Pinnacle West Capital Corp	PNW	119.21	93.75	11,176.40	0.03%	3.82%	0.00%	2.12%	0.00%
PNC Financial Services Group Inc/The	PNC	395.75	158.46	62,710.48	0.17%	4.04%	0.01%	7.49%	0.01%
PPG Industries Inc	PPG	226.97	102.57	23,280.82	0.06%	2.65%	0.00%	5.53%	0.00%
DoorDash Inc	DASH	398.14	187.76	74,755.03					
Progressive Corp/The	PGR	586.24	265.01	155,358.43	0.43%	0.15%	0.00%	14.70%	0.06%
Veralto Corp	VLTO	248.05	92.31	22,897.66		0.48%			
Public Service Enterprise Group Inc	PEG	498.56	81.03	40,398.44	0.11%	3.11%	0.00%	9.40%	0.01%
Cooper Cos Inc/The	COO	199.98	80.89	16,176.48	0.04%			9.91%	0.00%
Edison International	EIX	385.02	57.96	22,315.96		5.71%			
Schlumberger NV	SLB	1360.16	34.52	46,952.78		3.30%		-0.49%	
Charles Schwab Corp/The	SCHW	1815.92	79.94	145,164.48	0.40%	1.35%	0.01%	19.69%	0.08%
Sherwin-Williams Co/The	SHW	251.51	331.62	83,405.80	0.23%	0.95%	0.00%	5.49%	0.01%
West Pharmaceutical Services Inc	WST	71.85	214.55	15,414.42	0.04%	0.39%	0.00%	6.27%	0.00%
J M Smucker Co/The	SJM	106.42	115.23	12,262.39		3.75%			
Snap-on Inc	SNA	52.29	308.76	16,145.38	0.04%	2.77%	0.00%	3.46%	0.00%
AMETEK Inc	AME	230.75	166.69	38,463.20	0.11%	0.74%	0.00%	8.14%	0.01%
Uber Technologies Inc	UBER	2091.26	77.75	162,595.32				-6.02%	
Southern Co/The	SO	1100.19	90.43	99,490.51	0.28%	3.27%	0.01%	6.37%	0.02%
Truist Financial Corp	TFC	1305.39	37.67	49,174.07	0.14%	5.52%	0.01%	7.53%	0.01%
Southwest Airlines Co	LUV	569.87	26.49	15,095.75		2.72%		57.29%	
W R Berkley Corp	WRB	379.31	70.48	26,733.97	0.07%	0.45%	0.00%	6.85%	0.01%
Stanley Black & Decker Inc	SWK	154.54	61.58	9,516.42		5.33%			
Public Storage	PSA	175.42	290.91	51,030.70	0.14%	4.12%	0.01%	3.64%	0.01%
Arista Networks Inc	ANET	1255.63	77.91	97,825.78	0.27%			14.64%	0.04%
Sysco Corp	SYY	489.23	70.93	34,701.06		3.05%			
Corteva Inc	CTVA	683.01	61.47	41,984.91	0.12%	1.11%	0.00%	15.89%	0.02%
Texas Instruments Inc	TXN	908.47	162.86	147,953.76	0.41%	3.34%	0.01%	11.66%	0.05%
Textron Inc	TXT	180.54	68.42	12,352.46	0.03%	0.12%	0.00%	10.03%	0.00%
Thermo Fisher Scientific Inc	TMO	377.49	424.24	160,147.33	0.44%	0.41%	0.00%	8.08%	0.04%
TJX Cos Inc/The	TJX	1117.10	126.56	141,380.24	0.39%	1.34%	0.01%	7.62%	0.03%
Globe Life Inc	GL	83.24	122.96	10,235.53		0.88%			
Johnson Controls International plc	JCI	660.14	81.07	53,517.48	0.15%	1.83%	0.00%	9.17%	0.01%
Ulta Beauty Inc	ULTA	45.15	383.67	17,321.89	0.05%			3.98%	0.00%
Union Pacific Corp	UNP	597.48	213.29	127,435.57	0.35%	2.51%	0.01%	9.19%	0.03%
Keysight Technologies Inc	KEYS	172.81	144.01	24,886.44	0.07%			12.64%	0.01%
UnitedHealth Group Inc	UNH	910.22	418.64	381,056.09	1.06%	2.01%	0.02%	6.78%	0.07%
Blackstone Inc	BX	729.42	132.86	96,910.20		2.80%		21.63%	
Ventas Inc	VTR	437.70	68.16	29,833.48	0.08%	2.82%	0.00%	9.17%	0.01%
Labcorp Holdings Inc	LH	83.67	228.31	19,102.32	0.05%	1.26%	0.00%	10.01%	0.01%
Vulcan Materials Co	VMC	132.10	247.04	32,634.28	0.09%	0.79%	0.00%	12.90%	0.01%
Weyerhaeuser Co	WY	725.85	24.81	18,008.31		3.39%			
Williams Cos Inc/The	WMB	1220.69	59.03	72,057.14		3.39%			
Constellation Energy Corp	CEG	315.12	222.99	70,268.82	0.19%	0.70%	0.00%	12.00%	0.02%
WEC Energy Group Inc	WEC	319.09	107.73	34,375.48	0.10%	3.31%	0.00%	7.53%	0.01%
Adobe Inc	ADBE	426.20	367.72	156,722.26	0.43%			13.49%	0.06%
Vistra Corp	VST	340.16	126.64	43,077.49	0.12%	0.71%	0.00%	3.86%	0.00%
AES Corp/The	AES	711.90	10.05	7,154.60	0.02%	7.00%	0.00%	3.75%	0.00%
Expeditors International of Washington Inc	EXPD	137.76	108.58	14,957.62	0.04%	1.34%	0.00%	4.35%	0.00%
Amgen Inc	AMGN	537.65	280.84	150,993.80	0.42%	3.39%	0.01%	5.13%	0.02%
Apple Inc	AAPL	15022.07	209.28	3,143,819.44	8.71%	0.48%	0.04%	13.46%	1.17%
Autodesk Inc	ADSK	213.00	269.93	57,495.09	0.16%			14.19%	0.02%
Cintas Corp	CTAS	403.79	208.4	84,149.20	0.23%	0.75%	0.00%	14.37%	0.03%
Comcast Corp	CMCSA	3724.26	33.9	126,252.40	0.35%	3.89%	0.01%	3.20%	0.01%
Molson Coors Beverage Co	TAP	190.29	56.8	10,808.59	0.03%	3.31%	0.00%	8.44%	0.00%
KLA Corp	KLAC	132.89	694.61	92,304.47	0.26%	0.98%	0.00%	15.45%	0.04%
Marriott International Inc/MD	MAR	275.37	236.2	65,043.05	0.18%	1.07%	0.00%	9.71%	0.02%
Fiserv Inc	FI	554.43	177.53	98,428.64	0.27%			15.52%	0.04%
McCormick & Co Inc/MD	MKC	252.68	74.54	18,834.90	0.05%	2.41%	0.00%	6.37%	0.00%
PACCAR Inc	PCAR	524.93	91.89	48,236.26	0.13%	1.44%	0.00%	1.46%	0.00%
Costco Wholesale Corp	COST	443.68	977.16	433,549.63	1.20%	0.53%	0.01%	8.86%	0.11%
Stryker Corp	SYK	381.69	365.06	139,339.33	0.39%	0.92%	0.00%	9.83%	0.04%
Tyson Foods Inc	TSN	286.19	60.62	17,348.56		3.30%		21.06%	

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Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Lamb Weston Holdings Inc	LW	141.12	51.94	7,329.55		2.85%		-12.10%	
Applied Materials Inc	AMAT	812.44	151.55	123,125.41	0.34%	1.21%	0.00%	10.64%	0.04%
Cardinal Health Inc	CAH	241.57	137.56	33,230.09	0.09%	1.47%	0.00%	9.07%	0.01%
Cincinnati Financial Corp	CINF	156.56	133.69	20,931.14	0.06%	2.60%	0.00%	2.44%	0.00%
Paramount Global	PARA	630.01	11.73	7,389.99		1.71%			
DR Horton Inc	DHI	307.18	124.56	38,262.50	0.11%	1.28%	0.00%	1.58%	0.00%
Electronic Arts Inc	EA	260.62	146.6	38,206.54	0.11%	0.52%	0.00%	5.98%	0.01%
Erie Indemnity Co	ERIE	46.19	361.85	16,713.51		1.51%			
Fair Isaac Corp	FICO	24.42	1952.31	47,671.78				26.88%	
Fastenal Co	FAST	573.62	80.73	46,308.39	0.13%	2.18%	0.00%	10.52%	0.01%
M&T Bank Corp	MTB	164.29	167.39	27,500.56	0.08%	3.23%	0.00%	11.79%	0.01%
Xcel Energy Inc	XEL	576.76	69	39,796.48	0.11%	3.30%	0.00%	8.05%	0.01%
Fifth Third Bancorp	FITB	668.10	35.28	23,570.53		4.20%			
Gilead Sciences Inc	GILD	1245.16	103.17	128,463.45		3.06%		21.81%	
Hasbro Inc	HAS	139.89	60.99	8,532.09	0.02%	4.59%	0.00%	8.59%	0.00%
Huntington Bancshares Inc/OH	HBAN	1460.75	14.4	21,034.86	0.06%	4.31%	0.00%	12.92%	0.01%
Welltower Inc	WELL	651.54	146.96	95,749.79	0.27%	1.82%	0.00%	16.50%	0.04%
Biogen Inc	BIIB	146.37	118.84	17,395.20	0.05%			2.47%	0.00%
Northern Trust Corp	NTRS	194.97	91.59	17,857.45	0.05%	3.28%	0.00%	9.64%	0.00%
Packaging Corp of America	PKG	89.93	184.82	16,620.52		2.71%			
Paychex Inc	PAYX	360.19	143.21	51,582.91	0.14%	2.74%	0.00%	6.24%	0.01%
QUALCOMM Inc	QCOM	1106.00	148.56	164,307.36	0.46%	2.40%	0.01%	15.26%	0.07%
Ross Stores Inc	ROST	328.83	139.71	45,941.43	0.13%	1.16%	0.00%	6.48%	0.01%
IDEXX Laboratories Inc	IDXX	81.04	437.44	35,449.72	0.10%			12.52%	0.01%
Starbucks Corp	SBUX	1135.90	83.81	95,199.78	0.26%	2.91%	0.01%	10.29%	0.03%
KeyCorp	KEY	1095.72	14.72	16,128.96	0.04%	5.57%	0.00%	19.35%	0.01%
Fox Corp	FOXA	217.85	49.35	10,750.74	0.03%	1.09%	0.00%	8.98%	0.00%
Fox Corp	FOX	235.58	45.79	10,787.26	0.03%	1.18%	0.00%	8.98%	0.00%
State Street Corp	STT	288.59	87.38	25,217.08	0.07%	3.48%	0.00%	10.63%	0.01%
Norwegian Cruise Line Holdings Ltd	NCLH	443.22	17.23	7,636.67	0.02%			18.95%	0.00%
US Bancorp	USB	1558.01	39.92	62,195.78	0.17%	5.01%	0.01%	10.38%	0.02%
A O Smith Corp	AOS	117.66	64.99	7,646.66		2.09%			
Gen Digital Inc	GEN	616.30	25.26	15,567.77	0.04%	1.98%	0.00%	11.23%	0.00%
T Rowe Price Group Inc	TROW	222.24	88.44	19,655.12		5.74%		-3.02%	
Waste Management Inc	WM	402.33	228.31	91,856.51	0.25%	1.45%	0.00%	10.67%	0.03%
Constellation Brands Inc	STZ	177.99	185.35	32,991.01	0.09%	2.20%	0.00%	1.36%	0.00%
Invesco Ltd	IVZ	447.41	13.93	6,232.47	0.02%	6.03%	0.00%	3.37%	0.00%
Intuit Inc	INTU	279.56	624.12	174,480.24	0.48%	0.67%	0.00%	13.37%	0.06%
Morgan Stanley	MS	1608.51	116.01	186,602.99	0.52%	3.19%	0.02%	10.29%	0.05%
Microchip Technology Inc	MCHP	537.82	46.89	25,218.33		3.88%		-33.30%	
Crowdstrike Holdings Inc	CRWD	247.87	424.88	105,316.46				24.67%	
Chubb Ltd	CB	400.69	279.11	111,835.22	0.31%	1.30%	0.00%	4.24%	0.01%
Hologic Inc	HOLX	225.72	58.02	13,096.45	0.04%			8.86%	0.00%
Citizens Financial Group Inc	CFG	437.13	37.06	16,200.18		4.53%		23.45%	
Jabil Inc	JBL	107.35	146.92	15,771.18	0.04%	0.22%	0.00%	12.83%	0.01%
O'Reilly Automotive Inc	ORLY	57.24	1347	77,102.97	0.21%			9.80%	0.02%
Allstate Corp/The	ALL	265.14	192.91	51,147.98	0.14%	2.07%	0.00%	12.93%	0.02%
Equity Residential	EQR	379.84	68.53	26,030.48	0.07%	4.04%	0.00%	4.03%	0.00%
Keurig Dr Pepper Inc	KDP	1358.18	34.4	46,721.33	0.13%	2.67%	0.00%	6.20%	0.01%
Host Hotels & Resorts Inc	HST	698.67	13.88	9,697.56		5.76%		-2.44%	
Incyte Corp	INCY	193.52	59.16	11,448.90					
Simon Property Group Inc	SPG	326.24	156.66	51,109.29	0.14%	5.36%	0.01%	1.29%	0.00%
Eastman Chemical Co	EMN	115.46	75.84	8,756.50	0.02%	4.38%	0.00%	6.76%	0.00%
AvalonBay Communities Inc	AVB	142.37	205.76	29,293.77	0.08%	3.40%	0.00%	5.26%	0.00%
Prudential Financial Inc	PRU	354.43	102.9	36,470.55	0.10%	5.25%	0.01%	7.66%	0.01%
United Parcel Service Inc	UPS	733.69	97.91	71,835.27	0.20%	6.70%	0.01%	7.91%	0.02%
Walgreens Boots Alliance Inc	WBA	864.74	11.01	9,520.76				-21.88%	
STERIS PLC	STE	98.25	225	22,106.43		1.01%			
McKesson Corp	MCK	125.33	695	87,101.83	0.24%	0.41%	0.00%	13.47%	0.03%
Lockheed Martin Corp	LMT	234.30	477.64	111,909.12	0.31%	2.76%	0.01%	11.65%	0.04%
Cencora Inc	COR	193.71	285.9	55,382.43	0.15%	0.77%	0.00%	9.83%	0.02%
Capital One Financial Corp	COF	381.48	182.73	69,707.74	0.19%	1.31%	0.00%	14.96%	0.03%
The Campbell's Company	CPB	298.18	36.29	10,821.02	0.03%	4.30%	0.00%	2.22%	0.00%
Waters Corp	WAT	59.50	337.89	20,103.03	0.06%			7.42%	0.00%
Nordson Corp	NDSN	56.91	188.22	10,711.93		1.66%			
Dollar Tree Inc	DLTR	215.08	80.57	17,329.24	0.05%			8.42%	0.00%
Darden Restaurants Inc	DRI	117.03	199.1	23,299.93	0.06%	2.81%	0.00%	9.10%	0.01%
Evergy Inc	EVRG	229.75	67.88	15,595.15	0.04%	3.93%	0.00%	5.71%	0.00%
Match Group Inc	MTCH	246.68	30.07	7,417.62	0.02%	2.53%	0.00%	9.22%	0.00%
NVR Inc	NVR	2.97	7071.42	20,995.05	0.06%			4.50%	0.00%
NetApp Inc	NTAP	203.41	88.45	17,991.75	0.05%	2.35%	0.00%	8.16%	0.00%
Old Dominion Freight Line Inc	ODFL	212.15	146.74	31,130.46	0.09%	0.76%	0.00%	7.72%	0.01%
DaVita Inc	DVA	76.86	139.56	10,727.05	0.03%			10.03%	0.00%
Hartford Insurance Group Inc/The	HIG	284.10	118.76	33,740.07	0.09%	1.75%	0.00%	9.03%	0.01%
Iron Mountain Inc	IRM	294.97	87.72	25,874.61		3.58%			
Estee Lauder Cos Inc/The	EL	234.17	59.39	13,907.56	0.04%	2.36%	0.00%	8.85%	0.00%
Cadence Design Systems Inc	CDNS	274.31	289.63	79,449.45	0.22%			14.79%	0.03%
Tyler Technologies Inc	TYL	43.12	524.64	22,624.34					
Universal Health Services Inc	UHS	57.95	171.68	9,949.19	0.03%	0.47%	0.00%	11.19%	0.00%
Skyworks Solutions Inc	SWKS	153.57	61.52	9,447.92		4.55%		-9.02%	
Quest Diagnostics Inc	DGX	111.64	173.76	19,397.78	0.05%	1.84%	0.00%	8.44%	0.00%
Rockwell Automation Inc	ROK	113.07	248.38	28,085.06	0.08%	2.11%	0.00%	10.92%	0.01%
Kraft Heinz Co/The	KHC	1193.40	29.49	35,193.32		5.43%		-3.61%	
American Tower Corp	AMT	468.12	210.82	98,688.60		3.23%		23.46%	
Regeneron Pharmaceuticals Inc	REGN	106.95	602.64	64,453.26	0.18%	0.58%	0.00%	7.95%	0.01%
Amazon.com Inc	AMZN	10612.36	188.99	2,005,630.67	5.56%			11.42%	0.63%
Jack Henry & Associates Inc	JKHY	72.90	170.93	12,460.40	0.03%	1.36%	0.00%	9.25%	0.00%
Ralph Lauren Corp	RL	39.88	219.96	8,772.65	0.02%	1.50%	0.00%	13.79%	0.00%

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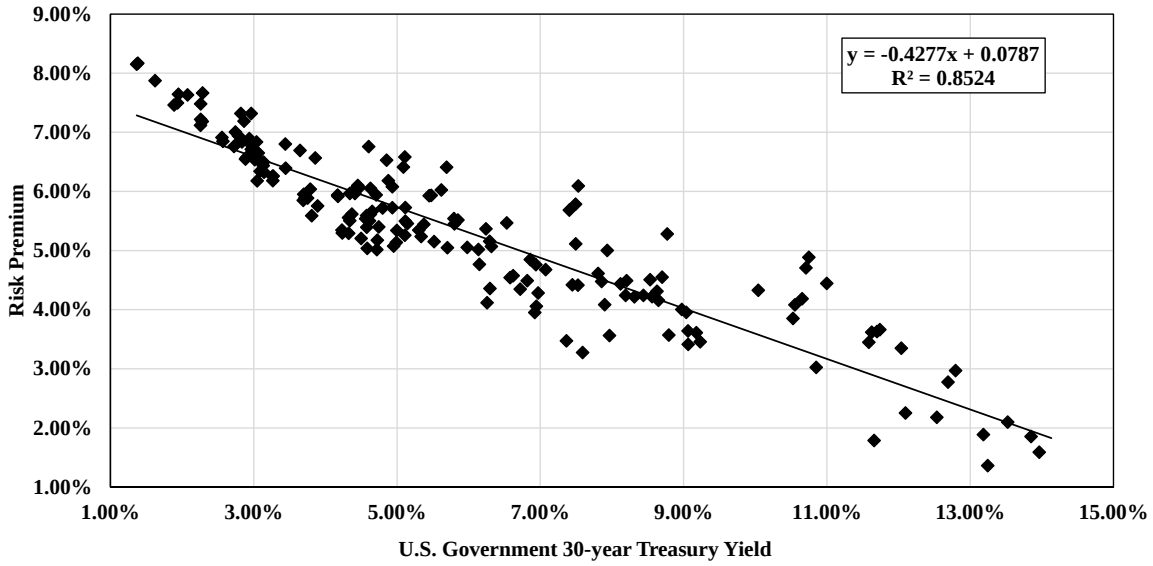
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
BXP Inc	BXP	158.21	65.85	10,418.10	0.03%	5.95%	0.00%	1.55%	0.00%
Amphenol Corp	APH	1211.78	75.85	91,913.76	0.25%	0.87%	0.00%	18.81%	0.05%
Howmet Aerospace Inc	HWM	404.46	135.76	54,910.00	0.15%	0.29%	0.00%	12.69%	0.02%
Valero Energy Corp	VLO	313.21	113.87	35,664.78	0.10%	3.97%	0.00%	4.67%	0.00%
Synopsys Inc	SNPS	154.62	446.62	69,056.42	0.19%			13.35%	0.03%
CH Robinson Worldwide Inc	CHRW	118.23	89.75	10,610.88	0.03%	2.76%	0.00%	16.60%	0.00%
Accenture PLC	ACN	626.03	293.39	183,669.72	0.51%	2.02%	0.01%	7.12%	0.04%
TransDigm Group Inc	TDG	56.08	1378.13	77,291.86	0.21%			13.51%	0.03%
Yum! Brands Inc	YUM	278.50	147.3	41,023.05	0.11%	1.93%	0.00%	11.00%	0.01%
Prologis Inc	PLD	926.18	102.24	94,692.13	0.26%	3.95%	0.01%	5.83%	0.02%
FirstEnergy Corp	FE	577.13	42.34	24,435.52	0.07%	4.20%	0.00%	0.83%	0.00%
VeriSign Inc	VRSN	93.90	272.79	25,614.98		1.13%			
Quanta Services Inc	PWR	148.26	287.34	42,602.07	0.12%	0.14%	0.00%	13.20%	0.02%
Henry Schein Inc	HSIC	122.51	65.17	7,984.10	0.02%			5.92%	0.00%
Ameren Corp	AEE	270.16	98.28	26,551.10		2.89%			
ANSYS Inc	ANSS	87.65	320.68	28,108.17					
FactSet Research Systems Inc	FDS	37.95	424.47	16,107.39		0.98%			
NVIDIA Corp	NVDA	24400.00	111.01	2,708,644.00		0.04%		29.34%	
Cognizant Technology Solutions Corp	CTSH	492.94	72.17	35,575.43	0.10%	1.72%	0.00%	6.14%	0.01%
Intuitive Surgical Inc	ISRG	358.42	514.59	184,438.45	0.51%			13.49%	0.07%
Take-Two Interactive Software Inc	TTWO	176.50	225.38	39,778.60				60.65%	
Republic Services Inc	RSG	312.50	243.56	76,111.77	0.21%	0.95%	0.00%	9.36%	0.02%
eBay Inc	EBAY	466.00	67.83	31,608.78	0.09%	1.71%	0.00%	7.84%	0.01%
Goldman Sachs Group Inc/The	GS	310.79	544.86	169,337.25	0.47%	2.20%	0.01%	13.24%	0.06%
SBA Communications Corp	SBAC	108.03	222.09	23,991.97	0.07%	2.00%	0.00%	6.59%	0.00%
Sempra	SRE	651.91	74.68	48,684.89	0.13%	3.45%	0.00%	7.02%	0.01%
Moody's Corp	MCO	179.90	438.62	78,907.74	0.22%	0.86%	0.00%	11.80%	0.03%
ON Semiconductor Corp	ON	422.05	39.63	16,725.82				-0.17%	
Booking Holdings Inc	BKNG	32.70	4838.44	158,212.83	0.44%	0.79%	0.00%	15.92%	0.07%
F5 Inc	FFIV	57.65	270.03	15,567.84	0.04%			7.07%	0.00%
Akamai Technologies Inc	AKAM	146.11	79.79	11,658.50					
Charles River Laboratories International Inc	CRL	49.12	114.66	5,631.61	0.02%			2.77%	0.00%
MarketAxess Holdings Inc	MKTX	37.20	219	8,147.10	0.02%	1.39%	0.00%	0.50%	0.00%
Devon Energy Corp	DVN	643.33	31.35	20,168.37	0.06%	3.06%	0.00%	11.01%	0.01%
Bio-Techne Corp	TECH	158.09	50.24	7,942.33		0.64%			
Alphabet Inc	GOOGL	5820.00	161.96	942,607.20	2.61%	0.52%	0.01%	12.96%	0.34%
Allegion plc	ALLE	86.05	136.49	11,744.87	0.03%	1.49%	0.00%	4.57%	0.00%
Netflix Inc	NFLX	425.57	1101.53	468,779.52				25.26%	
Agilent Technologies Inc	A	285.10	106.28	30,300.72	0.08%	0.93%	0.00%	8.80%	0.01%
Warner Bros Discovery Inc	WBD	2473.84	8.59	21,250.25				41.11%	
Trimble Inc	TRMB	238.58	61.71	14,722.99					
Elevance Health Inc	ELV	225.93	421.68	95,272.10	0.26%	1.62%	0.00%	10.65%	0.03%
CME Group Inc	CME	360.38	266.3	95,969.08	0.27%	1.88%	0.00%	7.82%	0.02%
Juniper Networks Inc	JNPR	334.28	35.6	11,900.26	0.03%	2.47%	0.00%	12.36%	0.00%
DTE Energy Co	DTE	207.52	134.76	27,965.09	0.08%	3.24%	0.00%	5.80%	0.00%
Nasdaq Inc	NDAQ	574.12	75.36	43,265.81	0.12%	1.43%	0.00%	12.82%	0.02%
Philip Morris International Inc	PM	1556.52	170.24	264,981.48	0.73%	3.17%	0.02%	11.22%	0.08%
Ingersoll Rand Inc	IR	403.08	74.98	30,223.18		0.11%			
Salesforce Inc	CRM	959.47	267.85	256,995.00	0.71%	0.62%	0.00%	12.19%	0.09%
Roper Technologies Inc	ROP	107.39	557.7	59,888.73		0.59%			
Huntington Ingalls Industries Inc	HII	39.24	226.05	8,869.20	0.02%	2.39%	0.00%	13.85%	0.00%
MetLife Inc	MET	681.23	75.19	51,221.54	0.14%	3.02%	0.00%	12.97%	0.02%
Tapestry Inc	TPR	207.02	68.88	14,259.23	0.04%	2.03%	0.00%	9.55%	0.00%
CSX Corp	CSX	1878.55	27.84	52,298.72	0.14%	1.87%	0.00%	7.13%	0.01%
Edwards Lifesciences Corp	EW	587.86	76.04	44,701.25	0.12%			7.04%	0.01%
Ameriprise Financial Inc	AMP	95.81	465.94	44,643.56	0.12%	1.37%	0.00%	7.28%	0.01%
Zebra Technologies Corp	ZBRA	51.14	246.24	12,593.53					
Zimmer Biomet Holdings Inc	ZBH	197.84	101.51	20,082.87		0.95%			
Camden Property Trust	CPT	108.80	114	12,403.11	0.03%	3.68%	0.00%	1.25%	0.00%
CBRE Group Inc	CBRE	298.10	120.73	35,990.20					
Mastercard Inc	MA	902.49	533.48	481,458.87	1.33%	0.57%	0.01%	13.27%	0.18%
CarMax Inc	KMX	152.68	65.03	9,929.06	0.03%			16.70%	0.00%
Intercontinental Exchange Inc	ICE	574.50	163.23	93,775.31	0.26%	1.18%	0.00%	14.41%	0.04%
Fidelity National Information Services Inc	FIS	529.69	79.26	41,983.36	0.12%	2.02%	0.00%	9.27%	0.01%
Smurfit WestRock PLC	SW	521.98	42.23	22,043.18		4.08%		63.58%	
Chipotle Mexican Grill Inc	CMG	1347.36	51.78	69,766.51	0.19%			16.26%	0.03%
Wynn Resorts Ltd	WYNN	106.17	82.11	8,717.40	0.02%	1.22%	0.00%	7.51%	0.00%
Live Nation Entertainment Inc	LYV	234.09	132.76	31,077.72	0.09%			9.42%	0.01%
Assurant Inc	AIZ	50.87	190.83	9,707.13		1.68%			
NRG Energy Inc	NRG	203.67	108.33	22,063.24		1.62%			
Monster Beverage Corp	MNST	973.16	58.67	57,095.23	0.16%			14.23%	0.02%
Regions Financial Corp	RF	905.47	20.28	18,362.83	0.05%	4.93%	0.00%	6.18%	0.00%
Baker Hughes Co	BKR	990.75	36.45	36,112.84	0.10%	2.52%	0.00%	8.81%	0.01%
Mosaic Co/The	MOS	317.23	29.13	9,240.90		3.02%			
Expedia Group Inc	EXPE	122.04	160.11	19,540.05	0.05%	1.00%	0.00%	19.43%	0.01%
CF Industries Holdings Inc	CF	166.47	78.47	13,062.68		2.55%		-5.40%	
APA Corp	APA	361.66	16.35	5,913.20	0.02%	6.12%	0.00%	0.35%	0.00%
Leidos Holdings Inc	LDOS	128.21	145.71	18,682.04	0.05%	1.10%	0.00%	7.40%	0.00%
Alphabet Inc	GOOG	5459.00	163.85	894,457.15	2.48%	0.51%	0.01%	12.96%	0.32%
TKO Group Holdings Inc	TKO	81.55	157.1	12,812.11		0.97%			
First Solar Inc	FSLR	107.24	141.86	15,213.13				41.87%	
Discover Financial Services	DFS	251.60	184.86	46,511.54	0.13%	1.51%	0.00%	1.61%	0.00%
Visa Inc	V	1723.36	335.17	577,619.36	1.60%	0.70%	0.01%	12.19%	0.20%
Mid-America Apartment Communities Inc	MAA	116.90	159.38	18,631.66	0.05%	3.80%	0.00%	2.74%	0.00%
Xylem Inc/NY	XYL	243.35	116.1	28,252.87		1.38%			
Marathon Petroleum Corp	MPC	311.53	137.44	42,816.87		2.65%			
Tractor Supply Co	TSCO	531.62	49.92	26,538.24	0.07%	1.84%	0.00%	8.70%	0.01%
Advanced Micro Devices Inc	AMD	1624.63	96.645	157,012.69				22.74%	

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
ResMed Inc	RMD	146.63	235.88	34,586.47	0.10%	0.90%	0.00%	12.63%	0.01%
Mettler-Toledo International Inc	MTD	20.84	1061.79	22,128.71	0.06%			8.83%	0.01%
VICI Properties Inc	VICI	1056.70	32.22	34,046.96	0.09%	5.37%	0.01%	2.59%	0.00%
Copart Inc	CPRT	966.09	60.9	58,835.06					
Jacobs Solutions Inc	J	122.54	121.57	14,897.63	0.04%	1.05%	0.00%	11.19%	0.00%
Albemarle Corp	ALB	117.65	57.73	6,791.97		2.81%		83.04%	
Fortinet Inc	FTNT	768.97	101.8	78,281.56	0.22%			9.01%	0.02%
Moderna Inc	MRNA	386.62	27.22	10,523.87	0.03%			15.26%	0.00%
Essex Property Trust Inc	ESS	64.33	275.5	17,721.70	0.05%	3.73%	0.00%	3.33%	0.00%
CoStar Group Inc	CSGP	421.76	82.82	34,930.39					
Realty Income Corp	O	891.77	56.89	50,732.75	0.14%	5.66%	0.01%	3.14%	0.00%
Westinghouse Air Brake Technologies Corp	WAB	171.13	184.03	31,492.38	0.09%	0.54%	0.00%	15.51%	0.01%
Palantir Technologies Inc	PLTR	2262.68	112.78	255,185.36				31.39%	
Pool Corp	POOL	37.72	291.59	10,998.25	0.03%	1.65%	0.00%	6.39%	0.00%
Western Digital Corp	WDC	347.82	40.78	14,184.26				189.78%	
PepsiCo Inc	PEP	1371.08	133.38	182,874.59	0.51%	4.06%	0.02%	3.13%	0.02%
TE Connectivity PLC	TEL	298.35	144.37	43,073.25	0.12%	1.97%	0.00%	8.35%	0.01%
Diamondback Energy Inc	FANG	294.08	136.76	40,218.78		2.92%		-1.38%	
Palo Alto Networks Inc	PANW	662.10	178.98	118,502.66	0.33%			13.48%	0.04%
ServiceNow Inc	NOW	207.00	945.26	195,668.82					
Church & Dwight Co Inc	CHD	246.11	99.31	24,441.08		1.19%			
Federal Realty Investment Trust	FRT	85.78	94.38	8,095.92	0.02%	4.66%	0.00%	4.52%	0.00%
MGM Resorts International	MGM	282.95	31.67	8,961.05	0.02%			7.37%	0.00%
American Electric Power Co Inc	AEP	533.99	106.74	56,997.85	0.16%	3.49%	0.01%	5.20%	0.01%
Invitation Homes Inc	INVH	612.88	33.78	20,703.19	0.06%	3.43%	0.00%	3.76%	0.00%
PTC Inc	PTC	120.32	154.03	18,533.43	0.05%			16.34%	0.01%
JB Hunt Transport Services Inc	JBHT	99.19	129.73	12,868.51	0.04%	1.36%	0.00%	14.67%	0.01%
Lam Research Corp	LRCX	1283.66	71.42	91,679.14	0.25%	1.29%	0.00%	17.27%	0.04%
Mohawk Industries Inc	MHK	62.52	106.87	6,681.04	0.02%			4.53%	0.00%
GE HealthCare Technologies Inc	GEHC	457.84	68.42	31,325.63	0.09%	0.20%	0.00%	9.53%	0.01%
Pentair PLC	PNR	164.53	90	14,807.43	0.04%	1.11%	0.00%	9.53%	0.00%
Vertex Pharmaceuticals Inc	VRTX	257.08	493.84	126,956.80					
Amcor PLC	AMCR	1445.34	9.54	13,788.57	0.04%	5.35%	0.00%	4.99%	0.00%
Meta Platforms Inc	META	2181.27	547.27	1,193,743.85	3.31%	0.38%	0.01%	12.01%	0.40%
T-Mobile US Inc	TMUS	1135.45	232.77	264,297.56		1.51%			
United Rentals Inc	URI	65.00	633.6	41,183.39	0.11%	1.13%	0.00%	6.76%	0.01%
Alexandria Real Estate Equities Inc	ARE	172.99	75.88	13,126.41	0.04%	6.96%	0.00%	2.61%	0.00%
Honeywell International Inc	HON	643.26	199.16	128,111.06	0.36%	2.27%	0.01%	6.99%	0.02%
Delta Air Lines Inc	DAL	652.96	41.58	27,149.88	0.08%	1.44%	0.00%	1.02%	0.00%
United Airlines Holdings Inc	UAL	327.70	68.2	22,349.40	0.06%			4.96%	0.00%
Seagate Technology Holdings PLC	STX	211.71	82.7	17,508.20		3.48%			
News Corp	NWS	189.34	31.23	5,913.11		0.64%			
Centene Corp	CNC	497.60	57.69	28,706.72	0.08%			7.97%	0.01%
Apollo Global Management Inc	APO	570.48	133.4	76,102.09	0.21%	1.39%	0.00%	14.13%	0.03%
Martin Marietta Materials Inc	MLM	60.60	504.44	30,569.21	0.08%	0.63%	0.00%	11.00%	0.01%
Teradyne Inc	TER	161.54	77.12	12,457.88	0.03%	0.62%	0.00%	6.69%	0.00%
PayPal Holdings Inc	PYPL	977.40	65.34	63,863.00	0.18%			12.44%	0.02%
Tesla Inc	TSLA	3220.96	284.95	917,811.47					
Blackrock Inc	BLK	155.02	907.69	140,711.97	0.39%	2.30%	0.01%	2.09%	0.01%
KKR & Co Inc	KKR	888.25	113.63	100,931.91		0.62%			
Arch Capital Group Ltd	ACGL	375.72	90.68	34,069.93	0.09%			3.20%	0.00%
Dow Inc	DOW	705.76	30.02	21,187.05	0.06%	9.33%	0.01%	14.77%	0.01%
Everest Group Ltd	EG	47.78	353.15	16,875.23		2.27%		27.82%	
Teledyne Technologies Inc	TDY	46.84	458.6	21,479.59	0.06%			9.78%	0.01%
Domino's Pizza Inc	DPZ	34.30	487.58	16,722.55	0.05%	1.43%	0.00%	9.04%	0.00%
GE Vernova Inc	GEV	272.93	372.42	101,646.36		0.27%		97.71%	
News Corp	NWSA	378.06	27.13	10,256.63		0.74%			
Exelon Corp	EXC	1009.54	46.22	46,660.74	0.13%	3.46%	0.00%	7.29%	0.01%
Global Payments Inc	GPN	245.88	72.48	17,821.11	0.05%	1.38%	0.00%	9.66%	0.00%
Crown Castle Inc	CCI	435.43	100.19	43,626.11		6.25%		33.10%	
Align Technology Inc	ALGN	73.21	183.35	13,423.11	0.04%			9.61%	0.00%
Kenvue Inc	KVUE	1918.69	23.01	44,149.08		3.56%		33.82%	
Targa Resources Corp	TRGP	217.59	177.62	38,647.51		2.25%			
Bunge Global SA	BG	133.97	80.91	10,839.35	0.03%	3.36%	0.00%	3.29%	0.00%
LKQ Corp	LKQ	258.15	37.41	9,657.30		3.21%			
Deckers Outdoor Corp	DECK	151.77	109.19	16,572.16				22.63%	
Workday Inc	WDAY	216.64	239.53	51,890.66					
Zoetis Inc	ZTS	446.18	153.47	68,475.24	0.19%	1.30%	0.00%	8.20%	0.02%
Equinix Inc	EQIX	97.82	838.1	81,981.48		2.24%			
Digital Realty Trust Inc	DLR	336.75	159.88	53,839.39	0.15%	3.05%	0.00%	6.61%	0.01%
Molina Healthcare Inc	MOH	54.20	314.51	17,046.44	0.05%			11.34%	0.01%
Las Vegas Sands Corp	LVS	706.63	35.89	25,360.86	0.07%	2.79%	0.00%	5.45%	0.00%

Notes:

[1] Equals sum of Col. [9]
[2] Equals sum of Col. [11]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Bloomberg Professional as of April 25, 2025
[5] Bloomberg Professional as of April 25, 2025
[6] Equals [4] x [5]
[7] Equals weight in S&P 500 based on market capitalization [6] if Growth Rate >0% and ≤20%
[8] Source: Bloomberg Professional, as of April 25, 2025
[9] Equals [7] x [8]
[10] Bloomberg Professional, as of April 25, 2025
[11] Equals [7] x [10]



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9232422
R Square	0.8523762
Adjusted R Square	0.8515374
Standard Error	0.0054701
Observations	178

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.03041	0.03041	1,016.21981	0.00000
Residual	176	0.00527	0.00003		
Total	177	0.03567			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0787	0.00	86.81	0.0000	0.0769	0.0805	0.0769	0.0805
U.S. Govt. 30-year Treasury	(0.4277)	0.01	(31.88)	0.0000	(0.4542)	(0.4012)	(0.4542)	(0.4012)

	[7] U.S. Govt. 30-year Treasury	[8] Risk Premium	[9] ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	4.68%	5.87%	10.55%
Blue Chip Near-Term Projected Forecast (Q3 2025 - Q3 2026) [5]	4.44%	5.97%	10.41%
Blue Chip Long-Term Projected Forecast (2026-2030) [6]	4.30%	6.03%	10.33%
AVERAGE			10.43%

Notes:
[1] Source: Regulatory Research Associates, rate cases through April 25, 2025
[2] Source: S&P Capital IQ Pro, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] Source: S&P Capital IQ Pro, 30-day average as of April 25, 2025
[5] Source: Blue Chip Financial Forecasts, Vol. 44, No. 5, May 1, 2025, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 43, No. 12, November 27, 2024, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.078703 + (-0.427712 x Column [7])
[9] Equals Column [7] + Column [8]

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Average Authorized Natual Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
1980.1	13.45%	11.66%	1.79%
1980.2	14.38%	10.52%	3.85%
1980.3	13.87%	10.85%	3.02%
1980.4	14.35%	12.10%	2.25%
1981.1	14.71%	12.53%	2.18%
1981.2	14.61%	13.24%	1.36%
1981.3	14.86%	14.13%	0.72%
1981.4	15.70%	13.85%	1.86%
1982.1	15.55%	13.96%	1.59%
1982.2	15.62%	13.52%	2.10%
1982.3	15.77%	12.79%	2.97%
1982.4	15.63%	10.75%	4.89%
1983.1	15.41%	10.71%	4.71%
1983.2	14.84%	10.65%	4.19%
1983.3	15.24%	11.62%	3.62%
1983.4	15.40%	11.74%	3.66%
1984.1	15.39%	12.04%	3.35%
1984.2	15.07%	13.18%	1.89%
1984.3	15.46%	12.69%	2.77%
1984.4	15.33%	11.70%	3.63%
1985.1	15.03%	11.58%	3.45%
1985.2	15.44%	11.00%	4.45%
1985.3	14.64%	10.55%	4.08%
1985.4	14.37%	10.04%	4.33%
1986.1	14.05%	8.77%	5.28%
1986.2	13.28%	7.49%	5.79%
1986.3	13.09%	7.40%	5.69%
1986.4	13.62%	7.53%	6.09%
1987.1	12.61%	7.49%	5.11%
1987.2	13.04%	8.53%	4.51%
1987.3	12.70%	9.06%	3.64%
1987.4	12.69%	9.23%	3.46%
1988.1	12.94%	8.63%	4.31%
1988.2	12.48%	9.06%	3.41%
1988.3	12.79%	9.18%	3.61%
1988.4	12.98%	8.97%	4.00%
1989.1	12.99%	9.04%	3.96%
1989.2	13.25%	8.70%	4.55%
1989.3	12.56%	8.12%	4.44%
1989.4	12.94%	7.93%	5.00%
1990.1	12.68%	8.44%	4.24%
1990.2	12.81%	8.65%	4.16%
1990.3	12.36%	8.79%	3.57%
1990.4	12.78%	8.56%	4.22%
1991.1	12.69%	8.20%	4.49%
1991.2	12.53%	8.31%	4.22%
1991.3	12.43%	8.19%	4.24%
1991.4	12.33%	7.85%	4.48%
1992.1	12.42%	7.81%	4.61%
1992.2	11.98%	7.90%	4.09%
1992.3	11.87%	7.45%	4.42%
1992.4	11.94%	7.52%	4.42%
1993.1	11.75%	7.07%	4.68%
1993.2	11.71%	6.86%	4.85%
1993.3	11.39%	6.32%	5.07%
1993.4	11.16%	6.14%	5.02%
1994.1	11.12%	6.58%	4.54%
1994.2	10.84%	7.36%	3.47%
1994.3	10.87%	7.59%	3.28%

	[1]	[2]	[3]
Quarter	Average Authorized Natual Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
1994.4	11.53%	7.96%	3.56%
1995.2	11.00%	6.94%	4.06%
1995.3	11.07%	6.72%	4.35%
1995.4	11.61%	6.24%	5.37%
1996.1	11.45%	6.29%	5.16%
1996.2	10.88%	6.92%	3.95%
1996.3	11.25%	6.97%	4.28%
1996.4	11.19%	6.62%	4.57%
1997.1	11.31%	6.82%	4.49%
1997.2	11.70%	6.94%	4.76%
1997.3	12.00%	6.53%	5.47%
1997.4	10.92%	6.15%	4.77%
1998.2	11.37%	5.85%	5.52%
1998.3	11.41%	5.48%	5.93%
1998.4	11.69%	5.11%	6.58%
1999.1	10.82%	5.37%	5.44%
1999.2	11.25%	5.80%	5.45%
1999.4	10.38%	6.26%	4.12%
2000.1	10.66%	6.30%	4.36%
2000.2	11.03%	5.98%	5.05%
2000.3	11.33%	5.79%	5.54%
2000.4	12.10%	5.69%	6.41%
2001.1	11.38%	5.45%	5.93%
2001.2	10.75%	5.70%	5.05%
2001.4	10.65%	5.30%	5.35%
2002.1	10.67%	5.52%	5.15%
2002.2	11.64%	5.62%	6.03%
2002.3	11.50%	5.09%	6.41%
2002.4	11.01%	4.93%	6.08%
2003.1	11.38%	4.85%	6.53%
2003.2	11.36%	4.60%	6.76%
2003.3	10.61%	5.11%	5.50%
2003.4	10.84%	5.11%	5.73%
2004.1	11.06%	4.88%	6.18%
2004.2	10.57%	5.34%	5.24%
2004.3	10.37%	5.11%	5.26%
2004.4	10.66%	4.93%	5.73%
2005.1	10.65%	4.71%	5.94%
2005.2	10.54%	4.47%	6.07%
2005.3	10.47%	4.42%	6.05%
2005.4	10.32%	4.65%	5.66%
2006.1	10.68%	4.63%	6.05%
2006.2	10.60%	5.14%	5.46%
2006.3	10.34%	5.00%	5.34%
2006.4	10.14%	4.74%	5.40%
2007.1	10.52%	4.80%	5.72%
2007.2	10.13%	4.99%	5.14%
2007.3	10.03%	4.95%	5.08%
2007.4	10.12%	4.61%	5.50%
2008.1	10.38%	4.41%	5.97%
2008.2	10.17%	4.57%	5.59%
2008.3	10.55%	4.45%	6.10%
2008.4	10.34%	3.64%	6.69%
2009.1	10.24%	3.44%	6.80%
2009.2	10.11%	4.17%	5.94%
2009.3	9.88%	4.32%	5.56%
2009.4	10.31%	4.34%	5.97%
2010.1	10.24%	4.62%	5.61%
2010.2	9.99%	4.37%	5.62%
2010.3	10.43%	3.86%	6.57%
2010.4	10.09%	4.17%	5.92%

	[1]	[2]	[3]
Quarter	Average Authorized Natual Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
2011.1	10.10%	4.56%	5.54%
2011.2	9.85%	4.34%	5.51%
2011.3	9.65%	3.70%	5.95%
2011.4	9.88%	3.04%	6.84%
2012.1	9.63%	3.14%	6.50%
2012.2	9.83%	2.94%	6.89%
2012.3	9.75%	2.74%	7.01%
2012.4	10.06%	2.86%	7.19%
2013.1	9.57%	3.13%	6.44%
2013.2	9.47%	3.14%	6.33%
2013.3	9.60%	3.71%	5.89%
2013.4	9.83%	3.79%	6.04%
2014.1	9.54%	3.69%	5.85%
2014.2	9.84%	3.44%	6.39%
2014.3	9.45%	3.27%	6.18%
2014.4	10.28%	2.96%	7.32%
2015.1	9.47%	2.55%	6.91%
2015.2	9.43%	2.88%	6.55%
2015.3	9.75%	2.96%	6.79%
2015.4	9.68%	2.96%	6.71%
2016.1	9.48%	2.72%	6.76%
2016.2	9.42%	2.57%	6.85%
2016.3	9.47%	2.28%	7.19%
2016.4	9.67%	2.83%	6.84%
2017.1	9.60%	3.05%	6.55%
2017.2	9.47%	2.90%	6.57%
2017.3	10.14%	2.82%	7.32%
2017.4	9.70%	2.82%	6.88%
2018.1	9.68%	3.02%	6.66%
2018.2	9.43%	3.09%	6.34%
2018.3	9.71%	3.06%	6.65%
2018.4	9.53%	3.27%	6.26%
2019.1	9.55%	3.01%	6.54%
2019.2	9.73%	2.78%	6.94%
2019.3	9.95%	2.29%	7.67%
2019.4	9.74%	2.26%	7.48%
2020.1	9.35%	1.89%	7.46%
2020.2	9.55%	1.38%	8.17%
2020.3	9.52%	1.37%	8.15%
2020.4	9.50%	1.62%	7.87%
2021.1	9.71%	2.07%	7.63%
2021.2	9.48%	2.26%	7.22%
2021.3	9.43%	1.93%	7.50%
2021.4	9.59%	1.95%	7.65%
2022.1	9.38%	2.25%	7.12%
2022.2	9.23%	3.05%	6.18%
2022.3	9.52%	3.26%	6.26%
2022.4	9.65%	3.89%	5.75%
2023.1	9.64%	3.75%	5.89%
2023.2	9.40%	3.81%	5.59%
2023.3	9.53%	4.23%	5.30%
2023.4	9.62%	4.58%	5.04%
2024.1	9.62%	4.32%	5.29%
2024.2	9.97%	4.58%	5.40%
2024.3	9.58%	4.23%	5.35%
2024.4	9.70%	4.50%	5.21%
2025.1	9.73%	4.72%	5.02%
2025.2	9.90%	4.72%	5.18%
AVERAGE	11.32%	6.03%	5.29%
MEDIAN	10.67%	5.11%	5.45%

BUSINESS SEGMENT DATA FOR CHESAPEAKE UTILITIES CORPORATION, NEW JERSEY RESOURCES CORPORATION AND SOUTHWEST GAS HOLDINGS

Chesapeake Utilities Corporation - Operating Income ($000)

Year	Total	Natural Gas Distribution	Electric Distribution	Natural Gas Transmission	Unregulated Energy	Other Businesses and Eliminations	Notes	Percent Elec. & Gas Dist. / Total	Percent Gas Dist. / Total
2024	228,200	104,212	10,221	81,767	31,700	300	[1]	50.15%	45.67%
2023	150,800	54,213	6,771	65,216	24,400	200	[1]	40.44%	35.95%
2022	142,900	52,803	6,501	55,996	27,500	100	[1]	41.50%	36.95%
3 yr. average								**44.03%**	**39.52%**

DTE Energy Company - Operating Income ($000)

Year	Total	Electric	Gas	DTE Vantage	Energy Trading	Reclassifications and Eliminations	Notes	Percent Elec. / Total	Percent Gas Dist. / Total
2024	2,091,000	1,437,000	434,000	34,000	189,000	(3,000)	[2]	68.72%	20.76%
2023	2,243,000	1,214,000	474,000	104,000	457,000	(6,000)	[2]	54.12%	21.13%
2022	1,748,000	1,305,000	447,000	95,000	(101,000)	2,000	[2]	74.66%	25.57%
3 yr. average								**65.83%**	**22.49%**

New Jersey Resource Corporation - Operating Income ($000)

Year	Total	Natural Gas Distribution	Clean Energy Ventures	Energy Services	Storage and Transportation	Home Services and Other & Eliminations	Notes	Percent Reg / Total	Percent Gas Dist. / Total
2024	458,104	207,118	58,652	154,279	27,198	10,857	[2]	51.15%	45.21%
2023	407,000	207,528	58,722	113,112	32,425	(4,787)	[2]	58.96%	50.99%
2022	406,475	218,973	66,178	95,639	22,163	3,522	[2]	59.32%	53.87%
3 yr. average								**56.48%**	**50.02%**

Operating Income ($000)

	Total Regulated Energy	Delmarva Natural Gas Distribution	Florida Natural Gas Distribution	Florida City Gas	FPU Electric Distribution	Eastern Shore	Peninsula Pipeline	Aspire Energy Express
2024	196,200	12,100	26,400	13,500	5,100	25,200	14,700	900
2023	126,200	9,256	23,840	(3,256)	3,727	23,284	12,195	417
2022	115,300	12,930	19,162	-	3,951	23,222	10,372	439

Net Income ($000)

Notes:

[1] Source: CPK - 2024 For 10-K, pgs. 4 and 78; CPK - 2023 For 10-K, pg. 4; and CPK - 2022 For 10-K, pg. 4

[2] Source: DTE - 2024 Form 10-K, pp. 32, 35, 37, 39, and 56

[3] Source: NJR - 2024 Form 10-K, pp. 42, 46, 47, 50, and 65

Mr. Megginson Constant Growth DCF
As Filed

		[1]	[2]	[3]	[4]	**[5]**	[6]	[7]	[8]	[9]	[10]	[11]
			Closing Monthly Stock Price									
Company	**Ticker**	**Annualized Dividend**	**Jan 1, 2025**	**Feb 1, 2025**	**Mar. 1, 2025**	**Average**	**Dividend Yield**	**Expected Dividend Yield**	**Value Line**	**Zacks**	**Average**	**Cost of Equity**
Atmos Energy Corporation	ATO	$3.48	$142.51	$152.13	$148.66	$147.77	2.36%	2.43%	6.00%	7.10%	6.55%	8.98%
DTE Energy Company	DTE	$4.36	$119.88	$133.70	$132.03	$128.54	3.39%	3.47%	4.50%	n/a	4.50%	7.97%
New Jersey Resources Corporation	NJR	$1.80	$47.95	$48.38	$48.48	$48.27	3.73%	3.83%	5.00%	6.00%	5.50%	9.33%
NiSource Inc.	NI	$1.12	$37.30	$40.81	$38.82	$38.98	2.87%	2.98%	9.50%	6.00%	7.75%	10.73%
Northwest Natural Gas Company	NWN	$1.96	$39.92	$40.88	$41.48	$40.76	4.81%	4.93%	6.50%	3.70%	5.10%	10.03%
ONE Gas, Inc.	OGS	$2.68	$70.64	$75.15	$73.53	$73.11	3.67%	3.74%	4.00%	3.98%	3.99%	7.73%
Southwest Gas Corporation	SWX	$2.48	$74.68	$75.05	$71.87	$73.87	3.36%	3.48%	10.00%	5.00%	7.50%	10.98%
Spire, Inc.	SR	$3.16	$70.96	$76.86	$75.36	$74.39	4.25%	4.36%	4.50%	5.62%	5.06%	9.42%
Average:												**9.40%**

Notes:
[1] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[2] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[3] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[4] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[5] Equals averages of [2], [3], [4]
[6] Equals [1] / [5]
[7] Equals [6] x (1 + 0.5 x [10])
[8] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[9] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[10] Equals average of [8], [9]
[11] Equals [7] + [10]

Mr. Megginson Constant Growth DCF
As Adjusted to Exclude NJR & DTE And Correct Zacks Growth Rates

		[1]	[2]	[3]	[4]	**[5]**	[6]	[7]	[8]	[9]	[10]	[11]
			Closing Monthly Stock Price									
Company	**Ticker**	**Annualized Dividend**	**Jan 1, 2025**	**Feb 1, 2025**	**Mar. 1, 2025**	**Average**	**Dividend Yield**	**Expected Dividend Yield**	**Value Line**	**Zacks**	**Average**	**Cost of Equity**
Atmos Energy Corporation	ATO	$3.48	$142.51	$152.13	$148.66	$147.77	2.36%	2.43%	6.00%	7.10%	6.55%	8.98%
NiSource Inc.	NI	$1.12	$37.30	$40.81	$38.82	$38.98	2.87%	3.00%	9.50%	8.20%	8.85%	11.85%
Northwest Natural Gas Company	NWN	$1.96	$39.92	$40.88	$41.48	$40.76	4.81%	4.96%	6.50%	n/a	6.50%	11.46%
ONE Gas, Inc.	OGS	$2.68	$70.64	$75.15	$73.53	$73.11	3.67%	3.75%	4.00%	4.70%	4.35%	8.10%
Southwest Gas Corporation	SWX	$2.48	$74.68	$75.05	$71.87	$73.87	3.36%	3.50%	10.00%	6.60%	8.30%	11.80%
Spire, Inc.	SR	$3.16	$70.96	$76.86	$75.36	$74.39	4.25%	4.36%	4.50%	6.50%	5.50%	9.86%
Average												**10.34%**

Notes:
[1] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[2] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[3] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[4] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[5] Equals averages of [2], [3], [4]
[6] Equals [1] / [5]
[7] Equals [6] x (1 + 0.5 x [10])
[8] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[9] Source: Zacks as of March 31, 2025
[10] Equals average of [8], [9]
[11] Equals [7] + [10]

Mr. Megginson Constant Growth DCF
As Adjusted to Exclude NJR & DTE and Update Through April 30, 2025

		[1]	[2]	[3]	[4]	**[5]**	[6]	[7]	[8]	[9]	[10]	[11]
			Average Monthly Stock Price									
Company	**Ticker**	**Annualized Dividend**	**Feb 1, 2025**	**Mar. 1, 2025**	**Apr. 1, 2025**	**Average**	**Dividend Yield**	**Expected Dividend Yield**	**Value Line**	**Zacks**	**Average**	**Cost of Equity**
Atmos Energy Corporation	ATO	$3.48	$152.13	$148.66	$154.91	$151.90	2.29%	2.37%	6.00%	7.20%	6.60%	8.97%
NiSource Inc.	NI	$1.12	$40.81	$38.82	$38.95	$39.53	2.83%	2.96%	9.50%	7.90%	8.70%	11.66%
Northwest Natural Gas Company	NWN	$1.96	$40.88	$41.48	$42.52	$41.63	4.71%	4.86%	6.50%	n/a	6.50%	11.36%
ONE Gas, Inc.	OGS	$2.68	$75.15	$73.53	$76.24	$74.97	3.57%	3.66%	4.00%	5.60%	4.80%	8.46%
Southwest Gas Corporation	SWX	$2.48	$75.05	$71.87	$71.63	$72.85	3.40%	3.57%	10.00%	9.50%	9.75%	13.32%
Spire, Inc.	SR	$3.14	$76.86	$75.36	$76.70	$76.31	4.12%	4.23%	4.50%	6.50%	5.50%	9.73%
Average												**10.58%**

Notes:
[1] Source: Bloomberg Professional
[2] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[3] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[4] Source: S&P Capital IQ Pro
[5] Equals averages of [2], [3], [4]
[6] Equals [1] / [5]
[7] Equals [6] x (1 + 0.5 x [10])
[8] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[9] Source: Zacks as of April 25, 2025
[10] Equals average of [8], [9]
[11] Equals [7] + [10]

Mr. Coppola Constant Growth DCF
As Filed

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
		Projected Annual Dividend			Average 30-Day High/Low	Expected Dividend	Projected EPS Growth Rates					
							Value Line			Zacks		Cost of
Company	Ticker	2025	2026	Average	Stock Price	Yield	2024 EPS	2029 EPS	Growth	Growth	Average	Equity
Atmos Energy	ATO	$3.48	$3.68	$3.58	$147.59	2.43%	$6.83	$8.65	4.84%	7.00%	5.92%	8.34%
Black Hills	BKH	$2.70	$2.80	$2.75	$59.90	4.59%	$3.91	$4.80	4.19%	n/a	4.19%	8.78%
Chesapeake Utilities	CPK	$2.64	$2.80	$2.72	$121.24	2.24%	$5.05	$6.80	6.13%	n/a	6.13%	8.37%
NiSource	NI	$1.12	$1.20	$1.16	$39.16	2.96%	$1.75	$2.55	7.82%	7.00%	7.41%	10.37%
Northwest Natural Holdings	NWN	$1.96	$1.97	$1.97	$40.94	4.80%	$3.00	$3.45	3.56%	n/a	3.56%	8.36%
One Gas	OGS	$2.68	$2.72	$2.70	$72.77	3.71%	$3.85	$5.25	6.40%	5.00%	5.70%	9.41%
Southwest Gas	SWX	$2.48	$2.48	$2.48	$75.43	3.29%	$3.60	$4.85	7.74%	6.00%	6.87%	10.16%
Spire	SR	$3.14	$3.26	$3.20	$74.43	4.30%	$4.19	$5.25	4.61%	5.00%	4.81%	9.11%
Average												**9.11%**

Notes:
[1] Source: Value Line
[2] Source: Value Line
[3] Equals average of [1], [2]
[4] Source: Exhibit AG-43
[5] Equals [3] / [4]
[6] Source: Value Line (For NWN & SWX - 2025 EPS)
[7] Source: Value Line
[8] Equals (([7] / [6])^(1/5))-1 (For SWX & NWN - Equals (([7] / [6])^(1/4))-1)
[9] Source: Exhibit AG-43
[10] Equals average of [8], [9]
[11] Equals [5] + [10]

Mr. Coppola Constant Growth DCF
As Adjusted Excl. BKH & CPK And Updated Through April 30, 2025

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
		Projected Annual Dividend			Average 30-Day High/Low	Expected Dividend	Projected EPS Growth Rates					
							Value Line			Zacks		Cost of
Company	Ticker	2025	2026	Average	Stock Price	Yield	2024 EPS	2029 EPS	Growth	Growth	Average	Equity
Atmos Energy	ATO	$3.48	$3.68	$3.58	$153.44	2.33%	$6.83	$8.65	4.84%	7.20%	6.02%	8.35%
NiSource	NI	$1.12	$1.20	$1.16	$39.15	2.96%	$1.75	$2.55	7.82%	7.90%	7.86%	10.82%
Northwest Natural Holdings	NWN	$1.96	$1.97	$1.97	$42.22	4.65%	$3.00	$3.45	3.56%	n/a	3.56%	8.21%
One Gas	OGS	$2.68	$2.72	$2.70	$75.48	3.58%	$3.85	$5.25	6.40%	5.60%	6.00%	9.58%
Southwest Gas	SWX	$2.48	$2.48	$2.48	$72.30	3.43%	$3.60	$4.85	7.74%	9.50%	8.62%	12.05%
Spire	SR	$3.14	$3.26	$3.20	$76.83	4.16%	$4.19	$5.25	4.61%	6.50%	5.56%	9.72%
Average												**9.79%**

Notes:
[1] Source: Value Line
[2] Source: Value Line
[3] Equals average of [1], [2]
[4] Source: S&P Capital IQ Pro.
[5] Equals [3] / [4]
[6] Source: Value Line (For NWN & SWX - 2025 EPS)
[7] Source: Value Line
[8] Equals (([7] / [6])^(1/5))-1 (For SWX & NWN - Equals (([7] / [6])^(1/4))-1)
[9] Source: Zacks as of April 25, 2025
[10] Equals average of [8], [9]
[11] Equals [5] + [10]

Calculation of Long-Term GDP Growth Rate
Consistent with *Ibbotson* Methodology

Description	Notes	Year	Amount
Change in Real GDP			
Real GDP ($ Billions)	[1]	1929	$ 1,191.1
Real GDP ($ Billions)	[1]	2024	$ 23,305.0
Compound Annual Growth Rate			**3.18%**
Projected Inflation			
Consumer Price Index (YoY % Change)	[2]	2031-2035	2.20%
Consumer Price Index (All-Urban)	[3]	2035	3.86
Consumer Price Index (All-Urban)	[3]	2050	5.37
Compound Annual Growth Rate			2.23%
GDP Chain-type Price Index (2012=1.000)	[3]	2035	1.66
GDP Chain-type Price Index (2012=1.000)	[3]	2050	2.30
Compound Annual Growth Rate			2.18%
Average Inflation Forecast	[4]		**2.20%**
Long-Term GDP Growth Rate	[5]		**5.45%**

Notes:
[1] Bureau of Economic Analysis, March 27, 2025
[2] Blue Chip Financial Forecasts, Vol. 43, No. 12, November 27, 2024, at 14
[3] Energy Information Administration, Annual Energy Outlook 2025 at Table 20, April 15, 2025
[4] Average of 3 inflation sources
[5] Equals (1+3.18%) x (1+2.20%)-1

Mr. Walters Constant Growth DCF Analysis Using Projected EPS Growth Rates
As Filed

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
			Analysts' Projected EPS Growth Rates						
Company	**Ticker**	**13-wk Avg Stock Price**	**Zacks**	**MI**	**I/B/E/S**	**Average**	**Annualized Dividend**	**Adjusted Yield**	**Cost of Equity**
Atmos Energy Corporation	ATO	$ 144.46	7.10%	7.44%	7.00%	7.18%	$ 3.48	2.58%	9.76%
Northwest Natural Gas Company	NWN	$ 40.45	n/a	6.50%	6.00%	6.25%	$ 1.96	5.15%	11.40%
ONE Gas, Inc.	OGS	$ 71.23	4.66%	2.63%	n/a	3.65%	$ 2.68	3.90%	7.54%
Southwest Gas Holdings, Inc.	SWX	$ 73.43	6.61%	10.55%	n/a	8.58%	$ 2.48	3.67%	12.25%
Spire, Inc.	SR	$ 71.81	6.54%	8.08%	n/a	7.31%	$ 3.14	4.69%	12.00%
American States Water Company	AWR	$ 75.57	1.75%	1.75%	1.70%	1.73%	$ 1.86	2.50%	4.24%
American Water Works Co. Inc.	AWK	$ 129.79	8.30%	7.96%	8.30%	8.19%	$ 3.06	2.55%	10.74%
California Water Service Group	CWT	$ 45.15	42.44%	42.44%	42.40%	42.43%	$ 1.12	3.53%	45.96%
Essential Utilities, Inc.	WTRG	$ 36.41	6.58%	6.51%	n/a	6.55%	$ 1.30	3.80%	10.35%
Middlesex Water Company	MSEX	53.23	13.96%	13.96%	n/a	13.96%	$ 1.36	2.91%	16.87%
SJW Group	SJW	$ 50.77	4.52%	4.52%	4.50%	4.51%	$ 1.60	3.29%	7.81%
Average									**13.54%**
Median									**10.74%**

Notes:
[1] Source: Exhibit AB-9
[2] Source: Exhibit AB-8
[3] Source: Exhibit AB-8
[4] Source: Exhibit AB-8
[5] Equals average of [2], [3], [4]
[6] Source: Exhibit AB-9
[7] Equals ([6] / [1]) X (1 + [5])
[8] Equals [7] + [5]

Mr. Walters Constant Growth DCF Analysis Using Projected EPS Growth Rates Adjusted to Include NiSource

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
			Analysts' Projected EPS Growth Rates						
Company	**Ticker**	**13-wk Avg Stock Price**	**Zacks**	**MI**	**I/B/E/S**	**Average**	**Annualized Dividend**	**Adjusted Yield**	**Cost of Equity**
Atmos Energy Corporation	ATO	$ 144.46	7.10%	7.44%	7.00%	7.18%	$ 3.48	2.58%	9.76%
NiSource Inc.	NI	$ 38.09	8.20%	8.22%	8.15%	8.19%	$ 1.12	3.18%	11.37%
Northwest Natural Gas Company	NWN	$ 40.45	n/a	6.50%	6.00%	6.25%	$ 1.96	5.15%	11.40%
ONE Gas, Inc.	OGS	$ 71.23	4.66%	2.63%	n/a	3.65%	$ 2.68	3.90%	7.54%
Southwest Gas Holdings, Inc.	SWX	$ 73.43	6.61%	10.55%	n/a	8.58%	$ 2.48	3.67%	12.25%
Spire, Inc.	SR	$ 71.81	6.54%	8.08%	n/a	7.31%	$ 3.14	4.69%	12.00%
American States Water Company	AWR	$ 75.57	1.75%	1.75%	1.70%	1.73%	$ 1.86	2.50%	4.24%
American Water Works Co. Inc.	AWK	$ 129.79	8.30%	7.96%	8.30%	8.19%	$ 3.06	2.55%	10.74%
California Water Service Group	CWT	$ 45.15	42.44%	42.44%	42.40%	42.43%	$ 1.12	3.53%	45.96%
Essential Utilities, Inc.	WTRG	$ 36.41	6.58%	6.51%	n/a	6.55%	$ 1.30	3.80%	10.35%
Middlesex Water Company	MSEX	53.23	13.96%	13.96%	n/a	13.96%	$ 1.36	2.91%	16.87%
SJW Group	SJW	$ 50.77	4.52%	4.52%	4.50%	4.51%	$ 1.60	3.29%	7.81%
Average									**13.36%**
Median									**11.05%**

Notes:

[1] Source: Exhibit AB-9 and Bloomberg Professional (NI)
[2] Source: Exhibit AB-8 and Zacks as of March 31, 2025 (NI)
[3] Source: Exhibit AB-8 and S&P Capital IQ Pro as of March 31, 2025 (NI)
[4] Source: Exhibit AB-8 and Eikon as of March 31, 2025 (NI)
[5] Equals average of [2], [3], [4]
[6] Source: Exhibit AB-9 and Bloomberg Professional (NI)
[7] Equals ([6] / [1]) X (1 + [5])
[8] Equals [7] + [5]

Mr. Bandyk DCF Analysis
As Filed

Company	Ticker	[1] Annualized Dividend	[2] 30-day Average High Stock Price	[3] 30-day Average Average Stock Price	[4] Average Stock Price	[5] Expected Dividend Yield	[6] Exp. Div. Yield Adj. for Flotation Cost	[7] Value Line Projected EPS Growth	[8] Yahoo! Finance Projected EPS Growth	[9] Zacks Projected EPS Growth	[10] Average Projected EPS Gwth Rate	[11] Weight on EPS	[12] Long-Term Gwth Rate	[13] Weight LT Gwth	[14] Cost of Equity
Atmos Energy	ATO	$3.22	$154.04	$145.16	$149.60	2.23%	2.31%	7.00%	7.40%	7.00%	7.13%	80.00%	3.80%	20.00%	8.78%
NiSource	NI	$1.06	$41.30	$38.07	$39.69	2.78%	2.88%	9.50%	7.70%	7.00%	8.07%	80.00%	3.80%	20.00%	10.10%
Northwest Natural Holdings	NWN	$1.95	$42.61	$40.32	$41.47	4.81%	4.99%	6.50%	2.80%	n/a	4.65%	80.00%	3.80%	20.00%	9.47%
One Gas	OGS	$2.64	$76.48	$71.96	$74.22	3.64%	3.77%	3.50%	5.00%	5.00%	4.50%	80.00%	3.80%	20.00%	8.13%
Southwest Gas Corporation	SWX	$2.48	$77.95	$71.39	$74.67	3.43%	3.56%	10.00%	4.00%	6.00%	6.67%	80.00%	3.80%	20.00%	9.65%
Spire	SR	$3.02	$78.33	$73.94	$76.14	4.07%	4.22%	4.50%	6.36%	5.00%	5.29%	80.00%	3.80%	20.00%	9.21%
Average															**9.22%**

Mr. Bandyk DCF Analysis
As Adjusted - Constant Growth DCF & Updated as of April 30, 2025

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	**Ticker**	**Annualized Dividend**	**30-day Average High Stock Price**	**30-day Average Average Stock Price**	**Average Stock Price**	**Expected Dividend Yield**	**Exp. Div. Yield Adj. for Flotation Cost**	**Value Line Projected EPS Growth**	**S&P Capital IQ Projected EPS Growth**	**Zacks Projected EPS Growth**	**Average Projected EPS Gwth Rate**	**Cost of Equity**
Atmos Energy	ATO	$3.48	$155.17	$151.71	$153.44	2.35%	2.43%	6.00%	7.47%	7.20%	6.89%	9.32%
NiSource	NI	$1.12	$39.65	$38.66	$39.15	2.98%	3.09%	9.50%	7.96%	7.90%	8.45%	11.55%
Northwest Natural Holdings	NWN	$1.96	$42.70	$41.74	$42.22	4.81%	4.99%	6.50%	8.25%	n/a	7.38%	12.37%
One Gas	OGS	$2.68	$76.38	$74.58	$75.48	3.64%	3.77%	4.00%	5.17%	5.60%	4.92%	8.70%
Southwest Gas Corporation	SWX	$2.48	$73.27	$71.34	$72.30	3.60%	3.73%	10.00%	n/a	9.50%	9.75%	13.48%
Spire	SR	$3.14	$77.76	$75.90	$76.83	4.21%	4.37%	4.50%	7.54%	6.50%	6.18%	10.55%
Average												**10.99%**

Mr. Megginson CAPM Analysis with Historical Market Risk Premium

As Filed

		[1]	[2]	[3]	[4]	[5]	[6]
Company	**Ticker**	**Risk-Free Rate**	***Value Line* Beta**	**Historical Market Return (1928-2023)**	**Historical Long-Term Government Bond Return (1928-2023)**	**Market Risk Premium**	**Cost of Equity**
Atmos Energy Corp	ATO	4.25%	0.90	11.79%	4.85%	6.94%	10.50%
DTE Energy	DTE	4.25%	1.00	11.79%	4.85%	6.94%	11.19%
New Jersey Resources	NJR	4.25%	1.00	11.79%	4.85%	6.94%	11.19%
NiSource, Inc.	NI	4.25%	0.85	11.79%	4.85%	6.94%	10.15%
Northwest Natural Gas Co	NWN	4.25%	0.90	11.79%	4.85%	6.94%	10.50%
ONE Gas, Inc.	OGS	4.25%	0.85	11.79%	4.85%	6.94%	10.15%
Southwest Gas Corp	SWX	4.25%	0.95	11.79%	4.85%	6.94%	10.84%
Spire Inc.	SR	4.25%	0.90	11.79%	4.85%	6.94%	10.50%
						Average:	**10.63%**

Notes:
[1] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[2] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[3] Source: Exhibit S-4, Schedule D-5, page 6 of 14
[4] Source: Exhibit S-4, Schedule D-5, page 6 of 14
[5] Equals [3] - [4]
[6] Equals [1] + [2] x [5]

Mr. Megginson CAPM Analysis
with Historical Market Risk Premium

As Adjusted to Account for Inverse Relationship in Interest Rates and the Market Risk Premium

		[1]	[2]	[3]	[4]	[5]	[6]
Company	**Ticker**	**Risk-Free Rate**	***Value Line* Beta**	**Historical Market Return (1926-2023)**	**Risk-Free Rate**	**Market Risk Premium**	**Cost of Equity**
Atmos Energy Corp	ATO	4.25%	0.90	12.17%	4.25%	7.92%	11.38%
DTE Energy	DTE	4.25%	1.00	12.17%	4.25%	7.92%	12.17%
New Jersey Resources	NJR	4.25%	1.00	12.17%	4.25%	7.92%	12.17%
NiSource, Inc.	NI	4.25%	0.85	12.17%	4.25%	7.92%	10.98%
Northwest Natural Gas Co	NWN	4.25%	0.90	12.17%	4.25%	7.92%	11.38%
ONE Gas, Inc.	OGS	4.25%	0.85	12.17%	4.25%	7.92%	10.98%
Southwest Gas Corp	SWX	4.25%	0.95	12.17%	4.25%	7.92%	11.77%
Spire Inc.	SR	4.25%	0.90	12.17%	4.25%	7.92%	11.38%
						Average:	**11.53%**

Notes:
[1] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[2] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[3] Source: 2023 Kroll SBBI Yearbook for 1926-2022 and S&P Capital IQ Pro for 2023
[4] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[5] Equals [3] - [4]
[6] Equals [1] + [2] x [5]

Mr. Megginson CAPM Analysis with Projected Market Risk Premium

As Adjusted to Utilize Mr. Megginson's Approach in Case No. U-21540

		[1]	[2]	[3]	[4]	[5]	[6]
Company	**Ticker**	**Risk-Free Rate**	***Value Line* Beta**	**Company's Projected Mkt Return in Direct Testimony**	**Risk-Free Rate**	**Market Risk Premium**	**Cost of Equity**
Atmos Energy Corp	ATO	4.25%	0.90	12.04%	4.25%	7.79%	11.26%
DTE Energy	DTE	4.25%	1.00	12.04%	4.25%	7.79%	12.04%
New Jersey Resources	NJR	4.25%	1.00	12.04%	4.25%	7.79%	12.04%
NiSource, Inc.	NI	4.25%	0.85	12.04%	4.25%	7.79%	10.87%
Northwest Natural Gas Co	NWN	4.25%	0.90	12.04%	4.25%	7.79%	11.26%
ONE Gas, Inc.	OGS	4.25%	0.85	12.04%	4.25%	7.79%	10.87%
Southwest Gas Corp	SWX	4.25%	0.95	12.04%	4.25%	7.79%	11.65%
Spire Inc.	SR	4.25%	0.90	12.04%	4.25%	7.79%	11.26%
						Average:	**11.41%**

Notes:
[1] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[2] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[3] Source: Exhibit A-14 (AEB-1), Schedule D-5, pages 16-21
[4] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[5] Equals [3] - [4]
[6] Equals [1] + [2] x [5]

Mr. Coppola CAPM Analysis

As Filed

		[1]	[2]	[3]	[4]
Company	**Ticker**	**Risk-Free Rate**	***Value Line* Beta**	**Market Risk Premium**	**Cost of Equity**
Atmos Energy Corp	ATO	4.00%	0.90	7.30%	10.57%
Black Hills	BKH	4.00%	1.00	7.30%	11.30%
Chesapeake Utilities	CPK	4.00%	0.85	7.30%	10.21%
NiSource, Inc.	NI	4.00%	0.95	7.30%	10.94%
Northwest Natural Gas Co	NWN	4.00%	0.90	7.30%	10.57%
ONE Gas, Inc.	OGS	4.00%	0.85	7.30%	10.21%
Southwest Gas Corp	SWX	4.00%	0.95	7.30%	10.94%
Spire Inc.	SR	4.00%	0.90	7.30%	10.57%
				Average:	**10.66%**

Notes:
[1] Source: Exhibit AG-44
[2] Source: Exhibit AG-44
[3] Source: Exhibit AG-44
[4] Equals [1] + [2] x [3]

Mr. Coppola CAPM Analysis

As Adjusted to Account for Inverse Relationship in Interest Rates and the Market Risk Premium and Update Risk-Free Rate

		[1]	[2]	[3]	[4]	[5]	[6]
Company	**Ticker**	**Risk-Free Rate**	***Value Line* Beta**	**Historical Market Return (1926-2023)**	**Risk-Free Rate**	**Market Risk Premium**	**Cost of Equity**
Atmos Energy Corp	ATO	4.50%	0.90	12.17%	4.50%	7.67%	11.40%
Black Hills	BKH	4.50%	1.00	12.17%	4.50%	7.67%	12.17%
Chesapeake Utilities	CPK	4.50%	0.85	12.17%	4.50%	7.67%	11.02%
NiSource, Inc.	NI	4.50%	0.95	12.17%	4.50%	7.67%	11.79%
Northwest Natural Gas Co	NWN	4.50%	0.90	12.17%	4.50%	7.67%	11.40%
ONE Gas, Inc.	OGS	4.50%	0.85	12.17%	4.50%	7.67%	11.02%
Southwest Gas Corp	SWX	4.50%	0.95	12.17%	4.50%	7.67%	11.79%
Spire Inc.	SR	4.50%	0.90	12.17%	4.50%	7.67%	11.40%
						Average:	**11.50%**

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 4, April 1, 2025, at 2.
[2] Source: Exhibit AG-44
[3] Source: 2023 Kroll SBBI Yearbook for 1926-2022 and S&P Capital IQ Pro for 2023
[4] Source: Blue Chip Financial Forecasts, Vol. 44, No. 4, April 1, 2025, at 2.
[5] Equals [3] - [4]
[6] Equals [1] + [2] x [5]

Mr. Bandyk CAPM Analysis

As Filed

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Company	**Ticker**	**Risk-Free Rate**	***Value Line* Raw Beta**	**Market Risk Premium**	**Cost of Equity**	***Bloomberg* Raw Beta**	**Market Risk Premium**	**Cost of Equity**	**Average Cost of Equity**
Atmos	ATO	4.41%	0.77	4.86%	8.17%	0.61	4.86%	7.40%	7.78%
NiSource	NI	4.41%	0.92	4.86%	8.90%	0.69	4.86%	7.75%	8.33%
Northwest Natural Gas Holding Co	NWN	4.41%	0.77	4.86%	8.17%	0.54	4.86%	7.05%	7.61%
ONE Gas, Inc.	OGS	4.41%	0.77	4.86%	8.17%	0.65	4.86%	7.56%	7.86%
Southwest Gas Corp	SWX	4.41%	0.85	4.86%	8.53%	0.74	4.86%	7.99%	8.26%
Spire, Inc.	SR	4.41%	0.77	4.86%	8.17%	0.64	4.86%	7.52%	7.84%
								Average:	**7.95%**

Notes:
[1] Source: Exhibit CUB-15
[2] Source: Exhibit CUB-17
[3] Source: Exhibit CUB-16
[4] Equals [1] + [2] x [3]
[5] Source: Exhibit CUB-17
[6] Source: Exhibit CUB-16
[7] Equals [1] + [5] x [6]
[8] Equals average of [4] and [7]

Mr. Bandyk CAPM Analysis

As Adjusted to Use Recent Market Return

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
			Value Line			Market		*Bloomberg*			Market		Average
Company	Ticker	Risk-Free Rate	Raw Beta	Market Return	Risk-Free Rate	Risk Premium	Cost of Equity	Raw Beta	Market Return	Risk-Free Rate	Risk Premium	Cost of Equity	Cost of Equity
Atmos	ATO	4.41%	0.77	12.04%	4.41%	7.63%	10.31%	0.61	12.04%	4.41%	7.63%	9.10%	9.70%
NiSource	NI	4.41%	0.92	12.04%	4.41%	7.63%	11.46%	0.69	12.04%	4.41%	7.63%	9.66%	10.56%
Northwest Natural Gas Holding Co	NWN	4.41%	0.77	12.04%	4.41%	7.63%	10.31%	0.54	12.04%	4.41%	7.63%	8.55%	9.43%
ONE Gas, Inc.	OGS	4.41%	0.77	12.04%	4.41%	7.63%	10.31%	0.65	12.04%	4.41%	7.63%	9.36%	9.83%
Southwest Gas Corp	SWX	4.41%	0.85	12.04%	4.41%	7.63%	10.88%	0.74	12.04%	4.41%	7.63%	10.03%	10.45%
Spire, Inc.	SR	4.41%	0.77	12.04%	4.41%	7.63%	10.31%	0.64	12.04%	4.41%	7.63%	9.30%	9.80%
												Average:	**9.96%**

Notes:
[1] Source: Exhibit CUB-15
[2] Source: Exhibit CUB-17
[3] Source: Exhibit A-14 (AEB-1), Schedule D-5, pages 16-21
[4] Source: Exhibit CUB-15
[5] Equals [3] - [4]
[6] Equals [1] + [2] x [5]
[7] Source: Exhibit CUB-17
[8] Source: Exhibit A-14 (AEB-1), Schedule D-5, pages 16-21
[9] Source: Exhibit CUB-15
[10] Equals [8] - [9]
[11] Equals [1] + [7] x [10]
[12] Equals average of [6] and [11]

Service Date: September 26, 2018

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

IN THE MATTER OF the Joint Application for Approval to Change and Establish Natural Gas Delivery Service Rates for Energy West Montana, Inc. and Cut Bank Gas Company	)))))	REGULATORY DIVISION DOCKET NO. D2017.9.80 ORDER NO. 7575c

FINAL ORDER

PROCEDURAL HISTORY

1. On September 29, 2017, Energy West Montana, Inc. ("EWM") and Cut Bank Gas Company ("CBGC") submitted their Joint Application to the Montana Public Service Commission ("PSC" or "Commission") for authority to increase and establish natural gas delivery service rates for each utility's service territory ("Joint Application"). EWM and CBGC request that the Commission: authorize EWM and CBGC to change their existing rates and establish new rates as set forth in their Joint Application and supporting testimony; authorize EWM and CBGC to establish the rate design described in the direct testimony filed in support of their Joint Application; and provide such other processes and relief as the Commission deems necessary for final resolution of the issues raised in their Joint Application and supporting testimony. EWM proposed an increase in total operating revenues of $1,526,960 or an increase of 6.53%. This would result in increases in the typical residential bills of EWM and West Yellowstone residential customers of 7.03% and 2.29% respectively. CBGC proposed an increase in total operating revenues of $183,284 or an increase of 14.23%. This would result in an increase in the CBGC typical residential bill of 5.42%. Test. Schulz 2 (Feb. 22, 2018).

2. EWM and CBGC stated the factors contributing to their application to increase rates are: increased investment in physical plant (a significant portion of which relates to the purchase of the Southern Montana Electric Cooperative ("SME") pipeline), general inflation, a new enterprise resource software planning ("ERP") system, which is a Systems, Applications, and Products Software ("SAP"), and decreased consumption by customers. In addition, the

Company proposes to introduce a Gas Infrastructure Reliability Clause ("GIRC") and an accompanying rate adjustment mechanism to fund the GIRC. Test. Degenstein 15 (Sept. 29, 2017).

3. On October 3, 2017, the Commission issued a *Notice of Application and Intervention Deadline*. On October 27, 2017, the Commission issued a *Notice of Staff Action Granting Intervention* to the Montana Consumer Counsel ("MCC"). On October 24, 2017, the Joint Applicants submitted the Supplemental Testimony of Charles E. Loy, making the Joint Application complete and compliant per Commission rules. *See* Mont. Admin. R. 38.2.315 (2017).

4. On November 20, 2017, the Commission issued Procedural Order 7575 setting deadlines for discovery. The Commission established March 8, 2018, as the final day for the Commission to identify additional issues in this docket.

5. On February 22, 2018, EWM/CBGC filed supplemental testimony incorporating the impact of the December 2017 Federal Tax Cut and Job Act ("TCJA") and an increase to the Additions to Plant Account due to a lease buyout of the SAP software from Verilease. These changes reduced the revenue increases requested by EWM and CGBC to $1,361,817 and $178,328, respectively.

6. The final revenue requirement increases submitted by EWM and CBGC incorporating certain of the adjustments suggested by the MCC were $1,144,172 for EWM and $177,964 for CBGC. These represent increases in Operating Revenues of 4.7% and 11.0%, respectively. Hr'g. Ex. JA-12, updated version of JDH-CBG-2R and Hr'g. Ex. JA-13, updated version of JDH-EWM-2R.

7. MCC submitted intervenor testimony on February 22, 2018, which concluded that EWM's requested annual revenue increase was excessive and recommended that the Commission approve a revenue increase of no more than $316,134. MCC recommended CBGC should be authorized an increase of no more than $109,367. These MCC increases did not incorporate the impact of the TCJA. Test. Schulz 2.

8. At a regularly scheduled work session held on March 6, 2018, the Commission voted to identify EWM's line extension policy as an additional issue, requesting additional testimony. The Commission issued a *Notice of Commission Action* providing direction on this

decision. Accordingly, on March 15, 2018, the Commission issued a revised procedural schedule to allow for testimony and discovery.

9. The Commission held a public hearing in this matter on May 9 and 10, 2018, in Great Falls, Montana.

10. At the hearing the MCC had not yet provided an update to rate base or revenue requirements incorporating the TCJA. MCC later provided its updated recommendations in post-hearing exhibits which include the impact of the TCJA. With these updates, MCC recommends a $133,017 increase for EWM and a $70,534 increase for CBGC. MCC Post Hrg. Provides (June 6, 2018).

DISCUSSION AND FINDINGS OF FACT

Gas Infrastructure Replacement Clause (GIRC)

11. EWM and CBGC are requesting the Commission approve a new cost recovery and infrastructure replacement program referred to as the GIRC. The Pipeline and Hazardous Materials Safety Administration ("PHMSA") required EWM/CBGC to establish a Distribution Integrity Management Plan ("DIMP"). The DIMP requires EWM/CBGC to identify and prioritize infrastructure that constitutes a public safety concern for maintenance and replacement. EWM states that "[t]he GIRC plan is a rate mechanism that would allow EWM/CBGC to accelerate DIMP associated capital investment with limited regulatory lag while avoiding the need for more frequent rates." Test. Degenstein 15. Mr. Degenstein states that "[a]n infrastructure replacement mechanism puts structure around activities that are going to take place regardless of rate treatment, as proven by the track record of EWM and CBGC . . . ." *Id.* at 18. Degenstein testifies that without the accelerated investment from the GIRC program, and based on historical replacement rates and current staffing, it would take approximately 45 years to replace the infrastructure identified in its DIMP. With the GIRC, the replacement could be accomplished in 10-12 years. *Id.* at 16. He argued that the lines would eventually leak. Hr'g Tr. 54:11-15 (May 9, 2018). Mr. Degenstein testified that he would accept a sunset provision in the GIRC that would require rate cases at three to five-year intervals. Hr'g Tr. 91:1-12. He also stated that if EWM replaces infrastructure that doesn't need to be replaced, via the GIRC, the Commission has the authority to deny it. Hr'g Tr. 95:20-23.

12. Under the GIRC, there would be an annual filing each year which would allow EWM/CBGC a return on and recovery of the GIRC capital investment from the previous year

(subject to certain tests within the mechanism). Test. Loy, Ex. CEL-EWM-2 (Sept. 29, 2017). The GIRC investment is cumulative on a going-forward basis and every year the associated revenue requirement increases. Per the testimony of EWM, assuming 2018 is the first year of the GIRC investment to be recovered in 2019, and GIRC investment continues for five years in similar amounts, the GIRC revenue requirement grows from $2.34 per year per customer in 2019 to $20.26 per year per customer in 2023. The proposed rate structure includes the same amounts for each customer rate class that would be recovered via a special tariffed GIRC rider. (Test. Loy, Table 2, p. 12).

13. MCC's witness, Mr. Donkin, argues that the GIRC would involve single-issue ratemaking. Donkin states that with or without the GIRC, EWM and CBGC have an obligation, as public utilities, to provide safe and reliable natural gas distribution service to their customers. This suggests they should pursue a proactive mains and services replacement program with or without the GIRC. Mr. Donkin states, "This obligation does not rest on its agreement with Commission rate setting decisions such as trackers like the GIRC proposal, authorized equity returns or other allowances." Test. Donkin 51 (Feb. 22, 2018).

14. The Commission finds that the GIRC program is in the public interest and is approved with a number of necessary modifications. The Commission appreciates the MCC's arguments regarding single-issue ratemaking and the fact that the program will be completed without a GIRC. The Commission agrees with MCC and expects the companies which have the privilege of monopoly to deploy capital at an accelerated pace when it is necessary to meet safety goals, so long as the Commission establishes a fair return on that investment, as this Order does. *Infra* ¶¶ 112-148. However, the Commission is also aware that in circumstances where anticipated incremental capital investment significantly outpaces the recovery of the utility's historic invested capital, the process of filing rate cases may impose such transaction costs and time lag that it may result in a misalignment of a firm's financial incentive with the goals of public utility regulation. Here, several factors combine to warrant the Commission's approval of the GIRC, which is single-issue ratemaking albeit subject to several key protections which protect consumers from the negative phenomena associated with other trackers. First, the spending in question is closely tied to specifically identified goals and discrete from other lines of capital spending by virtue of PHMSA's particularized requirements on natural gas local distribution companies. Test. Degenstein 15-19. Second, the transaction costs associated with a

rate case for companies the size of the Joint Applicants are significant. In this case, rate case expenses for the Joint Applicants are $350,000, which if amortized over five years, results in an annual increase of the revenue requirement for just the rate case expenses in the amount of $70,000. Rebut. Test. Henthorne 8 (Apr. 9, 2018). Although this rate case has allowed a thorough evaluation of the Joint Applicants, and has led the Commission to disallow substantial requests of the utilities in question, it is clear that the transaction costs are significant. Third, the incremental capital investments in question, while no doubt welcomed by a firm that seeks to invest capital and be paid a return largely assured by government for doing so, is being invested pursuant to legal requirements associated with public safety, which alongside affordability is the Commission's foremost priority.

15. In order to remedy the MCC's concerns, the Commission accepts the Joint Applicants' proposal that the GIRC be limited to incremental capital spending net of depreciation and be subject to an earnings test, although the Commission finds that these are unartfully described in the Joint Applicants' proposed tariff. The Commission orders more precise language for these calculations. In the GIRC tariff the Commission approves, language has been added specifying the rate of return used in the earnings test, specifying how the excess accumulated deferred income tax ("EDIT") amortization credit to the GIRC will be quantified, how the annual current year depreciation will be calculated, and how the current year average GIRC plant will be calculated. Likewise, a welcome attribute of the Joint Applicants' proposed GIRC is that its collections in rates are in arrears, only after the spending is made, and not made on projections. The Commission also approves this feature, but adds a reporting requirement of the utilities' anticipated spending, together with a rate filing, which the Commission believes will allow for greater regulatory oversight in both the ongoing surveillance of the GIRC and at that time when the spending is ultimately proposed for inclusion permanently in rate base through a general rate case. In order to cabin the specific programmatic costs, and to prevent the GIRC from becoming a catch-all mechanism for any spending said to be undertaken for the omnibus cause of public safety, the Commission includes specific, identifiable property elements within the tariffs. *See* Attachment A. These are tied to Mr. Degenstein's representations about the need for this program. To ensure transparency on an accounting level, the company will also be required to clear plant to specifically designated FERC accounts. Finally, while the Joint Applicants propose that this surcharge become active with respect to incremental capital

spending undertaken during the 2018 construction season, the Commission defers the implementation of the program by one year; the first year in which incremental capital spending under the GIRC is subject to be surcharged is 2019. The Commission does this in recognition of the fact that the construction season for 2018 is nearly passed, and because the Commission's requirements for the GIRC includes pre-submittal of a plan for each year's deployments, to ensure that the program is fully transparent and subject to ongoing surveillance. Clearly it would not be possible to effectuate such protection if the program were started in reference to 2018.

16. The Commission approves several additional features to the GIRC. First, because the GIRC is designed to avoid transaction costs of more frequent rate cases, it will include an automatic termination provision if either or both of the Joint Applicants file a rate case prior to several years' operation of the GIRC surcharge. Second, it will facilitate a review of whether the investments, in both their need and in the manner in which they have been deployed, were prudentially deployed and in fact used and useful. It does so by including an automatic termination provision for the surcharge after five years of its operation, before which time the Joint Applicants should again file a rate case if they desire these costs to be permanently included in rates. Finally, the GIRC surcharge will likewise automatically terminate if the either or both of the Joint Applicants file a proposal pursuant to Mont. Code Ann. § 69-3-308 (state and local tax tracker). One of the reasons the Commission is granting these utilities a GIRC is their unique regulatory setting, where they have chosen not to use tax tracking mechanisms. While the Joint Applicants are clearly legally entitled to use such a tax tracker, nothing in law permits to them the unilateral right to obtain the GIRC here approved, and because the Commission recognizes that the nature of its decision here is made relative to the overall regulatory setting facing the Joint Applicants, it conditions the GIRC's continued existence on the premise that all else in the regulatory setting is held even. These sunset provisions are an essential consumer protection without which the GIRC might ceaselessly grow without the normal rigors of oversight; without these provisions, the Commission would not approve the GIRC.

17. The Joint Applicants propose to recover the costs of the GIRC through a monthly surcharge on each customer's bill, which is not differentiated by customer class. The Commission, consistent with its discussion of the allocated cost of service of the utility, rejects the proposal insofar as it would charge each customer, regardless of its size, the same surcharge. *Infra* ¶ 158. Instead, the Commission will differentiate the size of the surcharge based on the

allocation factors established in this proceeding. *Id.* The Commission otherwise approves the rate design. While there may be arguments that such incremental capital investment is best recovered through a rate which is partially billed on the sale of gas volumes, such a design would be complex to administer, necessitating deferred accounts to remedy weather-driven over collections or under collections, and would thus frustrate the intention of making the GIRC straightforward but transparent. The Commission, meanwhile, considers the likely presence of a monthly fixed surcharge in the coming years in its decision to hold the existing charge at its present level. *Infra* ¶¶ 157-160.

18. Part of the tax benefits resulting from the Tax Cut and Jobs Act will constitute an offset of the programmatic costs of GIRC. The Commission applies the ongoing effects of the statutory rate reduction into the general rates it sets in this proceeding. *Infra* ¶ 50. The EDIT, which varies significantly year to year, is a coincidental but happy match against a program of variable spending, such as GIRC. The Commission will apply proceeds under EDIT to the program on a matched-year basis, in order to comply with IRS normalization requirements. Meanwhile, for the deferred tax savings that the Commission requires from the effective date of the Act to the date in which rates established under this order are effective, those 2018 savings will be applied to the 2019 spending under GIRC. Likewise, the EDIT from 2018 will be applied against the 2019 spending under GIRC. All of these tax benefits will be treated as customer-contributed capital, reducing the overall incremental capital investments made before a revenue requirement is calculated with respect to the balance. If, during GIRC, there is a year where the incremental capital spending does not meet the earnings test or the net-of-depreciation provision, the GIRC will be allowed to function as a vehicle to refund these tax benefits, although otherwise the surcharge never would be a negative value.

19. All of the associated capital investments made under GIRC, just like all other capital investments that are made in between rate cases, are subject to a complete review at the time when either or both of the utilities file their next general rate case. This will ensure that the annual GIRC proceeding is not unduly bogged down by such a review, addressing one concern MCC raises about the possibility that GIRC will *increase* transaction costs. MCC Br. 3 (June 22, 2018).

20. The Commission is sufficiently comfortable with the design of GIRC, as discussed above, that it is authorizing the program. However, the Commission also is conscious

that this is the first time in its history that such an incremental-capital surcharge has been authorized. The Commission regards the Joint Applicants' new GIRC as a pilot, and the Commission upon its review of the GIRC performance in the utilities' next rate case will be able to draw conclusions about GIRC's performance and may, if it is reauthorized, make modifications that are necessary or reasonable. For this reason, the Commission cautions that it is unlikely to approve similar mechanisms until it can be reasonably confident of the program's actual performance. While this may seem unfair to the other utilities the Commission regulates, the Commission reasons that the Joint Applicants have pressed this cause while others have settled cases by withdrawing such a proposal. *See* MDU/MCC Stipulation, D2017.9.79 ¶ 11 (Apr. 24, 2018). The Joint Applicants' persistence is therefore rewarded by the GIRC as it is here designed. The Commission hopes the GIRC will surface valuable insights about whether such mechanisms are reasonable to use generally and, if so, how they might be designed.

21. The Commission finds a GIRC tariff is appropriate, subject to the various protections written in the tariff, attached to this Order. *See* Attachment A.

SAP Software

22. In 2015, GNI and its subsidiaries, including EWM and CBGC, installed ERP system referred to as the SAP. Test. Henthorne 13 (Sept. 29, 2017). The initial estimate to complete the development and implementation of the SAP to GNI (now Hearthstone) was $4 million. However, the final cost of the SAP software to GNI/Hearthstone was approximately $18 million. *See* Appendix A, and Hr'g Ex. JA-9. Four separate components were considered in arriving at the $18 million figure. First, GNI obtained $10,091,490 in financing from Verilease. *Id.* In addition to the Verilease-provided financing, GNI contributed $3,155,616 of investor-supplied capital towards the purchase; this contribution is referred to as a Deferred Rent Asset by the Joint Applicants. *Id.* GNI also contributed $1,253,811 in additional investor-supplied capital, which is not included as part of the Deferred Rent Asset. *Id.* Finally, GNI bought out the lease obligation with Verilease for $3,558,629. *Id.* The utilities requested that the Commission approve an accounting order permitting them to reclassify the Deferred Rent Asset as a regulatory asset to be amortized over the remaining life of the SAP software (10 years). Test. Henthorne 14, 36; Test. Degenstein 10; Hr'g Tr. 106:17-22; 187:18-23. EWM initially proposed including $627,640 and CBGC proposed to include $51,575 in their rate base for the Deferred Rent SAP asset. Test. Henthorne 14, 36.

23. The MCC expressed concern that the SAP software's final cost far exceeded the initial estimated cost of $4 million. Test. Schulz 13-18; *see* DR PSC-040(b) (Dec. 7, 2018) and DR PSC-083(a) (Feb. 9, 2018). The MCC argued that the utilities are seeking an unusual application of an accounting order in order to recover expenses that exceeded initial estimates and resulted in operating costs that exceeded those they replaced, after those expenses were incurred, i.e., those portions of the SAP system spent by GNI beyond those received from Verilease. *Id.* at 13 (referencing Test. Henthorne 14, 16). According to the MCC, the SAP system "provides no cost 'advantages' but rather represents a dramatic increase in comparable costs from the last rate case," arguing that ratepayers are being "asked to pay for 'value' that cannot be quantified other than to suggest operating efficiencies that have no corresponding economic efficiencies." *Id.* at 14. Further, the MCC points out there are no shown reductions in payroll costs related to saving employee time because of the improved reporting, and "[i]n fact, it appears there are substantial contract labor costs" involved in running the system. *Id.* at 15.

24. The MCC argues that the Joint Applicants suggest "that the lessons of ring-fencing and the cost advantages that are supposed to follow from being part of a larger corporate organization should not apply" to the SAP and recommends the utilities should earn a return of, but not a return on, the $3.1 million deferred rent asset; in other words, the MCC recommends "a disallowance of deferred rent from the rate base." Test. Schulz 17-18. This treatment results in a reduction to rate base of $627,640 for EWM and $51,575 for CBGC. *See* Test. Schulz, Ex. PRS-6EW and Ex. PRS-6CB.

25. There were three schedules to the lease agreements with Verilease. The first terminated in December 2017, and the other two schedules would have terminated in September and October 2018. Hr'g Tr. 120:17-21. At the end of each lease schedule, the Joint Applicants could choose to buy out, extend, or terminate with a fee and with the sale of assets. *Id.* at 108:7-14 and PSC-045 (Dec. 19, 2017). On December 31, 2017, the first schedule reached its maturity and the Joint Applicants made an agreement to buy out the remaining two schedules, but were still obligated to pay the lease obligation through September and October. *Id.* at 120:17-24. The utilities state they did not include the exact buyout amount in the original filing because the final amount was not known and measurable, but argue they included an estimate of additional construction work in progress ("CWIP") they believed they would incur prior to the end of 2017 for the buyout of the SAP lease. DR PSC-138(d) (Mar. 23, 2018); DR PSC-154

(Apr. 20, 2018) ("This can be seen in [EWM's original filing] column F, "Estimated Additions Sep-Dec" of page 3 of Rule No. 38.5.124. In our supplemental filing on February 26, 2018 we trued-up these estimates to actual CWIP additions through the end of 2017, which included additional costs for the SAP asset.")

26. As noted above, the total amount of the SAP asset was $18 million: $13.6 million for the three lease schedules (which includes the $3.558 million lease buyout); $3.1 million for the deferred rent associated with the three lease schedules; and $1.25 million in additional SAP costs. *Id.* at 125:14-126:19; *see* Hr'g Ex. JA-9. When allocated from the parent GNI to EWM, according to Henthorne, "the effect on rate base for EWM of the SAP system is $3.2 million and then we've reduced it by the amount of the capital lease obligation of $1.5 million, so the effect to EWM in rate base in this case is $1.8 million." Hr'g Tr. 112:25-113:4. The Joint Applicants determined the cost of service for the utilities was $738,633 for EWM and $63,071 for CBGC. *Id.* at 127:16-19; *see* Hr'g Ex. JA-9. Ultimately, EWM and CBGC are requesting to place 38% of their allocated SAP costs into rate base at $1,793,345 and $147,898, respectively. Hr'g Ex. JA-9.

27. The Joint Applicants are treating the outstanding lease balance as a reduction to rate base. At hearing, Joint Applicants' witness Henthorne admitted they did not consider an accounting order before incurring expenses until it was raised by the MCC. Hr'g Tr. 107:10-16 ("To be honest with you, I didn't know that avenue was available. When I read Mr. Schulz's testimony, I thought oh, I didn't realize that was an option.").

28. In addition to their capital investment, EWM and CBGC are requesting to recover $291,273 and $26,196, respectively, of ongoing, annual, operating expenses related to the SAP software. DR PSC-013(c) (Nov. 29, 2017). This compares to the $82,452 in annual IT operating costs EWM included in its 2009 filing. Test. Schulz 14. The MCC proposes adjustments to operating expenses related to the SAP software. Mr. Schulz states that "[t]he ERP system resulted in operating costs that are three and a half times comparable costs included in the last EWM rate case. Ratepayers should not be the default insurers of a costly project that increased expenses." *Id.* at 19. In arriving at an alternative figure, the MCC applied the cumulative GDP Implicit Price Deflator of 12% to the comparable software costs reflected in the 2009 rate case filing. *Id.* This adjustment reduces operating expenses from $291,273 to $92,346, a reduction of

$198,927. *Id.* The MCC recommends reducing allowed IT expenses from $26,196 to $8,305 for CBGC. *Id.* at 19-20.

29. The Commission agrees with the Joint Applicants that the information technology landscape has changed dramatically since 2009. Rebut. Test. Henthorne 7. Perhaps the best evidence of this is that CBGC, in its last rate case, recorded no IT expense at all, because its billing was done entirely by hand. Hr'g Tr. 350:19-20. Likewise, in a more digital world, an enterprise system may not be a zero sum game, instead conferring on customers and the utility new benefits. The Commission acknowledges the Joint Applicants' argument that the new software provides customers and the utility benefits the previous software did not. DR PSC-013 (Nov. 17, 2017). However, the record, with a noteworthy exception related below, is absent of what such an enterprise system reasonably should have cost. The Commission reasons that in an era of cloud computing, increased Operations and Maintenance ("O&M") expenses would tradeoff against decreased capital costs. Here, both O&M expenses and capital spending have increased substantially. It is possible that the attendant costs of a more digitized utility are offset by efficiencies elsewhere, as EWM suggested at the hearing. *See* Hr'g Tr. 51:1-22. If indeed that is true, it is hidden amid the overall operations of these utilities, rather than shown by any kind of direct effect.

30. The Commission has not in recent memory seen cost overruns of so significant a magnitude as they present with respect to GNI's enterprise system. The lack of a clear explanation for what contributed to these overruns is frustrating. The situation is all the more confounding because the Joint Applicants' proposal to include the SAP in rates is an accounting morass which defies easy comprehension, as is evident from the summation of parties' testimony above. There is little in the way of a convincing explanation for the more dubious elements of the financial and accounting arrangement in which the Joint Applicants engaged. Two specific examples of this emerge through the parties' testimony and exhibits. First, the $3.2 million Deferred Rent represents, essentially, a cost overrun heaped atop a previous overrun of estimated costs; it goes almost fully unexplained. Meanwhile, the costs associated with the $3.6 million lease buyouts are both speculative, in the sense that testimonial evidence does not establish them as known and measurable changes, and in any case the costs are not convincingly argued relative to their benefits by the Joint Applicants. The Commission finds that the Joint Applicants in this regard have not met their burden of proof. The Commission is persuaded by MCC that absent a

clear showing of benefits relative to the excess costs that some of the cost overrun should be the Joint Applicants' responsibility. Indeed, even the Joint Applicants appear to believe the ultimate cost of the system was unreasonable. As Mr. Degenstein testified at hearing:

> If I were to look at an enterprise software system across a holding company that has multiple utilities with the abilities it has today, my personal opinion is I think it should have been in the 8 to $10 million range and the cost overruns were probably due to the nature of SAP and the difficulty to implement it. But I don't think 4 million was ever realistic.

Hr'g Tr. 75:25, 76:1-8. The Commission accepts Mr. Degenstein's and Mr. Schulz's representations in this regard. Based on both parties' testimony, the Commission disallows from rate base the two accounting elements that the Joint Applicants have provided the least justification for, and which appear to have been incurred only as the cost overrun continued to grow: the Deferred Rent and the lease buyout amounts. This resolution allows the Commission to see the forest for the trees, arriving at a total GNI asset amount of $11,345,301, still above what Mr. Degenstein thinks "should have been" the total cost, while founding its judgment on a disallowance of two of the most peculiar elements of this strange arrangement. When allocated to the Joint Applicants using the undisputed allocation methodology for GNI's subsidiaries, the Commission finds EWM's portion of this asset allowable in rate base is $702,525 and CBGC's portion of this asset is $57,727.

31. The MCC also questions the O&M expenses for GNI, including the costs for consultants. Test. Schulz 15 ("The costs for those consultants alone are more than double all the comparable expenses from the 2009 test year filing of $82,452.") While the Commission acknowledges this concern, the MCC's remedy is unpersuasive because it benchmarks a proposal for allowed spending on 2009 data. Given the degree to which the IT landscape has rapidly transformed life in the United States, it seems unreasonable to tie the allowed costs with those from the previous decade using a generic measure of inflation. Lacking an obvious alternative benchmark, the Commission accepts the Joint Applicants' proposal in this regard. To the degree the costs appear high, their levels will be mitigated in the next rate proceeding. This stands in distinction to the Commission's decision on capital returns; if the Commission were instead to accept the Joint Applicants' representations, it would in effect *reward* the companies for cost overruns for a substantial period of time. The Commission therefore finds that including

the $291,273 (EWM) and $82,452 (CBGC) annual operating costs for recovery in ongoing O&M associated with IT is appropriate.

Tax Cut and Jobs Act and EDIT

32. On December 22, 2017, the federal Tax Cut and Jobs Act ("TCJA") was signed into law. The TCJA, among other things, reduced the federal corporate income tax rate for EWM/CBGC from 34% to 21%, and required public utilities like EWM/CBGC to review their EDIT to align with the reduction in tax rates. TCJA of 2017, Pub. L. No. 115-97, 131 Stat. 2054 § 13001 (2017). On December 27, 2017, the Commission required that information regarding impacts of the TCJA be filed by EWM and CBGC for their gas operations in Montana, and EWM/CBGC filed an amended revenue requirement, accordingly.

33. The Commission identified four rate issues to be addressed as the result of the TCJA:

a. The reduction in the corporate tax rate from 34% to 21%.

b. The amortization of the EDIT balances.

c. The over collection of income taxes from January 1, 2018, until the new rates are implemented, and whether or not a refund is appropriate.

d. The over collection of the EDIT balance from January 1, 2018, until the new rates are implemented, and whether or not a refund is appropriate.

34. The Commission required the utilities to record on their books as a deferred liability the estimated excess revenues expected to be collected by the utility caused by the reduction in the tax rate for the time period preceding the issuance of the final approved rates, as well as a calculation of the EDIT balance caused by the reduction in the FIT rate. Furthermore, the Commission required the Joint Applicants to include a proposal to extinguish the EDIT balance along with a proposal to file periodic reports updating the Commission on the deferred liability and EDIT balances. Henthorne filed supplemental testimony and, subsequently, Ralph C. Smith submitted testimony on behalf of MCC discussing the effects of the TCJA and addressing the representations made by Mr. Henthorne.

35. A reduction in Joint Applicants' corporate income tax rate reduces their revenue requirement, because income taxes are recognized as a recoverable cost. *See* Mont. Admin. R. 38.5.175. Similarly, a reduction in the tax rate results in an EDIT balance. As EWM/CBGC utilize straight-line depreciation for regulatory accounting and accelerated depreciation for tax

purposes, they pay less in federal income tax during the early years of an asset's life than is collected through rates. This tax savings is accounted for as a deferred income tax, treated as zero-cost capital, and is deducted from rate base. Thus, a lower federal income tax rate creates an excess deferred tax balance, which the TCJA requires to be returned to ratepayers. *See* TCJA of 2017 § 13001. The EDIT balances fall into two categories, "protected" which is subject to IRS normalization rules and must be amortized using the Average Rate Assumption Method (ARAM), and "unprotected" where the amortization period is set by the Commission. The Joint Applicants accepted the MCC proposal to amortize the unprotected balance over 40 years.

36. Henthorne stated that while the Joint Applicants will have lower income tax expense in 2018, based on the normalized revenue requirements developed in this case, both companies are significantly under-earning from their most recent allowed rates of return despite the decrease in taxes as a result of the TCJA, and for that reason, no regulatory liability is warranted. Supp. Test. Henthorne 14-15, *see* Ex. JDH-EWM-2-NTL (page 1) and Ex. JDH-CBG-2-NTL (which illustrate an estimated 3.52% ROR to be earned by EWM and a -1.69% loss to be realized by CBGC, after the normalizing adjustments and rate base adjustments described in the preceding section). Accordingly, the Joint Applicants did not record a deferred liability as the Commission requested. The tables below show the TCJA impact on the revenue requirements for EWM (-$353,841) and CBGC (-$24,722) as calculated by the Joint Applicants. *Id.* at Ex. JDH-EWM-6-NTL; Ex. JDH-CBG-4-NTL.

Table 1

EWM	Initial filing	normalizing adjustments	TCJA impacts	Updated for NCA
rate base	$ 20,254,802.00	$ 354,282.00	$ 38,415.00	$ 20,647,499.00
Requested Increase	$ 1,532,291.00	$ 183,367.00	$ (353,841.00)	$ 1,361,817.00

CBGC	Initial filing	normalizing adjustments	TCJA Impacts	Updated for NCA
rate base	$ 1,158,692.00	$ 72,958.00	$ 4,969.00	$ 1,236,619.00
Requested Increase	$ 183,284.00	$ 19,764.00	$ (24,722.00)	$ 178,328.00

37. EWM stated that the net EDIT Balance for EWM is $2,023,842 and $204 for CBGC. Supp. Rebut. Test. Henthorne 4-5 (Apr. 25, 2018). The Joint Applicants proposed to amortize both the protected and unprotected EDIT balances using the ARAM, and to extinguish the EDIT balance by incorporating the credits into its proposed GIRC plan. Test. Henthorne 15-17, Ex. JDH-EWM-14; Resp. Test. Smith, 19-20 (Apr. 6, 2018). The utilities argued this would reduce the GIRC-eligible capital expenditures so ratepayers would get an

immediate benefit of this credit. *Id.* at 16. However, the Joint Applicants stated that if the Commission did not approve the extinguishment of the EDIT balances through a credit to GIRC, they would support including the refund calculated at the conclusion of this docket in the distribution rates or establish a negative surcharge separate from the distribution rates. Supp. Rebut. Test. Henthorne 6-8.

38. The Joint Applicants stated that they will not attempt to pursue a retroactive ratemaking defense regarding the deferred liability from excess income tax revenues collected in 2018. They recognize that the Commission was correct in identifying the FIT rate change issue before any effect from the new tax law could occur. However, the utilities state that the Commission's requirement to calculate the liability based on the effect of a full year of the difference in tax rates for a year that has not yet fully occurred creates an accounting problem. According to the Joint Applicants, in order to record a liability, regulatory or otherwise, it has to be: 1) established that there is indeed a liability and to whom; and 2) the liability has to be measurable. A regulatory liability implies that a refund to customers is necessary and therefore a liability is recorded for the amount to be refunded, and, the utilities argue, because both utilities are under-earning, a liability and subsequent refund is not warranted because any "gain" the companies have received as a result of the decreased FIT rate has been offset by increased costs and other items not included in current rates. If the utilities were over-earning, then a liability refund would be warranted, but that is not the case here. *Id.* at 8-9.

39. Henthorne also recognizes measurement as a problem: this case will result in new rates reflecting the reduction in the FIT rate and no liability will be warranted after those new rates go into effect. Furthermore, he notes the revenues of EWM and CBGC are seasonal, with losses projected for the months of May to September 2018.

> As Mr. Smith acknowledges, "the amount of savings associated with the reduction in the FIT rate will depend on the effective date of the new rates established in this rate case." Recording a liability for the full year would almost certainly overstate the amount of the liability, if any, that may be ultimately recorded, with a corresponding increase to expense that would have to be later reversed.

Supp. Rebut. Test. Henthorne 9-10. In summary, Henthorne states that Joint Applicants are not trying to avoid recording a liability and have complied with the Commission's order. Furthermore, if the Commission ultimately determines that a liability for 2018 is warranted, that liability should be based on the Joint Applicants actual results from January 1, 2018,

through the date that new rates at issue become effective. *Id.* at 10.

40. The MCC's witness Smith agrees with the Joint Applicants that the utilities' income tax expense should be reduced to reflect impact of the lower federal income tax rate that will be in effect for 2018. Resp. Test. Smith 7. However, because of differences between the MCC and the joint applicants regarding rate base, capital structure, allowed returns on equity, cost of debt, and net operating income, the income tax allowance proposed by the MCC will differ from that proposed by the Joint Applicants. *Id.* at 12. Smith suggests that the Joint Applicants' proposal to apply the EDIT amortization to their GIRC plan should be rejected. *Id.* at 9. The MCC, while analyzing the utilities' TCJA supplemental filing, did not itself present a recalculated revenue requirement reflecting the MCC's own TCJA analysis.

41. The MCC disagrees with the Joint Applicants that regulatory liability is unwarranted since the utilities are under-earning from their most recent allowed rates of return even after the impact of the decrease in taxes as a result of the TCJA. Smith also noted the Joint Applicants had not complied with the Commission's requirement that the utilities establish a deferred liability to account for the reduction in the FIT rate to 21%, and accordingly, he suggested that the utilities should be required to book the liability. Resp. Test. Smith 32-33. The Joint Applicants calculated the deferred liability (although they have not booked it) in accordance with the Commission directive with EWM's calculated deferred liability as $263,391 and CBGC's deferred liability as $15,992. DR MCC-115 (Mar. 23, 2018). However, the actual amount of income tax savings realized by the TCJA will depend on the effective date for the new rates in this docket since the net income earned fluctuates on a monthly basis. *Id.* at 35. Depending on the effective date of the new rates, Smith maintains that the associated deferred liability should be amortized over an appropriate period such as a 3-year period. *Id.* at 36.

42. As discussed below, the Commission will require the Joint Applicants to apply the accumulated deferral that the Joint Applicants have calculated starting on January 1, 2018, to the GIRC.

43. According to the MCC, the potential cash flow impact of the TCJA could adversely affect a public utility due to increased costs of common equity for utility stocks. Hr'g Tr. 208:3-14. For utility ratemaking purposes, increased estimates of common equity costs result in greater cash flows provided to the utility. These increased cash flows serve to mitigate

the adverse cash flow affect of the TCJA. The MCC also identified that there are alternative approaches available to utilities to mitigate the cash flow impact of the TCJA such as equity thickening in the ratemaking capital structure. Hr'g Tr. 304:15-25, 305:1-20. The greater proportion of equity included in ratemaking capital structure generally provides utilities with greater cash flows due to the fact that financing in the form of equity is costlier to a utility than debt financing. In the ratemaking paradigm, increased financing costs lead to higher allowed returns for utilities and these higher returns provide the utility with increased cash flows. Smith, witness for the MCC, infers that because the Joint Applicants' capital structures are overly equity thick as is, an adjustment to their capital structures is not appropriate in this proceeding, but defers to MCC's witness Hill on this matter. Hr'g Tr. 305:21-25.

44. According to Hill, a utility's operational risk remains unchanged as a result of the TCJA, but its financial situation could change. Hr'g Tr. 465:19-25, 466:1-3. He agrees that bond rating agencies are concerned about the cash flow effects of the TCJA, but contends that the rating agencies are not as concerned about operating companies as they are about holding companies that are highly levered. *Id.* at 466:23-25. Furthermore, he argues that the TCJA serves to potentially impact a utility's cost of debt, rather than equity, and that it is unclear how the TCJA impacts equity costs. *Id.* at 466:4-23. Accordingly, the Commission notes that Hill argues that the impact of the TCJA does not warrant any adjustment, whether it be to the Joint Applicants' authorized ROEs or their ratemaking capital structures.

45. The Joint Applicants, meanwhile, show no evidence to suggest that they have moved to infuse their balance sheet with additional equity in order to protect from potential negative cash flow effects of the TCJA. The Commission concludes this remains a largely hypothetical concern for the Joint Applicants and that adjustments to capital structure should not presume to anticipate managerial decisions which may or may not be prudent.

46. Regarding the amortization of the EDIT balance, the Joint Applicants assert the cleanest option would be to implement a negative surcharge to customers which would be changed every year to track the substantial variations in the amount of EDIT amortization as shown in the table below based upon exhibits provided by the utilities. Supp. Rebut. Test. Henthorne 7-8, Ex., JDH-EWM-14-SR and JBH-CBG-10-SR.

Table 2

EWM/CBGC Annual Edit Amortization		
	EWM	CBGC
2018	($5,184)	($1,273)
2019	$59,355	$1,184
2020	$95,035	$2,241
2021	$141,021	$3,576
2022	$156,409	$3,605
2023	$168,519	$3,439
2024	$176,057	$3,353
2025	$161,379	$2,715
2026	$122,439	$920
2027	$123,898	$890

47. The Commission finds that it is appropriate to require the Joint Applicants to segregate the benefit of the lower FIT resulting from the TCJA and apply it to the benefit of customers. The Commission rejects the Joint Applicants' contention that, because they are under-earning their authorized returns, they should have to refund none of the tax benefits of the lower FIT to customers. This approach would be unreasonable. The TCJA's passage was an extraordinary and unanticipated event, outside the utilities' control, and results in a material reduction in the cost of service. See *In the Matter of NorthWestern Energy's Petition for an Accounting Order Authorizing the Deferral of the Expense-Related Portion of the Costs Associated with Phasing in its Natural Gas Transmission Integrity Verification Program,* Order 7528a, Docket D2016.11.88 (Feb. 21, 2017); *NorthWestern Energy - Request for Accounting Order Authorizing the Accumulation of the Cost of Funding Participation in Northern Tier Transmission Group*, Order 6829, Docket D2007.4.39 (May 15, 2007); *MDU-Application for an Accounting Order*, Order 6840, D2007.5.57 (July 3, 2007). The Commission provided notice of the possibility of this adjustment before Jan. 1, 2018, when the law became effective, and the Commission accepts MCC's arguments that it is reasonable that customers benefit from the tax overhaul. The Commission expects that if Congress had instead passed a significant corporate tax increase, it would have precipitated requests of the Commission to adjust rates in the other direction, including the possibility of deferrals dating to the effective date.

48. One way to estimate what consumers are paying for a utility's income tax expense is to take that portion of the last approved revenue requirement which was associated with this

expense. The total benefit of a reduction in the income tax rate could then be calculated by applying to that expense the ratio of 1) the difference between the new and old FITs, and 2) the old FIT embedded in the last-approved revenue requirement. This benefit calculation could be reasonable because it is based on the tax expense used to set existing rates. This approach was anticipated by the Commission. Not. Comm'n Act. (Jan. 22, 2018). However, the Notice also permitted the utilities to propose alternative proposals to appropriately calculate the amount of the deferral.

49. The Joint Applicants contend this methodology does not capture the utilities' actual performance and tax liability in a given year, and they also contend that their performance varies over the course of the year. Here the Commission is unpersuaded by the former contention. The Commission, however, believes the Joint Applicants raise a valid point regarding the variance in performance over the course of the year, which makes an annualized revenue requirement a poor fit for calculating a proper deferral. The Commission acknowledges that, as gas utilities make substantially all of their sales during the winter heating season, the Joint Applicants may be assumed to earn most of their taxable income during this time. Given the fact that the new rates established in this docket will be in effect for three colder months of 2018, the Commission would have to prorate the revenue requirement effect to account for weather-related sales. There is no clear way to do this based on the evidence in this proceeding. Therefore, the Commission accepts as a second-best solution the Joint Applicants' deferrals as they propose to calculate it, subject to a compliance filing due simultaneously at the time of the Joint Applicants' first GIRC Plan.

50. The Commission finds it appropriate to apply the benefits of the TCJA to the cost of GIRC, including both the deferral starting January 1, 2018, forward to the effective date of the new rates, and the EDIT. Although GIRC will not begin until 2019, the Commission finds it appropriate to apply the 2018 EDIT amortization and the partial-2018 FIT reduction benefit to the costs of the first year of the GIRC, and to use the ongoing EDIT amortization as part of the GIRC funding stream in a way that otherwise matches the year's EDIT to the year's GIRC spending. This allocation results in zero-cost capital to the GIRC because it is being paid for by the money that would otherwise go to the customer. No return on those funds will be earned by the utility, resulting in the most efficient and least harmful financial impact for ratepayers and the utility. The Commission finds these adjustments to be just and reasonable, and directs the Joint

Applicants to incorporate them into the utilities' revenue requirements accordingly.

Southern Montana Electric Pipeline

51. In 2010, SME built 19 miles of 12" high-pressure distribution main pipeline to provide fuel to SME's power plant, the Highwood Generating Station (HGS). Test. Degenstein 11; Test. Henthorne 11. In its negotiations with landowners housing the pipeline, SME agreed to provide natural-gas distribution facilities at no cost and to provide them with natural gas services. Test. Degenstein 12. EWM was hired to construct and operate the pipeline for SME. *Id.* The original cost of the pipeline was approximately $5 million, which EWM incurred and billed to SME, and SME paid a majority of the costs prior to bankruptcy. *Id.* at 13; Hr'g Tr. 81:20-82:4 (around $125,000 did not get paid through the bankruptcy). As a result of SME's bankruptcy, EWM negotiated the purchase of the SME pipeline for $75,000 in March 2016. Test. Degenstein 13; Test. Henthorne 10. Neither SME nor EWM had on file a tariff for the service of gas to consumers from this pipeline.

52. EWM contends that the original cost of the pipeline to SME should bind the Commission to accepting this value. It argues the Commission "needs to determine if it should continue its past practices of using the original cost standard or if it should depart from that practice and reduce rate base by including some or all of the negative acquisition adjustment" from the pipeline purchase. Test. Loy 42. Further, the utility argues, because it purchased the pipeline as an operating unit that had been placed in public service prior to the purchase, the FERC Uniform System of Accounts requires the plant to be recorded at the original cost to the person first devoting it to public service. Test. Henthorne 11. Accordingly, EWM requested that rate base include the original cost of the pipeline to SME, approximately $5 million, less depreciation, arguing the $75,000 purchase price does not reflect the true economic value or the original cost of constructing the pipeline. Test. Degenstein 13; Test. Henthorne 11-12. Since EWM purchased the pipeline in the middle of this rate case's test year, the rate base amount the utility proposes is an average of the beginning and ending balance of the 13 months that span the test year, equaling $2,009,102. Test. Henthorne 11, Ex. JDH-EWM-6 at 2. Nonetheless, the Commission interprets EWM's initial request, putting aside temporal accounting issues, to be a request to find as used and useful the full cost to SME of the pipeline, and not EWM's purchase price of it. Notably, EWM does not submit any of the books and records of SME to substantiate

the supposed original cost of the pipeline. Instead, EWM relies on Mr. Degenstein's recollection of what EWM invoiced SME for the work. Hr'g. Tr. 80:15-23.

53. In order to obtain approval of this asset in rates, EWM must not merely substantiate its cost, but it also must demonstrate that this asset is used and useful. To do so EWM posits two reasons. First, EWM argues SME was the first person to put the pipeline into public service by allowing others to be served by the pipeline from its inception, "because the pipeline became a necessary part of the distribution system required to serve retail customers, regardless of the actual load on the pipeline after it was placed into service." DR PSC-089(c) (Feb. 8, 2018). Since EWM bought it, EWM's use of it has grown, and the pipeline now provides the capacity necessary to serve over 250 customers. Test. Loy 43. Second, EWM also argues the SME pipeline is essential to providing safe, reliable, and uninterruptible service to the City of Great Falls by providing a redundancy that will accommodate future improvements to EWM's core system. Test. Degenstein 12; Test. Loy 42.

54. The MCC disagrees, arguing that SME did not devote the pipeline into public service, rather allowing its contractor, EWM, to provide retail gas service with the pipeline, which was incidental to the SME's primary purpose for the pipeline: to provide gas to the now-defunct HGS. Hr'g Tr. 45:18-19. According to the MCC, the original-cost standard holds that rate base should be measured on the "cost of the property to the person first devoting it to public service." Test. Schulz. 6; *see* 18 C.F.R. § 201 (2018). Accordingly, the MCC argues that since SME built the pipeline "for SME's power generation facility," although it allowed EWM to provide service to certain landowners, at no cost, it wasn't until EWM purchased the pipeline that it became devoted to public service, and therefore EWM's purchase price of $75,000 is the original cost. Test. Schulz 6-7 (quoting Test. Degenstein 11-12).

55. The MCC's witness, Paul Schulz, testified that in order for an acquisition premium to have merit, the acquisition must be the least-cost alternative, and in this case, any amount over what EWM actually paid would not be a least-cost alternative. Test. Schulz 7-8. The MCC argued that development of the SME project negated the need to consider an independent EWM project to provide similar system benefits. Test. Schulz 11. Absent the bankruptcy of SME, EWM customers would be enjoying the benefits of the SME pipeline at no additional capital cost, rather than the $75,000 paid by EWM to acquire the pipeline or the amount requested by EWM for rate base. *Id.*; Hr'g Tr. 378. Schulz argued that assessment of

positive and negative acquisition premiums is not symmetrical: the exclusion of positive acquisition premiums from rate base is not the same as allowing the creation of phantom investor capital when the price is below book. *Id.* at 7-9. According to Schulz, the FERC policy on acquisition premiums ensures that ratepayers will not incur higher rates solely because of a change in ownership of an asset or entity. In the case where price is less than original cost, FERC has limited cost recovery to the purchase price. *Id.* at 9 (citing *Ameren Corp*., 147 F.E.R.C. 61,224, 62,282 (2014)).

56. Schulz stated that rate base is intended to reflect investor-supplied capital and that reductions to rate base are commonly made for customer advances and contributions, and accumulated deferred income taxes, and in the case where a utility has acquired an asset at a cost above book value, the acquisition premium is contributed by utility investors, and this is not the same as the case where the asset is acquired at a price below book value. *Id.* at 9-10. Schulz applauded EWM for taking the opportunity to purchase the SME pipeline at a steep discount from book, but stated there is no advantage to EWM customers if that discount is wiped out and shouldered by ratepayers as a phantom amount added to rate base. *Id.* at 10.

57. MCC witness Hill testifies that placing the $5 million that the pipeline cost SME into EWM's rate base would allow EWM to earn a return that is far higher than its own cost of capital or that of comparable enterprises. Test. Hill 45 (Feb. 22, 2018). He argues that while a utility is entitled to a return similar to ventures of comparable risk, it "has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures." *Id.* (citing *Bluefield Water Works & Imp. Co. v. Public Service Commission*, 262 U.S. 679, 692-3 (1923)). Hill argued that if EWM earned the MCC recommended after-tax return on EWM's requested SME pipeline increase to rate base, i.e., 6.62% on $2.1 million, the $130,000 in annual income would represent a 177% return on the actual investment of $75,000. *Id.* at 45-46. He considers this return inappropriate for a utility operation, arguing the $4.9 million original cost of the pipeline is not cost justified by the addition of 200 new customers. *Id.* Further, Hill argues the additional revenues from new customers could provide the utility with an adequate return and that EWM's proposal to "rate base" the SME pipeline at a value of $2,009,102 would allow EWM to double-recover the cost of building the line. *Id.* at 47.

58. In rebuttal, EWM submitted a revised accounting proposal for the SME asset proposing to recover a return of the original cost to SME, rather than a return on the same. Such a proposal takes the form of depreciation included in the cost of service, and would cause an amortization of the negative acquisition adjustment below the line in other income, rather than to enter net original cost into rate base. Rebut. Test. Henthorne 12-13. This revised accounting entered net plant of $59,796 into rate base, which is the difference between original cost and the negative acquisition adjustment, adjusted for accumulated depreciation; this value is averaged over the test year to produce a rate base effect of $29,898. *Id.* at Ex. JDH-EWM-19. EWM also depreciated an amount of $4,830,867, or the original cost of $4,905,867 less the purchase price of $75,000, and from this function, depreciation expense of $90,579 is included in the revenue requirement. *Id.* Finally, EWM would amortize the negative acquisition adjustment of $(4,094,985), and the amortized amount of $(76,781) is not requested to be included in the revenue requirement. *Id.*

59. As more fully explained below, the Commission rejects EWM's position. The Commission has regulated service that is incidental to other nonregulated uses of natural gas transportation, distribution or gathering infrastructure. *In the Matter of Havre Pipeline Company's Service Quality and Its Response to Notice of Commission Action in N2014.11.92*, Order 7413b, Docket D2015.3.32, ¶¶ 6-9 (Feb. 23, 2016) (finding a gas gathering system is a public utility service and that system is subject to Commission regulation). However, this does not mean that whatever it cost to build the SME pipeline, which was primarily intended to serve an unregulated natural-gas fired electric power plant, must be the cost accepted as the "used and useful" value that this Commission enters in rate base when the original purpose has become defunct and it is left a stranded asset, serving only a shadow of its purpose. No regulatory commission ever accepted that the pipeline was "useful" in the economy and, indeed, SME's bankruptcy suggests it was not. The value of the property is to be determined as of the time when the inquiry is made regarding the rates and is not a matter of formulas, but must be based on fair and enlightened judgment in proper consideration of all relevant facts. *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679, 690-92 (1923). The bankruptcy court, in permitting the sale or auction of SME's assets, afforded to other parties rival economic uses—other than simply salvaging it for metals—and the proper value of that use was established by EWM's winning bid. Indeed, as described by EWM's lead witness' own words, this bid reflects

the value the utility placed on it at the time it was purchased. Degenstein called this winning bid a good investment and the "right price" at the hearing: "$75,000 was all I was willing to spend because ultimately we shouldn't spend money that we don't need to spend . . . we had the right price." Hr'g Tr. 48:4-20, 49:17-21. "I would not have paid 4.9 million. . . The right decision was to get the best cost, the best price for the utility and the ratepayers of Montana." *Id.* at 49:4-12. The Commission notes a more proper lens of inquiry would be to ascertain what, within the bankruptcy, would have been the likely salvage value of the pipeline, since that appears from the record to have been, other than its attachment to EWM's pre-existing utility system, its only rival economic use. However, the Commission will not gainsay $75,000.

60. Relatedly, EWM's arguments that it faced a need that, without the SME pipeline, would have eventually caused a greater investment, are irrelevant. The Commission does not authorize rates for the cost of sub-optimal solutions to problems; it expects utilities to solve them in the most cost-effective manner possible, in this case by acquiring a pipeline from SME, after the City of Great Falls already had paid dearly for SME's bankruptcy. If the pipeline had not been purchased opportunistically by EWM, it may have been a completely pointless loss. Hr'g Tr. 83:12-85:13.

61. The Commission's decision largely moots the question of whether the asset had a public service purpose before its value, as a matter of first impression, was presented to this Commission. However, even if the Commission were not to view the situation in the light of the "used and useful" value of an asset, EWM has not met its burden of proof for establishing an original cost basis of the pipeline. It has presented none of the books and records of the entity that is said to have devoted it first to public service. It relies only on what EWM itself, as a contractor, was paid by SME for the work of constructing the pipeline. Test. Henthorne 13. EWM retained this money, applying it not just to capital costs of constructing the pipeline but also returning some portion of that money to itself as profit or to offset other operating expenses. *Id.* at 11. Thus, even if the Commission were to accept an original cost based not on public utility records but on a contractor's estimate of what it is was paid, the Commission would also have to account for what contribution in aid of construction were made to offset utility investor-contributed capital for this project. As EWM acknowledged, SME's focus for the pipeline was private use for its power plant, HGS. *See* Hr'g Tr. 45:18-19. The HGS payment to EWM should be accounted for as customer-contributed capital, offsetting the project's cost and discounting it

to a value which could then be allocated for the purposes of public utility regulation. Since the proposed cost to be included in rate base equals what EWM was paid for its work, this would properly result in a rate base of exactly $0. It seems much fairer to the Commission to pay EWM exactly what, in SME's bankruptcy, it actually paid for this asset.

62. The Commission finds that rate base should reflect the $75,000 for which EWM purchased this asset in bankruptcy, adjusting for ratemaking conventions based on average test-year balances and any accumulated depreciation.

Upstream Capacity Costs (MDDQ proposals)

63. EWM pays NorthWestern Energy ("NorthWestern") for upstream capacity and commodity transmission costs to deliver gas to all of its customers, including full service, distribution transportation, large commercial, and negotiated contract customers. In turn, upstream costs are shared by all customers. Upstream capacity costs are determined by the Maximum Daily Demand Quantity ("MDDQ") that EWM requires from NorthWestern.

64. Negotiated contract customers pay EWM for this capacity according to agreements in their respective contracts. Large commercial customers pay according to a two-tier system established in tariff. Customers with daily metering capability or purely interruptible volumes at the time of the last rate decision pay for MDDQ requirements and contribute additional payments for volumes exceeding daily MDDQ. Pasta Montana and Great Falls Sand and Gravel are the only customers using Option 1 of the tariff. A second option is currently available to Benefis Hospitals ("Benefis") since they did not have adequate daily metering when Order 7132c was issued. Under Option 2, Benefis pays a transport rate (capacity and commodity) that equals 80% of the extended general service tariff rate excluding storage costs. *See* Order 7132c, Docket D2010.9.90 (Nov. 17, 2011).

65. EWM proposes three modifications to improve the allocation of upstream capacity costs. First, EWM adds language to the Large Commercial and Negotiated Contract class tariffs to reset a customer's MDDQ to the new level if contract MDDQ is exceeded. Second, EWM adds language requiring a new customer requesting service under either of these tariffs to address its MDDQ needs, so that EWM may consult with its transportation provider–NorthWestern–regarding acquisition of new capacity before granting service. Third, because Benefis now has daily metering capability, and EWM's analysis shows that it is likely they could save money by switching to Option 1 of the Large Commercial tariff, EWM will discuss that

issue with Benefis in the near future. These issues were not contested by MCC. Test. Henthorne 31.

66. The Commission approves EWM's proposals to reset MDDQ and review the MDDQ needs of new customers on the Large Commercial tariffs. Regarding its third proposal, the Commission finds that termination of Option 2 in the Large Commercial tariff is appropriate. Benefis now has daily metering capability, so it is reasonable to track and cost daily volumes up to and in excess of contract MDDQ. Under Option 1, the rate structure passes through all transportation costs EWM incurs up to daily volumes equaling contract MDDQ. Volumes in excess of contract MDDQ are charged at a rate equal to the rate EWM pays NorthWestern for commodity transport, plus 75% of the difference between that rate, including ancillary volume charges, and the extended general service customer transport rate excluding storage costs. Order 7132c ¶ 142. The Commission finds elimination of Option 2 would simplify the tariff and implement standard treatment of comparable customers.

Modification to collection of PSC/MCC tax expense for EWM

67. EWM currently collects its PSC/MCC tax expense as part of its base charge and volumetric rate distribution rate. Hr'g Ex. JA-4, 26:5-6. EWM has proposed to collect the tax cost on a per CCF basis through a separate rate component in EWM's tariffs. Hr'g Ex. JA-4 26:6-14; Test. Henthorne, Ex. JDH-EWM-8 and Ex. JDH-EWM-10. The requested method is the same method used by CBGC. MCC did not contest the proposal. The Commission approves this method and finds in favor of adopting the EWM/CBGC proposal and directs the Joint Applicants to file compliance tariffs, accordingly. *Infra* ¶ 170.

Line Extension Tariff

68. EWM's distribution main extension allowance is $500 per residential customer and a 5-year simple payback calculation for other customers. Add. Issue Test. Henthorne 3 (Mar. 30, 2018). EWM will provide the service stub from the main to the customer's property, and is responsible for the cost and installation of meter and regulators. *Id.* The customer is responsible for all other installation costs. *Id.* Under this policy, no incremental costs are passed to existing customers when new customers are attached. *Id.* at 4. EWM recovers the costs of the free allowances in base rates from new customers. Incremental costs exceeding free allowances are recovered through Contributions in Aid of Construction ("CIAC"). *Id.* at 6. In instances where the CIAC may be so large as to discourage expansion, Rule 17 of the tariff permits an area

rate for a subdivision or group of customers, subject to approval by the Commission. *Id.* An area rate for a subdivision or large group of customers should be structured for recovery over time rather than requiring CIAC to cover all costs exceeding the allowance immediately. *Id.* at 8. CBGC doesn't have a written line extension policy, but generally follows EWM's policy. CBGC will adopt any changes the Commission orders in EWM's policy. *Id.* at 2.

69. EWM proposed to offer a new extension allowance for installation of services between the service stub and the house. *Id.* at 10. EWM currently charges residential customers $300 for the first 50 feet of service line, and $5.50/ft. thereafter. *Id.* at 10. For non-residential customers (2" line), EWM charges $400 for the first 50 feet and $6.50/ft. thereafter. *Id.* at 10-11. EWM proposed to offer a free allowance to install the first 100 feet of service line. Street cuts and excessively rocky conditions would still require customer contribution. *Id.* The allowance value to customers for a 100' service line is $575 for standard service and $725 for 2" line. *Id.* This proposal was not contested by MCC.

70. An infinite lifeline extension allowance is derived using the perpetual net present value method.[1] The allowance equals the net present value over an infinite period of the expected net margin provided by a customer, as an approximation to the marginal value of a line extension over a lifespan of 50 years or more. The infinite life assumption reduces the calculation to the ratio of annual net distribution margin to pre-tax cost of capital or rate of return. Thus, if a customer is expected to contribute margin of $300 annually, and the pre-tax cost of capital is 10%, the extension allowance would be $3,000. EWM testified that it would not support an infinite line allowance, as it ignores the incurrence of added O&M costs required to serve additional customers, and because pre-tax cost of capital is not sufficiently stable to use in an infinite life calculation. DR PSC-010(a) (Nov. 29, 2017).

71. Using an economic carrying charge rate of 7.70%, EWM calculated the incremental cost in main allowance, service stub allowance, meter, regulator, and customer service to equal $110 per year for residential customers. Add. Issue Test. Henthorne, Ex. JDH-EWM-16 at 1. The incremental cost to non-residential customers is $1,338 per year. *Id.* at 2. The

[1] *Line Extensions for Natural Gas: Regulatory Considerations*, by Ken Costello. February 2013, National Regulatory Research Institute. See page 20.

proposal for a new service allowance would increase the incremental cost to $154 per year for residential customers, and $1,394 for other customers. *Id.*

72. EWM testified that line extension and fuel switching may provide societal or public benefits such as economic development, but these benefits are hard to quantify. If existing customers do enjoy measurable system benefit from line extension, there is no reason why they should not pay a share of the costs commensurate with the benefit. Further, EWM argued that that structuring EWM's rate design so that revenue recovery is more stable and less dependent on usage would enhance EWM's opportunity to recover line extension costs; another reason to support increased customer charges. Add. Issue Test. Henthorne 5, 7.

73. According to EWM, main extensions are typically sized to accommodate growth, so the incremental capacity typically exceeds the incremental peak load of new customers. *Id.* at 7-8. The cost of the extra capacity may be recovered in a rate case before the anticipated growth occurs, so that existing customers are paying for a share of incremental capacity. *Id.* at 8. EWM does not consider this a permanent harm to existing customers, as payments today will be offset in time by the benefits of future growth. *Id.*

74. In response to discovery, EWM submitted cost studies regarding extension of service to Belt and Sand Coulee. DR PSC-146 (Apr. 17, 2018). The total cost to extend service to Belt is $1,765,738. *Id.* at DR PSC-146(b) at 7. Total allowance including the proposed service allowance is $375,203, and required CIAC is the residual $1,390,535. *Id.* EWM calculates the all-in area rate including gas costs would be $18.15/Dkt for residential customers assuming simple 5-year payback, compared to a $20/Dkt cost of propane. *Id.* If extension allowances were increased to the ratio of annual margin and a 10% pre-tax cost of capital, the all-in rate for residential customers would decrease to $16.54/Dkt. *Id.* at PSC-146(c), Attach. at 2.

75. The all-in rate includes the current distribution rate for Great Falls-Cascade customers, a surcharge to recover the shortfall (total project cost less allowances), and a surcharge to collect incremental A&G and O&M costs associated with the investment. It does not include commodity, transportation, or ancillary rates, and doesn't include fuel transition costs on the customer side of the meter. Thus the all-in rate understates the total customer cost associated with service extension and fuel switching.

76. The total cost to extend service to Sand Coulee is $214,922, with allowance of $72,147 and required CIAC of $142,775. DR PSC-146(b), Attach. at 3. EWM calculates the

all-in area rate including gas costs would be $11.53/Dkt for residential customers. *Id.* at 3. If extension allowances were increased to the ratio of annual margin and a 10% pre-tax cost of capital, the all-in rate for residential customers would decrease to $9.87/Dkt. DR PSC-146(c), Attach. at 4.

77. EWM believes that extending service to Belt is not economic, because the cost is too great and the number of customers and total volumes are too small. DR PSC-147 (Apr. 17, 2018). Even under current low natural gas prices the area rate required would make the cost about equal to propane. *Id.* EWM plans to extend service to Sand Coulee in 2018, using funds committed in Docket D2015.1.11, Order 7399a ¶ 19. *Id.* Remaining funds will not permit a similar extension to Belt. Hr'g Tr. 173:20-174:10.

78. EWM states that calculating residential customer allowance as the ratio of annual distribution margin and a 10% pre-tax cost of capital would require existing customers to cover part of the cost of extending service to a new customer. DR PSC-149(b) (Apr. 17, 2018). Calculating the allowance for non-residential customers with annual margin of $3,000 in this fashion would reduce the customer contribution to fixed cost recovery to $507 from the $1,616 contribution under the current allowance. *Id.* at PSC-149(c).

79. At hearing, EWM testified that although it "probably violates everything we talked about earlier about new customers and old customers," it might be possible to fold Belt customers in with the Great Falls customers, similar to the extension to Cascade, and perhaps the impact on the Great Falls customers would not be excessive. Hr'g Tr. 177:8-16.

80. MCC testified that the Commission should provide EWM a reasonable opportunity to recover costs associated with line extensions, but should not guarantee recovery of these costs. Add. Issue Test. Donkin 2-3 (Apr. 24, 2018). MCC does not support the use of a tracker to recover costs, arguing a tracker would be a single-issue regulatory device that violates the matching principle. *Id.* at 3. It is the MCC's position that the Commission should not approve EWM's proposed increases to customer charges in an effort to improve its ability to recover incremental line extension costs, because EWM presently has a reasonable opportunity to recover these costs. *Id.* at 6.

81. Free line-extension allowances may be used to award the customer a CIAC benefit for his contributions to net margin, that is, a calculation of customer contributions to fixed costs after deducting the incremental costs of serving the customer. These costs may

include property taxes, return of depreciated investment, debt service, and other A&G and O&M costs. Allowances may also be used to encourage the extension of service to new areas where future growth opportunities or other benefits provide value to existing customers or society. In this case, EWM is proposing to increase residential and commercial allowances to include allowance for installation of service lines, and the MCC did not contest this proposal. The Commission approves the Joint Applicants' proposal for the line extension tariff.

82. EWM also calculated infinite life allowances for customers. However, the calculations appear to use gross rather than net annual customer contributions to margin. The record is not clear why the calculations were performed this way, and how an alternate calculation of infinite life allowances using contributions to net margin may affect the utility's ability to recover prudently incurred costs. The record is sparse regarding external benefits that may be obtained through extension of service to Belt or other communities. EWM did testify that it expects little future population growth in Belt. DR PSC-148 (Apr. 17, 2018).

83. The record in this case does not support adoption of a change to Rule 17.1 that permits or directs the use of infinite life allowances. If the Commission or any party wishes to investigate the merits of alternative methods for calculating free main extensions, the investigation can be pursued in a generic non-contested docket, or in a future rate case.

Main Extension Service to Belt, Montana

84. Main extensions are regulated under Rule 17 of the tariff. Rules 17.1 and 17.3 would apply to extension of service to Belt. Rule 17.1 describes the free allowances available for main extensions. Rule 17.3 requires that applicants provide CIAC to cover the difference between the total estimated project cost and available allowances, or that applicants shall be assessed an incremental surcharge or area rate on volumes. The area rate and time period are determined by the Commission. The area rate is set to pay down the balance of utility investment, so this option essentially allows customers to provide CIAC on a term plan.

85. EWM examined three cost-recovery options for extending service to Belt, a five-year area rate with EWM proposed allowances, a five-year area rate with infinite life allowances, and traditional recovery of investment. For the area rate options, costs in excess of the initial allowance would be recovered through an area rate that would provide CIAC. After five years, the CIAC is designed to offset the shortfall so that the initial investment entered into rate base in the next rate case would be limited to any undepreciated allowances. The traditional option

isolates Belt investment to be depreciated through separate surcharge over 40 years. DR PSC-146.

86. Using Commission-ordered rates and returns, staff recalculated five-year area rates under the proposed and infinite life allowance options, and using traditional rate methods. The Commission agrees with EWM that if extension costs net of proposed allowances are imposed entirely on Belt customers, it is not certain that enough customers will find the offer attractive to make the build-out feasible. The Commission estimates the total rate will exceed $22 per dekatherm for residential customers, and since this cost does not include costs on the customer side of the meter, the savings will be significantly negative for five years under the model. After five years, assuming customer participation is consistent with expectation, the investment shortfall and allowance would be largely depreciated through the area rate, so the remaining balance could be rolled into Great Falls - Cascade rate base without significant disturbance. In that event, Belt customers would receive service at rates consistent with other Great Falls customers. However, it is not clear why EWM uses five years, instead of another period of time, as the threshold

87. If extension costs net of infinite life allowances are imposed entirely on Belt customers, the build-out is more attractive to customers, but savings remain negative over five years for all customers except for the school. For reasons described above, adoption of infinite life allowances is not well supported in the record. It is not clear that the calculation used in this case defines the present value of net contributions to margin, as it should.

88. Foremost, the traditional rate based recovery option generates positive savings for customers, excluding household upgrade costs. However, these results rely upon a propane unit cost of $20/Dkt, and a transport/supply cost for natural gas of just over $3/Dkt. This relation may not hold over 40 years. EWM believed this option would not be attractive to many customers. Since EWM does not support any of these options, and because each of these options exposes the utility to risk of under-participation with consequent cost under-recovery, the Commission will refrain from ordering any of these options until the utility establishes firm, enforceable commitments from customers.

89. The Commission analyzed rolling Belt customers into the Great Falls - Cascade tariff. This choice would provide higher certainty of cost recovery for EWM, but would require significant contributions from existing customers.

90. The incremental rate applied to all customers would be about $0.085 per dekatherm. This would result in an increase of about $6 per year to existing residential customers, and $10, $74, and $520 per year for small, large, and extended general service customers. Increased revenues from robust customer and volume growth in the Belt area could potentially reduce rates for all customers in future rate proceedings, but as noted above, EWM currently expects little future population growth in Belt. DR PSC-148 (April 17, 2018).

91. All of the above analyses assumed a 70% participation rate for Belt customers. Due to the attractive savings associated with the roll-in option, the Belt participation rate may be higher, resulting in a slight reduction in the estimated rolled incremental rate and incremental costs to existing customers.

92. The Commission approves the Joint Applicants' proposal to increase its free main extension allowance to customers to include a service line allowance. The Commission encourages EWM to continue investigating costs and benefits of a line extension to Belt, with particular emphasis on potential opportunities for economic development and expected contributions to capital cost from new customers.

Working Capital

93. EWM witness Henthorne includes $724,166 of cash working capital in rate base for EWM and $78,486 for CBGC, utilizing the 1/8 of test year average of actual annual operating and maintenance expense. Supp. Test. Henthorne 1 (Feb. 26, 2018). MCC's witness Schulz has concerns regarding working capital insomuch as not all expenses incurred by a utility to provide service are required prior to the receipt of revenues from customers, and believes two examples of this are property taxes and interest payments. Test. Schultz 24. He states that property taxes are paid in arrears, meaning the Company pays for those taxes after the time period they cover has passed. *Id.* at 24-25. Consequently, this represents a source of working cash for the utilities, not a use of working cash. *Id.*

94. Schulz states he had to determine the average time that EWM and CBGC, respectively, are in possession of that created working cash. *Id.*at 25. The Joint Applicants have slightly different intervals between meter reading and payment due date. DR MCC-063 (Jan. 31, 2018). Customers' meters are read, and customers are billed throughout the month, but this should average out overall as the meter reading periods are 25 to 35 days. *Id.* For EWM, the revenue to cover property taxes for the time January 1 to January 31 is typically received by

February 14. *Id.* For CBGC, the revenue to cover property taxes for January is typically received by February 20. *Id.* In the case of EWM, this means that EWM is in possession of the funds to pay January property taxes due to Cascade County on December 30 of the same year for 10.5 months, for February property taxes the expense lead is 9.5 months and so on. *Id.* EWM is then in possession of interest free funds in the amount of those property tax payments for an average of 8.01 months out of the year. *Id* at 26. Consequently, these funds reduce the working capital addition to rate base because they do not represent invested or borrowed capital for which the utilities should receive a return. *Id.* Schulz proposed to include in rate base for EWM $91,411 and for CBGC $57,970. Test. Schulz, Exs. PRS-6EW and PRS-6CB.

95. Henthorne states the Commission has accepted EWM's 1/8 of O&M method to calculate working capital in EWM's previous cases: D2010.9.90 and D2004.3.46. Rebut. Test. Henthorne 9. He states property taxes and interest expenses are not included in operating and maintenance expenses, therefore Schulz is making a reduction for amounts that are not included in EWM's calculation. *Id.* at 10. According to Henthorne, FERC provides guidance on the methodology for lead/lag studies, *see* CFR-2012-Title 18-vol.-sec.-154-312, and simple common sense indicate that a proper lead/lag study must consider all of the factors related to cash receipts and cash payments. *Id.* at 9. Picking two of the items delivers a result that is not complete and is inaccurate. *Id.*

96. Both EWM/CBGC and MCC provided testimony that neither is opposed to a lead lag study. Henthorne stated:

> Well, my understanding is there is basically two methods in the regulatory world of establishing a working capital allowance. One is the one-eighth of O&M method, which we use, and another one is a complete lead/lags study the taxes would be a portion of that, it ignores items on the other side so, you know, pre-paid items on the other side so, you know pre-paid items we've already put out money for that we're not collecting on. So my point is that if we're not going to doing a one-eighth of O&M, then we should do a complete lead/lag study and consider all of the sources and uses of cap.

Hr'g Tr. 154:2-16. According to Schultz:

> I certainly think it's worth consideration. The adjustment I made to working cash was an attempt to bring in significant sources of working capital to balance the ledger there without going to a full lead/lag study, recognizing there are expenses associated with that. However, I wouldn't be opposed to that. Yes, there would be costs to do it. No, I don't know exactly what the results may be. However, based on what we've seen, for example, with NorthWestern, it may very well be a

> reduction in working cash, not necessarily a - a total rate base reduction in terms of an actual deduct, but it just may be a lower amount for working cash."

Id. at 397:7-20.

97. Although the property tax and interest payments are not included in the working capital calculation itself, the two examples provided by Schultz are possible ways a firm can offset or reduce its working capital needs. The Commission finds utilizing the cash working capital amount as filed by the Joint Applicants is appropriate. The 1/8 method is a recognized methodology utilized to calculate working capital requirements.

98. In addition, the Commission notes the Joint Applicants have not provided a lead/lag study in the past 10 years. The affordability of the study and the fact that both parties agree such a study would be useful indicate that the Joint Applicants should provide such a study in any future revenue requirement filings.

Cost of Capital

Capital Structure

99. Gregory E. Scheig, Principal of ValueScope, Inc., filed testimony on behalf of the Joint Applicants regarding their proposed costs of equity ("ROE"), capital structures, and overall rates of return ("ROR"). Test. Scheig (Sept. 29, 2017); Rebut. Test. Scheig (April 9, 2018). Scheig's proposed capital structures for the Joint Applicants are based on the long-term debt and equity figures represented in their balance sheets as of December 31, 2016. Test. Henthorne 7, 33. Scheig considered the short-term debt a component of working capital to be repaid within a year and not a source of permanent financing, and therefore excluded it from his analysis. Rebut. Test. Scheig 19. He considered the proposed capital structures and calculated requested ROE for EWM of 10.75%, as reproduced in Table 3 below. Rebut. Test. Scheig 38.

Table 3

Cost of Equity Estimation Method	Indicated Cost of Equity	Weighting	Weighted Cost of Equity
CAPM	7.29%	5%	0.4%
ECAPM	7.69%	5%	0.4%
Modified CAPM	9.88%	10%	1.0%
Modified ECAPM	10.51%	10%	1.1%
Constant Growth DCF	8.96%	20%	1.8%
Non-Constant Growth DCF	10.51%	10%	1.1%
Risk Premium	9.57%	30%	2.9%
Expected Earnings	10.17%	10%	1.0%
Total Weighted Cost of Equity			9.5%
Additional Small Stock Risk Premium			1.25%
Total Requested ROE			**10.75%**

100. Scheig also calculated the Joint Applicant's requested ROR's of 8.32% (EWM) and 8.90% (CBGC), as shown in Exhibit (GES-2), Schedules I.1 and I.2, as reproduced in Table 4 below. *Id.* at 38-39, Ex. GES-2 at 80-81.

Table 4

EWM	% of total Capital Structure	Cost	Weighted Average Cost
Long-Term Debt	39.95%	4.66%	1.86%
Equity	60.05%	10.75%	6.46%
Total Requested ROR			**8.32%**

101. Stephen G. Hill, Principal of Hill Associates, filed testimony on behalf of the MCC. Hill uses his DCF analyses as his primary indicator of the cost of equity capital, indicating a range of 8.64%-8.74%. Test. Hill 42 (Feb. 22, 2018). He argues that due to uncertainty regarding the direction of the U.S. economy and interest rates, it is reasonable to utilize the upper end of this range for setting the Joint Applicants' rates in this proceeding. *Id.* at 43. Therefore, the MCC suggests an 8.75% allowed return on equity is reasonable and appropriately balances the interests of the Company and its customers, as reflected in Table 5 below. *Id.*

Table 5

Cost of Equity Estimation Method	Indicated Cost of Equity
Sustainable Growth DCF	8.74%
Mechanical DCF	8.64%
CAPM-vs. Long-Term Treasury total return	7.75%
CAPM-vs. Long-Term Treasury bond yield	8.50%
MEPR vs. 2017 Forecasted ROE	6.83%
MEPR vs. 2020-2022 Forecasted ROE	7.46%
MTB vs. 2017 estimated ROE, Retention Ratios	8.74%
MTB vs. 2020-2022 estimated ROE, Retention Ratios	8.79%
Total Requested ROE	**8.75%**

102. Hill's proposed capital structures for EWM and CBGC are based on the average capital structures of his proxy group companies. Test. Hill 19. He is critical of Scheig's decision to exclude short-term debt from his proposed capital structure and to use equity and long-term debt figures represented by the Joint Applicants, arguing they are a function of intercorporate capital allocations and not derived as a result of their relative risk interaction with the capital markets. Test. Hill 17. In contrast, the capital structures of the similar-risk sample group of gas utility holding companies which Hill relied on to estimate the cost of capital are a direct result of their relative risk and interaction with the capital markets. *Id.* Taking Hill's proposed capital structure and the requested return on equity of 8.75% (see Table 5 above), the MCC's requested rates of return (6.62% (EWM) and 6.42% (CBGC)) can be seen below in Table 6.

Table 6

CBGC	% of total Capital Structure	Cost	Weighted Average Cost
Long-Term Debt	43.25%	4.31%	1.86%
Short-Term Debt	7.32%	3.13%	0.23%
Equity	49.43%	8.75%	4.33%
Total Requested ROR			**6.42%**

EWM	% of total Capital Structure	Cost	Weighted Average Cost
Long-Term Debt	43.25%	4.66%	2.02%
Short-Term Debt	7.32%	3.77%	0.28%
Equity	49.43%	8.75%	4.33%
Total Requested ROR			**6.62%**

103. Hill contends that these returns will allow EWM an opportunity to earn 3.6 times its pre-tax interest coverage and CBGC an opportunity to earn 3.8 times its pre-tax interest

coverage, which in turn will afford the Companies an opportunity to maintain their financial position and attract capital, as required by Hope and Bluefield. *Id.* at 44.

104. The Commission did not consider whether to include short-term debt in the company's capital structure in EWM's last rate case in 2010. *See* Docket D2010.9.90, Order 7132c (Nov. 17, 2011). In that docket, EWM and the MCC both recommended capital structures that excluded short-term debt, and the Commission adopted such a capital structure (CBGC was not a party).

105. The Commission disagrees with Hill that short-term debt should necessarily be included in the capital structure. Short-term debt may finance spending that is not part of rate base. It would seem such borrowing should not be reflected in the capital structure. However, EWM has proposed, and the Commission has approved, a discrete rate base value of approximately $2.6 million for natural gas held in storage, on which it will earn a return. Rebut. Test. Henthorne, Statement E - Working Capital (Apr. 6, 2018). At hearing, the Joint Applicants conceded that the utility uses short-term debt, or a line of credit, to finance these purchases. Hr'g. Tr. 155:17-24. When the utility earns a return on an asset by including it in its rate base, as the Commission allows here, the cost of financing these purchases should be reflected in the approved capital structure. Not doing so would effectively impute a return on this asset that reflects higher-cost debt and equity financing.

106. The Commission calculates that 4.25% is the effective rate for short-term debt under the utility's line of credit, reasoning that 4.25% was the average interest rate paid on the line of credit during the test period and that, consistent with its discussion of interest rates below, the rate for the line of credit is also likely to rise. The short-term debt cost of 4.25% is less than either the cost of long-term debt or the cost of equity, either as proposed by the Joint Applicants or approved by the Commission in this Order. The inclusion of short-term debt results in a slightly lower cost of capital primarily because it results in the capital structure being less weighted toward equity.

107. In this Order, the Commission is also making two disallowances to rate base which should be considered in the capital structure. *Supra* ¶¶ 22-31 and 51-62. In rebuttal, EWM changed its position on including the SME pipeline as part of rate base and withdrew its request to earn a return on the asset's supposed value. Rebut. Test. Henthorne 12-13. The effect of this request, without a further adjustment to the capital structure, is to implicitly contend that both

equity and debt were used to "finance" the withdrawn value. Meanwhile, the approximately $1.0 million disallowance related to SAP, which the Commission makes by this order, involves an actual capital outlay that the utility would somehow have had to finance. *Supra* ¶¶ 22-31. Here, where real money is being spent, it seems reasonable to assume that the company invested in the disallowed SAP-related costs using the proceeds of long-term debt and equity in a ratio proportional to those elements' weight in the company's overall capital structure.

108. For these reasons, EWM's proposed capital structure is not reflective of the plant the utility earns an authorized return on, and the Commission finds it should be corrected. Hill proposes a hypothetical capital structure based on an average of the proxy group. Test. Hill 19. The Commission instead finds that because of the substantial amount of rate base that is financed through short-term debt, it is reasonable in the case of EWM to use a capital structure that reflects the company's actual financing scaled to rate base, net of the adjustments described above. The Commission accomplishes this calculation as follows. First, the Commission accepts the approximately $11.4 million and $7.6 million in equity and long-term debt reported by the company. Test. Scheig 29. To this, the Commission adds approximately $2.6 million, which reflects the amount of natural gas inventory in storage, as it is reflected in rate base. Test. Henthorne, Ex. JDH-EWM-9, Rule 38.5.142. This sums to approximately $21.6 million, which must be reconciled to the final submitted rate base value of $18.5 million. The Commission scales the former to the latter by reducing the shares of long-term debt and equity in a proportionate share; it does not reduce short-term debt, because this is the only part of financing that is directly tied to a discrete asset, and a scalar would therefore be inappropriate. Thus calculated, long-term debt and equity have been scaled to approximately $6.3 million and $9.5 million, respectively. Together with short-term debt, this sums to the final submitted rate base value of $18.5 million. This amount then must be reduced to reflect the Commission's disallowance of part of the SAP asset, consistent with the Commission's reasoning above. *Supra* ¶ 30. This results in a total rate base of approximately $17.5 million, with a final long-term debt and equity in the amounts of approximately $5.9 million and $8.9 million, alongside approximately $2.6 million of short-term debt.

109. Meanwhile, CBGC proposes a capital structure which reflects 71 % equity, with the remainder long-term debt. Test. Scheig, Ex. GES-2, Sch. 1.2. Approving such an equity-thick capital structure is not reasonable, as the Commission previously found with respect to EWM

when it asked the Commission to approve a capital structure with 73 % equity. Order 7132c, ¶ 93. In this proceeding, CBGC has identified no other gas utility with a comparable capital structure. Like it does for EWM, MCC recommends establishing a hypothetical capital structure based on the industry proxy group, including short-term debt. However, CBGC does not include natural gas inventory, financed by short-term debt, in its rate base; making such an imputation would be inappropriate. Instead, the Commission will establish a capital structure of 55% equity with the remainder long-term debt. This is consistent with the industry proxy group that Scheig presents when short-term debt is excluded, as it properly is with respect to CBGC. Rebut. Test. Scheig, Ex. GES-1R at 81. It also is consistent with the finding that a 55% hypothetical equity ratio falls within the range of reasonableness, pursuant to Commission precedent. Order 7132c ¶ 94.

110. Consistent with the discussion above, the Commission approves the following capital structure for EWM:

Table 7

Energy West	Dollar Amount of Rate Base	Capital Structure Percentage	Cost	Weighted Average Cost
Long-term Debt	$5,935,207	33.91%	4.66%	1.58%
Short-term Debt	$2,647,418	15.12%	4.25%	0.64%
Equity	$8,921,126	50.97%	9.20%	4.69%
Total	$17,503,751	100.00%		6.91%

As described above, the cost of EWM's short-term debt is 4.25%. Further, the cost of long-term debt is presented by Scheig and not disputed by Hill. The cost of EWM's long-term debt is 4.66%, and 4.31% for CBGC.

Cost of Debt

111. As described above, the cost of EWM's short-term debt is 4.25%. The cost of long-term debt is presented by Scheig and not disputed by Hill; it is 4.66% and 4.31% for EWM and CBGC.

Base Cost of Equity

112. The remaining 51% and 55% for EWM and CBGC's capital structures, respectively, are equity. The cost of equity is a vigorously contested issue in this proceeding, because unlike long-term debt which is priced based on transparent agreements between the

utility and a third-party issuer, the cost of equity is estimated based on expectations of what equity investors demand in return for the time-value of their money and the risk of the investment at hand. The Commission will more thoroughly examine the ROE in this Order than it has in previous orders in the hope that its resolution will indicate a starting point for the Commission's jurisprudence for parties to future rate cases.

113. The Joint Applicants present eight separate methodologies, with various permutations of data input, for a sum total of 24 different results for ROE, each of them given a different weighting by the Joint Applicants' witness, Scheig. Test. Scheig, Ex. GES-2 at 1. Hill presents a smaller set of analyses, and focuses on a variant of a methodology presented by Scheig, the sustainable growth Discounted Cash Flow ("DCF") method. Test. Hill 20, 66.

114. The evidence in this proceeding has convinced the Commission that Empirical Capital Asset Pricing Model ("ECAPM") should be the primary method for estimating the Joint Applicants' cost of equity in two different variations, as explained below. The Commission also checks the results of the ECAPM against the most straightforward form of DCF, finding the other DCF variants in this proceeding to be flawed. The Commission accords little weight to the remaining analyses, finding them at best cumulative and usually flawed in ways that the Commission's primary methods are not. The Commission discusses each of these models in turn, before presenting its calculation. The Commission also rejects an ex post small-size risk premium to its ROE calculation, because it is not supported by evidence in the record, and the Commission's most recent precedent presents an issue which the Joint Applicants have not answered.

The Capital Asset Pricing Model and the Discounted Cash Flow Methodologies

115. The Capital Asset Pricing Model ("CAPM") has several attributes which favor its use. Most importantly, it is a theoretically superior model because it attempts to anchor the firm's ROE to market-wide trends, in a way that rival methodologies do not. The Commission acknowledges that investors in utilities may choose to buy some other equity, not just other utility stocks. It is, therefore, important to sample the wider market, while considering also the less risky nature of an investment which is subject to the protections of economic regulation. This is consistent with CAPM's conceptual basis, as can be seen through its algebraic expression, $k = Rf + \beta$(Market Risk Premium ("MRP")), where the ROE is calculated by the addition of a the risk-free rate to the premium commanded by the equity market, as adjusted by

β, which in this instance is the co-variance of a proxy group of gas utilities to the wider equity market. Both Hill and Scheig present CAPM results, and Scheig also presents various ECAPM results. Test. Scheig 19-26, Ex. GES-2 2-3, 5-6; Test. Hill 33-36, Ex. SGH-8.

116. Other methods lack a basis tied to the wider equity market, and instead focus more closely on how analysts believe a proxy group of regulated firms will perform. The conventional DCF method, for example, is expressed algebraically as $k = D/P + g$, where the ROE equals the anticipated dividend yield added to analysts' expectations of the firm's growth. The reliance exclusively on the proxies' results will tend toward self-reference, as other utility commissions establish authorized returns and set expectations for capital investment, which drive the proxies' earnings and growth, and which in turn produce the ROE result which an application of the DCF method would suggest the Commission to adopt. This positive feedback loop makes the methodology unreliable, and this circularity is further aggravated by the limited size of the proxy group. In this proceeding, Scheig's proxy group is comprised of 11 firms. Test. Scheig 6, 37, Ex. GES-2 2-3, 5-10. Hill excludes four firms, citing various irregularities, and is left with only seven firms. Test. Hill 23. Either way, it is a small sample of companies from among the many hundreds that are included in the wider public equity market.

117. CAPM necessarily relies on the proxy group, but only for one of its variables, the calculation of β (beta). In this proceeding, β shows little variance between Bloomberg and Value Line, which calculate the variable for each of the proxy companies, and the value is clustered between X and Y for the highest and lowest β proxies. Test. Scheig, Ex. GES-2 2-3. Hill arrives at essentially the same value for β. Test. Hill, Ex. SGH-8. Meanwhile, the multitude of discretionary inputs in the DCF model can cause the results to vary, sometimes considerably. The Commission, were it to rely on DCF substantially, would want to very carefully parse all inputs (e.g., analysts' projections) for the limited number of proxies before accepting their validity. Such an initiative, however, would risk turning the ROE exercise into a yet more subjective undertaking. The Commission, again, is attempting to avoid a flyspeck analysis, and favors one that exists with reference to the wider market, while considering comparable risk.

118. As β shows little variability, then, the main question in relation to β is whether it has fidelity to the actual results of the firms whose return requirements are being projected. Scheig cites to a widely used textbook by Roger Morin which incorporates study results showing that the realized returns of low-β firms exceeded CAPM projections, even with the use of

adjusted betas. Test. Scheig 23, n.19. On this point, the Commission agrees with Scheig that CAPM's empirical results understate the actual returns of low-β equities. In order to remediate this issue, Scheig again borrows from Morin's textbook, which incorporates this α (alpha) effect in simplified form, as a factor x, as a modification to the basic CAPM equation, such that k = Rf + x(MRP) + (1-x) β (MRP). *Id.* In essence, x represents an adjustment which will cause the results of CAPM to regress to the MRP in proportion to the attributed value of x. Its justification, Scheig suggests, is to moderate CAPM's results so to better align to the empirical observations that CAPM forecasts understate the eventual returns of equities which have a relatively smaller value for β; thus, this methodology is known as the ECAPM. *Id.* at 21-23. Hill asserts that the use of the ECAPM with the use of adjusted betas is inappropriate as both serve to lower the slope of the Capital Market Line. Test. Hill 65. However, the Commission is persuaded by Morin's representation that "[t]he ECAPM and the use of adjusted betas comprise two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks." *See* Morin, Roger A. "Chapter 6: Alternative Asset Pricing Models." New Regulatory Finance Vienna: Public Utilities Reports, Inc. 2006.191. The Commission agrees with Scheig that the issue should be remedied by adopting the ECAPM, including his x factor of 0.25, which is intended to approximate the α effect identified by the academic literature reviewed in Morin's textbook.

119. In future proceedings, the Commission strongly suggests those who wish to justify a particular α within ECAPM, or who wish to use a conventional CAPM because the adjusted β already embeds α, present those arguments robustly. Additionally, much of the academic literature appears to refer to CAPM's general empirical results, and not to whether it is an accurate predictor of economically regulated firms' β. Hill does not raise this point, and the Commission invites testimony on it in future proceedings.

120. Aside from β, the main input to CAPM is the MRP. The MRP is by definition a function of the return of the wider equity market over the risk-free rate. Both the Joint Applicants and the MCC agree that the risk-free rate should be represented by long-term U.S. Treasury bonds ("T-bills"), although Hill suggests a short-term T-bill is truly the greater measure of a risk-free asset because it avoids the question of opportunity cost implicated by a longer-maturity asset, which has the effect of tying up an investor's capital over decades. Test. Hill 34. The Commission accepts that a long-term T-bill is most appropriate, especially in circumstances

where the MRP is being calculated on the basis of results perceived over a longer term; as seen below, the Commission adopts one such variant of CAPM. The Commission adopts Scheig's expected 3.19%, which represents the projection of the return of long-term T-bills in an environment where interest rates seem to be rising, after many years of stagnation at the hands of the Federal Reserve. Rebut. Test. Scheig, Ex. GES-1R 5-6, 9-10.

121. Having reasoned a risk-free rate, the value of MRP is the return of the market net of it. How the return of the wider market should be measured is thus a primary consideration of CAPM, equal to or greater than the importance of β. Within both Hill's CAPM and Scheig's CAPM and ECAPM analyses, the MRP is derived with respect to the performance of the market between 1926 and 2016, and the risk-free rate. Test. Hill 34. Scheig notes a tension in this approach, given that ROE determinations are intended to be forward-looking projects for rates not yet in effect, and thus should be grounded in the present-day market, not the past. He thus prepares modified ECAPM analyses which are grounded on the recent performance and anticipated growth of various firms from among the S&P 500.

122. Consistent with the Commission's reasoning above, it is important to calculate an ROE that represents the opportunity of investors to trade off in the wider equity market. In this vein, it is reasonable that the ROE determination should incorporate equity conditions looking forward over the next several years, when the public equity market looks volatile but somewhat robust. However, the Commission is conscious of Hill's criticism that an MRP in excess of 9%, as most of Scheig's Modified ECAPM analyses suggest, is exorbitant. Test. Hill 56-62. When asked directly, Scheig could cite to no literature that supports such an MRP. DR MCC-049 (Dec. 12, 2017). Indeed, Duff and Phelps, the source of the historic MRP data, suggests a going-forward premium of 7.0%. Test. Hill 34.

123. The Commission does two things to mitigate this concern. First, the Commission, will accept only one of Scheig's four variants of the Modified ECAPM, which limits the number S&P 500 companies sampled to only those which pay dividends and which have an analyst-projected growth rates and total equity returns between 5 and 20%. Test. Scheig 29. This analysis still includes a large sample of companies. [*Id.* at Ex. GES-2, Sched C.4. The Commission also reasons that the limitation to dividend-paying companies is important because investors, while they may trade-off utilities against the wider market, likely seek some dividend payout, and not just capital appreciation, as an attribute of their equity investment. See Test. Scheig 26. Hill

criticizes Scheig's decision to collar the sample to 5 to 20%. Test. Hill 62. He calculates that if one were to limit this sample to dividend-paying companies with between 0 and 10% results, which he expects is a more reasonable proxy for the economically regulated firm in question, that the result would be 9.88%, although he does not present work papers associated with this analysis in his testimony. *Id.*

124. The Commission believes that the 5 to 20% range is more reasonable than the 0 to 10% range. It may be reasonable in future proceedings to adopt a different range, perhaps 0 to 20%. Although the Commission does not engage in that calculation here, and upon review of the very large sample group in question, the Commission is satisfied that anomalous results are largely mitigated by this upper collar. Accordingly, the Commission adopts Scheig's Modified ECAPM MRP of 9.19%. Test. Scheig, Ex. GES-1R, Schedule C.20 at 65]. Additionally, while the Commission makes adjustments to the group of companies for the basis of measuring MRP, the main element of the CAPM or ECAPM equation which will internalize the risk adjustment for the firm in question should be β. The Commission also modifies Scheig's proxy group of companies for calculating β. WGL holdings recently merged with another holding company. Therefore, the Commission adopts a .72 which represents the arithmetic average of the proxy group used in Exhibit GES-1R, excluding WGL. *Id.*

125. Second, the Commission will moderate the effects of this application of a Modified ECAPM by equally weighting it with a more conventional analysis that relies on the historical MRP. The Commission does this in recognition of Hill's valid concerns about a potentially anomalous MRP. *Supra* ¶¶ 120-122. Local distribution companies such as the Joint Applicants and equities like them serve the rest of the economy, and their growth is likely slower than the broader economy at times of rapid growth but also more persistent than other parts of an economy when other equities slump. Investors also presumptively understand that certain firms boom-and-bust while others ride-through, and it is reasonable to consider this phenomenon in making an ROE determination. The long-duration average growth of the United States economy captures the basis on which to measure the return demands of more stable firms such as regulated gas utilities.

126. As explained above, the Commission views either of the variants of CAPM on which it relies to be superior to DCF. *Supra* ¶¶ 116-117. One additional problem of the Constant Growth DCF methodology is that it assumes that observations about the small proxy group's

near-term expected growth will endure as a constant. This is a reason why both Scheig and Hill perform variants of the DCF model, with Scheig performing a Non-Constant Growth DCF analysis and Hill performing a Sustainable Growth model, which he uses as his primary indication of the cost of equity capital. Test. Scheig 29; Test. Hill 42. Scheig's Non-Constant Growth DCF analysis relies on investors' short-term earnings projections to an extent, but relies more heavily on future stock price projections. Hill's Sustainable Growth DCF analysis substitutes sole reliance on short-term earnings expectations for an approach considering multiple factors such as dividend, earnings, and book value growth projections. The idea being that by considering various factors other than earnings estimates, one can arrive at a growth estimate that is more "sustainable." This is conceptually appealing as the Commission finds merit in Hill's representations that sell-side analysts' earnings projections are likely to offer "rosy" expectations for the stocks they follow. Test. Hill 28. However, the manner in which the witness employed this approach made its deficiencies clear.

127. As explained in Appendix B, this model is intended to derive a growth rate as an arithmetic function of internal growth (br) and external growth (sv), where g=br + vs. Test. Hill, Appendix B at 1-3. Implicit in this formula is the assumption that both "br" and "sv" result in growth. As seen in the appendix, "br" is calculated as the return on equity times the retention ratio and "sv" is the funds raised from the sale of stock as a fraction of existing equity times the fraction of new common stock sold that accrues to current shareholders. *Id.*. Hill did not employ this formula as designed. His Sustainable Growth DCF results did not use a "br" value arithmetically calculated as described in Appendix B. DR PSC-129(c) (Mar. 23, 2018) Rather, as noted above, the witness considered multiple factors and used subjective judgment to arrive at a value for "br." *Id.*; Test. Hill, Appendix C, Ex. SGH-4 at 1. Moreover, in the process of discovery, it became apparent that the manner in which the witness employed this model did not result in any growth from his "sv" input. When asked to amend his "sv" calculation to be theoretically consistent with the concept of growth and consistent with the narrative found in Appendix B, the witness concluded that his DCF results would "result in an overstatement of the cost of equity (the growth rate would be too high)," and amended the manner in which he derived "br." DR PSC-129(c). Since the witness adjusted his approach with regards to his "br" input when asked to only change his approach to the "sv" input, the degree to which subjectivity influenced the results of his Sustainable Growth DCF analysis is highlighted.

128. The Commission does not consider Hill's Sustainable Growth DCF results in this proceeding. Scheig's Non-Constant Growth DCF analysis is similarly unreliable as it places an inordinate amount of reliance on longer-term projections of the proxy companies' stock prices at intervals several years into the future. The Commission accepts Hill's criticism of this method, which replaces a shorter-term variable known with greater certainty for a much more speculative estimate of stock price, which is not only unpredictable but also may not be a sound indicator of growth. Test. Hill 66-70.

129. Ideally, DCF would incorporate a longer-term perspective on growth, but both variants presented are unreliable. Therefore, the Commission is left with the basic, constant-growth or mechanical DCF method. The Commission finds that when aberrant companies, those with DCF-indicated ROE's of >20% or <5%, are excluded from proxy group(s), the restated DCF, using the latest data available from Scheig's rebuttal testimony, results in an average indicated return on equity of the proxy companies of 9.40%. Rebut. Test. Scheig, Ex. GES-1R at 71. The Commission uses this as a check against the CAPM results, because while it suffers from the infirmities of self-reference, it can inform the Commission about whether its measures using CAPM are too radical a departure from the expectations of the regulated gas-utility sector investors. The Commission calculates the allowed ROE as follows:

(1) calculates the arithmetic mean of the three DCF results,
(2) calculates the arithmetic mean of the two ECAPM analyses,
(3) takes the results of the Commissions Modified ECAPM using a MRP of 9.19% and a β of .72 *Supra* ¶ 124.
(4) calculates both the arithmetic and geometric means of the resulting figures from steps 1-3.

Accordingly, the Commission adopts 9.2% as the cost of equity to be used in calculating the revenue requirements of the Joint Applicants, as represented in Table 8.

Table 8

DCF Analyses-Scheig (Rebuttal)		Estimated ROE
Sched D.1	Value Line	10.38%
Sched D.2	Zacks	9.02%
Sched D.3	Bloomberg	8.82%
		9.40%
ECAPM Analyses-Scheig (Rebuttal)		Estimated ROE
Sched B.8- forecasted rf rate	Value Line β	7.91%

Sched B.9-forecasted rf rate	Bloomberg β	7.77%
		7.84%
Modified ECAPM Analyses-Scheig (Rebuttal)		Estimated ROE
Sched C.20- forecasted rf rate	Value Line β	10.45%
		10.45%
GEOMETRIC AVERAGE ROE		**9.17%**
ARITHMETIC AVERAGE ROE		**9.23%**

Risk Premium - Authorized Gas Returns

130. Scheig also performed a risk premium study which compares gas utility authorized ROEs to long-term utility debt rates. Test. Scheig 30.

131. Because the risk premia used in deriving regression equation rely on historic Commission-approved natural gas ROEs, this methodology is perhaps the most susceptible to self-referential outcomes of all the methods employed by the witnesses. Widespread adoption of such a method would inherently result in a circular, positive feedback loop with no grounding in the wider equity market. *Supra* ¶ 116. The Commission is persuaded by Hill's argument that differences between allowed returns and bond yields are not necessarily reliable indicators of investor-required risk premiums, given the fact that the market prices of gas utilities over the time period studied by Scheig have been substantially above book value. Test. Hill 71-72. Therefore, the results of these analyses do not receive consideration by the Commission. It is noted that if the historical market values of natural gas utility stocks were equal to the historic book values, this method could potentially be considered a valid indicator of actual investor required returns for that historic period. However, there is no indication that current (or forecasted) market conditions mirror the conditions faced by investors during the historic time periods. Therefore, it is not reasonable to assume that current (or forecasted) market-to-book ratios would resemble the historic market-to-book ratios. This method is not grounded in the current, wider equity market(s) and is rejected.

Expected Earnings

132. Expected earnings methodology, more commonly referred to as a Comparable Earnings analysis, relies on analysts' earnings and book value projections. Test. Hill 74. The ROE is calculated as a function of forecasted earnings divided by forecasted book values. Scheig

argues that this methodology avoids the complexities of other methods and is consistent with the fair rate of return concepts set forth in Hope and Bluefield. Test. Scheig 40. Moreover, he states that the resulting ROE is an indicator of investor expectations for current and future equity returns. *Id.* The Commission is not persuaded by this statement. The average market-to-book ratio of Scheig's proxy group companies is 2.26. Test. Scheig, Ex. GES-2 at 77. It is reasonable to assume that investors' expectations are lower than what the results of these analyses would indicate as the earnings-to-(market) price ratios of the proxy group companies more accurately depict actual returns earned by investors. Moreover, because this method solely relies on proxy group projections, it is not grounded in the wider equity market(s) and suffers from the same self-referencing, circular, positive feedback loop shortcomings as the other methods which rely on the proxy group companies. *Supra* ¶ 116. Therefore, the Commission does not consider the results of these analyses.

Modified Earnings - Price Ratio

133. Hill's Modified Earnings-to-Price Ratio ("MEPR") methodology calculates an ROE as the midpoint(s) of the proxy group's average earnings-to-price ratio and its average current and projected ROEs. Test. Hill 36-37. Due to its reliance on the proxy group companies, this method suffers from the same self-referencing, circular, positive feedback loop shortcomings as the other methods which rely on the proxy group companies. *Supra* ¶ 116. Moreover, the Commission finds merit in Scheig's representation that this is not a model used by actual market participants. Rebut. Test. Scheig 11. If this were a widely-used model, Hill likely would have been able to cite specific examples of its use by market participants employing the model in the exact same manner as he proposes. Rather, Hill cites to an arithmetic equation that merely illustrates the stochastic relationship between expected returns and earnings-to-price ratios. Test. Hill 38. Therefore, the Commission does not consider the results of these analyses.

Market-to-Book Ratio

134. Hill's Market-to-Book Ratio analysis is essentially an algebraic derivative of his Sustainable Growth DCF model. Test. Hill 40. He uses the same proxy group and growth ("g") assumptions as he did in his Sustainable Growth DCF analysis, and thus, this model suffers from the same degree of subjectivity as his DCF results. Moreover, because of the widespread use of proxy groups in rate cases, the results of DCF analyses tend provide circular ROE estimates lacking any real foundation in the wider equity markets. Therefore, these results tend to reflect

commission approved ROEs as opposed to actual investor required returns. For these reasons, the Commission does not consider the results of these analyses.

Small-Size Adjustment

135. Most of the substance of the debate on an appropriate ROE turns on the formulaic calculations using market data that are discussed above. However, in terms of impacts on the allowed ROE, the Joint Applicants' advocacy to impose a "small size risk premium" ("SSRP") is no less important. An SSRP is an ex post adjustment to the ROE result calculated above; the Commission therefore considers it separately, and upon consideration of the evidentiary record, rejects it.

136. Scheig advises that a size risk adjustment is appropriate because EWM & CBGC are significantly smaller than the proxy group he relied upon for his cost of capital analyses and argues the companies are not public and, therefore, have illiquid equity interests. Test. Scheig 32. Therefore, an adjustment must be made to that ROE to account for the Joint Applicant's small size in arriving at a final ROE estimate. *Id.* He bases his suggested SSRP adjustment on Duff and Phelps' size premia studies which examine the Stock Size Premiums of the entire universe of NYSE-, AMEX-, and NASDAQ-listed securities from 1926 to the present. *Id.* at 32-34. In the studies, the risk premium required due to each firm's size is estimated by dividing the universe of securities into portfolios by capitalization and measuring the premium required beyond the risk-free rate and the security's equity risk premium estimate (beta). *Id.* at 33. The study concludes that the required SSRP increases inversely to firm size and is in addition to the required systematic (i.e., market) risk. *Id.* According to Scheig, based on this study, EWM and CBGC would fall into the 10th decile, which equates to an SSRP of 5.59%. *Id.* at 34. However, Duff & Phelps only considered unregulated companies in their survey, therefore, the regulated nature of EWM & CBGC offsets some of the risk factors reflected in the SSRP indicated above *Id.* at 33. He used data provided by Duff & Phelps' studies to calculate a weighted average SSRP for the proxy group of 1.13%. *Id.* at 36. Taking these factors into consideration, and relying on his professional experience and judgment, Scheig selected 1.25% as a minimum SSRP for EWM & CBGC. *Id.* at 36; DR PSC-034 (Feb. 8, 2018); Rebut. Test. Scheig 14-15.

137. Hill argues the market-based cost of capital for a small gas distribution utility operations such as EWM and CBGC should not be adjusted upward due to its relative size for what appears to be a long-term historical return difference between large and small firms:

- Although there is substantial evidence that a size premium does not currently exist, even if a size premium does appear in the long-term historical record for unregulated stocks, utility-specific research shows that it does not apply to utilities;
- The evidence on which the "size effect" logic is based (the long-term historical return difference between large and small unregulated companies in the broad stock market) suffers from what is termed "survivor bias"; and
- The Duff & Phelps studies relied on by Scheig are based on broad market indices such as the New York Stock Exchange (NYSE) Index. In order for a small company to be listed on a national stock index like the NYSE, it has to be extraordinarily successful.

Test. Hill 49-51. Therefore, the returns of the small companies being measured are considerably higher than the returns of the many small firms that: a) are not successful enough to be listed, or b) may have failed altogether. *Id.* at 51.

138. The Commission is not persuaded by this argument by Hill as it does not appear to be translatable to the regulated utility sector. The paradigm of utility regulation requires commissions to authorize ROEs commensurate with returns on alternative investments with similar risk. *See* Hope and Bluefield. If an investor were to supply equity to these unsuccessful (or failed) companies referred to by Hill, they would likely require higher returns due to the heightened unsystematic risk reflected in the risk profiles of those companies.

139. Hill argues the "size effect" is also called the "January effect" because virtually all (95%) of the small stock effect occurs only in the month of January. *Id.* at 54. The Commission is not persuaded by this argument as returns are "annualized." Therefore, it is unreasonable to parcel-out the month of January as it is inherently included in any calculation of annual returns.

140. The Commission previously opined on how a regulated company's size should affect its allowed return. This decision, made seven years ago, was not a model of clarity, appearing to hold that an adjustment for size was appropriate but resisting the nomenclature associated with it. First, the Commission surmised that it was "reasonable" to authorize a higher return for EWM than for a larger utility the Commission regulates, NorthWestern Energy, because "small utilities have a higher financial risk profile than large utilities." Docket D2010.9.90, Order 7132d ¶ 96-97 (Dec. 30, 2011). The MCC sought reconsideration of that finding, and the Commission went on to explain:

> The Commission did not authorize a small size risk premium in its calculation for rate of return, but did recognize that a smaller company is more sensitive to like

> dollar revenue streams than a larger company. The commission has not recently awarded small and microcap companies a significant basis point premium on their ROE compared to larger cap companies…The Commission did not establish a small size risk premium as EWM requested in this docket but only discussed how EWM is smaller than NorthWestern Energy and Montana-Dakota Utilities and should be awarded an ROE that is slightly higher.

Order 7132d ¶ 13.

141. More recently, the Commission rejected a small-size risk premium, more clearly articulating its reasoning:

> MDU contended that its small size and relatively undiversified service territory makes it more risky and therefore it should command a higher reward. However, many of the proxy companies are an amalgamation of small utilities. The proxy group's dividend and growth forecasts in the DCF results may incorporate all or some portion of those risks. The Commission finds that adding an ex post risk premium adjustment to the DCF results would result in double-counting those risks.

Order 7433f, Docket D2015.6.51, ¶ 22, (Mar. 25, 2016).

142. The Commission will continue to reject an SSRP and in doing so will articulate a number of reasons. First and foremost, the Commission's foundational concern expressed in Order 7433f has gone unanswered in this proceeding. Most of the proxy companies in Scheig's and Hill's analysis are made up of numerous operating companies. Hr'g Tr. 232:4-5. As Scheig noted at the hearing in this matter, "[m]ost of them have rate cases in each specific jurisdiction as opposed to one large one for the holding company." *Id.* at 232:11-13. Scheig conceded that he did not study whether the larger holding companies of his proxy group already contained an implied premium due to their composition of multiple, small operating companies. *Id.* at 233:15-21. Since the Joint Applicants do not answer the specific concern that led the Commission to reject the SSRP most recently, the Commission finds they have not met the burden of proof to substantiate this substantial ex post adjustment.

143. There are additional reasons on the merits of the issue which lead the Commission also to reject the SSRP. First, if a firm is more financially risky than its peers because of its size, such a trait should be reflected in its relative volatility to the peers' performance and to the market's as a whole. Yet the primary empirical measurement of the volatility of return, β, does not bear this out. *Supra* ¶ 117. The smallest members of the proxy group, Chesapeake Utilities Corporation and Northwest Natural Gas Company, have β values which are below the mean; in

other words, they are less volatile in their market performance despite being less well capitalized than their larger peer regulated gas companies. Rebut. Test. Scheig 13 (showing the relative market capitalization of proxy group members), Ex. GES-1R at 50 (showing Beta). Meanwhile, the highest-β member of the proxy group, UGI Corporation, is the third-largest of its 11 members. *Id.* The β values suggest no obvious correlation between size and risk.

144. Scheig did not study the endogenous factors that would inform the risk of the Joint Applicants in particular. Test. Scheig 18. Instead, his is an analysis which adopts ipso facto the proposition that smaller firms will require a higher return. Clearly there is empirical support that the historical market returns for small public companies are larger on average than those of larger public companies. *Id.* at 33. However, sufficient evidence has not been presented supporting the proposition that this information is translatable to the regulated utility sector.

145. The Commission, however, primarily agrees with Hill in his criticism of Scheig's premise, that the risk premia associated with the wider public equity market can be translated seamlessly to the experience of regulated utilities. Test. Hill 50-51. Both large and small utilities are insulated from the type of risk which may present for smaller firms, because they are economically regulated by public service commissions. As noted above, the only empirical evidence of size-based risk suggests no correlation. *Supra* ¶ 117. Moreover, the Commission reasons that risk has more to do with the peculiarities of the service territory and business model of a regulated utility than its size. Large utilities may serve a more sprawling service territory that exposes them to greater risk of natural disasters, like wildfires, or may serve more dense urban communities where infrastructure may be more aged and dangerous, or where gas line replacements are more difficult to undertake. Indeed, the riskiest utilities may be those which have the largest balance sheets such that in the first instance they may make big bets that fail.

146. Even were the Commission inclined to accept Scheig's advice on conceptual grounds, his calculation of his proposed SSRP leaves much to be desired. The recorded SSRP for the smallest decile of public companies is 5.59%. Test. Scheig, Ex. GES-2 at 77. He reasons that the holding companies comprising the proxy group already include an implied risk premium based on their fitting within particular deciles, which averages to 1.13%. Therefore, Scheig calculates that the "additional required SSRP" for the Joint Applicants would be 4.46%. *Id.* Then, however, he scales this down to 1.25%. *Id.* He reasons, generically, that "some of the risk factors reflected in Duff and Phelps' study above are offset by the regulated nature of their

business," but nowhere does Scheig calculate or show any detail of how, from a basis of 4.46%, he has arrived at a proposal of 1.25%. Test. Scheig 33. Given that the cost of capital witnesses in this proceeding spend cumulatively hundreds of pages of testimony and discovery debating over methodologies that result in adjustments of hundredths of percentage points, the Commission is naturally very hesitant to accept a suspiciously round number whose exact provenance cannot even be identified.

147. For all these reasons, the Commission rejects the SSRP. The Joint Applicants have not met their burden of proof. In the future, should a utility applicant seek an SSRP, they must demonstrate through clear evidence several things. First, they must demonstrate that size serves as an adequate proxy for utility-specific, unsystematic risk. Second, show that the risk premia effect that appears for small public companies relative to larger public companies is actually translatable to the regulated utility sector; the primary evidence of this should be β of proxy companies, or other direct evidence which suggests a size-based return differential associated with regulated utilities. Third, and relatedly, such an applicant must clearly answer through comprehensive analysis the problem identified in Order 7433f. *Supra* ¶¶ 141-142. Such analysis would include breaking down a public holding company into its various operating companies, and contrasting their performance and returns, which presumably would be reporting in the holding companies' financials, with market-wide risk premia.

148. The Commission also rejects Scheig's proposition that consideration should be given to the Joint Applicants' private, illiquid, equity interests. *Supra* ¶ 136. A long-standing Commission practice has been to evaluate utility ROEs on a stand-alone basis. If the Commission were to consider the upstream ownership structure and equity provided therefrom, it would also be necessary to consider other factors beyond the scope of this proceeding.

Cost Allocation and Rate Design

Cost Allocation

149. In its last rate case, Energy West relied on minimum system theory to classify investment in distribution mains 70% customer-related and 30% demand-related. Docket D2010.9.90, Order 7132c, ¶ 103 (Nov. 18, 2011). The Commission rejected the classification of mains to customer on the basis that the utility's asserted cost causality was not convincing, and that the classification appeared to violate the principle of vertical equity through assignment of

equal cost responsibility to very small and very large customers. *Id.*, ¶ 106. Additionally, the Commission faulted the utility for presenting a study for the allocation of system costs which could not be reconciled to the physical reality of the utility in question. *Id.*, ¶ 108. Here, Mr. Loy's testimony does not suffer from the same infirmities. He has conducted a Minimum System Study that estimates the cost of "a minimum size system to hook up customers," in contrast to "the cost of the actual mains, sized to meet capacity requirements at times of maximum demand." Test. Loy 18. The import of such a study is that the incremental cost of larger-diameter mains can be considered to be a function of meeting demand, and thus properly allocated on that basis; meanwhile, the hypothesized cost of the minimally-sized system is a function of the number of customers connected to the utility. The results of Loy's study suggest classifying distribution mains, and their attendant costs, as 44% customer-related and 56% demand-related in the Energy West/Cut Bank service areas. *Id.*

150. Donkin does not specifically reply to the Joint Applicants' Minimum System Study, but does offer a hypothetical example that suggests the premise behind such a study is flawed. He posits that a small manufacturing plant with a peak demand of 20 Mcf requires the same investment in mains infrastructure as do 20 residential customers, each with a coincident peak of 1 Mcf, which, he suggests, demonstrates that "a gas utility's distribution lines are sized and installed to meet customer loads and not customer counts." Test. Donkin 27. The Commission believes Donkin's example incorrectly hypothesizes that the length of mains necessary to serve less and more dense sources of demand for natural gas is similar. A minimum system study that actually identifies the mileage of the system, as Loy's does, will correctly identify the attributes of length and width, and their attendant relation to customer count and demand, that tend to drive investment in mains.

151. Previously, the Commission was "not persuaded that it would be reasonable to classify a substantial portion of mains costs [to be] customer-related, as EWM proposed." Order 7132c, ¶ 106. Loy's classification is sufficiently demand-weighted to satisfy the Commission's concerns about vertical equity. For the reasons explained above, the Commission is now persuaded to accept Loy's Minimum System Study as a reasonable basis for allocating mains and their attendant costs.

152. Loy's direct testimony contains little discussion of another major category of rate base value: the service lines, meters, and regulator equipment. He cursorily suggests a complete

allocation of these items as 100% customer-related. Test. Loy 18. Upon close review of his work papers, the Commission finds that Loy allocates these costs largely on the basis of weighted-average meter costs rather than on customer numbers. This results in a weighting that generally distinguishes between the more expensive meters installed to serve larger general service and commercial tariff customers and standard residential meter technology. The Commission surmises that this allocation generally satisfies its criterion from Docket D2010.9.90 that costs should be allocated in part on the basis of capacity, since the cost of a meter is related to its capacity, but is frustrated that Loy has left much of this to the Commission's inference. Or. 7132c, ¶ 106.

153. Donkin cites to Commission precedent which favors his classification of this plant as 50% demand-related and 50% customer related. Test. Donkin 30-31 (citing to Order 7132c, ¶ 106). In rebuttal, Loy mounts a more substantial, less cursory argument, citing to a gas utilities' trade association manual in support of the proposition that "the closer the plant item (e.g., a meter and service lines) is located to a customer, the more that particular item is related to the specific requirements of that customer." Rebut. Test. Loy 9 (Apr. 9, 2018). He suggests that while costs of meters and services for individual customers may be greater because of that individual customer's demand, it does not follow that such incremental costs should be allocated to *system-wide* demand. *Id.* at 10.

154. The Commission finds that neither witness has particularly well explained their recommendations on this point. On one hand, although Mr. Donkin has classified Accounts 380 (Services) and 381 (Meters) 50% demand-related and 50% customer-related, he classifies other significant categories associated with services and meters, such as Accounts 382 (Meter Installations), 383 (House Regulators), and 384 (House Regulator Installations), as 100% customer-related. Test. Donkin, Excel support file "GLD-2 EWM COS," tab 'Totals Functional,' lines 18-24. Such a proposal appears self-contradicting. On the other hand, although Loy classifies all service and meter plant accounts 100% to customer, he allocates these costs to customer classes on the basis of weighted average meter costs by class. *Id.*; Excel support file "Dist COS WPs," tabs 'Meters' and 'Great Falls.' Because the cost of a meter is in large part driven by its capacity, this results in allocations of service and meter plant costs that are more demand-weighted than the meter and service plant allocations of Donkin, who allocates demand-related service and meter costs on the basis of non-coincident peak monthly volumes, and

customer-related costs on customer numbers. Test. Donkin 31, 38. Thus, Donkin allocates *more costs* of services and meters to the customer-heavy residential class than Loy does, because of the difference in their allocations of customer-related costs. *Compare* "GLD-2 EWM COS," tab 'COS-Total,' line 18, in the amount of $9.6 million, to "EWM COS," tab 'COS-Total,' line 18, $8.0 million. One cannot especially blame Donkin for the oversight, because Loy's work in this regard is not transparent.

155. All in all, the Commission agrees with Loy's observation, made in rebuttal, that "the per customer level of service and meter plant in the EWM COSS are close to the MCC's level [of] per customer costs." Rebut. Test. Loy 10. The Commission, therefore, will go no further than that in trying to make sense of the confusing, rival studies in this regard, and especially in the absence of a clearly explained methodology in the first instance; it will continue its prior precedent, while noting that, like in the example of the allocation of mains, the Commission remains open to being persuaded otherwise.

156. The Commission's complete and final resolution of the allocated cost of service studies is apparently not necessary in any case, because Donkin and Loy only loosely follow their recommendations in allocating costs to classes. For Energy West, both witnesses appear to concede a rigorous adherence to their studies would mean substantial increases to the residential class, which they both propose to moderate, and with respect to Cut Bank Gas Company, it is just the opposite, which again they propose to moderate. Test. Loy 25-30; Test. Donkin 35, 40-42. The Commission, while offering the general guidance it does above, does not find it necessary to tabulate cost of service results in a precise form. Rather, the Commission sets forth the following allocation, which coheres to the commentary above:

Table 9

Final Cost Allocation of CBGC Revenues

Customer Classes	Current[1]	Ordered	Pct Chg
Residential	$ 487,393	$ 556,152	14.11%
General Service	211,192	270,671	28.16%
Total Cost of Service	$ 698,585	$ 826,823	18.36%

1: Source - Henthorne Dir. Test. Exh. JDH-CBG-6, Statement H

Rate Design

157. Rates must be designed to recover the costs that have been allocated to particular customer classes. Since some of those costs were allocated in the first instance on the basis of customer counts, the Commission finds it reasonable that there should be a corresponding fixed charge billed to each customer in a class regardless of gas consumption. Thus, the percentage of residential class revenues classified to customer should equal the percentage of revenues recovered through a fixed charge, with projected revenues scaled to authorized revenues in this case. Accepting either Mr. Donkin's or Mr. Loy's cost-allocation study for this purpose, the customer charge for EWM would be either $6.25 or $12.75, respectively, which is the function of allocating 42% or 86% of distribution revenues to this charge. Mr. Loy's and Mr. Donkin's bookends happen to be wide apart, due to the utility's predilection to classify costs as customer-related (and thus increase the fixed charge, which would be charged year-round and not be subject to the vicissitudes of weather-related gas demand), and to the countervailing tendency of the consumer advocate to classify costs as commodity- or demand-related (which has the effect of minimizing the rate impact on residential customers). The current residential customer charge is $7.25 for EWM, $13.00 for CBGC, and $7.25 for the West Yellowstone utility. The Commission maintains each of these charges at their current levels, for two reasons.

158. First, the approval of GIRC, will mean that for EWM and CBGC an additional monthly surcharge calculated on a per-customer basis will be added to monthly bills beginning in September 2020. If GIRC operates as expected, this surcharge will grow through 2024, until it is rolled into rates or lapses in 2025. Maintaining the customer charge at current levels allows for headroom so that the rate design of GIRC can be simplified and billed as a customer charge. The following table illustrates the expected rate impacts on customers regarding cost recovery of GIRC investment, with cost allocation similar to the allocation of the general revenue requirement.

Table 10

Expected Standard and GIRC-Related Monthly Customer Charges

Standard Monthly Customer Charge

Class	2018	2019	2020	2021	2022	2023
GF Res	$ 7.25	$ 7.25	$ 7.25	$ 7.25	$ 7.25	$ 7.25
GF SGS	18.00	20.00	20.00	20.00	20.00	20.00
GF LGS	110.00	110.00	110.00	110.00	110.00	110.00
GF EGS	850.00	850.00	850.00	850.00	850.00	850.00
GF Sand & Gravel	850.00	850.00	850.00	850.00	850.00	850.00
Pasta Montana	850.00	850.00	850.00	850.00	850.00	850.00
Benefis Hospitals	850.00	850.00	850.00	850.00	850.00	850.00

Per Customer Monthly GIRC Charge[1]

Class	2018	2019	2020	2021	2022	2023
GF Res	$ -	$ 0.12	$ 0.37	$ 0.62	$ 0.85	$ 1.08
GF SGS	-	0.26	0.78	1.29	1.78	2.26
GF LGS	-	1.46	4.34	7.21	9.97	12.62
GF EGS	-	10.55	31.43	52.28	72.34	91.55
GF Sand & Gravel	-	14.19	42.28	70.33	97.31	123.16
Pasta Montana	-	30.50	90.90	151.21	209.21	264.77
Benefis Hospitals	-	35.25	105.06	174.76	241.80	306.02

Standard Customer Charge plus GIRC

Class	2018	2019	2020	2021	2022	2023
GF Res	$ 7.25	$ 7.37	$ 7.62	$ 7.87	$ 8.10	$ 8.33
GF SGS	18.00	20.26	20.78	21.29	21.78	22.26
GF LGS	110.00	111.46	114.34	117.21	119.97	122.62
GF EGS	850.00	860.55	881.43	902.28	922.34	941.55
GF Sand & Gravel	850.00	864.19	892.28	920.33	947.31	973.16
Pasta Montana	850.00	880.50	940.90	1,001.21	1,059.21	1,114.77
Benefis Hospitals	850.00	885.25	955.06	1,024.76	1,091.80	1,156.02

1: Referencing the Direct Testimony of Charles Loy, Exhibit CEL-EWM-3, p. 1 of 2

159. Second, while the Commission desires to base its decision on the customer charge on a more analytical foundation, the Commission notes that the parties' witnesses themselves do not rigorously follow their cost allocation studies. Instead, they make largely subjective judgments about how the study-allocated costs should be moderated for the sake of actually allocating those costs to various customer classes. The lack of reliance on these studies to obtain

a result for a phase of ratemaking—cost allocation—which is the necessary predicate of rate design, raises the question of why the Commission would then rigorously adhere to these studies for the sake of calculating a precise customer charge. Accordingly, the Commission declines to do so. The existing customer charges are within the bookends of Donkin's and Loy's proposal if one accepts, as the Commission does, that the proportion of total costs allocated on the basis of customer determinants should be reflected in a customer charge. In the absence of a convincing proposition that the existing rates are unjust or unreasonable, the Commission finds that maintaining them is appropriate.

160. Since these utilities have a two-part bill for distribution cost recovery—the customer charge and the volume of gas used—the incremental revenue authorized by this Order will thus be allocated to the latter. In the absence of a demand charge, that costs allocated on the basis of demand are best approximated by a rate design that attributes these to the volumetric gas consumption component of the bill; the Commission reasons that most customers of these utilities are likely to use the most gas at the same time other customers are doing so, on very cold days.

CONCLUSIONS OF LAW

161. Energy West Montana furnishes gas service for consumers in the State of Montana, and is a "public utility" under regulatory jurisdiction of the Montana Public Service Commission. Mont. Code Ann. § 69-3-101.

162. The Montana Public Service Commission properly exercises jurisdiction over Energy West Montana's rates and operations. Mont. Code Ann. § 69-3-102, and Mont. Code Ann. Title 69, Ch. 3, Pt. 3.

163. The Montana Public Service Commission has provided adequate public notice of all proceedings, and an opportunity to be heard to all interested parties in this Docket. Mont. Code Ann. §§ 69-3-303, 69-3-104, and Mont. Code Ann. Title 2, Ch. 4.

164. The Montana Public Service Commission may prescribe classifications of the service of all public utilities. Each public utility is required to conform its schedule of rates, tolls, and charges to such classifications. Mont. Code Ann. § 69-3-306.

165. The Montana Public Service Commission may, after hearing and investigation, fix and order substituted rates, tolls, charges, or schedules as are just and reasonable if the rates are found to be unjust, unreasonable, or unjustly discriminatory or to be preferential or otherwise in

violation of the provisions of this chapter. Mont. Code Ann. § 69-3-330 (1).

166. The Montana Public Service Commission may, in its discretion, investigate and ascertain the value of the property of each public utility actually used and useful for the convenience of the public. The Commission is not bound to accept or use any particular value in determining rates. However, if any value is used, the value may not exceed the original cost of the property, except that the commission may include all or some of an acquisition adjustment for certain property purchased by a public utility in the purchasing utility's rate base if the transfer of the property to the purchasing utility is in the public interest. In making the investigation, the Commission may avail itself of all information contained in the assessment rolls of various counties or in the public records of the various branches of the state government or of any other information obtainable, and the Commission may at any time on its own initiative make a revaluation of the property. Mont. Code Ann. § 69-3-109.

167. Montana Public Service Commission is given the power to investigate and ascertain the value of the property of every public utility actually used and useful for the convenience of the public; under Mont. Code Ann. § 69-3-109, the Montana Public Service Commission is obligated to eliminate from rate base all utility costs in excess of original cost. *In re Montana Power Co.,* 180 Mont. 385, 590 P.2d 1140, 1979 Mont. LEXIS 713.

168. The rate levels approved herein are just, reasonable, and not unjustly discriminatory. Mont. Code Ann. §§ 69-3-330 and 69-3-201.

ORDER

169. For EWM, the Commission approves a total revenue requirement of $24,226,558 which results in an increase of previously approved revenue requirement of $479,461. This is based on a capital structure of 33.91% Long-Term Debt, 15.12% Short-Term Debt and 50.97% Equity. The Commission approves a 9.20% Return on Equity and a 6.91% overall return. For CBGC, the Commission approves a total revenue requirement of $1,416,130 or an increase of $128,238. This is based on a capital structure of 55.0% Equity and 45.0% Long-Term Debt. The Commission approves a 9.20% Return on Equity and a 7.45% overall return.

170. EWM is permitted to collect the PSC/MCC taxes on a per CCF basis through a separate rate component and is required to file compliance tariffs, accordingly. *Supra* ¶ 67.

171. EWM must file compliance tariffs implementing the approved rates and rate design within 30 days of the service date of this order.

172. All Findings of Fact and Conclusions of Law that can be properly considered an Order and that should be considered as such to preserve the integrity of this Order are incorporated herein as an Order.

173. These rates will be effective for services rendered on and after October 1, 2018.

DONE IN OPEN SESSION at Helena, Montana, on the 30th day of July, 2018, with Commissioner Lake dissenting as to the ROE and denial of SSRP; Commissioner Koopman dissenting as to the GIRC; Commissioners Koopman and O'Donnell dissenting as to the application of TCJA benefits; and Vice Chairman Kavulla dissenting as to keeping the monthly service charge at current rates.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

BRAD JOHNSON, Chairman

TRAVIS KAVULLA, Vice Chairman

ROGER KOOPMAN, Commissioner

BOB LAKE, Commissioner

TONY O'DONNELL, Commissioner

ATTEST:

Rhonda J. Simmons
Commission Secretary

(SEAL) PUBLIC SERVICE COMMISSION MONTANA

ATTACHMENT A

PUBLIC SERVICE COMMISSION OF MONTANA

Energy West Montana, Inc. Tariff No. 05, Schedule GI, Sheet 01, Release 01

GAS INFRASTRUCTURE RELIABILITY CLAUSE

GENERAL DESCRIPTION

Purpose
To provide the Utility with the resources to accelerate the replacement of aging infrastructure as identified in Energy West's general rate case filed in D2017.9.80. To accomplish these tasks, the utility is permitted to recover the costs to replace Eligible Property, as defined below, when such Eligible Property is placed into service and recorded in the individual accounts, as referenced below.

To the extent that capital investment (as measured by original cost clearings to plant less GIRC related plant clearings) in a calendar year meets or exceeds the Utility's current year annual depreciation (excluding GIRC related depreciation), all GIRC Eligible Property costs from that calendar year will be included in the recovery determination. To the extent that capital investment falls short of annual depreciation, for purposes of determining revenue recovery, the investment in Eligible Property will be reduced by the shortfall for that calendar year to determine the quantity of GIRC-Eligible Property.

All costs of Eligible Property are subject to a review for whether its costs should be permanently included in the utility's rates when Energy West next files a general rate cost. The inclusion of such costs in a rate charged under this tariff shall not be evidence that the property is used and useful, or that associated expenses were prudently incurred.

The costs of extending facilities to serve new customers are not recoverable through the GIRC.

Eligible Property
Eligible Property Identified Through DIMP

- Approximately 42 miles of pre-1984 Aldyl-A pipe
- Mechanical couplings on approximately 11,000 steel services
- Couplings on the original, approximately 4.5 miles of 12" header main
- Other capitalized costs (labor, benefits, overheads)

The Eligible GIRC Property will be booked to the following FERC plant accounts where GIRC costs will be separately identifiable. Other capitalized costs such as labor charges, related benefits, and other appropriate overheads will also be booked to the appropriate FERC account and will be separately identified.

All GIRC costs must be tracked and accounted for separately from all other costs such that for any given calendar year GIRC costs are readily identifiable and trackable and shall be subject to audit by the Commission.

- **Account 376** - Mains and related parts and fittings such as couplings, valves, excess flow valves, risers, etc. booked to this account Piping (account 376);
- **Account 378** - Measuring and regulating equipment, insulated and non-insulated fittings;
- **Account 380** - Gas services lines and related parts and fittings;
- **Account 381** - Meters;
- **Account 382** – Meter Installations, meter bars, etc.;

Commission Filings
EWM will file by November 1 of each calendar year its GIRC Plan for the following year. That plan shall detail all DIMP related projects and projected costs.

EWM will file its GIRC Cost Calculation filing by May 1 of each year to recover the GIRC costs from the previous calendar year. The GIRC Calculation filing will contain all information necessary to calculate the annual GIRC costs and a proposed rate design. The first Commission GIRC Plan filing will be due November 1, 2018 for calendar year 2019. The first GIRC Calculation filing will be made by May 1, 2020 for recovery of 2019 eligible GIRC costs. The monthly charge derived from the GIRC Calculation filing will be effective on the first billing cycle in September, beginning in 2020.

COMPUTATION OF THE GIRC

Determination of GIRC Revenue Requirement to be Recovered. The revenue requirement recovery of the costs of GIRC eligible distribution system improvements projects will consist of a pre-tax return on the GIRC Eligible Net Plant plus depreciation.

Formula:
The formula for calculation of the GIRC Revenue Requirement is as follows:

GIRC = (NP * PTRR) + DEPR

Where:

Current Year = Current Year is defined as the calendar year for which the GIRC Cost Calculation Filing is seeking recovery of GIRC costs. For example, for a filing made in May, 2020 to recover GIRC Costs for the year 2019, the Current Year is defined as 2019.

Net Plant (NP) = NP shall be calculated by subtracting AD, EDIT, and Deferred Tax Benefits (2019 only) from GP as defined below.

Gross Plant (GP) = GP is the cumulative total of all previous calendar years original cost investment in GIRC Eligible Property, plus the 13 month average GIRC original cost investment for the current year.

Accumulated Depreciation (AD) = AD is the accumulated GIRC related depreciation as booked at the end of the current year.

EDIT – EDIT is the annual total credit due to customers to reflect the annual amortization of the Excess Deferred Income Tax balance resulting from the 2017 Tax Act and Jobs Cut. The EDIT deduction from GP will be booked as zero cost customer contributed capital and is cumulative.

Deferred Tax Benefits– For the GIRC Calculation to be filed in 2020 only, the EDIT amortization associated with year 2018 and the deferred tax benefits resulting from the change in statutory tax rate accrued from Jan. 1, 2018 until Sept. 30, 2018 will be applied as an offset against the GIRC GP investment of 2019, in addition to the application of EDIT associated with year 2019. The Deferred Tax Benefit deduction from GP will be treated as zero cost customer contributed capital for the five year period 2019 through 2023.

Pre-Tax Return Rate (PTRR) = The pre-tax return shall be calculated using the statutory state and federal income tax rates, the Utility's capital structure and cost rates for long-term and short-term debt as reflected in the most recent base rate case. The cost of equity will be the equity return rate approved in the last base rate case for which a final order was entered. The pre-tax return for EWM, based on the D2017.9.80 approved capital structure and long and short term debt costs and return on equity, is 8.75%. (CBGC is 8.81%.)

Depreciation Expenses (DEPR) = DEPR related to GIRC-Eligible Property. Annual depreciation expense shall be calculated by applying the annual accrual rates employed in the Utility's most recent base rate case for the plant accounts in which each retirement unit of GIRC-Eligible Property is recorded to the original cost of GIRC-Eligible Property. DEPR equals the total amount of GIRC related depreciation expenses booked in the current year.

Rate of Return Recovery Limitation: The GIRC surcharge will be subject to a review of the utility's overall rate of return as normalized for weather and filed in the Annual Report with the Commission on or before May 1. In any year where the reported rate of exceeds the most recent authorized rate of return (defined as the overall allowed weighted cost of capital), a reduction will be made to the GIRC Revenue Requirement by the amount of incremental revenue that results in the over-earning rate of return portion. The GIRC will not be permitted to be negative, unless the surcharge would be set to zero either because of the Rate of Return Recovery Limitation or in a situation where GIRC has no incremental amount of capital spending because it is not in excess of depreciation, in which case the surcharge will be the negative value associated with the tax benefits due to be applied to GIRC's costs.

Recovery of GIRC Program Revenue Requirement

The GIRC approved revenue requirement will be recovered through a monthly customer charge. These charges will vary by customer class and will be based on the customer class allocation factors established in the current general rate case D2017.9.80. The GIRC surcharge will be

separately disclosed on customers' monthly bills.

GIRC Termination

The GIRC surcharge automatically terminates if EWM files a rate case prior to Oct. 1, 2023. The GIRC charge automatically terminates on June 1, 2025. The GIRC surcharge automatically terminates if at any time EWM files an application pursuant to Mont. Code Ann. § 69-3-308 (state and local tax tracker). Costs associated with GIRC are recoverable through a rate case filing. If EWM/CBGC desires to renew the GIRC program, it will request to do so in the general rate case filing.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the Final Order issued on September 26, 2018 in Docket D2017.9.80 was served upon the following,

Mailing a true and correct copy:

Robert Nelson
Montana Consumer Counsel
111 N. Last Chance Gulch, Ste. 1B
P.O. Box 201703
Helena, MT 59620-1703

Jed Henthorne
Energy West Montana, Inc.
Cut Bank Gas Company
PO Box 2229
Great Falls, MT 59403-2229

Kevin Degenstein
Gas Natural Inc.
PO Box 2229
Great Falls, MT 59403-2229

Thorvald A. Nelson
Nikolas S. Stoffel
6380 S. Fiddler's Green Circle
Suite 500
Greenwood Village, CO 80111

Emailing a true and correct copy:

Montana Consumer Counsel
robnelson@mt.gov;
ssnow@mt.gov;
jbrown4@mt.gov;

Holland and Hart
aclee@hollandhart.com;
ppenn@hollandhart.com;
tnelson@hollandhart.com;
nsstoffel@hollandhart.com;

Energy West
jhenthorne@egas.net;

Gas Natural
kdegenstein@egas.net;

Dated: September 26, 2018

/s/*Sydney Kessel*
Sydney Kessel, Administrative Assistant

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1300

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Progress, LLC	)	ORDER ACCEPTING
For Adjustment of Rates and Charges	)	STIPULATIONS, GRANTING
Applicable to Electric Service in North Carolina	)	PARTIAL RATE INCREASE, AND
and Performance Based Regulation	)	REQUIRING PUBLIC NOTICE

HEARD: Monday, March 6, 2023, at 7:00 p.m., Haywood County Courthouse, Courtroom 2-A, 285 N. Main Street, Waynesville, North Carolina

Monday, March 13, 2023, at 7:00 p.m., Person County Courthouse, Superior Courtroom, 105 S. Main Street, Roxboro, North Carolina

Tuesday, March 14, 2023, at 7:00 p.m., Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina

Monday, March 20, 2023, at 7:00 p.m., Greene County Courthouse, 301 N. Green Street, Courtroom 1, Snow Hill, North Carolina

Tuesday, March 21, 2023, at 7:00 p.m., Robeson County Courthouse, Courtroom B, 500 N. Elm Street, Lumberton, North Carolina

Thursday, April 20, 2023, at 6:00 p.m. via Videoconference, Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina

Thursday, May 4, 2023, at 2:00 p.m., Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina

BEFORE: Chair Charlotte A. Mitchell, Presiding; and Commissioners ToNola D. Brown-Bland; Daniel G. Clodfelter; Kimberly W. Duffley; Jeffrey A. Hughes; Floyd B. McKissick, Jr.; and Karen M. Kemerait

APPEARANCES:

For Duke Energy Progress, LLC (DEP):

Jack E. Jirak, Deputy General Counsel, Kendrick C. Fentress, Associate General Counsel, Duke Energy Corporation, 410 South Wilmington Street, Raleigh, North Carolina 27602

James H. Jeffries IV, Partner, McGuireWoods LLP, 201 North Tryon Street, Suite 3000, Raleigh, North Carolina 28202

Andrea Kells, Counsel, McGuireWoods LLP, 501 Fayetteville Street, Suite 500, Raleigh, North Carolina 27601

Kiran H. Mehta, Partner and Melinda L. McGrath, Partner, Troutman Pepper Hamilton Sanders LLP, 301 South College Street, Suite 3400 Charlotte, North Carolina 28202

Brandon F. Marzo, Partner, Melissa Oellerich Butler, Associate, and Joshua Warren Combs, Associate, Troutman Pepper Hamilton Sanders LLP, 600 Peachtree Street, NE, Suite 3000, Atlanta, Georgia 30308

For Carolina Industrial Group for Fair Utility Rates II (CIGFUR):

Christina D. Cress and Douglas E. Conant, Bailey & Dixon, LLP, 434 Fayetteville Street, Suite 2500, Post Office Box 1351, Raleigh, North Carolina 27602

Chris S. Edwards, Ward and Smith, P.A., Post Office Box 7068, Wilmington, North Carolina 28406

For Carolina Utility Customers Association, Inc. (CUCA):

Marcus W. Trathen, Craig D. Schauer, Matthew Tynan, and Christopher B. Dodd, Brooks, Pierce McLendon, Humphrey & Leonard, LLP, 150 Fayetteville Street, Suite 1700, Raleigh, North Carolina 27601

For North Carolina Sustainable Energy Association (NCSEA):

Taylor M. Jones and Ethan Blumenthal, North Carolina Sustainable Energy Association, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For North Carolina League of Municipalities (NCLM):

Ben Snowden and Jonathan L. Taggart, Fox Rothschild LLP, 434 Fayetteville Street, Suite 2800, Raleigh, North Carolina, 27601

For North Carolina Justice Center (NCJC), North Carolina Housing Coalition (NCHC), Southern Alliance for Clean Energy (SACE), Natural Resources Defense Council (NRDC), and Vote Solar (collectively, NCJC, et al.):

David L. Neal, Munashe Magarira, and Thomas Gooding, Southern Environmental Law Center, 601 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

For the United States Department of Defense and all other Federal Executive Agencies (DoD-FEA):

Kyle J. Smith, General Attorney, 9275 Gunston Road, Fort Belvoir, Virginia 22060

For the Commercial Group:

Alan R. Jenkins, Jenkins at Law, LLC, 2950 Yellowtail Avenue, Marathon, Florida 33050

Brian O. Beverly, Young Moore and Henderson, P.A., 3101 Glenwood Avenue, Suite 200, Raleigh, North Carolina 27612

For Kroger Co. and Harris Teeter LLC, a Division of Kroger Co. (Kroger Co. and Harris Teeter):

Kurt J. Boehm and Jody Kyler Cohn, Boehm, Kurtz & Lowry, 36 East Seventh Street, Suite 1510, Cincinnati, Ohio 45202

Ben M. Royster, Royster and Royster, PLLC, 851 Marshall Street, Mount Airy, North Carolina 27030

For Carolinas Clean Energy Business Association (CCEBA):

John D. Burns, General Counsel, 811 Ninth Street, Suite 120-158, Durham, North Carolina 27705

For Fayetteville Public Works Commission (FPWC):

James P. West and Dustin K. Doty, Fayetteville Public Works Commission, 955 Old Wilmington Road, Fayetteville, North Carolina 28302

For Sierra Club:

Catherine Cralle Jones and Andrea C. Bonvecchio, Law Offices of F. Bryan Brice, Jr., 130 South Salisbury Street, Raleigh, North Carolina 27601

Justin Somelofske, The Sierra Club, 50 F. Street, Northwest, Washington, District of Columbia 20001

For Haywood Electric Membership Corporation (Haywood EMC):

Christina D. Cress, Bailey & Dixon, LLP, 434 Fayetteville Street, Suite 2500, Post Office Box 1351, Raleigh, North Carolina 27602

For the Using and Consuming Public:

Tirrill E. Moore, Assistant Attorney General, North Carolina Department of Justice, 114 West Edenton Street, Raleigh, North Carolina 27603

Lucy E. Edmondson, Robert B. Josey, Nadia L. Luhr, Anne M. Keyworth, William S.F. Freeman, William E.H. Creech, and Thomas Felling, the Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

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BY THE COMMISSION: On June 8, 2022, pursuant to Rule R1-17B(c) of the Rules of Practice and Procedure of the North Carolina Utilities Commission, DEP filed its Request to Initiate Technical Conference Regarding the Projected Transmission and Distribution Projects to be Included in a Performance-Based Regulation (PBR) Application.

On September 6, 2022, pursuant to Commission Rule R1-17(a), DEP filed notice of its intent to file a general rate case application that includes a performance-based regulation application as authorized under N.C. Gen. Stat. § 62-133.16.

On October 6, 2022, DEP filed its Application to Adjust Retail Rates and for Performance-Based Regulations, and Request for an Accounting Order (the Application), supported by a Rate Case Information Report Commission Form E-1 (Form E-1), and direct testimony and exhibits. As required by N.C.G.S. § 62-133.16 and Commission Rule R1-17B, DEP's PBR Application included a residential decoupling rate-making mechanism, performance incentive mechanisms (PIMs) and tracking metrics, and a Multiyear Rate Plan (MYRP), including an earnings sharing mechanism (ESM).

PROCEDURAL HISTORY AND JURISDICTION

Procedural History

The following is a summary of the most pertinent filings by DEP, the parties, and procedural orders issued by the Commission.

Petitions to intervene were filed by CIGFUR on June 13, 2022, and CUCA on June 16, 2022. The Commission entered orders granting the petitions to CIGFUR on June 15, 2022, and CUCA on June 22, 2022.

On June 15, 2022, the Commission issued an Order Scheduling and Setting Procedures for the Technical Conference. The Commission's Order established that the Technical Conference would be held in person on July 25, 2022, that DEP should make its Transmission and Distribution (T&D) Information Filing by July 15, 2022, and that parties would be allowed to file written comments on DEP's T&D Information Filing on or before July 25, 2022.

Notice of intervention and of intent to participate in the Technical Conference was filed by the Attorney General's Office (AGO) on June 29, 2022.

Petitions to intervene and notices of intent to participate in the Technical Conference were filed by North Carolina Electric Membership Corporation (NCEMC) on June 30, 2022; NCJC, NCHC, SACE, and NCSEA on July 5, 2022; Vote Solar on July 11, 2022; and NRDC on July 11, 2022. The Commission entered orders granting the petitions of NCJC, NCHC, SACE, and NCSEA on July 7, 2022; Vote Solar on July 12, 2022; and NRDC on July 13, 2022. The Commission denied NCEMC's petition to intervene and granted NCEMC amicus curiae status on July 11, 2022.

CIGFUR also filed a notice of intent to participate in the Technical Conference on July 11, 2022. Notice of the Public Staff's intent to participate in the Technical Conference was filed by the Public Staff on July 11, 2022.

On July 15, 2022, DEP filed its T&D Information Filing. Comments in response to DEP's T&D Informational Filing were filed by the Public Staff, CIGFUR, NCSEA, and NCJC, et al. on July 25, 2022.

On July 25, 2022, a technical conference was held before the Commission with Chair Charlotte A. Mitchell, Presiding; and Commissioners ToNola D. Brown-Bland; Daniel G. Clodfelter; Kimberly W. Duffley; Jeffrey A. Hughes; Floyd B. McKissick, Jr.; and Karen M. Kemerait.

On August 3, 2022, DEP filed a letter advising that it would provide the additional information in response to Chair Mitchell's request that it identify "Red Zone" projects and associated cost-benefit analyses (CBAs) included in DEP's T&D Information Filing, as part of DEP's direct testimony to be filed on August 19, 2022, in Docket No. E-100, Sub 179.

On September 6, 2022, pursuant to Commission Rule R1-17(a), DEP filed notice of its intent to file a general rate case application that includes a performance-based regulation application as authorized under N.C.G.S. § 62-133.16.

On September 12, 2022, pursuant to N.C.G.S. § 62-69, DEP, Duke Energy Carolinas, LLC (DEC), the Public Staff, CIGFUR, and Carolina Industrial Group for Fair Utility Rates III (CIGFUR III), filed the Agreement and Stipulation of Partial Settlement regarding the cost of service study (COSS Stipulation) for consideration by the Commission in Docket Nos. E-2, Sub 1300 and E-7, Sub 1276. On September 13, 2022, a revision to the Stipulation was filed by the aforementioned parties attaching exhibits which were inadvertently omitted from the version filed the previous day.

On October 6, 2022, DEP filed its Application, Form E-1, and the direct testimony and exhibits of Stephen G. De May, North Carolina President, DEP, DEC, and Progress Energy, Inc.; Jonathan L. Byrd, Managing Director of Rate Design and Regulatory Solutions for Duke Energy Business Services, LLC (DEBS); [1] Brent C. Guyton, Director of Asset Management in Customer Delivery for DEP and DEC; Laura A. Bateman, Vice President of Carolinas Rates and Regulatory Strategy; Phillip O. Stillman, Managing Director of Load Forecasting and Corporate Strategic Regulatory Initiatives; LaWanda M. Jiggetts, Rates and Regulatory Strategy Manager for DEC; Retha Hunsicker Vice President, Customer Experience Design and Solutions for DEBS; Tim S. Hill, Vice President, Coal Combustion Products (CCP) Operations, Maintenance and Governance for DEBS; Bradley G. Harris, Rates and Regulatory Strategy Director for DEBS; Janice D. Hager, President of Janice Hager Consulting, LLC; Tom Ray, Senior

[1] DEBS provides various administrative and other services to DEP and other affiliated companies of Duke Energy Corporation (Duke Energy).

Vice President of Nuclear Operations for Duke Energy Corporation (Duke Energy); Lesley G. Quick, Vice President of Customer Technology, Advocacy, Regulatory and Business Support within Customer Services for Duke Energy; Karl W. Newlin, Senior Vice President, Corporate Development and Treasurer, DEBS; Dr. Roger A. Morin, Emeritus Professor of Finance at the Robinson College of Business and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry, both at Georgia State University; Laurel M. Meeks, Director of Renewable Business Development for DEP; Evan W. Shearer, Principal Integrated Planning Coordinator for DEC; Daniel J. Maley, Director of Transmission Compliance Coordination for DEBS; Justin C. LaRoche, Director of Renewable Development for Duke Energy; Julie K. Turner, Vice President of Carolinas Coal Generation for Duke Energy; Kathryn S. Taylor, Rates and Regulatory Strategy Manager for DEC; Jacob J. Stewart, Director Health and Wellness for DEBS; Nicolas G. Speros, Director of Accounting for DEBS; John J. Spanos of Gannett Fleming Valuation and Rate Consultants, LLC (Gannett Fleming); and Teresa Reed, Director of Rates and Regulatory Planning for DEBS.

On October 31, 2022, the Commission issued an order which declared a general rate case, suspended the proposed new rates, established the test year period as ending December 31, 2021, and advised that an order scheduling hearings and requiring public notice would be issued at a later date.

Petitions to intervene were filed by Kroger Co. and Harris Teeter on November 4, 2022, and the Commercial Group on November 11, 2022. The Commission entered orders granting the petitions of the Commercial Group and Kroger Co. and Harris Teeter on November 15, 2022.

Petitions to intervene were filed by FPWC on November 23, 2022, and by the Sierra Club on December 14, 2022. The Commission entered orders granting the petitions of FPWC and the Sierra Club on January 10, 2023.

On December 16, 2022, the Commission issued an Order Scheduling Investigation and Hearings, Establishing Intervention and Testimony Due Dates and Discovery Guidelines, and Requiring Public Notice (Scheduling Order). The Order scheduled public witness hearings in Lumberton, Raleigh, Waynesville, Roxboro, and Snow Hill, North Carolina on February 21, February 27, March 6, March 13, and March 20, 2023, respectively. Further, the order set the relevant test period to be used by all parties as the twelve-month period ending December 31, 2021, with appropriate adjustments. The Commission directed, among other instructions, that DEP publish the Public Notice of Hearings on Rate Increase Application (Public Notice) attached to the order as Appendix A, once a week for two consecutive weeks and mail the Public Notice to its customers no later than 30 days in advance of the first set hearing. Subsequently, on December 21, 2022, the Commission issued its Order Rescheduling Public Witness Hearings, Revising Public Notice, and Revising Requirement for Mailing Public Notice (Second Scheduling Order) correcting public hearing location addresses for Lumberton and Raleigh; rescheduling the public witness hearing in Lumberton to March 21, 2023, and the public witness hearing in Raleigh to March 14, 2023; authorizing corresponding

revisions to the Public Notice; and instructing DEP to mail each of its customers a copy of the Public Notice no later than 14 days in advance of the public witness hearing scheduled for March 6, 2023.

A petition to intervene was filed by DoD-FEA on January 30, 2023. The Commission entered an order granting DoD-FEA's petition on January 31, 2023.

On December 20, 2023, DEP filed a motion requesting leave to file direct testimony of Kendal C. Bowman adopting the direct testimony of Stephen G. De May, file the direct testimony and exhibits of Graham C. Tompson adopting the direct testimony of Laurel Meeks, and to amend the direct testimony of the Battery Energy Storage Panel. On January 10, 2023, the Commission entered an order granting DEP's motion filed December 20, 2023, and accepted the testimony and exhibits filed into the record.

A joint petition to intervene was filed by ElectriCities of North Carolina, Inc. (ElectriCities) and North Carolina Eastern Municipal Power Agency (NCEMPA) on February 1, 2023. The Commission entered an order denying Electricities' and NCEMPA's joint petition on February 10, 2023.

On February 13, 2023, DEP filed the supplemental direct testimony and exhibits of witnesses Jiggetts; LaRoche; Turner; Taylor; Martin M. Strasburger, Chief Security and Information Security Officer for Duke Energy; Reed; Ray; John R. Panizza, Director, Tax Operations for DEBS; Morin; Shearer; Graham C. Tompson, Business Development Manager for Duke Energy; Maley; Guyton; and Bateman.

On March 13, 2023, Haywood EMC filed a petition to intervene. On March 15, 2023, the Commission issued an order granting Haywood EMC's petition and establishing the scope of its intervention.

On March 14, 2023, the Commission issued its Order Scheduling Virtual Public Witness Hearing and Establishing Requirements for Notice of Virtual Public Witness Hearing (March 14, 2023 Scheduling Order). The March 14, 2023 Scheduling Order scheduled an additional virtual hearing for the purpose of receiving public witness testimony on DEP's Application for April 20, 2023.

On March 15, 2023, CCEBA filed a petition to intervene. On March 17, 2023, NCLM filed a Petition to Intervene. The Commission issued orders granting the petitions filed by CCEBA and NCLM on March 27, 2023.

In March, April, and May of 2023, the Commission held seven public hearings as scheduled by the Scheduling Order, Second Scheduling Order, and March 14, 2023 Scheduling Order for the purpose of receiving the testimony of public witnesses.

NCEMC filed a petition to intervene on March 17, 2023. The Commission issued an order denying NCEMC's Petition on March 28, 2023.

On March 27, 2023, the Commercial Group filed the direct testimony and exhibits of Steve W. Chriss, Director, Energy Services, Walmart; DoD-FEA filed the direct testimony and exhibits of Maureen L. Reno, Founder and Principal Consultant of Reno Energy Consulting Services, LLC, and Larry Blank, Principal of TAHOEconomics, LLC; NCLM filed the direct testimony of Terry Mann, Mayor of the City of Whiteville, North Carolina, and Bill Saffo, Mayor of the City of Wilmington, North Carolina; The Sierra Club filed the direct testimony and exhibits of Roger D. Colton, Co-Founder, Fisher, Sheehan, and Colton, Public Finance and General Economics and Michael Goggin, Vice President, Grid Strategies, LLC; NCJC, et al. filed the direct testimony and exhibits of John Howat, Senior Policy Analyst, National Consumer Law Center, Mark E. Ellis, independent consultant and testifying expert, David B. Posner, Manger, RMI and the joint direct testimony of David G. Hill, Managing Consultant at Energy Futures Group, Inc. and Jake Duncan, a Southeast Regulatory Director for Vote Solar; FPWC filed the direct testimony and exhibits of Laurie A. Tomczyk, Senior Manager, NewGen Strategies and Solutions, LLC; CIGFUR filed the direct testimony and exhibits of Michael P. Gorman, Managing Principal, Brubaker & Associates, Inc. and Nicholas Phillips, Jr., Principal, Brubaker & Associates, Inc.; Kroger Co. and Harris Teeter filed the direct testimony and exhibits of Justin Bieber, Principal, Energy Strategies, LLC; CUCA filed the direct testimony of Charles Heilig, President, Parkdale Mills, and Kevin W. O'Donnell, President, Nova Energy Consultants, Inc.; the AGO filed the direct testimony and exhibits of Edward Burgess, Senior Director of Integrated Resource Planning, Strategen Consulting, and Ron Nelson, Senior Director, Strategen Consulting.

Also on March 27, 2023, the Public Staff filed the direct testimony and exhibits of James S. McLawhorn, Director of the Energy Division of the Public Staff; Evan D. Lawrence, Engineer with the Energy Division of the Public Staff; Roxie McCullar, Consultant, William Dunkel and Associates; John W. Chiles, Principal, GDS Transmission Services group at GDS Associates, Inc.; Thomas C. Williamson, Engineer with the Energy Division of the Public Staff; Christopher C. Walters, Associate, Brubaker & Associates, Inc.; Blaise C. Michna, Engineer with the Energy Division of the Public Staff; Jay B. Lucas, Manager of the Electric Section, Operations and Planning in the Energy Division of the Public Staff; Jordan A. Nader, Engineer with the Energy Division of the Public Staff; Jeff Thomas, Engineer with the Energy Division of the Public Staff; David M. Williamson, Engineer with the Energy Division of the Public Staff; Dustin Metz, Engineer with the Energy Division of the Public Staff, the joint testimony and exhibits of Fenge Zhang, Financial Manager, Electric Section with the Accounting Division of the Public Staff, and Michelle Boswell, Director of Accounting for the Accounting Division of the Public Staff, and the joint testimony and exhibits of David M. Williamson and Jeff T. Thomas, Engineers with the Energy Division of the Public Staff.

On April 3, 2023, DEP filed a motion seeking to substitute Melissa B. Abernathy as the sponsor of the direct testimony and exhibits prefiled by Kathryn S. Taylor. On April 20, 2023, the Commission issued its Order Granting DEP's Motion for Substitution of Witness and Adoption of Testimony.

On April 14, 2023, DEP filed the rebuttal testimony and exhibits of DEP's witnesses Maley; Kevin A. Murray, Vice President of the Project Management and Construction Organization for DEBS; Morin; Bowman, President of Duke Energy's Utility Operations in North Carolina; Donna T. Council, Senior Vice President, Corporate Real Estate, Aviation, and Business Services for DEBS; LaRoche; Ray; Turner; Guyton; Panizza; Newlin; Quick; Speros; Spanos; Jiggetts; Melissa B. Abernathy, Director of Rates and Regulatory Planning for DEC; Stewart; and joint rebuttal testimony of witnesses Bowman, Quick, Abernathy, and Speros; Bateman and Stillman; Tompson and Shearer; Conitsha B. Barnes, Director of Energy Policy Management for DEC, Harris, and Quick; and Byrd and Reed.

On April 17, 2023, DEP filed amended rebuttal testimony of witness Morin.

On April 18, 2023, DEP filed second supplemental direct testimony of witness Reed and third supplemental direct testimony of witnesses Abernathy and Jiggetts.

On April 25, 2023, the Public Staff filed a motion to withdraw portions of witness Thomas' testimony. On May 1, 2023, the Public Staff filed a motion to withdraw portions of witness T. Williamson's testimony. On May 8, 2023, the Commission issued its order granting the Public Staff's motions to withdraw portions of testimony filed by witnesses T. Williamson and Thomas.

On April 26, 2023, the Public Staff and DEP filed an Agreement and Stipulation of Partial Settlement (April 26, 2023 Partial Settlement).

On April 27, 2023, the Commission issued its Order Continuing Hearing and Modifying Dates for Additional Hearing Procedures. Pursuant to the order, the expert witness hearing was rescheduled to commence on May 4, 2023. Also on April 27, 2023, the AGO filed its motion to substitute Ron Nelson as the sponsor of the testimony and exhibits filed by AGO witness Burgess. On May 8, 2023, the Commission issued its order granting the AGO's motion.

Also on April 27, 2023, the Public Staff filed a Transmission Cost Allocation Agreement and Stipulation of Settlement between DEP, DEC, and the Public Staff (TCA Stipulation).

On April 28, 2023, DEP filed settlement testimony of witness Bateman to support the TCA Stipulation. Also on April 28, 2023, DEP filed the settlement testimony and exhibits of witnesses Abernathy, Jiggetts, and Bowman in support of the April 26, 2023 Partial Settlement.

On May 1, 2023, DEP, the Public Staff, and CIGFUR filed an Agreement and Stipulation of Settlement on Performance Incentive Mechanisms, Tracking Metrics and Decoupling Mechanism (the PIMS Stipulation). Also on May 1, 2023, DEP and CIGFUR filed a separate Agreement and Stipulation of Settlement (the Power Quality Stipulation).

Additionally, on May 1, 2023, the Public Staff filed the supplemental and settlement joint testimony and exhibits of witnesses Zhang and Boswell; the supplemental testimony of witnesses Metz and Williamson; and the settlement testimony of witnesses Metz and McLawhorn in support of April 26, 2023 Partial Settlement.

On May 2, 2023, CIGFUR filed supplemental direct testimony of witness Phillips, Jr. in support of the Power Quality Stipulation. Also on May 2, 2023, DEP, the Public Staff, and CIGFUR filed an Amended Agreement and Stipulation of Partial Settlement that amended the April 26, 2023 Partial Settlement, including through the inclusion of CIGFUR as a party (as amended, the Revenue Requirement Stipulation). Also on May 2, 2023, the Public Staff filed the joint testimony of witnesses Thomas and D. Williamson and DEP filed the joint settlement testimony of witnesses Bateman and Stillman supporting the PIMS Stipulation.

On May 4, 2023, DEP, Sierra Club, NCJC, et al., and the Public Staff filed an Agreement and Stipulation of Partial Settlement Regarding Low-Income/Affordability Performance Incentive Mechanism and Affordability Issues (the Affordability Stipulation). On May 5, 2023, DEP filed the settlement testimony of witnesses Barnes, Harris, and Quick and the Public Staff filed testimony of witness D. Williamson in support of the Affordability Stipulation.

On May 4, 2023, the expert witness hearing commenced.

From May 5, 2023, through June 6, 2023, DEP filed 18 Late-Filed Exhibits, and the Public Staff filed Late-Filed Exhibit Nos. 1 and 2.

On May 10, 2023, DEP, the Commercial Group, and Kroger and Harris Teeter filed an Agreement and Stipulation of Settlement (MGS Partial Rate Design Stipulation).

On May 16, 2023, DEP filed a Notice of Intent to Place Temporary Rates into Effect and Request for Expedited Approval of Notice of Undertaking, as well as a revised Appendix A, and on May 17, 2023, a second revised Appendix A. Also on May 17, 2023, the Commission filed an Order Approving Public Notice of Temporary Rates Subject to Refund and Financial Undertaking and Expiration of EDIT-3 Rider.

On May 23, 2023, DEP filed its Temporary Rates Compliance Filing.

On May 26, 2023, the Public Staff filed a Motion to Strike Portions of DEP's Late-Filed Exhibits 9 and 10, which DEP filed a response to on May 30, 2023. On June 2, 2023, the Commission issued an Order Denying the Public Staff's Motion to Strike Portions of DEP's Late-Filed Exhibits 9 and 10.

On June 7, 2023, DEP and CIGFUR filed an Agreement and Stipulation of Settlement (the LGS Partial Rate Design Stipulation).

On June 27, 2023, the Public Staff filed the second supplemental testimony of witnesses Zhang and Boswell, the second supplemental testimony of witness D. Williamson, and the supplemental testimony of witness Thomas. On that same date, DEP and the Public Staff filed an Agreement and Stipulation of Settlement (the Supplemental Revenue Requirement Stipulation) and the Public Staff filed the supplemental settlement testimony of Metz, Zhang, and Boswell.

On June 27, 2023, the Public Staff filed a Motion for Leave to File Testimony on the June 7, 2023 Stipulation filed between DEP and CIGFUR.

On June 28, 2023, the Public Staff filed the corrected second supplemental exhibits of witness D. Williamson.

On July 3, 2023, CIGFUR filed a motion to strike the second supplemental testimony and corrected second supplemental exhibits of Public Staff witness D. Williamson. On that same date, CIGFUR filed in opposition to the Public Staff's motion for leave to file testimony on the June 7, 2023 Stipulation.

On July 3 and 5, 2023, DEP, NCLM, and the Public Staff filed responses to the July 3, 2023 CIGFUR filings.

On July 6, 2023, the Commission issued an Order on Post-Hearing Motions and Reconvening Hearing which denied CIGFUR's motion to strike the second supplemental testimony and corrected second supplemental exhibits of Public Staff witness D. Williamson, denied the motion for leave of the Public Staff to file testimony on the June 7, 2023 Stipulation, and reconvened the expert witness hearing for limited purposes.

On July 24, 2023, the expert witness hearing was reconvened.

Jurisdiction

No party has contested the fact that DEP is a public utility subject to the Commission's jurisdiction pursuant to the Public Utilities Act (Act), Chapter 62 of the North Carolina General Statutes. The Commission concludes that it has personal jurisdiction over DEP and subject matter jurisdiction over the matters presented in DEP's Application.

Application

In summary, DEP requested in its Application and initial direct testimony and exhibits, a base rate increase of approximately $227.6 million, or 5.9%, in its annual electric sales, offset by a rate reduction of $8.5 million to refund certain tax benefits, for a net revenue increase of $219.2 million, or 5.7% from its North Carolina retail electric operations, including a rate of return on common equity of 10.2% and a capital structure consisting of 47.0% debt and 53.0% equity. DEP's Application and initial direct testimony and exhibits also sought approval of PBR and a series of rate increases based on DEP's proposed three-year MYRP, and other mechanisms required as part of PBR, with the first

rate increase effective November 5, 2022. DEP sought increases to the revenue requirement of $106.6 million, $150.8 million, and $138.3 million in Rate Year 1, Rate Year 2, and Rate Year 3, respectively.

DEP submitted evidence in this case with respect to revenue, expenses, and rate base using a test period consisting of the 12 months ending on December 31, 2021, adjusted for certain known changes in revenue, expenses, and rate base through March 31, 2023[2].

DEP, by its supplemental direct testimony and exhibits, revised its requested base revenue requirement increase to approximately $283.5 million, offset by a rate reduction of $8.5 million to refund certain tax benefits, for a net revenue increase of $275 million, including an increase to the rate of return on common equity to 10.4% and an increase to the cost of debt to 3.88% based on the average embedded cost of debt financing as of December 31, 2022. DEP also revised its series of rate increases based on DEP's proposed three-year MYRP. DEP's updated MYRP revenue requirements were $104 million, $133.4 million, and $147.5 million in Rate Year 1, Rate Year 2, and Rate Year 3, respectively.

DEP, by its second supplemental direct testimony and exhibits, revised its requested base revenue requirement increase to approximately $308.8 million, offset by a rate reduction of $8.5 million to refund certain tax benefits, for a net revenue increase of $300.3 million including an increase to the cost of debt to 3.9% based on the average embedded cost of debt financing as of February 28, 2023. DEP also revised its series of rate increases based on DEP's proposed three-year MYRP. DEP's updated MYRP revenue requirements were $104.1 million, $133.5 million, and $147.6 million in Rate Year 1, Rate Year 2, and Rate Year 3, respectively.

DEP, by its March 2023 supplemental direct testimony and exhibits, revised its requested base revenue requirement increase to approximately $314.6 million, offset by a rate reduction of $8.5 million to refund certain tax benefits, for a net revenue increase of $306.1 million, including an increase to the cost of debt to 4.03% based on the average embedded cost of debt financing as of March 31, 2023. DEP also revised its series of rate increases based on DEP's proposed three-year MYRP. DEP's updated MYRP revenue requirements were $104.5 million, $133.5 million, and $148.2 million in Rate Year 1, Rate Year 2, and Rate Year 3, respectively.

[2] DEP's Application initially proposed a capital cut-off date of April 31, 2023; however, upon further discussion and agreement with the Public Staff, the parties agreed to, and the Commission's Scheduling Order established, a capital cut-off date of March 31, 2023. The change in capital cut-off was reflected in DEP's supplemental filings.

Whole Record

The Commission held public witness hearings as noted above. The following public witnesses appeared and testified:

Waynesville: Les Cochran, Charles Guyton, Andrew Jarbeau, Porter Hughes, Gray Jernigan, Rob Denton, Mary Curry, Walker Spruill, Delisa Ensley, Ken Brame, Judy Mattox, Abby Frye, and Angelica Cote.

Raleigh: William Terry, Criss Berke, Amelia Covington, Divine Earth-Dowd, Jennifer Eison, Stacey Campbell, Paul Baer, Lisa Brewer, Peter Thomas, Agnes Foucha, Ashleigh Armstrong, Ziyad Habash, Ebony McKinnan, Cathy Buckley, Deborah Ford, Ernestine Ledbetter, Matthew Muse, Eleanor Weston, Kaitlyne Sheehan, and Brenda Jackson.

Snow Hill: Gwen Johnson, David Barnes, Phyllis Merritt-James, Brianna Howard, Jaylind Lampa, Larry James, Glenda Thomas, Vicky Bailey, Barbara Dantonio, Don Cavellini, Beatrice Jones, Syene Jasmin, Bobby Jones, and Constance Coram.

Lumberton: Debra David, Robert Macy, Jaquline Banks; Les Cochran; Sallie McLean; Lauren Martin; Samantha Sirabian; Daniel Dimaria, Hannah Jeffries, Esther Murphy, Ryua Hishikawa, Georgette Hunt, Mac Legerton, Ricky Johnson, Felicia Bethea, Carol T. Richardson, Frankie Hall, and William Fairley.

Virtual Hearing: Michael Righi, Reagan McGuinn, Ruby Bell, Kay Reibold, Steven Norris, Sean Lewis.

In summary, almost all the public witnesses stated their opposition to DEP's proposed rate increase. *See generally*, Tr. vols. 2-6. Many witnesses testified that they were on fixed incomes and about the poverty in some of the counties served by DEP. Moreover, public witnesses testified to their concern regarding DEP's use of fossil fuels, including coal and natural gas power plants, fracking, and DEP not adequately increasing the use of clean energy and renewables. Finally, some public witnesses voiced their view that DEP's executive compensation and shareholder dividends are excessive.

In addition to the public witness testimony, the Commission received a number of consumer statements of position, all of which were filed in the docket. *See generally*, Docket No. E-2, Sub 1300CS. The public witness testimony and consumer statements of position have been considered by the Commission in its deliberations on DEP's rate case Application.

The testimony and exhibits in this proceeding are voluminous. The Commission has carefully considered all the evidence and the record as a whole. However, the Commission has not attempted to recount every statement of every witness in this Order.

Rather, the Commission has summarized the evidence that is in the record. Likewise, while the Commission has read and fully considered the parties' post-hearing briefs, it has not in this Order attempted expressly to summarize or discuss every contention advanced or authority cited in the briefs.

Based upon the foregoing and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

Stipulations

1. On April 26, 2023, DEP and the Public Staff filed the Revenue Requirement Stipulation, which resolved a portion of the base period and MYRP revenue requirement issues in this proceeding. On May 2, 2023, DEP and the Public Staff amended the Revenue Requirement Stipulation, adding CIGFUR as a party and resolving an additional revenue requirement issue.

2. On September 13, 2022, DEP, DEC, the Public Staff, CIGFUR, and CIGFUR III (the COSS Stipulating Parties) filed the COSS Stipulation. The COSS Stipulation provides that DEP will first allocate production and transmission demand costs to the North Carolina retail jurisdiction using the Twelve Coincident Peak (12 CP) method and will allocate production demand costs among the North Carolina retail rate classes using the modified Average and Excess (A&E) Demand Method (the Modified A&E Method).

3. On April 27, 2023, DEP, DEC, and the Public Staff filed the TCA Stipulation. The TCA Stipulation provides for a pro forma adjustment of approximately $20 million to increase the revenue requirement in DEC's pending rate case proceeding in Docket No. E-7, Sub 1276 (DEC Rate Case) and to decrease the revenue requirement in the instant proceeding.

4. On May 1, 2023, DEP, the Public Staff, and CIGFUR filed the PIMs Stipulation.

5. On May 1, 2023, DEP and CIGFUR filed the Power Quality Stipulation.

6. On May 4, 2023, DEP, DEC, Sierra Club, NCJC, et al., and the Public Staff filed the Affordability Stipulation.

7. On May 10, 2023, DEP, the Commercial Group, and Kroger Co. and Harris Teeter filed the MGS Partial Rate Design Stipulation.

8. On June 7, 2023, DEP and CIGFUR filed the LGS Partial Rate Design Stipulation.

9. On June 27, 2023, DEP and the Public Staff filed the Supplemental Revenue Requirement Stipulation.

10. The Revenue Requirement Stipulation, the COSS Stipulation, the TCA Stipulation, the PIMs Stipulation, the Power Quality Stipulation, the Affordability Stipulation, the MGS Partial Rate Design Stipulation, the LGS Partial Rate Design Stipulation, and the Supplemental Revenue Requirement Stipulation are the product of give-and-take settlement negotiations between the respective stipulating parties.

Depreciation

11. The depreciation rates proposed by DEP, which reflect the accelerated retirement of DEP's coal units, as amended by the Revenue Requirement Stipulation to reflect 20-year amortization periods for General Plant FERC accounts 391 and 397 and a 70-year life for Transmission FERC account 356, are reasonable.

12. The deferral of 75.0% of the impact of accelerating the depreciation of DEP's Mayo and Roxboro Units 3 and 4 from the current retirement dates to a regulatory asset as agreed upon in the Revenue Requirement Stipulation is reasonable.

13. Any portion of net book value upon the retirement of DEP's subcritical coal-fired plants that will not be recovered through securitization will be recovered with a return over an amortization period to be determined by the Commission in a future rate case proceeding.

Base Period Plant-Related Items

14. DEP's plant-related capital investments during the test year in its transmission, distribution, fossil/hydro, nuclear, solar, and storage assets, as adjusted by the Revenue Requirement Stipulation, were prudently and reasonably made and should be reflected in the revenue requirement.

Grid Improvement Plan Costs

15. Since DEP's last general rate case, DEP has deferred incremental operation and maintenance expense, depreciation and property taxes associated with its three-year grid improvement plan (GIP), as well as the carrying cost on the investment and the deferred costs at DEP's weighted average cost of capital.

16. DEP proposes to amortize the GIP deferral of $36.4 million, associated with the GIP investment of $196.7 million on a North Carolina retail basis, over an amortization period of three years, which results in an annual amortization expense of $12.9 million.

17. Section III, Paragraph 11 of the Revenue Requirement Stipulation provides that DEP should be permitted to recover the full balance of its GIP deferral over an amortization period of 18 years, with a debt-only return during the deferral period and rate

base treatment during the amortization period.

Coal Ash

18. DEP's request to amortize costs associated with its coal combustion residual (CCR) obligations incurred through March 31, 2023, over a five-year period and to continue the deferral of any CCR costs incurred subsequent to March 31, 2023, is reasonable.

19. The over-amortization of CCR recovery in the amount of $8.5 million should be applied against the Coal Ash CCR Asset Retirement Obligations (ARO) deferral.

Harris Land Sales

20. Section III, Paragraph 22 of the Revenue Requirement Stipulation provides for a flowback period of three years for the liability related to the gains on Harris land sales and provides that DEP will include the unamortized balance in rate base.

21. It is appropriate for DEP to continue to defer any gains on Harris land sales to be returned to customers in a future general rate case proceeding.

Roxboro Wastewater Treatment Regulatory Asset

22. DEP's request for an accounting order to establish a regulatory asset upon the retirement of the Roxboro Wastewater Treatment Plant in which to defer the unrecovered remaining net book value of the plant and costs related to obsolete inventory, net of salvage was approved in the Commission's Order in DEP's last general rate case proceeding in Docket No. E-2, Sub 1219 (the 2019 Rate Case).

23. Section III, Paragraph 24 of the Revenue Requirement Stipulation establishes an amortization period of 12 years for the recovery of the deferred balance associated with the Roxboro Wastewater Treatment Facility and that the unamortized balance will be included in rate base.

Storm Securitization Over Collections

24. Per DEP's Agreement and Stipulation of Partial Settlement with the Public Staff in Docket No. E-2, Sub 1262, DEP agreed to establish regulatory asset or regulatory liability accounts for the purpose of tracking up-front financing costs and servicing and administration fees related to storm securitization.

25. The amortization over three years of the regulatory liability for the over-recovered balance of $0.9 million for storm securitization over collections is just and reasonable.

Cost of Debt

26. The embedded cost of debt of 4.03% as set forth in Section III, Paragraph 1 of the Revenue Requirement Stipulation is reasonable and appropriate for use by DEP in this case.

Accounting Adjustments

27. The accounting adjustments set forth in the Revenue Requirement Stipulation, as further described in detail in Jiggetts Partial Settlement Exhibit 2 and the Public Staff Accounting Supplemental and Settlement Exhibit 1, Schedule 1, are the reasonable product of give-and-take negotiations among the parties.

28**.** The accounting adjustments set forth in the Supplemental Revenue Requirement Stipulation, as further described in detail in Supplemental Revenue Requirement Stipulation Exhibit 1, are the reasonable product of give-and-take negotiations between the stipulating parties.

MYRP Capital Investments

29. DEP's proposed MYRP capital investments, reflecting the projected costs associated with the transmission, distribution, fossil/hydro, nuclear, cybersecurity, solar, and storage capital investments, as adjusted in the Revenue Requirement Stipulation, are just and reasonable to all parties in light of the evidence the parties presented, consistent with statutory and regulatory requirements, and appropriate for approval as part of DEP's overall Application in this proceeding.

Reporting Requirements

30. Section IV of the Revenue Requirement Stipulation establishes several reporting obligations of DEP.

Storm Normalization

31. The adjustment to DEP's revenue requirement, calculated using the method approved by the Commission in Docket Nos. E-2, Sub 1023, E-2, Sub 1142, and E-2, Sub 1219 to account for anticipated storm expenses based upon a 10-year average of storm costs after removing costs associated with major storms, is approximately $22.243 million.

DSDR

32. DEP has requested approval to recover the future costs associated with its Distribution System Demand Response (DSDR) energy efficiency program through base rates in lieu of the Demand-Side Management/Energy Efficiency (DSM/EE) rider, beginning with the rates established in this proceeding.

Payment Navigator

33. DEP has requested approval for its Payment Navigator program, which is designed to provide support to customers in need of assistance with managing payment of their electric bills, and the request is reasonable.

Customer Connect

34. DEP has proposed to recover approximately $60 million associated with the implementation of the Customer Connect platform, which is DEP's customer engagement platform, and the Customer Information System (CIS).

COSS Stipulation

35. The COSS Stipulation between DEP, DEC, CIGFUR, and the Public Staff, requires DEP to allocate production demand and transmission demand costs by using the 12 CP allocation method for jurisdictional allocations and the Modified A&E method among North Carolina retail customer classes.

Transmission Cost Allocation Stipulation

36. The TCA Stipulation establishes a pro forma adjustment to increase the revenue requirement for DEC in the DEC Rate Case by approximately $20 million on a North Carolina retail basis as well as a corresponding decrease to the revenue requirement for DEP in the instant proceeding.

PIMs Stipulation

37. On May 1, 2023, DEP, the Public Staff, and CIGFUR filed the PIMs Stipulation.

38. The PIMs Stipulation consists of the following three PIMs: Time Differentiated and Dynamic Rate Enrollment PIM, Reliability PIM, and the Renewables Integration and Encouragement PIM (consisting of Metrics A, B, and C) (collectively, the Settled PIMs). The PIMs Stipulation also provides for three tracking metrics – customer service, beneficial electrification from incremental load of EVs, and reporting and analyzing the 10 worst performing circuits (collectively, the Settled Tracking Metrics) – and provides a process for DEP to work with the Public Staff to develop tariffs and programs to estimate and update revenue associated with EV sales.

Power Quality Stipulation

39. DEP and CIGFUR filed the Power Quality Stipulation, which has the objective of enabling DEP to analyze power quality issues.

Affordability Stipulation

40. On May 4, 2023, DEP, DEC, Sierra Club, NCJC, et al., and the Public Staff filed the Affordability Stipulation, pursuant to which DEP and DEC agreed to make shareholder financial contributions totaling $16 million over three years to benefit eligible customers.

41. The Affordability Stipulation supports the Customer Assistance Program (CAP) and the corresponding tariffs associated with the CAP.

Rate Design

42. The objective of DEP's proposed rate design is to recover the revenue requirement while aligning the cost to serve customers within the customer classes and reflecting the costs a customer causes DEP to incur. DEP's proposed rate design allocates the revenue increase between customer classes by rate base amounts.

43. DEP's rate design involves adjustments that are intended to achieve DEP's rate design objective, including a subsidy reduction, a customer migration adjustment, and customer growth and weather normalization adjustments.

44. DEP proposes changes to residential rate schedules, the small general service (SGS) rate schedules, the medium general service (MGS) rate schedules, the large general service (LGS) rate schedules, the seasonal and intermittent rate schedules, the lighting rate schedules, and the traffic signal rate schedules.

45. DEP proposes changes to its service riders, which are offered to reflect the cost of meeting unique or special customer requirements.

46. DEP proposes updated and aligned TOU periods across its rate schedules that include time-differentiated pricing for residential and non-residential customers.

47. The MGS Partial Rate Design Stipulation, entered into by DEP, the Commercial Group, and Kroger Co. and Harris Teeter, provides that 75.0% of the reduction in revenue requirement, as determined by final Commission order, applicable to rate schedule MGS-TOU should be applied to energy rates.

48. LGS Partial Rate Design Stipulation, entered into by and between DEP and CIGFUR, provides that any increase in energy charges resulting from an increase in DEP's revenue requirement, which to be recovered from the LGS, LGS-TOU, and LGS-Real Time Pricing (RTP) rate schedules, as determined by final Commission order, shall be limited to a percentage that is less than half of the approved overall increase percentage to the LGS, LGS-TOU, and LGS-RTP classes, respectively, exclusive of any decrements for the LGS, LGS-TOU, and LGS-RTP rate schedules.

Capital Structure, Cost of Equity and Overall Rate of Return

49. DEP proposed a rate of return on common equity of 10.4%, with a capital structure consisting of 53.0% common equity and 47.0% debt.

50. The overall rate of return and rate of return on common equity must be supported by competent, material, and substantial record evidence; consistent with the requirements of N.C.G.S. § 62-133 considering changing economic conditions; and must balance DEP's need to maintain the safety, adequacy, and reliability of its service with the benefits to DEP's customers to receive from safe, adequate, and reliable electric service.

51. Ultimately, the capital structure, rate of return on common equity, and overall rate of return set by this Order must result in just and reasonable rates.

COVID Deferral Recovery

52. The Commission's December 21, 2021 Order in Docket No. E-2, Sub 1253 (Deferral Order) approved DEP's request to create a regulatory asset into which to defer incremental COVID-19 pandemic-related costs.

53. In this proceeding, DEP seeks to recover the deferred balance, including accrued carrying costs, of approximately $107 million related to: (1) customer fees waived; (2) bad debt charge-offs; (3) employee stipends to cover unplanned expenses associated with the COVID pandemic; (4) costs related to employee safety; (5) costs related to remote work; and (6) miscellaneous costs, such as employee overtime.

54. DEP identified and calculated two categories of COVID-related savings in the amount of approximately $4.5 million on a North Carolina retail basis related to: (1) reduced printing and postage costs due to the moratorium on customer disconnections; and (2) reduced travel expenses. DEP benefited from certain measures taken by the federal government to assist employers during the pandemic, including federal employee retention credits (ERCs) and the delay of payment obligation of the employer portion of social security tax.

55. DEP seeks to recover the deferred balance over a three-year period.

56. DEP requests to continue the deferral of the incremental bad debt, for future recovery.

Inflation Adjustment

57. DEP's calculation of the increase in Non-Labor and Non-Fuel Operating and Maintenance (O&M) costs due to the effect of inflation relies on the same method proposed and approved by the Commission in DEP's last three general rate cases.

Rate Case Expense

58. DEP proposes to recover additional rate case expense leftover from the 2019 Rate Case in this proceeding.

59. DEP proposes to recover rate case expenses, incurred in this proceeding over a three-year period.

60. DEP proposes to include the unamortized balance of rate case expense in rate base.

Over-Amortizations

61. DEP's approach to over-amortization of Commission-approved regulatory assets is to apply the amount of over-amortization for recovery of like kind expenses.

Storm Balancing Account and Winter Storm Izzy

62. DEP requested deferral of approximately $15 million in O&M costs associated with system restoration necessitated by Winter Storm Izzy, which occurred in January 2022.

63. DEP spent $87.126 million on a North Carolina retail jurisdictional basis in 2022 on annual storm costs (inclusive of both Winter Storm Izzy and Hurricane Ian, among other storms), which is beyond the normal range of fluctuation of storm costs of $27.4 million.

64. DEP and the Public Staff agree on the amount of $15 million of O&M costs to be recovered for Winter Storm Izzy but do not agree on the method of recovery.

65. DEP proposes to recover 2022 incremental Winter Storm Izzy costs by applying a portion of the $17 million over-amortization of Hurricane Matthew costs from the DEP's general rate case proceeding from 2017 in Docket No. E-2, Sub 1142 (the 2017 Rate Case).

66. DEP proposes to create a storm balancing account that would, in essence, operate as a rider or tracker. DEP proposes to use the remaining amount of over-amortization of Hurricane Matthew costs, approximately $2 million, to establish the storm balancing account.

Other Deferrals

67. DEP requests to defer the estimated tax benefits, net of costs, associated with the Inflation Reduction Act (IRA) and Infrastructure Investment Job Act (IIJA).

68. DEP has proposed three customer programs for approval by the Commission, the CAP, the Payment Navigator Program, and the Tariffed On-Bill Program.

69. DEP expects to incur incremental O&M costs related to the implementation of the CAP the Payment Navigator Program, and the Tariffed On-Bill Program, and implementation of the PIMs, including the required PIMs dashboard, and proposes to defer its incremental O&M costs associated with the implementation of the customer programs and PIMs.

Interconnection CIAC Regulatory Liability Recommendation

70. The Public Staff has identified an issue with respect to DEP's recording of contributions in aid of construction (CIAC) in the context of interconnection agreements (IA) between DEP and third party interconnection customers and proposed that a regulatory liability be established to record any instances in which DEP incorrectly recovered costs associated with interconnection agreements (IAs) from ratepayers.

Quality of Service

71. DEP and the Public Staff presented evidence as to the adequacy of electric service provided by DEP.

Tax-Related Items

72. DEP proposes revision to its previously approved North Carolina excess deferred income taxes (EDIT) rider (EDIT-4) to reflect additional amounts due to customers.

73. The levelized return rate should reflect a capital structure consisting of 47.0% long-term debt and 53.0% equity, a 4.03% embedded cost of debt, and a rate of return on equity of 9.8%.

Base Fuel and Fuel-Related Factors and Fuel Cost Allocation

74. DEP proposes to continue its use of the equal percentage fuel adjustment allocation methodology.

75. DEP proposes to allocate purchased power capacity costs to North Carolina retail and across North Carolina retail customer classes based on production demand.

Residential Decoupling Mechanism and Earnings Sharing Mechanism

76. DEP's PBR Application includes a residential decoupling mechanism, a rate-making mechanism intended to break the link between DEP's revenue and the level of consumption of electricity on a per customer basis by its residential customers, as required by N.C.G.S. § 62-133.16(c) and Commission Rule R1-17B.

77. DEP proposes as a component of the MYRP an ESM, an annual rate-making mechanism that shares surplus earnings between DEP and its customers over

the period of time covered by a MYRP, as required by N.C.G.S. § 62-133.16(c) and Commission Rule R1-17B.

Performance-Based Regulation

78. DEP filed its first PBR Application in accord with N.C.G.S. § 62-133.16 and with Commission Rule R1-17B.

Revenue Requirement

79. After giving effect to the portions of the stipulations approved herein and the Commission's decision on contested issues, the annual revenue requirement for DEP for Rate Years 1, 2, and 3 will allow DEP a reasonable opportunity to recover its operating costs and earn the overall rate of return on its rate base that the Commission has found just and reasonable upon consideration of the findings in this Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-10

The evidence supporting these findings of fact is contained in DEP's verified Application and Form E-1; the stipulations between DEP and the other parties; the testimony and exhibits of DEP witnesses Bowman, Abernathy, Hager, Bateman, Stillman, Barnes, Harris, Quick and Jiggetts; Public Staff witnesses Zhang, Boswell, McLawhorn, D. Williamson, Thomas, and Metz; CIGFUR witness Phillips; and the entire record in this proceeding.

Revenue Requirement Stipulation

On April 26, 2023, the Public Staff and DEP filed the Revenue Requirement Stipulation resolving a portion of the revenue requirement issues between the parties. On May 2, 2023, DEP and the Public Staff amended the stipulation to include CIGFUR as a party and resolve among themselves an additional issue pertaining to vegetation management.

Witness Bowman testified that the stipulation resolves most of the revenue requirement issues between DEP and the Public Staff. She stated that the parties fully resolved the recovery of capital projects and related costs to be included in DEP's MYRP. Tr. vol. 7, 53-54. Witness Bowman also testified that the parties reached agreement on the inclusion of plant in service and depreciation rates and agreed to revenue requirement adjustments for the following items: cost of debt; executive compensation; board of directors expenses; rent expenses; lobbying; sponsorships and donations; incentive compensation; reliability assurance operations and maintenance (O&M) spend; aviation expenses; non-residential credit card fees; end of life nuclear reserve; coal inventory; salaries and wages; gain on Harris land sales; production O&M; and the treatment of various deferrals DEP is requesting to recover. *Id.* She explained that the Revenue Requirement Stipulation shows these accounting and ratemaking adjustments and the resulting effect on the revenue requirement. Witness Bowman also testified to DEP's commitment to perform a lead-lag study before its next rate case application and agreement to various reporting obligations. *Id*. Witness Bowman further testified that the stipulation represents a balanced settlement between the stipulating parties on the settled issues, is in the public interest, and should be approved by the Commission. *Id.*

Public Staff witnesses McLawhorn, Metz, Zhang, and Boswell testified that, from the Public Staff's perspective, the most important benefits the stipulation provides are: (1) an aggregated reduction in DEP's proposed revenue increase resulting from the agreed-upon adjustments; and (2) the avoidance of protracted litigation between DEP and the Public Staff before the Commission and possibly the appellate courts on the settled issues and the associated increased rate case expense recovery from customers. Tr. vol. 16, 514; Tr. vol. 19, 87. Based on these ratepayer benefits, and other provisions of the stipulation, the Public Staff believes the stipulation is in the public interest and that the Commission should approve it. *Id.*

Sections III and IV of the Revenue Requirement Stipulation outline several accounting and ratemaking adjustments, as well as reporting obligations, to which DEP,

the Public Staff, and CIGFUR agree. The Commission fully discusses these agreed-upon issues later in this Order.

COSS Stipulation

On September 13, 2022, the COSS Stipulating Parties filed the COSS Stipulation with the Commission. Tr. vol. 11, 80. The COSS Stipulation provides that DEP will first allocate production and transmission demand costs to the North Carolina retail jurisdiction using the 12 CP method and then will allocate production demand costs among North Carolina retail customer classes using the Modified A&E method. *Id.* Because transmission demand does not have average or excess energy components, the transmission demand factors at the customer class level are equivalent to the 12 CP calculation. *Id.* The COSS Stipulation also provides that, for purposes of allocating production demand costs on a jurisdictional basis as well as to North Carolina retail rate classes, DEP will make an adjustment to exclude certain curtailable/interruptible loads if they were not curtailed at the twelve system peak hours during the test year. *Id.* The COSS Stipulation only applies in the current rate case, and the COSS Stipulating Parties are free to advocate for different methodologies in future DEP cases. *Id.* DEP witness Hager testified that the stipulation is reasonable and that the Commission should approve it, noting that it was the result of give-and-take negotiations of parties with diverse views on the appropriate methodologies reaching a settlement. *Id.* at 80-81.

TCA Stipulation

On April 27, 2023, DEP, DEC, and the Public Staff filed the TCA Stipulation. The TCA Stipulation sets forth the agreement of the parties thereto to a pro forma adjustment of approximately $20 million to increase the revenue requirement in the pending DEC Rate Case and to decrease the revenue requirement in the instant proceeding.

The TCA Stipulation calculates a pro forma amount of transmission expense for DEC and transmission revenue for DEP by multiplying the net transfers from DEP to DEC which occurred in 2022 pursuant to the joint dispatch agreement (JDA)[3]by the DEP non-firm transmission rate established in the FERC-approved Joint Open Access Transmission Tariff (OATT) of DEP, DEC, and Duke Energy Florida, LLC.[4] The stipulation also provides that the adjustment is for North Carolina ratemaking purposes only and will not change the terms or conditions of the JDA or result in any accounting entries for DEP or DEC. The TCA Stipulation provides that the adjustment will become effective on

[3] The JDA is the framework by which DEC and DEP manage and utilize their electric generation assets jointly to serve their respective retail customers with the most efficient generating plants available on a daily basis and was approved by the Commission as a part of the 2012 merger of DEP and DEC. Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, Docket Nos. E-7, Sub 986, and E-2, Sub 998, June 30, 2012.

[4] DEC OATT Transmission Rate Formula Template Using Form 1-Data Utilizing Cost Data for (Historic Years) with Year-End Average Balances Development of Revenue Requirement OATT, p. 3 of 7 (328 of 1170); DEP OATT Transmission Non-Levelized Rate Formula Template Using Form-1 Data Development of Revenue Requirement, p. 3 of 5 (510 of 1170).

October 31, 2023 for both DEP and DEC, and will terminate at the sooner of the effective date of rates in DEP's or DEC's next general rate case or the effective date of a full merger of DEP and DEC, unless the Commission orders otherwise.

DEP witness Bateman testified in support of the TCA Stipulation. Tr. vol 14, 146. She explained that the TCA Stipulation is the result of substantial discovery and extensive negotiation among the stipulating parties and that it reflects a constructive near-term approach to addressing rate disparity concerns arising from the increasing net transfers of energy from DEP to DEC under the JDA. *Id.* Public Staff witness Metz also testified in support of the TCA Stipulation. Tr. vol. 16, 517-18. Witness Metz testified that the TCA Stipulation addresses the growing level of net transfers and the subsequent rate disparity between DEP and DEC in North Carolina and explained that the adjustment will compensate DEP and DEC ratepayers for the use and annual maintenance of each utility's transmission system for energy transfers under the JDA. *Id.*

PIMs Stipulation

On May 1, 2023, the DEP, the Public Staff, and CIGFUR filed the PIMs Stipulation. The PIMS Stipulation reflects an agreement between the parties regarding certain of the PIMs, tracking metrics, and the electric vehicle (EV) adjustment to DEP's decoupling mechanism.

DEP's PBR Policy Panel provided testimony in support of the PIMs Stipulation. Tr. vol. 14, 131. The PBR Policy Panel testified that the resolution reached among the parties to the stipulation represents a balanced approach to achieving policy goals in DEP's first PBR Application. Tr. vol. 15, 17, 70. DEP witness Stillman testified that the settled PIMs originated from the North Carolina Energy Regulatory Process (NERP) PBR Working Group,[5] were informed by DEP's pre-filing PIM stakeholder process, and evolved over discussions among the parties in the instant proceeding. Tr. vol. 14, 132-33. DEP witness Bateman testified that the Commission must examine the PIMs in the context of the entire MYRP. Tr. vol. 15, 15. Witness Bateman testified that DEP took a conservative approach in this first PBR Application in order for DEP, customers, and the Commission to gain experience with the operation and implementation of PIMs. *Id.* at 69. DEP witness Stillman explained DEP's approach to designing the PIMs around the 1.0% cap set forth in N.C. Gen. Stat. § 62-133 and stated that DEP was deliberate in choosing to propose only a select number of PIMs that meet the maximum number of policy goals. *Id.* at 65.

Public Staff witnesses D. Williamson and Thomas provided testimony in support of the PIMs Stipulation. Tr. vol. 18, 424-25. Witnesses D. Williamson and Thomas testified that the PIMs Stipulation benefits ratepayers by providing improved compliance with N.C.G.S. § 62-133 and that each PIM in the stipulation appropriately targets a specific policy goal set forth in N.C.G.S. § 62-133. They further testified that the PIMs Stipulation

[5] The NERP was a stakeholder process to examine ways to align utility regulation with the 2019 Clean Energy Plan initiated by Governor Roy Cooper. Tr. vol. 14, 74.

will benefit ratepayers through improved operational efficiencies, cost savings, and reliability of electric service over the course of the MYRP. *Id*.

Power Quality Stipulation

On May 1, 2023, DEP and CIGFUR filed the Power Quality Stipulation. The Power Quality Stipulation provides that DEP and CIGFUR will work together to identify up to 13 industrial customer premises with DEP-owned transmission-to-distribution retail substations exclusively or primarily dedicated to the respective customer (Eligible Premises). Subject to a feasibility review, DEP will install power quality monitoring technology at each of the Eligible Premises and meet with the identified customer at least once annually to review the data from the power quality monitoring technology.

In his testimony supporting the Power Quality Stipulation, CIGFUR witness Nicholas Phillips stated that the stipulation will help ensure that DEP will satisfy the requirement to maintain or improve reliability as North Carolina implements the Carbon Plan. Tr. vol. 21, 495. He testified that the reliability risks posed by inverter-based resources are well-documented and that the Commission has recognized those risks. *Id*. at 496-97.

Witness Phillips explained in his testimony that the power quality pilot program would allow DEP to mitigate the reliability risks associated with inverter-based resources. *Id*. at 497-98. Specifically, he testified that it would allow DEP to: (1) proactively monitor power quality during implementation of the Carbon Plan; (2) gather and share data analytics with the Public Staff and the Commission; (3) determine whether power quality incidents are the result of an individual circuit or customer problem, or potentially part of a larger trend; (4) diagnose potential power quality issues and, pursuant to review, implement solutions to address any such issues; and (5) take a proactive approach to customer service and service quality. *Id.*

Regarding the cost of the pilot program, DEP witness Stillman testified on cross examination that the Power Quality Stipulation does not expressly limit the amount to be spent on the program. Tr. vol. 15, 76. He testified that the cost of installing the power quality monitoring technology would be approximately $10,000 to $25,000 per meter and that the total number of meters necessary for this pilot program is unknown. *Id.* at 75. He further testified that the cost of implementing solutions to any problems identified through the pilot program, as contemplated in the Power Quality Stipulation, will depend on the cause of the specific power quality issue for each premise. He added that the lessons learned from the pilot program will help the whole system, because the more meters that DEP installs, the more DEP will learn about the source of the power quality issues. In acknowledging that DEP intends to seek cost recovery on a cost-of-service basis, witness Stillman testified that the pilot program will help DEP better understand power quality issues, which, ultimately, will be to the benefit of all customers. Tr. vol. 21, 474-76.

Affordability Stipulation

On May 4, 2023, DEP, DEC, Sierra Club, NCJC, et al., and the Public Staff filed the Affordability Stipulation. The Affordability Stipulation obligates DEP to withdraw the affordability PIM proposed in this proceeding. In lieu of the affordability PIM, $16 million of shareholder funds will be dedicated over the next three years to address affordability concerns as follows: $10 million will be contributed to support health and safety repairs that would allow for energy efficiency and weatherization upgrades to homes; and $6 million will be contributed to the Share the Light Fund, which offers customers bill payment assistance. Tr. vol. 22, 99-100. In addition, the stipulation obligates DEP to collect and report annually, in Docket No. M-100, Sub 179, the monthly payments ratio, which is the number of residential payments remitted divided by the number of active residential accounts. Finally, the stipulation obligates DEP to establish its CAP as a three-year pilot program and convene a stakeholder engagement process to consider CAP data, metrics, and future CAP program features.

MGS Partial Rate Design Stipulation

On May 10, 2023, DEP, the Commercial Group, and Kroger Co. and Harris Teeter filed the MGS Partial Rate Design Stipulation, which resolves some of the issues in this proceeding among the parties. The MGS Partial Rate Design Stipulation provides that 75.0% of any reduction in revenue requirement, as determined by final Commission order, applicable to rate schedule MGS-time-of-use (TOU), should be applied to energy rates. The MGS Partial Rate Design Stipulation also obligates Kroger Co. and Harris Teeter to withdraw their proposal related to a multi-site aggregate commercial rate. Finally, the MGS Partial Rate Design Stipulation provides that Kroger Co. and Harris Teeter do not oppose the Revenue Requirement Stipulation or the PIMs Stipulation.

LGS Partial Rate Design

On June 7, 2023, DEP and CIGFUR filed the LGS Partial Rate Design Stipulation, which provides that any increase in energy charges resulting from any increase in DEP's revenue requirement to be recovered from the LGS, LGS-TOU, and LGS-Real Time Pricing (RTP) rate schedules, as determined by final Commission order, shall be limited to a percentage that is less than half of the approved overall increase percentage to the LGS, LGS-TOU, and LGS-RTP classes, respectively, exclusive of any decrements for the LGS, LGS-TOU, and LGS-RTP rate schedules. By its terms, the LGS Partial Rate Design Stipulation would apply to any customer currently taking service under an LGS, LGS-TOU, or LGS-RTP rate schedule who proceeds to take service under either the High Load Factor tariff or Hourly Pricing (HP) tariff, in the event the Commission approves such tariffs in this proceeding.

Supplemental Revenue Requirement Stipulation

On June 27, 2023, DEP and the Public Staff filed the Supplemental Revenue Requirement Stipulation which resolves issues related to the Public Staff audit of DEP's

third and final update. On that same date the Public Staff filed the joint supplemental testimony of witness Metz, Zhang, and Boswell in support of the stipulation. DEP also filed testimony in support of the stipulation.

Discussion and Conclusions

Because not all parties to this docket have adopted the stipulations outlined above, the standards set out by the North Carolina Supreme Court in *State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc.,* 348 N.C. 452, 500 S.E.2d 693 (1998) (*CUCA I*), and *State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc*., 351 N.C. 223, 524 S.E.2d 10 (200) (*CUCA II*) govern the Commission's acceptance of the stipulations. In *CUCA I,* the Supreme Court held that:

> [A] stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under Chapter 62 should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding. The Commission must consider the nonunanimous stipulation along with all the evidence presented and any other facts the Commission finds relevant to the fair and just determination of the proceeding. The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes "its own independent conclusion" supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented.

CUCA I, 348 N.C. at 466, 500 S.E.2d at 703.

However, as the Court made clear in *CUCA II*, the fact that not all parties have adopted a settlement does not permit the Court to subject the Commission's order adopting the provisions of a nonunanimous stipulation to a "heightened standard" of review. *CUCA II*, 351 N.C. at 231, 524 S.E.2d at 16. Rather, the Court said that Commission approval of the provisions of a nonunanimous stipulation.

> requires only that the Commission ma[k]e an independent determination supported by substantial evidence on the record [and] ... satisf[y] the requirements of chapter 62 by independently considering and analyzing all the evidence and any other facts relevant to a determination that the proposal is just and reasonable to all parties.

Id. at 231-32, 524 S.E.2d at 16.

The Commission concludes that the Revenue Requirement Stipulation, the COSS Stipulation, the TCA Stipulation, the PIMs Stipulation, the Power Quality Stipulation, the Affordability Stipulation, the MGS Partial Rate Design Stipulation, the LGS Partial Rate Design Stipulation, and the Supplemental Revenue Requirement Stipulation result from

the give-and-take negotiations between the stipulating parties and represent compromises that are fair and adequate to each party. The Commission has fully evaluated the provisions of these stipulations, the testimony proffered by parties in support of these stipulations cited above, the dearth of evidence in the record opposing any of these stipulations, and concludes, exercising its independent judgment, that it should accept in part and reject in part the provisions of the stipulations, consistent with the specific discussion and resolution of the issues set forth below.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-13

Depreciation

The evidence supporting these findings of fact is included in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Spanos and Jiggetts, Public Staff witnesses Zhang and Boswell, Lucas, and McCullar, FPWC witness Tomcyzk, and CIGFUR witness Gorman; and the entire record in this proceeding.

Spanos Direct Exhibit 1 to DEP witness Spanos's direct testimony is the 2021 DEP Depreciation Study prepared by Gannett Fleming (2021 Depreciation Study). Tr. Ex. vol. 10. Witness Spanos testified that the purpose of the 2021 Depreciation Study was to estimate the most current annual depreciation accruals related to electric plant in service for ratemaking purposes and to determine appropriate average service lives and net salvage percentages for each plant account. *Id.* at 352-53.

Section III, Paragraphs 2 and 3 of the Revenue Requirement Stipulation provides that DEP's depreciation rates will be set based on the rates in DEP's 2021 Depreciation Study, as adjusted in the stipulation. In conjunction with the use of DEP's proposed accelerated retirement dates for its Mayo and Roxboro Units 3 and 4, the Revenue Requirement Stipulation provides that 75.0% of the increased depreciation expense due to the accelerated retirement dates will be placed in a regulatory asset. *Id.* Section 5 of S.L. 2021-165 permits securitization for 50.0% of the remaining net book value of subcritical coal plants. The Revenue Retirement Stipulation further provides that at retirement, the net book value amounts that are not securitized will be recovered with a return over an amortization period that the Commission will determine in a future rate case. *Id.* In addition, the Revenue Requirement Stipulation sets forth the following specific adjustments to DEP's depreciation rates: (1) the amortization periods Public Staff witness McCullar proposes for General Plant FERC accounts 391 and 397 will be adopted; and (2) the 70-year life for Transmission FERC account 356 witness McCullar proposes will be adopted. *Id.*

Summary of Evidence

Retirement Dates for Coal Plants

DEP witness Spanos testified that life span estimates included in depreciation studies are based on informed judgment, incorporating factors for each facility such as facility technology, management plans and outlook for the facility, and estimates for similar facilities of other utilities. Tr. vol. 10, 358. Witness Spanos testified that he used these factors to evaluate DEP's recommended retirement dates and agreed that they were reasonable. *Id.* at 417. The 2021 Depreciation Study identified the following retirement dates for the Mayo and Roxboro units:

Unit	2021 Depreciation Study Retirement Dates
Mayo 1	December 31, 2028
Roxboro 1	December 31, 2028
Roxboro 2	December 31, 2028
Roxboro 3	December 31, 2027
Roxboro 4	December 31, 2027

As DEP witness Spanos testified, the Mayo and Roxboro lifespans are shorter than those identified in DEP's 2018 Depreciation Study, with Mayo Unit 1 having a change in retirement date from 2029 to 2028 and Roxboro Units 3 and 4 having a change in retirement date from 2029 to 2027. Tr. vol. 10, 359. The 2021 Depreciation Study indicates a life span for Mayo Unit 1 of 45 years, for Roxboro Unit 3 of 54 years, and for Roxboro Unit 4 of 47 years. *Id.* Witness Spanos testified that while the most common range of life spans for steam production facilities had been 55 to 65 years, these originally proposed life spans have been shortened in recent years due to unit efficiencies and environmental regulations. *Id.* He also testified that the industry average of similar units in recent years has been 46 years. *Id.*

In connection with these retirement dates, DEP witness Jiggetts testified that DEP was requesting permission to defer to a regulatory asset 50.0% of the impact of the accelerated depreciation of DEP's coal plants for North Carolina retail customers in order to preserve the ability to recover those costs through securitization as S.L. 2021-165 authorizes. Tr. vol. 13, 208. Jiggetts testified that because the accelerated dates reflected in the 2021 Depreciation Study would reduce the net book value of the plants at retirement and because DEP wants customers to benefit from any savings that securitization could provide, upon retirement of the facilities DEP proposes to defer to a regulatory asset 50.0% of the remaining net book value. *Id.* Witness Jiggetts testified that this approach preserves for securitization the level of net book value that would have resulted had the expected retirement dates not been updated in the 2021 Depreciation Study. *Id.* DEP also seeks permission to defer to this regulatory asset any costs related to obsolete inventory, net of salvage, at the time of retirement. *Id.* at 208-09.

Public Staff witnesses Lucas and McCullar both addressed the coal plant retirements and life spans in their testimony. In his direct testimony, witness Lucas

recommended the use of the retirement dates DEP provided in its 2014 and 2016 Integrated Resource Plans filed in Docket Nos. E-100, Sub 141 and 147, respectively. Tr. vol. 20, 38.

Witness Lucas testified that his recommended retirement dates differ solely for calculating rates in the rate case, not for planning purposes. *Id.* He does not dispute the physical retirement dates that the Commission's Carbon Plan Order established, rather, he testified that issues of reliability and cost inform his recommendations. *Id.* at 38-39; Order Adopting Initial Carbon Plan and Providing Direction for Future Planning (Carbon Plan Order), *Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan*, No. E-100, Sub 179 (Dec. 30, 2022). Witness Lucas testified that if DEP can accelerate depreciation before retirement, customers will not only pay more in the near-term but also that the plants will have less value to securitize in the long-term, thereby muting the benefit of securitization to ratepayers. *Id.* at 39. He testified that because Session Law 2021-165 and Commission Rule R8-74 allow securitization of remaining plant value, the financial benefit of potentially delaying the retirement of either Mayo or Roxboro should not accrue solely to DEP. *Id.*

Witness Lucas further testified that DEP has a plan to replace Roxboro's capacity with hydrogen-enabled combustion turbines and combined-cycle capacity, but it has not fully developed this plan. *Id.* He also testified that DEP has not indicated its plans for replacing general capacity for the Mayo plant. *Id.* Witness Lucas stated that if DEP retires either Mayo or Roxboro before its recommended date, DEP should securitize 50.0% or more of the remaining book value while continuing to depreciate any amount not securitized. *Id.*

Witness McCullar proposed depreciation rates based on the final retirement years provided by witness Lucas. Tr. vol. 21, 138.

FPWC witness Tomcyzk recommended final retirement dates for certain coal units that are later than dates proposed by DEP and recommended that the Commission reject DEP's request to defer 50.0% of the incremental increase in the depreciation expense because implementation of FPWC's revised retirement dates renders the deferral unnecessary. Tr. vol. 21, 729, 734. FPWC's recommended retirement dates would make DEP's request to defer 50.0% of the incremental depreciation unnecessary. *Id.* Witness Tomcyzk stated that, should the Commission approve DEP's retirement dates or otherwise accelerate retirement, then all of the resulting incremental depreciation expenses should be deferred to a regulatory asset. *Id.* at 734-35.

CIGFUR witness Gorman recommended that the Commission reject DEP's proposal to recover the 50.0% of non-deferred accelerated depreciation expenses associated with Mayo Unit 1 and Roxboro Units 3 and 4 through its base rates. Tr. vol. 21, 436. Witness Gorman testified that accelerating the retirement of these units may not be feasible and recommended that the Commission not allow DEP to include costs for such early retirement in its cost of service. *Id.* at 434.

In rebuttal, DEP witness Spanos testified that the retirement dates for the Mayo and Roxboro plants are consistent with informed judgment based on each unit and the expectation within the industry. Tr. vol. 10, 358-59. He testified that many other coal plants either have been or are planned to be retired with lifespans of around 40-45 years and that the proposed lifespans of DEP's plants are consistent with those of other utilities. Tr. vol. 10, 373. DEP witness Jiggetts testified that the retirement dates Public Staff witness Lucas proposed are from DEP's 2013 Depreciation Study and that it is inappropriate to use dates from a 2013 Depreciation Study that is almost 10 years old. Tr. vol. 23, 91. Further, in response to Public Staff witness Lucas' recommendation that DEP securitize 50.0% or more of the remaining book value while continuing to depreciate any amount not securitized, DEP witness Jiggetts responded that S.L. 2021-165 only permits securitization for 50.0% of the remaining net book value for subcritical coal plants and, therefore, that it is only appropriate to apply this proposed ratemaking treatment to 50.0% of the plant balances. *Id.*

In response to Public Staff witness Lucas' proposal to change coal plant retirement dates "for ratemaking purposes only," DEP witness Jiggetts testified that DEP is aligned with this proposal in principle, but not in methodology. *Id.* at 90. DEP witness Jiggetts testified that the depreciation rates should be set based on the actual planned retirement dates, and then deferrals and regulatory assets should be used for jurisdictionally specific ratemaking purposes. *Id.* Witness Jiggetts testified that the methodology is particularly important because securitization of the coal plant balances is only available for DEP's North Carolina retail jurisdiction and, therefore, the more appropriate way to accomplish the result that Public Staff witness Lucas supports is to use deferral and regulatory assets. *Id.* at 91.

Amortization Periods for General Plant FERC Accounts 391 and 397

Public Staff witness McCullar and FPWC witness Tomczyk both object to DEP's proposal to change the amortization period for General Plant FERC account 391, Office Furniture and Equipment, from 20 years to 15 years, and to change the amortization period for General Plant FERC account 397, Communication Equipment, from 20 years to 10 years. Tr. vol. 21, 142, 754. Both witnesses recommend the continued use of the currently approved 20-year amortization period for these accounts. *Id.* Public Staff witness McCullar noted that the Commission previously approved the continued use of 20-year amortization periods for accounts 391 and 397 in the 2019 Rate Case. Witness McCullar stated that DEP is proposing the same amortization periods for these accounts that it initially proposed in the 2019 Rate Case and others. She further stated that the 2021 Depreciation Study in this case did not provide any life data for either account. Tr. vol. 21, 142-43.

In response, DEP witness Spanos notes that the amortization period for these accounts are approved for DEC, and asserted that it is reasonable to use the same amortization periods currently approved for DEC, as those periods are more representative of the appropriate useful life. Tr. vol. 10, 397. He further testified that witness Tomczyk's rationale supporting her proposal to maintain the periods approved in

a prior case is insufficient and that an amortization period should reflect the most reasonable useful life of the actual assets in each account. *Id.*

70-year life for Transmission FERC Account 356

For Transmission FERC account 356, Overhead Conductors and Devices, DEP proposes a 65-year estimated average service life with an R2.5 survivor curve. In contrast, Public Staff witness McCullar proposes a 70-year estimated average service life. Witness McCullar argued that the Public Staff's proposal is mathematically a better fit to the actual data and that her estimate included a review of historic observed life data provided in the 2021 Depreciation Study, the relevant information DEP provided in response to discovery, and her previous experience. *Id.* at 147-48.

In response, DEP witness Spanos testified that the witnesses have taken different approaches in interpreting the relevant data, and that he disagrees with these approaches. Tr. vol. 10, 382. FPWC witness Tomczyk and Public Staff witness McCullar both stated that they considered other factors in the development of their life estimates, but they appear to support their estimates primarily with mathematical fitting results, which is one, but not the only, factor to consider when developing a life estimate. *Id.* at 386. DEP witness Spanos argued that the life estimates witnesses Tomczyk and McCullar propose omit any consideration of changes to the transmission system resulting from impacts of DEP's evolving generation fleet, produce overall life cycles that are longer than what is reflected in the historical data, and serve only to lengthen the proposed life of the assets and reduce depreciation expense. *Id.* Additionally, DEP witness Spanos testified that their estimates reflect an expectation that too high a percentage of the overhead conductors will remain reliable.

Other Depreciation Recommendations

Other Production FERC Account 343 and Transmission FERC Account 352 – Survivor Curves

FPWC witness Tomczyk recommends adjustments to the survivor curve applied to Other Production FERC account 343, Prime Movers, and Transmission FERC account 352, Structures and Improvements.

For Other Production FERC account 343 FPWC witness Tomczyk recommends the use of the L0-35 survivor curve, as opposed to the L0-30 survivor curve DEP witness Spanos proposes. Tr. vol. 21, 739. Witness Tomczyk testified that DEP did not provide a reason either in its 2021 Depreciation Study or in DEP witness Spanos' direct testimony as to why the actuarial data for this account was truncated at 39.5 years in the original and smooth survivor curve graphs in the 2021 Depreciation Study. When selecting her recommended survivor curve, witness Tomczyk testified that she considered the sum of the squared deviations (SSDs) for both truncated and full curves to be important. *Id.* at 741. Additionally, she considered the survivor curves other electric utilities use for this account and relied on her professional judgment. Based on her experience, the survivor curves other comparable utilities use typically have associated service lives that exceed

those that DEP recommends in this case. *Id.* at 741-42. FPWC witness Tomczyk noted that the only supporting information DEP provided for its survivor curve for this account is that its statistical analyses resulted in "good to excellent indications" of the survivor patterns experience for this account. *Id.* at 742.

For Transmission FERC account 352, FPWC witness Tomczyk recommends the use of an R2.5-70 survivor curve, while DEP recommends an R2.5-65 survivor curve. She testified that, in response to data requests, DEP noted that it truncated actuarial data for this account at 56.5 years in the original and smooth survivor curve graph because assets exposed to retirement above 56.5 years are less significant when compared to the total assets exposed to retirement. Additionally, the retirement activity occurring at ages in excess of 56.5 years is not typical of retirement activity for assets of those ages. Witness Tomczyk generally noted that her proposed survivor curves had lower SSDs when not truncated. Additionally, she noted that FPWC requested, but DEP did not provide, any information that explained the rationale for DEP's recommended survivor curve. As with account 343, the only information DEP provided indicated that their statistical analyses resulted in what DEP characterized as "good to excellent indications" of the survivor patterns experienced for this account.

In rebuttal, DEP witness Spanos stated that the primary reason for differences between his estimates and FPWC's estimates for survivor curves is that the parties interpreted the data differently. For Other Production FERC account 343, he argued that FPWC witness Tomczyk appears to base her proposed estimate solely on "mathematical curve matching," whereas he used a method of "visual curve matching." He also stated that FPWC witness Tomczyk's proposed survivor curve for account 343 appears to ignore the most significant portion of the historical data, and instead focuses on assets that have been in service for 35 years or more. These assets represent less than half of the assets exposed to retirement during the overall band of experience and are ones that are less indicative of asset lives into the future. Witness Spanos testified that this is inappropriate when considering an interim survivor curve and that the narrow mathematical curve matching approach is not reasonable. In regard to Transmission FERC account 352, witness Spanos testified that a review of witness Tomczyk's mathematical approach for this account shows that she was focusing her proposed, elongated survivor curve on a period reflecting nominal retirement experience and that this is not consistent with the future expectations of retirement activity in this account. Tr. vol. 10, 391. Witness Spanos explained during his cross-examination that the job of an analyst doing life estimation is not to match what has happened in the past, but rather to predict what is happening going forward. *Id.* at 462-63. Witness Spanos testified that a focus on mathematical matching can only match what has occurred in the past, which is only a part of the necessary overall analysis. *Id.* at 463.

Transmission FERC Account 353 – Net Salvage Rate

FPWC witness Tomczyk recommends that the Commission use a net salvage rate of negative 10.0%, as opposed to DEP's proposed net salvage rate of negative 15.0%. Tr. vol. 21, 750. In support of this recommendation, she noted that for the period 1979

through 2021, net salvage averaged 9.0% and that the most recent five-year average is negative 10.0%. *Id.* She also noted that, after reviewing net salvage statistics, the swings in the more recent three-year moving averages for account 353 were much less significant than for most other transmission accounts. *Id.* at 751. She testified that, based on her recent experience, net salvage rates for account 353 most often are in the negative 10.0% to negative 15.0% range. *Id.*

In rebuttal, DEP witness Spanos testified that, although the numbers FPWC witness Tomczyk cited from the 2021 Depreciation Study are correct, she ignored the fact that two of the last five years (2019 and 2021) reflect very low, anomalous cost of removal activity, which DEP should consider when developing a net salvage estimate. Tr. vol. 10, 391. During recent years, annual retirements have been increasing. *Id.* However, in 2019 and 2021, the recorded cost of removal was extremely low related to the retirements. *Id.* Given this nominal cost of removal activity in 2019 and 2021, DEP gave these years less weight than prior years. *Id.* at 391-92. Therefore, given the lag in recording cost of removal to the associated retirements and the increase in the industry for removal cost for substation equipment, witness Spanos argued that the negative 15.0% net salvage estimate is a more reasonable representation of net salvage for future retirements. *Id.* at 392.

Revenue Requirement Stipulation

Sections III, Paragraphs 2 and 3 of the Revenue Requirement Stipulation provide that DEP's depreciation rates will be set based on the rates in the 2021 Depreciation Study as adjusted in the stipulation. In conjunction with use of DEP's proposed accelerated retirement dates for its Mayo and Roxboro Units 3 and 4, the Revenue Requirement Stipulation provides that the 75.0% of the increased depreciation expense due to the accelerated retirement dates will be placed in a regulatory asset. *Id.* S.L. 2021-165 permits the securitization for 50.0% of the remaining net book value for subcritical coal plants. The Revenue Retirement Stipulation further provides that at retirement the net book value amounts that are not securitized will be recovered with a return over an amortization period that the Commission will determine in a future rate case. *Id.* The Revenue Requirement Stipulation sets forth the following specific adjustments to DEP's depreciation rates: (1) the amortization periods proposed by Public Staff witness McCullar for General Plant FERC accounts 391 and 397 will be adopted; and (2) the 70-year life for Transmission FERC account 356 proposed by witness McCullar will be adopted. *Id.*

Discussion and Conclusions

Retirement Dates for Coal Plants

Based on the Revenue Requirement Stipulation and the entire record in this proceeding, the Commission concludes that it is appropriate to depreciate Mayo Unit 1 and Roxboro Units 1-4 based on the accelerated retirement dates proposed by DEP. Section III, Paragraph 2 of the Revenue Requirement Stipulation provides that DEP's proposed retirement dates for its coal plants will be used to set depreciation rates. Witness Spanos testified that he performed a thorough analysis of the life spans for Mayo

Unit 1 and Roxboro Units 1-4 using accepted depreciation methods. His analysis specifically considered factors for each facility such as facility technology, management plans and outlook for the facility, and the estimates for similar facilities for other utilities. As witness Spanos testified on cross-examination, he made site visits, had discussions with operational personnel at each plant site, and took the necessary steps to understand the expectations for the assets and how things may change functionally for various reasons. Tr. vol. 10, 405. Witness Spanos has reviewed DEP's facilities in developing his depreciation studies over numerous years and has a great deal of experience with the specific facilities at issue in this proceeding, as well as steam plants across the country. Furthermore, the life spans DEP proposes for Mayo and Roxboro are consistent with the 45-to-50-year life spans that are occurring across the industry as more utilities transition away from coal burning generation facilities.

The Commission is not persuaded by FPWC witness Tomczyk's assertion regarding the level of uncertainty regarding the retirement dates of Mayo and Roxboro. The Commission notes that the asset retirement dates are established by the Commission in the integrated resource planning process and the retirement dates for Mayo Unit 1 and Roxboro Units 1-4 were addressed in the Carbon Plan Order. The Commission determines that the agreement encapsulated in the Revenue Requirement Stipulation, which addresses DEP's plans for Mayo Unit 1 and Roxboro Units 1-4 using the accelerated retirement dates while also accomplishing the type of rate mitigation that witness Lucas proposed strikes a reasonable balance. The Commission further determines that the provision in the Revenue Requirement Stipulation to increase the proposed deferral to a regulatory asset from 50.0% to 75.0% of the incremental depreciation expense that results from the accelerated retirement is reasonable and appropriate. As provided under the Revenue Requirement Stipulation, DEP will recover 50.0% of net book value through securitization and will recover the remaining amount, with a return, over an amortization period to be determined in a future rate case.

Amortization Periods for Plant FERC Accounts 391 and 397, and 70-year life for Transmission FERC Account 356

Based upon the evidence Public Staff witness McCullar presented, the Commission finds that the settled-upon amortization periods for General Plant FERC accounts 391 and 397 and the 70-year life for Transmission FERC account 356, as outlined in the Revenue Requirement Stipulation, are just and reasonable and appropriate for use in this case.

Other Production FERC Account 343 and Plant FERC Account 352 – Survivor Curves

Based on the entirety of the record the Commission concludes that the survivor curves proposed by DEP in this proceeding are just and reasonable and appropriate for use in this case.

Transmission FERC Account 353 – Net Salvage Rate

Based on all the evidence presented, the Commission concludes that it should not adopt FPWC witness Tomczyk's Transmission FERC account 353 proposal. In particular, the facts that annual retirements have been increasing in recent years, and that DEP reduced the weight afforded to removal activity in 2019 and 2021, weigh in favor of DEP's proposed net salvage rate. Accordingly, the Commission concludes that the proposed net salvage rate of negative 15.0% is just and reasonable and appropriate for use in this case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

Base Period Plant-Related Items

The evidence supporting this finding of fact appears in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Turner, Jiggetts, Guyton, Maley, and Ray, and Public Staff witnesses Metz, Thomas, Michna, and T. Williamson, the joint settlement testimony of Public Staff witnesses Metz and McLawhorn, and the joint testimony of Public Staff witnesses Boswell and Zhang; the Revenue Requirement Stipulation; and the entire record in this proceeding.

Summary of Evidence

Generation Capital Investments

DEP witness Turner described DEP's traditional/renewable/storage generation fleet and the operational performance of those assets during the test year. Tr. vol. 12, 91. Witness Turner testified as to the major capital projects undertaken by DEP for maintenance of its fossil, renewable, and storage fleets. *Id*. at 96. In testifying on the importance of the traditional fossil fleet to customers in North Carolina, she explained that the diversity of the resource and fuel mix, and availability of coal generation during the transition away from coal, must be strategically managed to ensure the remaining coal fleet can reliably contribute to resource adequacy. She testified that as DEP makes plans to retire its remaining coal fired assets, and replace those assets with other resources, DEP must keep these remaining units in efficient working order to support the energy needs of its customers. She explained that DEP will continue to make investment in these assets to ensure that the same reliable cost effective electricity that customers have counted on for decades remains available while the replacement of those units is developed and implemented. Additionally, she testified that the combination of generation resources that replaces coal must be able to provide the same level of reliability that the coal units have provided and that because natural gas is critical to the resource mix – particularly during the winter months and while energy storage capacity is being developed and deployed – DEP will continue to rely on its natural gas fleet as part of the diverse and dispatchable resource mix to ensure the reliability of service to DEP customers. Tr. vol. 12, 91-95. Witness Turner also testified regarding DEP's hydro fleet capital maintenance projects, which were undertaken primarily for regulatory compliance. She further testified as to DEP's addition of three battery installations, including the

Asheville/ Rockhill storage project, the Hot Springs Microgrid, and the Camp Lejeune project. *Id.* at 96-97. Finally, she testified as to her opinion that DEP has reasonably and prudently operated its fossil/hydro/solar fleet during the test period. *Id.* at 99-101.

DEP witness Ray described DEP's nuclear generation assets and capital additions made to the fleet since the 2019 Rate Case to enhance safety and efficiency preserve performance and reliability of the plants throughout their extended life operations, and address regulatory requirements. Tr. vol. 16, 154. Witness Ray described how these capital additions are or would be by the capital cutoff date used and useful in safely and efficiently providing reliable electric service to DEP's customers. Tr. vol. 16, 152-62. He testified about the exceptional performance of the nuclear fleet during the test period and initiatives that DEP has undertaken to increase nuclear operational efficiency. *Id.* at 168-70. He testified that, in comparison to others in the industry, DEP's nuclear fleet has a history of top performance, including a test period capacity factor of 94.94%, which exceeds the average capacity factor for comparable units published in the most recent North American Electric Reliability Council's (NERC) Generating Unit Statistical Brochure. *Id.* at 70.

Public Staff witnesses Metz, Thomas, and Michna reviewed aspects of DEP's capital investments in its traditional/renewable/storage generation fleet. Public Staff witness Metz described his review of DEP's historic costs associated with projects placed in service for the period June 2020 through November 2022, noting that his investigation included multiple site visits to DEP's fleet of generating stations and to an operations center, as well as numerous meetings with DEP personnel. Tr. vol. 16, 412. Witness Metz did not propose any adjustments to the base case capital investment costs for the fossil/hydro or nuclear fleets. Public Staff witness Thomas reviewed DEP's capital additions to solar, storage and hydro plant since the 2019 Rate Case and recommended an adjustment regarding the Blewett Falls Fishing Pier and the Hot Springs Microgrid. Tr. vol. 19, 172. Public Staff witness Michna reviewed DEP's capital additions for steam generation since the 2019 Rate Case and recommended an adjustment to the aqueous ammonia conversion project at Mayo Station (Mayo Ammonia Conversion Project). Tr. vol. 21, 285.

Blewett Falls Fishing Pier

Public Staff witness Thomas recommended that DEP remove the Blewett Falls fishing pier from the base case and include it in the MYRP Rate Year 1 based on his conclusion that, although DEP asserted that it placed the fishing pier in service in 2021, it is not yet complete or open for public use and will remain closed for safety reasons. Tr. vol. 19, 208-09.

DEP witness Turner testified that DEP placed the pier in service pursuant to DEP's capital accounting guidelines in January 2021, but that it is not currently open for public access due to ongoing construction of a fish passage facility directly next to the pier. Witness Turner asserts that public accessibility does not determine whether an asset is in service, and that Public Staff witness Thomas did not meaningfully challenge DEP's application of the accounting guidelines, which govern the in-service determination. Tr. vol. 12, 141.

In the Revenue Requirement Stipulation, DEP accepted the Public Staff's recommendation to move the fishing pier project and its associated costs out of the base case and into the MYRP Rate Year 1. Revenue Requirement Stipulation § II.33.a, Tr. Ex. vol. 7. DEP witnesses Abernathy and Jiggetts and Public Staff witnesses McLawhorn and Metz supported this provision in their settlement supporting testimony. Tr. vol. 13, 138-40, 254-55, 262; Tr. vol. 16, 514.

Mayo Ammonia Conversion Project

Public Staff witness Michna recommended an adjustment to remove $3,230,371 in costs for the Mayo Ammonia Conversion Project. Witness Michna recommended the adjustment based on his conclusion that DEP's decision to not update the cost benefit analysis for the project after significant delays to account for significant changes in cost and the projected station retirement date was not prudent. Tr. vol. 21, 295-97.

DEP witness Turner testified that DEP's development and execution of the project has been reasonable and prudent, emphasizing that the driving factor for the project was elimination of the safety risk to plant personnel that the existing ammonia system presents. Tr. vol. 12, 139-40.

As part of the Revenue Requirement Stipulation, DEP accepted the Public Staff's proposed adjustment related to the Mayo Ammonia Conversion Project. Revenue Requirement Stipulation § III.10, Tr. Ex. vol. 7. DEP witness Jiggetts and Public Staff witnesses McLawhorn and Metz supported this provision in their settlement supporting testimony. Tr. vol. 13, 254-55, 263; Tr. vol. 16, 514.

Hot Springs Microgrid

Public Staff witness Thomas recommends that the solar costs associated with the Hot Springs Microgrid be allocated 100.0% to the "Other Production Plant" account as opposed to DEP's proposed allocation of 50.0% to "Distribution Plant" and 50.0% to "Other Production Plant." Tr. vol. 19, 192. DEP accepted this recommendation in rebuttal testimony and agreed to make the corresponding accounting adjustment. Tr. vol. 11, 47. The Revenue Requirement Stipulation reflects this adjustment.

Transmission and Distribution Base Period Investments – Non-Grid Improvement Plan (GIP)

In their direct testimonies, DEP witnesses Guyton and Maley discussed DEP's distribution and transmission investments since its last general rate case. DEP Witness Guyton testified that DEP had invested approximately $814 million in new distribution infrastructure since DEP's last rate case, which included investments in DEP's GIP. Witness Guyton testified that non-GIP distribution investments during the base period included targeted reliability and maintenance programs, and customer driven line and substation expansions. Tr. vol. 10, 38. In his direct testimony, witness Maley testified that DEP had spent

approximately $390 million in additional transmission infrastructure since its last rate case, the bulk of which was for reliability and capacity improvements. Tr. vol. 10, 169-70.

In their direct testimonies, Public Staff witnesses Metz and T. Williamson took issue with some of the transmission and distribution capital investments made by DEP since its last case, as discussed in more detail below. Specifically, witness Metz took issue with the inclusion in rate base of capital associated with a newly refurbished transmission service building project (Project Florence), as well as the timing of inclusion in rate base of investments in a new Electric Systems Operation center (Project Walter). In addition, in his direct testimony, witness T. Williamson recommended a $712,867 disallowance for costs associated with contractor damage to a Wilmington voltage regulator platform.

Project Florence and Project Walter

Public Staff witness Metz described DEP's Project Florence to support maintenance and construction for transmission service projects in Florence, South Carolina. Project Florence included demolishing facilities at DEP's existing site to build a new consolidated single building to serve DEP's Carolinas East Southern Region. Tr. vol. 16, 416-18. In his direct testimony, Public Staff witness Metz recommended removal of the costs for Project Florence due to insufficient information from DEP to justify the project. *Id.* at 420.

Witness Metz also described DEP's Project Walter, a new energy control/operations center to operate DEP's bulk electric system and manage DEP's distribution system. Tr. vol. 16, 424. Based on his review of when the project would begin to serve its intended purpose, witness Metz recommended that DEP include the project in Rate Year 1 of the MYRP rather than in the base period. *Id.*

On rebuttal, DEP witness Guyton testified that Project Florence was prudent, and that the refurbishment of facilities was necessary to efficiently meet increased and growing demand on the transmission operations center in terms of personnel and equipment and that the pre-existing buildings were no longer sufficient to meet DEP's need. Tr. vol. 10, 139-40. On rebuttal, witness Guyton also asserted that Project Florence is currently used and useful as evidenced by the fact that construction is complete, local authorities have issued certificates of occupancy, and the building is in active use for certain functionalities, with the remaining functionalities to be working out of the building before rates are in effect in this proceeding. Tr. vol. 10, 135.

Section III, Paragraph 9 of the Revenue Requirement Stipulation provides that the Project Florence costs shall be included in rate base and the costs of Project Walter shall be moved into Rate Year 1 of the MYRP as recommended by Public Staff witness Metz.

Wilmington Voltage Regulator Platform

Public Staff witness T. Williamson described the Wilmington Voltage Regulator Platform project, which DEP undertook in order to provide additional clearance below the regulator platform DEP uses in its Distribution System Demand Response (DSDR)

project. Tr. vol. 21, 203-04. Witness T. Williamson recommends an adjustment due to equipment damage a contractor caused during this project. *Id.* at 205. In his rebuttal testimony, DEP witness Guyton challenged the amount of the Public Staff's disallowance for the Wilmington voltage regulator platform incident, on the grounds that witness T. Williamson did not allege that DEP had been negligent or responsible in any way for the contractor damage. Witness Guyton also asserted that any adjustment should only be for the incremental cost of the contractor damage ($267,282), rather than the entire cost of the project. Tr. vol. 10, 140.

Section III, Paragraph 7 of the Revenue Requirement Stipulation reduces the Wilmington voltage regulator costs as Public Staff witness Williamson recommended but with the further adjustment witness Guyton suggested in his rebuttal testimony.

Discussion and Conclusions

Based on the entire record in this proceeding, the Commission concludes that the costs related to DEP's investments in its fossil, renewable, storage, and nuclear fleet assets as well as its transmission and distribution investments made during the test period, as adjusted by the Revenue Requirement Stipulation, were reasonably and prudently incurred and should be recovered. The Commission further concludes that the adjustments for the Blewett Falls Fishing Pier, the Mayo Ammonia Conversion Project, and the Hot Springs Microgrid as the Public Staff and DEP agreed in the Revenue Requirement Stipulation are reasonable. Finally, the Commission concludes that the adjustments related to Project Walter, Project Florence, and the Wilmington Voltage Regulator Platform project, as included in the Revenue Requirement Stipulation are reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-17

Grid Improvement Plan Cost Recovery

The evidence supporting these findings of fact is included in the testimony and exhibits of DEP witnesses Guyton, Maley, and Jiggetts, Public Staff witnesses Zhang and Boswell, the Revenue Requirement Stipulation, and the entire record in this proceeding.

Summary of Evidence

DEP witness Maley testified that DEP's GIP is enabling new grid capabilities and that the System Intelligence program has begun deployment of dynamic, smart devices with the ability to remotely locate, sectionalize, and assess damage. Tr. vol. 10, 179. Witness Maley testified that the deployment of remote monitoring and control devices with digital relays supports rapid response to system outages and disturbances to quickly restore power to the maximum number of customers and to enable better management of distributed energy resources. *Id.* DEP installed approximately 350 relays and 9 remotely capable switches over the 19 months immediately preceding the date on which DEP filed the Application. In the period starting June 1, 2020, through December 31, 2021, DEP made North Carolina GIP transmission investments totaling $9.2 million. *Id.* at 179-80. Witness Maley testified that DEP

was on track to complete North Carolina GIP work scope in its three-year plan by December 31, 2022. *Id.* at 181.

DEP witness Guyton testified that DEP developed its GIP to build grid capabilities needed to address the implications of seven megatrends. These megatrends represent key trends that drive the need to prepare the grid to safely and efficiently distribute the energy which customers depend on in their daily lives. *Id.* at 56. Witness Guyton also testified about the operational benefits associated with the GIP work that DEP had completed as of the filing of the Application. He testified that the GIP projects, which reduce the frequency and impact of outages, are contributing to the improving trends for the System Average Interruption Index (SAIFI) and the System Average Interruption Duration Index (SAIDI). *Id.* at 50. He testified that, as an example, the Self Optimizing Grid program redesigns key portions of the distribution system, transforming it into a dynamic, smart-thinking grid that can automatically reroute power around trouble areas so that power can be quickly restored to the maximum number of customers and line crews can directly and rapidly be dispatched to the source of the outage. *Id.*

He testified that the GIP distribution investments and the North Carolina retail allocated portion of general and intangible plant investments through the December 31, 2021, test period totaled $52.6 million. *Id.* at 54.

DEP witness Jiggetts testified that in the 2019 Rate Case the Commission approved deferral of certain GIP-related costs for projects placed in service through December 31, 2022, until the costs could be considered for recovery in DEP's next general rate proceeding. Tr. vol. 13, 194-95. With respect to the specific costs that have been deferred, DEP witness Maley testified that DEP has deferred incremental O&M expenses, depreciation, and property taxes associated with the GIP, as well as the carrying cost on the investments and the deferred costs at DEP's weighted average cost of capital. Tr. vol. 10, 182. In her initial direct testimony DEP witness Jiggetts testified that by of the end of 2022, DEP will have placed in service investments of approximately $236.7 million on a North Carolina retail basis. She explained that DEP proposes to amortize the GIP regulatory asset of $38.8 million over a three-year period, which results in an amortization expense of $12.9 million. Tr. vol. 13, 195. In supplemental testimony, DEP witness Jiggetts updated the GIP-related costs to replace estimated data with actual amounts incurred through December 31, 2022, and to reflect a change in the capital cutoff date to March 31, 2023. [6] *Id.* at 224. Witness Maley testified that DEP proposes to roll these costs into base rates in the current rate case. Tr. vol. 10, 182.

While the Public Staff agreed with DEP's assertion that the Commission approved deferral accounting treatment for the GIP programs, the Public Staff took issue with DEP's calculation of the GIP deferral balance. Tr. vol. 19, 59-63. Specifically, Public Staff

[6] The total GIP investment made by DEP as of December 31, 2022, on a North Carolina retail basis is approximately $197 million as shown in the December 2022 NC GIP Biannual Report filed on March 1, 2023 in Docket Nos. E-7, Sub 1214B and E-2, Sub 1219B and Jiggetts Partial Settlement Exhibit 4.

witnesses Zhang and Boswell testified that DEP's inclusion of O&M expenses are outside of the allowable expenses envisioned by the Commission's approval in the 2019 Rate Case. Tr. vol. 19, 62-63. The Public Staff argued that the GIP deferral approved in the 2019 Rate Case is restricted to incremental expenses net of operating benefits. Therefore, the deferral does not include overhead or administrative and general costs but may include a reasonable allocation of management and supervision costs. *Id.* The Public Staff asserted that some of the O&M expenses included in the deferral were not incremental, that DEP had not determined the amount of any operating benefits, and that the O&M expenses included overhead and administrative and general costs. *Id.* As explained by DEP witness Jiggetts, the Public Staff proposed the following adjustments related to DEP's proposed recovery of the deferred GIP costs: 1) removal of $6 million in system O&M costs based on the contentions that DEP did not provide support for amounts after March 2022 and that certain of the costs did not meet the criteria for deferral based on 2019 Rate Case; and 2) an amortization period of 30 years.

DEP witness Guyton testified on rebuttal that the labor expense deferred for GIP projects was incremental to base labor included in rates since DEP had already reduced the deferral by the amount of installation O&M included in current rates. He asserted that the Public Staff's adjustment to remove O&M for GIP O&M-only projects is not reasonable, on the basis that incremental installation is correctly accounted for as O&M. Tr. vol. 10, 141. He also disputed the Public Staff's position on administrative and general costs and testified that such costs were appropriately included in allocation pools that are added to capital projects in accordance with DEP's accounting practices and cost allocation manual. *Id.* at 142. DEP witness Jiggetts also testified on rebuttal as to DEP's disagreement with the Public Staff's adjustment to remove O&M expenses, with the contention that certain expenses were not appropriately allocated to the GIP projects, and with the contention that 30 years is the appropriate amortization period. Tr. vol. 23, 67-70.

Section III, Paragraph 11 of the Revenue Requirement Stipulation provides that DEP is permitted to recover the full balance of its Grid Improvement Deferral over an 18-year amortization period, with a debt-only return during the deferral period and rate base treatment during the 18-year amortization period. No intervenor took issue with this provision of the stipulation. The costs associated with the GIP deferral, as settled upon by the Public Staff and DEP, results in a deferred balance on September 30, 2023, of $22.364 million, and annual amortization expense of $1.242 million, as set forth in DEP witness Jiggetts Partial Settlement Exhibit 4. Tr. Ex. vol. 14.

Discussion and Conclusions

The Commission concludes that the evidence presented supports the treatment of the deferred GIP-related costs as agreed to by DEP and the Public Staff in the Revenue Requirement Stipulation and that the treatment strikes a just and reasonable balance between recovery of costs and mitigation of impacts to customers and, thus, should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 18-19

Coal Ash

The evidence supporting these findings of fact is included in the Coal Combustion Residuals Settlement Agreement approved in the Commission's Order in the 2019 Rate Case, Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice, *Application by Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-2, Sub 1219 (Apr. 16, 2021) (CCR Settlement); DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Jiggetts and Hill, Public Staff witnesses Zhang and Boswell and Lucas, CIGFUR witness Gorman; and the entire record in this proceeding.

DEP witness Hill provided testimony as to DEP's activities to close ash basins and landfills along with other CCR management units for the period since DEP's last rate case. Tr. vol. 16, 86. Witness Hill testified that the actual and forecasted activities, as well as costs incurred, were reasonable and prudent. *Id.* Moreover, he testified that DEP implemented its plans in accordance with closure and corrective action plans that have been approved by the relevant state environmental agencies – in North Carolina, the Department of Environmental Quality, and in South Carolina, the Department of Health and Environmental Control. *Id.* He testified that DEP has also complied with its obligations under the CCR Settlement. DEP witness Jiggetts presented DEP's request to amortize deferred costs associated with the CCRs and to continue deferring costs related to compliance with coal ash regulations. Tr. vol. 13, 163. Witness Jiggetts testified as to the key components of the CCR Settlement and the associated adjustments made in this case to comply with the CCR Settlement, including the use of proceeds from insurance claims to offset CCR compliance costs. *Id.* at 191. She explained that the CCR costs sought for recovery are based upon actual costs incurred from March 1, 2020 through December 31, 2022, and updated amounts through March 31, 2023, provided in the supplemental filing made on April 18, 2023. *Id.*; Tr. vol. 23, 63. She testified that the cost, less the adjustments, totals approximately $647.8 million on a system basis and $399.3 million on a North Carolina retail basis. *Id.* She testified that DEP's adjustment amortizes the net deferred balance over a five-year period. *Id.* Witness Jiggetts also testified that DEP proposes to offset the over-amortization for the CCR costs established in the 2017 Rate Case in the amount of $8.5 million against the Coal Ash CCR ARO deferral DEP sought recovery of in this case. Witness Jiggetts testified that the balance sought for recovery in this case is being offset by North Carolina retail customer's share of insurance proceeds, calculated in accordance with the CCR Settlement terms, of $80.7 million. *Id.* at 193.

Public Staff witness Lucas investigated DEP's management of CCRs, construction and operation of DEP's CCR beneficiation projects, and proceeds from DEP's litigation of CCR insurance claims. Tr. vol. 20,15. After performing a thorough review, witness Lucas concluded that DEP's CCR management practices have been sufficient to prevent unnecessary costs to its customers, that DEP has complied with the coal ash beneficiation statute and the Commission's requirements, and that DEP's construction and operation of its two beneficiation projects since the last rate case have been sufficient to prevent unnecessary costs to customers. *Id.* at 20-25. Finally, witness Lucas found that DEP

properly credited North Carolina retail customers with proceeds from the insurance litigation. *Id.* at 26.

Public Staff witnesses Zhang and Boswell recommended that the Commission return all expiring amortizations to customers as a single rider over a period of one year with interest. Tr. vol. 19, 73.

CIGFUR witness Gorman recommended two revenue requirement adjustments to DEP's recovery of CCR compliance costs. Tr. vol. 21, 438-39.

The adjustments recommended by the Public Staff and CIGFUR regarding CCR costs were resolved in the Revenue Requirement Stipulation. While the Revenue Requirement Stipulation did not specifically address the CCR cost adjustments recommended by CIGFUR or the Public Staff, Section III of the stipulation provides that no further adjustments other than those specifically identified in the stipulation would be made to DEP's base period revenue requirement. In addition, Paragraph 7 of Section II of the Revenue Requirement Stipulation notes that the Public Staff's proposal to return expiring amortizations to customers in a single rider only applies to non-CCR over-amortizations. Tr. Ex. vol. 7.

Based on the entire record in this proceeding, including the testimony cited above as well as the relevant provisions of the Revenue Requirement Stipulation, the Commission concludes that the CCR costs sought for recovery are reasonable and prudent and consistent with the CCR Settlement. The Commission also concludes that DEP has complied with the CCR Settlement and has made the agreed-upon adjustments in this case to reflect that settlement. The Commission approves DEP's applying the over-amortization of CCR costs as established in the 2017 Rate Case in the amount of $8.5 million against the CCR deferred balance in this case, and the Commission approves the recovery of the net deferred balance over a five-year period. The Commission also approves DEP's request to continue the deferral of any CCR cost DEP incurs subsequent to March 31, 2023, for future recovery consistent with the CCR Settlement.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 20-21

Harris Land Sales

The evidence supporting these findings of fact is included in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witness Jiggetts and Public Staff witnesses Zhang and Boswell; the Revenue Requirement Stipulation; and the entire record in this proceeding.

The Commission required deferral of the gains on the sale of excess land at DEP's Harris nuclear plant in its August 13, 1992 Order in Docket Nos. E-2, Subs 537 and 333. In 2020 and 2021, DEP completed five sales transactions of excess land and deferred the North Carolina retail share of the gains on those transactions in compliance with the Commission's order. Tr. vol. 13, 195. DEP proposes to amortize those deferred gains over

a six-year period. *Id.* The Public Staff, however, proposed a four-year amortization period. Tr. vol. 19, 72. The Revenue Requirement Stipulation provides for a three-year amortization period. Revenue Requirement Stipulation § III.22, Tr. Ex. vol. 7. No intervenor took issue with this provision of the stipulation. The Commission concludes that the evidence supports the three-year amortization period the parties propose in the Revenue Requirement Stipulation, and that the three-year amortization period is just and reasonable and fair to all parties and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 22-23

Roxboro Wastewater Treatment Regulatory Asset

The evidence supporting these findings of fact is in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witness Jiggetts and the joint testimony and exhibits of Public Staff witnesses Zhang and Boswell; the Revenue Requirement Stipulation; and the entire record in this proceeding.

In the 2019 Rate Case, the Commission allowed DEP to establish a regulatory asset for the unrecovered costs associated with the Roxboro Wastewater Treatment Plant at the time of its early retirement. The Commission allowed amortization of the regulatory asset at the existing depreciation rate to continue until it determined an appropriate amortization period in a future rate case. DEP proposed to amortize the remaining regulatory asset over a five-year period. Tr. vol. 13, 189-90. Public Staff witnesses Zhang and Boswell recommended an amortization period of 11 years, consistent with the overall remaining depreciable life of the assets if they had remained in service. Tr. vol. 19, 71. The Revenue Requirement Stipulation, Section III, Paragraph 24, provides for a 12-year amortization period for the recovery of the Roxboro Wastewater Treatment Plant regulatory asset. Tr. Ex. vol. 7. The Commission concludes that the evidence presented supports the 12-year amortization period in the Revenue Requirement Stipulation, and that the 12-year amortization period is just and reasonable and fair to all parties and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 24-25

Revenue Requirement Stipulation – Storm Securitization Overcollections

The evidence supporting these findings of fact is in DEP's verified Application and Form E-1, the testimony and exhibits of DEP witness Jiggetts, and the entire record in this proceeding.

In the Agreement and Stipulation of Partial Settlement with the Public Staff filed in Docket No. E-2, Sub 1262, DEP agreed to establish regulatory asset or regulatory liability accounts for the purpose of tracking up-front financing costs and servicing and administration fees related to storm securitization. In the instant proceeding, DEP proposed to amortize the regulatory liability of $1.0 million for overcollections associated with storm securitizations over a three-year period. Tr. vol. 13, 202-03. The Public Staff

did not oppose this recovery timeframe. No intervenor took issue with this proposal. The Commission concludes that the evidence supports the three-year amortization period DEP proposes, and that the three-year amortization period is just and reasonable and fair to all parties and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 26

Cost of Debt

The evidence supporting this finding of fact is in DEP's verified Application and Form E-1, the testimony and exhibits of DEP witness Newlin, the Revenue Requirement Stipulation, and the entire record in this proceeding.

DEP witness Newlin testified that DEP's long-term debt cost as of December 31, 2021, was 3.71%, which was the value DEP used to determine the revenue requirement in DEP's Application. Tr. vol. 9, 97. Section III, Paragraph 1 of the Revenue Requirement Stipulation establishes that the embedded cost of debt as of March 31, 2023 shall be used to calculate DEP's revenue requirement. Tr. Ex. vol. 7. DEP witness Jiggetts presented in her supplemental testimony that the embedded cost of debt as of March 31, 2023, is 4.03%.

No intervenor offered any evidence opposing this provision of the stipulation. The Commission therefore concludes that the use of a debt cost of 4.03% per the terms of Section III, Paragraph 1 of the Revenue Requirement Stipulation is just and reasonable to all parties considering all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 27

Accounting Adjustments in Revenue Requirement Stipulation

The evidence supporting this finding of fact is included in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Council, Jiggetts, Quick, Speros, Stewart, Ray, and Turner, Public Staff witnesses Zhang and Boswell, McLawhorn, and Metz, and CIGFUR witness Gorman; the Revenue Requirement Stipulation; and the entire record in this proceeding.

Summary of Evidence

Incentive Compensation

In his direct testimony, DEP witness Stewart included as a cost of service incentive compensation at target levels that are assigned or allocated to DEP. Tr. vol. 16, 212. Public Staff witnesses Zhang and Boswell testified that incentive compensation related to the Earnings Per Share (EPS) and Total Shareholder Return (TSR) metrics for all employees should be removed from the revenue requirement because these metrics

provided a direct benefit to shareholders rather than ratepayers. Tr. vol. 19, 48-49. CIGFUR witness Gorman concurred with this assessment. Tr. vol. 21, 405.

In rebuttal, DEP witness Stewart refuted these contentions, asserting that metrics such as EPS and TSR are appropriate for recovery, as they benefit customers. Tr. vol. 23, 293-95.

The Revenue Requirement Stipulation establishes that DEP employee incentives should be adjusted to remove incentive pay related to EPS and TSR for the top levels of DEP's leadership, but not for the remainder of the employees. Revenue Requirement Stipulation § III.12, Tr. Ex. vol. 7. No intervenor took issue with this provision of the Revenue Requirement Stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Rent Expense

DEP witness Jiggetts' direct testimony included a pro forma adjustment to increase O&M expenses to reflect incremental rent expenses, net of savings, associated with the changes in the Charlotte real estate portfolio and the Duke Energy Plaza building. Tr. vol. 13, 187. Public Staff witnesses Zhang and Boswell removed the portion of rent expense related to the Duke Energy Plaza building because the building is still under construction and cannot be utilized for its intended purpose. Tr. vol. 19, 58. The Public Staff included additional amounts to bring the rent expense to a representative level by utilizing some 2021 costs and applying the updated DEBS allocation. In addition, the Public Staff expressed concerns about the real estate portfolio, considering the reduction in work force and DEP's new workforce model allowing employees to work a hybrid schedule, reducing the office facilities necessary at any given time. *Id.*

In rebuttal testimony, DEP witness Jiggetts testified that DEP does not agree with the Public Staff's adjustments to rent expense and that the rent expense as calculated by DEP reflects all known and measurable updates to the rent costs expected to be incurred by DEP. Tr. vol. 23, 76-77. In addition, she noted that DEP began incurring rent expense for the Duke Energy Plaza on January 1, 2023, and that DEP included a full year of expense for the building because, as explained in the rebuttal testimony of DEP witness Council, the detailed schedule for the building shows that all construction will be completed, and the building occupied by the effective date of the new rates in this proceeding. *Id.* at 77. Thus, she testified that the Duke Energy Plaza rent expense is a known and measurable and prudent and reasonable expense that will be incurred by DEP, which is a fact that the Public Staff had not challenged. *Id.* Further, she testified that because DEP is paying rent expense to DEC for the Duke Energy Plaza building, if the Duke Energy Plaza rent expense is removed from DEP's revenue requirement, the comparable adjustment to remove the rent income from DEC should be made to keep the revenue and costs between the affiliates aligned. *Id.* at 78. In her rebuttal testimony, DEP witness Council testified that the Duke Energy Plaza building is presently in use, with several floors currently occupied, and that the entire building is anticipated to be

completed and fully occupied by third quarter 2023, which is before the requested rates become effective in this case. *Id.* at 247.

The Revenue Requirement Stipulation, in Section III, Paragraph 13, provides for an increase in test year rent expense of $4,440,000 on a North Carolina retail basis for increased rent expense, net of depreciation savings. Tr. Ex. vol. 7. The parties further agreed to address the reasonableness and prudence of the costs of the Duke Energy Plaza in the DEC Rate Case in Docket No. E-7, Sub 1276. Tr. vol. 23, 78. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Reliability Assurance O&M Adjustment

In her direct testimony, DEP witness Turner testified regarding the importance of keeping DEP's remaining coal-fired assets in efficient working order to support customer's energy needs as DEP plans for those units' retirement and explained that DEP will continue to incur costs for these assets as appropriate and prudent to ensure that reliable cost-effective electricity remains available while DEP develops and implements replacement of the coal fleet. Witness Turner also testified that the fossil/hydro units operated efficiently and reliably during the test period. Tr. vol. 12, 94-95, 99.

In her supplemental testimony, witness Turner explained the rationale for DEP's pro forma adjustment to O&M expenses for reliability assurance. Witness Turner stated that the adjustment increased by $7.8 million the test period O&M costs related to planned reliability assurance projects. These additional projects are necessary to contribute to the reliability of plans for the Roxboro and Mayo plants and include winterization projects. Tr. vol. 12, 118.

Public Staff witness Metz testified regarding DEP's historic operations of its generating fleet since the 2019 Rate Case and other discrete performance metrics over the last decade. Part of his review considered the overall system reliability, service quality, and reasonableness of using DEP's test year O&M costs as a proxy for expected future costs. The primary purpose of the review was to determine whether and how DEP's historic operation of its generation fleet has changed. Witness Metz supported the use of the weighted equivalent availability factor (WEAF) or weighted equivalent unplanned outage factor (WEUOF), as well as other metrics, in reviewing fleet performance and noted that different conclusions are possible depending on the performance metrics one uses. He clarified that the intent of the review was not to determine reasonableness or prudence of DEP's historic operations of its fleets. Witness Metz concluded that the fossil fleet's performance has degraded over the last decade, and suggested that if that trend continues, reliability could be impacted, especially as these units must perform in a different manner than originally designed and as DEP removes other generation units from service. Witness Metz also noted DEP's reduction of fleet O&M expenses, which DEP accomplished in part by reducing staffing, in the years following its recent rate cases. Tr. vol. 16, 431-42, 447.

Witness Metz testified that there is merit to the proposed adjustment based on the coal unit availability and outage rates but also asserted that DEP reduced the level of ongoing generating plant non-fuel O&M expense the very next year after Commission approval in the last two general rate cases. Tr. vol. 16, 447. Based on the concerns he identified with O&M expenses and fleet performance, witness Metz recommended several modifications to the adjustment to coal test year O&M expenses (Form E-1, Item 10, NC-2160[7]):

- Since DEP should have already completed the Reliability Threat Analysis and Winterization O&M project work, witness Metz recommended exclusion of the costs related to Reliability Threat Analysis work from any proposed pro forma adjustment and supported the inclusion of a reduced amount for the Winterization O&M work. Tr. vol. 16, 449.

- Since the majority of the costs related to reliability improvements appeared to be capital-related rather than O&M related, witness Metz recommended inclusion of those costs in the MYRP and their exclusion from the pro forma adjustment. *Id.* at 450.

- Since there is no certainty that DEP will hire and continue to employ the proposed level of increased staff at the Roxboro and Mayo coal plants, witness Metz proposed decreasing by half DEP's 2023 staffing work request. *Id.*

- Witness Metz recommended that the Repair Hold category adjustment should be rejected because this category is an attempt to clear a backlog of a larger volume of inventory (spare parts) to be repaired. *Id.* at 449-51.

In her rebuttal testimony, DEP witness Turner described the challenge of optimizing plant investments and maintaining sufficient staffing for the coal-fired assets that DEP will retire in the near-term future. Mayo and Roxboro Stations will be the last DEP coal-fired stations DEP will retire, but DEP continues to need them to serve customers. Witness Turner explained that DEP must maintain the continued reliability of these units until replacement generation is in place. Witness Turner explained further that DEP's strategy for addressing this challenge has evolved as circumstances have changed. DEP seeks to allocate more investment to the fossil units that are the most efficient and economical, and therefore most often dispatched (as well as projected to be necessary over the long term), while still making prudent but measured investments in the coal units, balancing the need to maintain their reliability while looking forward to their eventual retirement. Tr. vol. 12, 121-22.

Witness Turner also responded to witness Metz's specific recommendations regarding the Reliability Assurance pro forma NC-2160 and provided additional details regarding this work. With respect to the major components/Reliability Threat Analysis work, she explained that DEP identified this work as necessary through the Reliability Threats

[7] Pro-forma NC-2160 was filed in DEP's February update.

Analysis that DEP conducted in late 2022 and that DEP intends the work to address large items of equipment DEP needs to maintain unit reliability. Witness Turner disagreed with witness Metz's recommendation to remove the costs for the major components/Reliability Threat Analysis work from the pro forma. She explained that the Reliability Threat Analysis is not winter storm related and that, therefore, DEP would not have done the work reflected in the pro forma item subsequent to previous winter storms. Tr. vol. 12, 124-25. Witness Turner testified that the winterization O&M project category represents work DEP identified as necessary in early 2023 following winter storm Elliott and includes the estimated cost of a study of needed repairs and installation of additional insulation, wind breaks, and updated heat trace systems to address freeze issues. Witness Turner stated that the operator workaround project category of reliability improvements represents a deeper level review of system health at the coal stations. The operator workaround project category typically addresses smaller items that can impact reliability, particularly when combined with other reliability issues. *Id.* at 127-29. Witness Turner testified that the staffing project category represents DEP's forward projection of costs, primarily salary, benefits, and overhead, to ensure that DEP has adequate resources to operate the coal units until retirement. *Id.* at 130-31. Witness Turner also testified that DEP identified the repair hold project category through the Reliability Threat Analysis and that it represents major components that do not have a readily available spare and have long lead times that supply chain challenges have exacerbated. *Id.* at 131-32.

Witness Turner also responded to witness Metz's testimony regarding fossil fleet performance and O&M investment, noting that it is important to view the entire fleet's performance and not focus solely on coal. Based on the equivalent forced outage factor (EFOF) metric, she stated that DEP's fossil fleet is performing consistent with or better than the industry average, and the natural gas units have exceeded industry average performance. Tr. vol. 12, 133-35. Witness Turner emphasized that the evaluation of fleet performance and reliability assurance needs has changed over time and will differ between coal units and natural gas units. She concluded that the Reliability Assurance pro forma represents the adjustments that DEP has identified as needed to maintain the coal units in reliable condition. *Id.* at 136-38.

The Revenue Requirement Stipulation provides for inclusion of an additional $6 million (North Carolina retail) of annual incremental spend for ongoing O&M for DEP's coal generation fleet for discrete programs and targeted categories that witness Turner lists in her supplemental and rebuttal testimony and for which she includes supporting workpapers. The parties agreed that DEP will track and report on an annual basis the actual spend and employee head count for each coal generation station over the MYRP period in a manner to be agreed upon between DEP and the Public Staff. DEP will record any cumulative underspend to a regulatory liability account accrued through the end of the MYRP period (September 2026) and return it to customers in the next general rate case. Revenue Requirement Stipulation § III.14, Tr. Ex. vol. 7. DEP witness Jiggetts and Public Staff witnesses McLawhorn and Metz supported this provision in their settlement supporting testimony. Tr. vol. 13, 254-56, 259; Tr. vol. 16, 513.

The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding. DEP has demonstrated that these funds are necessary to maintain the reliability of the coal units until their anticipated retirement. The Public Staff raised valid concerns regarding the performance of the DEP fossil fleet, specifically the coal units, and the Commission recognizes that reviews of performance can have different results depending on the metric the reviewer uses to evaluate it. DEP's tracking and annual reporting of the actual spend and employee head count for each coal generation station over the MYRP period will help to further inform this discussion as these units' retirements approach. The parties' agreement that DEP will record any cumulative underspend to a regulatory liability account accrued through the end of the MYRP period and return it to customers in the next general rate case addresses the concerns the Public Staff raised regarding O&M spending. In its first annual report, the Commission directs DEP to update the Commission on the agreed-upon specifics for the tracking and reporting of the actual spend and employee head count for each coal generation station.

Aviation Expense

In its initial filing, DEP removed 50.0% of corporate-related aviation expenses allocated to DEP in the test period that are not related to aerial patrol. DEP witness Jiggetts testified that DEP believes these costs were reasonable, prudent, and appropriate to recover from customers, but elected to remove them in this case. Tr. vol. 13, 184. Public Staff witnesses Zhang and Boswell recommended, in addition to the 50.0% already removed by DEP, removal from DEP's cost of service of additional flight costs that the Public Staff found to be unrelated to the provision of utility service, including portions of certain commercial international flights. Tr. vol. 19, 49.

The Revenue Requirement Stipulation removes aviation expenses associated with international flights, in addition to the 50.0% of aviation expenses removed in the Application. Revenue Requirement Stipulation § III.15, Tr. Ex. vol. 7. No intervenor took issue with this provision of the stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Executive Compensation

In its Application, DEP removed 50.0% of the compensation of the five Duke Energy executives with the highest level of compensation allocated to DEP. DEP witness Jiggetts explained that while DEP believes these costs are reasonable, prudent, and appropriate to recover from customers, DEP has, for purposes of this case, made an adjustment to this item. Tr. vol. 13, 181. Public Staff witnesses Zhang and Boswell recommended an additional adjustment to remove 50.0% of the benefits of these top five Duke Energy executives, noting that the adjustment was consistent with similar recommendations the Public Staff has made and the Commission has approved in past rate cases. Tr. vol. 19, 45-46.

Section III, Paragraph 16 of the Revenue Requirement Stipulation provides for removal of 50.0% of the benefits of the five Duke Energy executives with the highest amounts of compensation, in addition to the 50.0% of their compensation DEP removed in the Application. Tr. Ex. vol. 7. No intervenor took issue with this provision of the stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Charitable Contributions and Sponsorships

In his direct testimony, DEP witness Speros certified that DEP's cost of service does not include any expenditures for charitable contributions in accordance with the requirement of Commission Rule R12-13(a) as amended. Tr. vol. 13, 46. Witness Speros testified that Commission Rule R12-13(a) requires that in every application for a change in rates, a utility must certify in its prefiled testimony that its application does not include certain costs, including charitable contributions. *Id.* Witness Speros further explained that he performed additional reviews of DEP's cost of service to ensure that DEP did not include any costs that Commission Rule R12-13 prohibits in the Application. *Id.* at 47.

Public Staff witnesses Zhang and Boswell recommended an adjustment to charitable contributions of approximately $152,000 to exclude expense amounts paid to the Chambers of Commerce and other donations. Tr. vol. 19, 56; Tr. vol. 23, 59; the Public Staff Accounting Exhibit 1, Schedule 1, line 33, Tr. Ex. vol. 19. Witnesses Zhang and Boswell stated that these expenses should be disallowed because they do not represent actual costs of providing electric service to customers. Tr. vol. 19, 56.

In his rebuttal testimony, witness Speros explained that Chambers of Commerce promote business and economic development, which in turn helps to retain and attract customers to DEP's service territory. In addition, funds DEP paid to Chambers of Commerce that DEP does not specify as a donation or lobbying are in fact supporting business or economic development and DEP properly considers them utility operating expenses and includes them in DEP's cost of providing electric service to customers. Tr. vol. 13, 73.

The Revenue Requirement Stipulation establishes that no adjustment will be made to charitable contributions and sponsorships. Revenue Requirement Stipulation § III.17, Tr. Ex. vol. 7. No intervenor took issue with this provision of the stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Board of Directors Expense

With respect to Board of Directors expense, Public Staff witnesses Zhang and Boswell recommended an adjustment to remove 50.0% of the expenses associated with the Board of Directors of Duke Energy that had been allocated to DEP, similar to the Public Staff's recommendation regarding executive compensation and benefits of the five Duke Energy executives with the highest level of compensation allocated to DEP in the

test period. Tr. vol. 19, 47. In his response, DEP witness Stewart indicated that the law requires DEP to have a Board of Directors and that the costs of being an investor-owned utility, including Board costs, are in fact costs of service. Tr. vol. 23, 304. He argued that it is not fair or reasonable to penalize DEP for being an investor-owned utility with attendant requirements to that corporate structure. *Id.*

The Revenue Requirement Stipulation accepts the Public Staff's recommended adjustments to the Board of Directors' expenses. Revenue Requirement Stipulation § III.18, Tr. Ex. vol. 7. No intervenor took issue with this provision of the stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Lobbying Expense

In his direct testimony, DEP witness Speros certified that DEP's cost of service does not include any expenditures for lobbying, political or promotional advertising, political contributions, or charitable contributions in accordance with the requirement of Commission Rule R12-13(a) as amended. Tr. vol. 13, 47. Witness Speros further explained that he performed additional reviews of DEP's cost of service to ensure that DEP did not include costs that Commission Rule R12-13 prohibits in the Application. *Id.* With respect to lobbying expenses, Public Staff witnesses Zhang and Boswell adjusted O&M expenses to remove additional costs associated with Federal Government Affairs, Governmental Affairs and External Relations, and National Engagements that DEP recorded above the line in the test year. Witnesses Zhang and Boswell stated that Commission Rule R12-12 and the Commission's Order in Dominion Energy North Carolina's 2012 Rate Case (2012 DENC rate case) justify removal of these expenses. Tr. vol. 19, 50.

In rebuttal testimony, witness Speros stated that DEP disagrees that any adjustment to remove any additional cost from the cost of service under Commission Rule R12-12 or the Commission's decision in the 2012 DENC rate case is necessary. Tr. vol. 13, 63.

The Revenue Requirement Stipulation establishes that, while DEP maintains its position that its cost of service in this case did not include any lobbying expenses, for the purposes of settlement, DEP accepted the adjustments proposed by the Public Staff for lobbying expenses. Revenue Requirement Stipulation § III.19, Tr. Ex. vol. 7. No intervenor took issue with this provision of the stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Nuclear End-of-Life Reserve

Public Staff witness Metz recommended an $8 million disallowance of four-year Repair Hold and Quality Assurance (QA) Hold costs for nuclear inventory that has been on hold for four years or more. Tr. vol. 16, 427-28. He further recommended that a 5.0%

salvage value be applied to nuclear materials and supplies (M&S) inventory for purposes of calculating DEP's end of life nuclear reserve. *Id.* at 430.

In his rebuttal testimony, DEP witness Ray opposed witness Metz's recommendation of removal of $8 million from the end-of-life nuclear reserve, explaining that DEP holds this inventory to support plant operations and it is therefore beneficial to customers. Tr. vol. 23, 282. Witness Ray clarified that the fact that DEP maintains an item of M&S inventory in Repair Hold or QA Hold longer than four years does not mean that DEP will not ultimately use such inventory or have it available for use. *Id.* at 282-85. Regarding salvage value, witness Ray testified that if DEP receives approval of its requests for subsequent license renewal of its nuclear units, there will be few to no similar technology nuclear plants in operation at the time DEP's units retire in the next 20 years. With few to no similar vintage nuclear or coal plants in operation, the market for the more expensive inventory items such as pumps, motors, and valves will be severely limited or nonexistent. DEP does not expect markets for inventory components at or near market value to exist. Witness Ray indicated that, while DEP generally agrees that there may be some small amount of salvage value for nuclear M&S inventory at its end of life, disposal expenses will largely offset any such value. He concluded that DEP does not support maintaining a particular salvage value going forward until the retirement of the nuclear units because doing so would reduce DEP's ability to adjust the salvage value for M&S inventory as needed in the future based on changed circumstances. *Id.* at 288.

The Revenue Requirement Stipulation accepts the Public Staff's adjustment to end-of-life nuclear materials and supplies reserve expense, reduced as described in the direct testimony of Public Staff witness Metz. Revenue Requirement Stipulation § III.20, Tr. Ex. vol. 7. DEP witness Jiggetts and Public Staff witnesses McLawhorn, Metz, Zhang, and Boswell supported this provision in their settlement supporting testimony. Tr. vol. 13, 254, 60; Tr. vol. 16, 512. The Commission concludes that the adjustments to the nuclear end-of-life reserve established in the Revenue Requirement Stipulation are supported by the evidence presented, is just and reasonable and fair to all, and should be approved.

Coal Inventory

Based on DEP's historical performance, updated coal inventory analysis, and recent coal inventory holdings, Public Staff witness Michna recommended that DEP maintain its current coal inventory of 35 days of 100.0% full load burn and reduce the corresponding DEP adjustment that increased coal inventory to 40 days by $9,971,719 to account for this change. Tr. vol. 21, 292-93.

DEP witness Turner opposed witness Michna's adjustment. Witness Turner asserted that the adjustment failed to contemplate the changing market factors impacting a reliable fuel supply, namely the inability of the coal supply chain to timely respond to volatility in coal generation demand and ignored DEP's updated average inventory of 38.8 days. Witness Turner concluded that it is prudent to increase the target from 35 days to 40 days. Tr. vol. 12, 142.

The Revenue Requirement Stipulation accepts the annual 35 full load day burn average to establish the level of coal inventory for purposes of establishing a revenue requirement. Revenue Requirement Stipulation § III.21, Tr. Ex. vol. 7. DEP witness Jiggetts and Public Staff witnesses McLawhorn, Metz, Zhang, Boswell supported this provision in their settlement supporting testimony. Tr. vol. 13, 254, 261; Tr. vol. 16, 513-15. The Commission concludes that the 35-day coal inventory target proposed in the Revenue Requirement Stipulation is supported by the evidence presented, is just and reasonable and fair to all, and should be approved.

Credit Card Payment Fees

In her direct testimony, DEP witness Quick proposed to offer a Fee-Free program for small and medium nonresidential customers who make payments using debit, credit, prepaid, or electric check (Card Payments) to pay their electric bills. Tr. vol. 7, 65. In support of DEP's request, she noted that residential customers have a transaction Fee-Free program for Card Payments, which the Commission approved in DEP's last general rate case. Witness Quick recounted that nonresidential customers making a Card Payment are subject to a convenience fee of $8.50 per payment for payments up to $10,000; for payments in excess of $10,000, the convenience fee is 2.75% of the amount paid. *Id.* at 105. DEP's vendor charges the convenience fee and DEP receives no portion of it. *Id.* at 105-06. Based on customer feedback and requests, witness Quick proposed in this case to offer the Fee-Free program for Card Payments to nonresidential customers making bill payments up to $3,000. *Id.* at 106. DEP, instead of the customer, would pay the vendor the convenience fees for these Card Payments and incorporate the expense into the cost of service for recovery through its base rates. Tr. vol. 7, 104-06.

In their joint testimony, Public Staff witnesses Zhang and Boswell opposed DEP's proposal to socialize the credit card payment fees for nonresidential customers. Tr. vol. 19, 51. They noted that the current volume of customers who use this method of payment accounts for less than 1.0% of the overall bill pay transactions volume. *Id.* Additionally, witnesses Zhang and Boswell distinguished this proposal from the socialization of the residential credit card fees the Commission allowed in DEP's previous general rate case order by noting that the residential Fee-Free program had the potential to produce reductions in late payments and uncollectibles, but nonresidential customers do not experience the same level of late payments and uncollectibles as residential customers**.** *Id.* Therefore, they testified that they found no offsetting benefit of socialization of Card Payment fees for the nonresidential customers to general ratepayers. *Id.*

The Revenue Requirement Stipulation establishes that the credit card payment fees for nonresidential customers shall be removed from the revenue requirement in this case. Revenue Requirement Stipulation § III.23, Tr. Ex. vol. 7. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Payroll and Benefits

DEP and other Duke Energy affiliates continuously review operational matters including workforce staffing levels. In connection with such a review, DEP implemented planned headcount reductions beginning in 2021 through the first part of 2023, leading to a reduction in DEP's otherwise applicable revenue requirement. While DEP witness Jiggetts' schedules reflected the reduction through the March 31, 2023 cutoff date applicable to this case, Section III, Paragraph 25 of the Revenue Requirement Stipulation provides for a further reduction of the revenue requirement for the payroll costs and associated benefits for the former employees subject to the Work Reduction Initiative through the end of May 2023. *Id.* No intervenor took issue with this provision of the stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Production O&M Reduction to Reflect Capitalization Policy Change

In his supplemental testimony, Public Staff witness Metz described how DEP reclassified miscellaneous line items from O&M to capital plant. Witness Metz did not take issue with this action for purposes of this proceeding but testified to his concern that test year O&M expenses used to establish an ongoing expectation of future spending may be overstated. To account for the impact of the reclassification, he recommended the removal of $463,000 on a system basis from DEP's test year expenses. Tr. vol. 16, 506-08.

The Revenue Requirement Stipulation establishes a reduction in production O&M of $463,000 on a system basis to account for the change in DEP's capitalization policy. Revenue Requirement Stipulation § III.26, Tr. Ex. vol. 7. DEP witness Jiggetts and Public Staff witnesses McLawhorn, Metz, Zhang, and Boswell supported this provision in their settlement supporting testimony. Tr. vol. 13, 254, 262; Tr. vol. 16, 512. The Commission concludes that the production O&M reduction proposed in the Revenue Requirement Stipulation is supported by the evidence presented, is just and reasonable and fair to all, and should be approved.

Vegetation Management O&M

In his direct testimony, DEP witness Maley described DEP's transmission Integrated Vegetation Management (IVM) Plan and its goal of removing and/or controlling incompatible vegetation within and along transmission rights of way. Witness Maley indicated that the IVM includes planned corridor work, reactive work, and floor management work, with DEP's prioritizing the first two categories based on threat assessments. Witness Maley also indicated that DEP had included an increase in vegetation management costs in its test period pro forma adjustments to account for increased outside labor costs and that this adjustment also covers vegetation management costs associated with the expansion of existing substation sites. Tr. vol. 10, 178-79.

In his direct testimony, DEP witness Guyton testified that DEP utilized a reliability prioritization model to drive its routine IVM program. The other important components of

DEP's vegetation management include the following programs: herbicide management, hazard trees, reactive customer requested activities, and post outage vegetation management activities. Witness Guyton also testified that DEP continues to utilize a seven-year cycle for distribution vegetation management in nonurban areas and a three-year cycle in urban areas consistent with DEP's 2015 Tree Growth Study. Tr. vol. 10, 51-52.

In his direct testimony, Public Staff witness T. Williamson described DEP's IVM Plan and provided a summary of the operation of that plan since 2015. This description included both vegetation within DEP's rights of way and vegetation that lies outside DEP's rights of way. DEP's hazard tree program manages the vegetation which lies outside DEP's rights of way. Witness T. Williamson also recommended changes to DEP's assessment activities (which would increase the frequency of its review of distribution lines), and recommended reductions in two parts of the Distribution System Vegetation Management budgets. Finally, witness T. Williamson recommended changes to the Distribution and Transmission vegetation plan reporting requirements. Tr. vol. 21, 205-18.

In his rebuttal testimony, DEP witness Guyton addressed Public Staff witness T. Williamson's vegetation plan recommendations and indicated that the significant increase in work that would be necessary to implement his recommendations for increased observation of the distribution system would increase costs and endanger DEP's ability to meet its other vegetation management plan goals. Witness Guyton further stated that reductions in Distribution Vegetation Management plan budgets were contrary to DEP's actual experience of increasing vegetation management costs. Tr. vol. 10, 143. Witness Guyton also objected to two of the additional reporting requirements witness T. Williamson suggested on the grounds that the practicalities of how the vegetation management plan operates precludes reporting on vegetative miles and hazard tree targets. *Id.*at 147.

No other party presented evidence on these matters.

The Revenue Requirement Stipulation provides for a reduction in DEP's Distribution O&M Demand Program budget to $2,721,604[8] and for adoption of the additional vegetation management reporting requirements recommended by Public Staff witness T. Williamson except for reporting on vegetative miles and hazard tree targets, as noted on page 52 of the rebuttal testimony of DEP witness Guyton. Revenue Requirement Stipulation §§ III.27 and IV.37, Tr. Ex. vol. 7. The Commission concludes that these adjustments in the Revenue Requirement Stipulation are supported by the evidence presented and are just and reasonable and fair to all and should be approved.

Lead-Lag Study

As part of its filing in this case, DEP submitted a lead-lag study that was performed by Ernst & Young, LLP, and approved in the Commission's Order in the 2019 Rate Case.

[8] The $2,721,604 is the adjusted total related to O&M Demand Program. The amount of the adjustment was $789,309 on a system basis.

Tr. vol. 13, 43; Speros Direct Ex. 2, Tr. Ex. vol. 13. The lead-lag study was used to analyze transactions throughout the year to determine the number of days between the time services are rendered and payment is received (revenue lag), and the number of days between the time expenditures are incurred and payment is made for such services (expense or payment lead). Public Staff witnesses Zhang and Boswell recommended that DEP prepare and file a fully updated lead-lag study in its next general rate case. Tr. vol. 19, 43.

In his rebuttal testimony, DEP witness Speros stated that DEP plans to pursue a merger of the DEP and DEC utilities in the next rate case and will work with the Public Staff to determine if the timing of the next lead-lag study makes more sense before or after that case. Tr. vol. 13, 73.

The Revenue Requirement Stipulation incorporates DEP's agreement to perform a lead-lag study before the next general rate case proceeding and incorporate the results of that study in DEP's next rate case application. No intervenor took issue with this provision of the stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT 28.

The evidence supporting this finding of fact is included in DEP's verified Application and Form E-1; the testimony and exhibits of Public Staff witnesses Metz, Zhang, and Boswell, including Accounting Second Supplemental Ex. 1, the Supplemental Revenue Requirement Stipulation, including Ex. 1; and the entire record in this proceeding.

The Revenue Requirement Stipulation involves a comprehensive resolution between the stipulating parties of a majority of the revenue requirement issues in this case. Because the Revenue Requirement Stipulation was entered into before the Public Staff had completed its audit of DEP's third and final update of costs, the stipulation provides expressly that the stipulation does not prevent the Public Staff from completing its audit of DEP's updates or making proposed adjustments to the updated revenue requirements based on the audit. The Public Staff completed its audit of the updates in June 2023, and the Public Staff and DEP entered into the Supplemental Revenue Requirement Stipulation, filed on June 27, 2023, in which the parties agreed to certain further minor adjustments to the revenue requirement. The Supplemental Revenue Requirement Stipulation lists four areas of agreement between DEP and the Public Staff. Tr. Ex. vol. 24.

Sheds (New Hill Timpson Training Sheds)

DEP and the Public Staff agreed that DEP shall remove 50% of the costs associated with the New Hill Timpson Training Sheds from its revenue requirement for purposes of this proceeding only. The removal will result in a decrease of $186,000 in Plant in Service on a North Carolina retail basis. *Id.*

Wilson 230kV Project

DEP and the Public Staff agreed that DEP will reclassify $670,989 system amount related to the Wilson 230kV project from distribution to transmission plant. They further agreed that DEP shall offset the March 2023 plant in service amount of $1.423 million on a system basis associated with the Wilson 230kV project with an estimate of the insurance proceeds in the amount of $897 thousand on a system basis that DEP will receive. The parties acknowledged that actual proceeds received may be different than the estimates captured and agree that they will address any necessary adjustments in a future proceeding. *Id.*

Laptop Issuance

DEP and the Public Staff agreed that, for purposes of this proceeding, DEP will remove new laptop devices not issued to employees as of the capital cutoff date from the revenue requirement. The removal will result in a decrease to Plant in Service of $2,370,000 on a North Carolina retail basis. *Id.*

Capitalization Policy

DEP and the Public Staff agreed that there will be no adjustment to the capitalized costs related to the February 2023 Brunswick Unit 2 nuclear refueling outage in this proceeding. They further agreed that DEP will assist the Public Staff in reviewing DEP's capitalization procedures before DEP files its next general rate case. *Id.*

On June 27, 2023, the Public Staff filed the joint supplemental settlement testimony of witnesses Metz, Zhang, and Boswell in support of the Supplemental Revenue Requirement Stipulation. According to the Public Staff witnesses, the most important benefits that the stipulation and the agreed upon adjustments provide are: (1) an aggregate reduction in DEP's proposed revenue increase in this proceeding; and (2) the avoidance of litigation between the parties on the settled issues and the associated increased accumulation of rate case expense recovery from ratepayers. Tr. vol. 24, 47. The Public Staff further testified that the Commission should approve the Supplemental Revenue Requirement Stipulation because of these benefits to ratepayers. *Id.*

The Commission concludes that the adjustments in the Supplemental Revenue Requirement Stipulation are supported by the evidence presented and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 29

MYRP Capital Investments

The evidence supporting this finding of fact is included in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Maley, Guyton, Ray, Turner, Strasburger, and LaRoche, Public Staff witnesses Thomas, Metz, T. Williamson, Nader,

Zhang, and Boswell, AGO witness Nelson, NCJC, et al. witnesses Hill and Duncan, , Sierra Club witness Goggin; the Revenue Requirement Stipulation; and the entire record in this proceeding.

In its Application, DEP identified capital spending projects projected to be placed in service during the MYRP period. These projects consist of transmission and distribution infrastructure, solar and battery storage, enterprise technology and security, and fossil, hydro, and nuclear investments.

DEP provided support for its MYRP projects through its Application, direct, supplemental direct, and rebuttal testimony of DEP witnesses discussed below, as well as at the July 2022 Transmission and Distribution Technical Conference. Furthermore, the Public Staff conducted substantial discovery regarding the projects DEP proposed in its MYRP. DEP's witnesses assert that DEP has provided sufficient information to justify the MYRP projects, while the Public Staff witnesses offered multiple critiques of DEP's documentation of the MYRP projects. The Revenue Requirement stipulating parties agreed to support the MYRP projects as modified in the Revenue Requirement Stipulation.

Transmission

DEP witness Maley testified in support of the MYRP transmission projects. Regarding future needs, witness Maley testified that, while DEP has worked hard to maintain the system and reliably meet customer needs, it must do more to improve the state's energy infrastructure to meet the challenges and opportunities that lie ahead. Tr. vol. 10, 170. Witness Maley testified that DEP designed its MYRP to address future challenges and opportunities and that the MYRP transmission projects include investments in the following categories: system intelligence, hardening and resiliency, transformer and breaker upgrades, and capacity and customer planning. *Id.* at 185.

Witness Maley testified that DEP selected and grouped targeted reliability improvements in the following MYRP projects, based on the areas that provide the greatest value to customers: system intelligence, vegetation management, transmission line hardening and resiliency, substation hardening and resiliency, transformer upgrades, breaker upgrades, and capacity and customer planning. *Id.* at 187. He explained that although these seven proposed MYRP investments are the same as those DEP presented in the July 25, 2022, MYRP Technical Conference, DEP has refined some of the location details and informed the Cost Benefit Analysis (CBA) with those details. *Id.*

In witness Maley's direct testimony and accompanying exhibits, he described the estimated costs of DEP's proposed MYRP transmission projects. *Id.*

In his supplemental direct testimony, witness Maley provided an update on the cost estimates applicable to transmission projects that DEP included in its MYRP based on certain criteria agreed upon with the Public Staff. *Id.* at 212-13. Witness Maley identified additional transmission MYRP project locations that DEP added to the MYRP after filing

his direct testimony, and identified those that it removed, along with the reasons behind such changes. *Id.* at 208. He provided updated project cost estimates for certain transmission MYRP projects, including explanations for the basis for such updated cost estimates. *Id.* at 212-13.

DEP witness Maley's Direct Supplemental Exhibit 1 provides the total updated costs of the proposed MYRP Transmission projects as follows:

1. Breakers - $103,434,999;

2. Capacity and Customer Planning - $624,078,511;

3. Substation Hardening and Resilience - $359,579,976;

4. System Intelligence - $72,766,544;

5. Transmission Line Hardening and Resiliency - $129,651,500;

6. Transformers - $114,269,580; and

7. Vegetation Management - $113,884,377.

Tr. Ex. vol. 10.

The modifications to proposed MYRP Transmission projects described in witness Maley's supplemental direct testimony and accompanying exhibits resulted in an updated estimated capital cost of DEP's proposed MYRP Transmission projects of $1,517,665,486.

Public Staff witness Metz testified as to multiple concerns with the MYRP projects, including outdated cost estimates, insufficient staffing levels to complete the projects on schedule, and the lack of coordination between business groups to increase project efficiencies. Tr. vol. 16, 461, 465-66, 481-83. Witness Metz recommended reducing the project contingency by half, arguing that DEP failed to justify the high contingency amount DEP budgeted for the projects. *Id.* at 491-92. He further recommended a 5.0% downward adjustment for all transmission projects in the MYRP to address potential construction efficiencies that could arise in the implementation of the MYRP. *Id.* at 494. Witness Metz also recommended the removal of certain transmission projects from the MYRP based on the analysis of Public Staff witness Chiles. *Id.* at 458.

AGO witness Nelson critiqued DEP's transmission planning and made several recommendations. AGO witness Nelson recommended that the Commission require DEP to conduct a study on the costs and benefits of grid-enhancing technologies (GETs). Tr. vol. 18, 123-30. Witness Nelson also recommended that DEP engage in regional transmission planning and asserted that regional planning could potentially displace projects in the MYRP. *Id.* at 138-41. Finally witness Nelson recommended that DEP pursue all funding options for transmission projects that are part of the IRA. *Id.* at 134.

Sierra Club witness Goggin recommended that the Commission require DEP to file a proactive transmission plan for all transmission expansion and upgrades needed to accommodate the interconnection of all new renewable resources required by 2035 under Duke's Carbon Plan. Tr. vol. 21, 789. Witness Goggin also recommended that the Commission direct DEP to use a "multi-value approach to planning transmission so that the identified upgrades meet needs related to public policy, economics, reliability, expanded interconnection with neighboring Balancing Authorities, and other categories of benefits…" Tr. vol. 21, 790.

Witness Maley addressed testimony from Public Staff witnesses Metz and Chiles. Specifically, he: (1) spoke of each MYRP project witnesses Metz and Chiles challenged and explained why the projects are necessary and appropriate for inclusion in the MYRP; (2) discussed DEP's methodology for ensuring that there is no overlap between the scope of different projects; (3) countered the argument that the Commission should reduce contingency components of the estimates for all MYRP transmission projects by 50.0%; (4) explained the basis for the contingency component of DEP's transmission projects; and (5) addressed witness Metz's recommendation that the Commission reduce all transmission project estimates by 5.0%. Tr. vol 10, 227-29, 246-47.

Witness Maley also addressed testimony of witnesses for the AGO and the Sierra Club. Witness Maley stated that he disagreed with AGO witness Nelson's recommendations. *Id.* at 259-60. Witness Maley testified that witness Nelson's recommendation to study GETs is inappropriate in this proceeding because the Commission already considered GETs in the Carbon Plan proceeding. *Id.* at 260. Also, witness Maley disputed witness Nelson's recommendations because they require activities already underway or that should be considered in the Carbon Plan or in the North Carolina Transmission Planning Collaborative (NCTPC). *Id.* Witness Maley mentioned that DEP witness Roberts explained how GETs are evaluated in his Carbon Plan testimony. Witness Maley stated that the Commission has already noted in its Carbon Plan Order that it "expects Duke to pursue all potential tax incentives or federal funding." *Id.* Witness Maley countered that new requirements imposed in this proceeding that circumvent resource planning and transmission planning are not reasonable. *Id.*

In his rebuttal testimony, witness Maley responded that Sierra Club witness Goggin's recommendations regarding transmission planning would fit better in the Carbon Plan and Integrated Resource Process (CPIRP) efforts than within the limited three-year window of the MYRP. Tr. vol. 10, 261. Witness Maley explained that Duke Energy stated in the March 15, 2023, NCTPC Transmission Advisory Group (TAG) presentation that it is pursuing the integration of a multi-value strategic transmission planning study into the local transmission planning process. Tr. vol. 10, 261. Since DEP is already pursuing this in the NCTPC, witness Maley testified that any further requirement is unnecessary. *Id.*

The Revenue Requirement Stipulation includes a 50.0% adjustment to the contingency amounts of the transmission projects as recommended by Public Staff witness Metz. The stipulation further provides that DEP will leverage project efficiencies to the extent practical in the implementation of the MYRP. The stipulation also establishes

that the transmission MYRP projects identified in DEP witness Abernathy's February 2023 MYRP update of Exhibit 4, Workpaper 5 and described in the direct and supplemental testimonies of DEP witness Maley are appropriate for inclusion in the MYRP. Based on the entire record in this proceeding, the Commission finds that DEP's proposed transmission projects are reasonable and shall be included in the MYRP for recovery. Tr. Ex. vol. 13.

The only parties that opposed portions of DEP's transmission projects included in the MYRP but not resolved through the Revenue Requirement Stipulation and other settlements are the AGO, as indicated by the testimony filed by AGO witness Nelson, and the Sierra Club, as indicated by witness Sierra Club witness Goggin.

The Commission agrees with DEP witness Maley's assertion that the recommendations of AGO witness Nelson and Sierra Club witness Goggin regarding transmission planning are designed to change DEP's decision-making regarding the types of transmission projects it undertakes. The Commission finds that the appropriate proceeding for consideration of changes to transmission planning is the CPIRP, or other proceedings.

N.C.G.S. § 62-133.16(c)(1)(a) provides that for the first year of an MYRP, the

> base rates . . . shall be fixed in a manner prescribed under G.S. 62-133 . . . plus costs associated with a known and measurable set of capital investments, net of operating benefits, associated with a set of discrete and identifiable capital spending projects to be placed in service during the first rate year.

The same provision specifies that:

> [s]ubsequent changes in base rates in the second and third rate years of the MYRP shall be based on projected incremental Commission-authorized capital investments that will be used and useful during the rate year and associated expenses, net of operating benefits, including operation and maintenance savings, and depreciation of rate base associated with the capital investments, that are incurred or realized during each rate year of the MYRP period.

N.C.G.S. § 62-133.16(c)(1)(a).

After having carefully reviewed all the evidence in the record, the Commission concludes that the evidence demonstrates that the proposed MYRP transmission projects satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a). The Commission further concludes that the evidence supports approval of the Revenue Requirement Stipulation's provisions regarding these transmission projects and that the transmission MYRP costs thereunder are just and reasonable and consistent with the public interest.

Distribution

DEP witness Guyton described the discrete and identifiable capital spending projects associated with DEP's distribution system proposed to be placed in service for each rate year of the MYRP. His testimony included the reason for, scope of, timing for (projected in-service month and year), and operating benefits of each project. Tr. vol. 10, 35-36. Witness Guyton testified that DEP's proposed MYRP distribution and other projects covered in his testimony total $2.2 billion and include the $1.8 billion in distribution MYRP projects discussed at the T&D technical conference held on July 25, 2022, as well as $0.4 billion in other non-T&D MYRP projects. *Id.* at 42. The other MYRP project categories include DEP's allocated share of the costs of enterprise communications and enterprise systems, as well as facilities and fleet electrification infrastructure. *Id.* These other projects are closely aligned with the distribution business or enabling the grid capabilities. *Id.*

While discussing the preliminary findings in the ongoing Climate Risk and Resilience Study (CRRS) of the Carolinas transmission and distribution system, witness Guyton testified that the preliminary findings of the CRRS reinforces the benefits of the proposed MYRP projects, and that the additional headroom provided by capacity upgrades and improvements accommodates customer load growth and generation, but also increases resilience to the effects of extreme heat. *Id.* at 63-64. He testified that targeted undergrounding, distribution hardening and resiliency, and hazard tree removal increase resilience to the impact of wind and storms, which are likely to increase in frequency and strength due to climate change. *Id.* at 64. Witness Guyton also testified that Duke Energy implemented Integrated Systems Operations Planning (ISOP) to leverage increasing amounts of data, such as the propensity of customers to adopt solar and purchase EVs, when planning future projects. *Id.* at 40. He testified that, when appropriate, the distribution projects will take advantage of new processes and technologies that will aid in the delivery of the energy goals and requirements of North Carolina. *Id.* at 40-41. As such, he stated that the proposed MYRP projects and the grid capabilities that are achieved through these projects will serve as a foundation to support future technologies, and will result in significant customer benefits, particularly in the areas of reliability and resiliency. *Id.* at 41.

With respect to reliability, witness Guyton stated that DEP anticipates fewer and shorter outages resulting from programs such as Self-Optimizing Grid (SOG), Targeted Underground (TUG), distribution automation, and equipment retrofitting. *Id.* Regarding resiliency, the MYRP projects will provide increased protection against physical/cyber-attacks and severe weather impacts. Increases in capacity and voltage regulation and management will accommodate increasing amounts of renewable resources and Distributed Energy Resources (DERs). *Id.* Enhanced automation and control, and situational awareness will enable DEP to operate the grid more efficiently and support new customer programs, which will provide customers more options to control their energy usage and decrease their energy costs. *Id.* Witness Guyton testified that DEP will spread its proposed distribution MYRP projects across its service territory and retail customer classes to provide equitable access to these benefits. *Id.* The programs in

DEP's MYRP projects make the grid more flexible and adaptable. Automation and control technologies will help generate and capture large volumes and types of data which was not previously available. *Id.* Witness Guyton asserted that these benefits are helpful not only for DEP's Grid Operators but also for its Planning Engineers as they analyze and model DEP's grid for future improvements and capabilities using ISOP toolsets like Morecast and Advanced Distribution Planning (ADP). *Id.* at 41-42. He indicated that grid technologies will continue to and will be integrated into new solutions to address changing customer needs. *Id.* at 42.

Witness Guyton testified that distribution projects included in the MYRP total $2,197,627,366 in estimated capital investment and fall into four investment categories: (1) Substation and Line MYRP projects which total estimated capital costs of $1.582 billion comprise most of the distribution MYRP project costs; (2) Retail and System Capacity Projects which total estimated capital costs of $0.210 billion include the traditional identification and execution of capacity projects to support traditional loads as well as DERs and EVs; (3) Hazard Tree Removal Projects which total estimated capital costs of $0.028 billion consist of the traditional identification and execution of hazard tree removal which is performed in conjunction with normal trimming cycles; and (4) non-transmission and distribution MYRP projects which total estimated capital cost of $0.4 billion include DEP's allocated share of the cost of enterprise communications and systems as well as facilities and fleet electrification infrastructure. *Id.* at 42-44, 64-65.

Witness Guyton testified that the Substation and Line MYRP projects are geographically based and include a combination of ongoing work necessary for safe and reliable service and the work necessary to deliver essential grid capabilities that DEP has identified to address the megatrends and support the clean energy transition. *Id.* at 42. DEP's Distribution MYRP consists of the following 12 programs:

1. SOG Program, also known as the smart-thinking grid, redesigns key portions of the distribution system and transforms it into a dynamic self-healing network that isolates grid issues and limits customer impacts to hundreds versus thousands of customers. The total capital cost for this program is $231.9 million.

2. Voltage Regulation and Management Program improves the grid's ability to address intermittency and fluctuations that DERs cause and improves power quality to customers. The total capital cost for this program is $204.6 million.

3. Distribution Automation Program targets the lateral segments of the grid and focuses on modernizing single-use fuses with automated devices capable of intelligently resetting themselves for reuse. The total capital cost for this program is $50.3 million.

4. Capacity Upgrades and Improvements Program consists of the same work that DEP has always performed to serve its new and existing customers. The total capital cost for this program is $461.6 million.

5. Hardening and Resiliency – Laterals Program focuses on the lateral sections or tap lines, which branch from the main feeder lines and feed neighborhoods, businesses, and commercial/industrial customers. The total capital cost for this program is $175.3 million.

6. Hardening and Resiliency – Public Interference Program improves reliability by targeting DEP's most outage prone overhead backbone power line sections most impacted by vehicle accidents and determining the proper hardening and resiliency solution to reduce the number of outages customers experience. The total capital cost for this program is $18.1 million.

7. Hardening and Resiliency – Storm Program consists of improvements to locations of the distribution grid that DEP has identified, through analysis of historical outage data, as being more vulnerable to outage impacts from extreme weather events. The total capital cost for this program is $77.2 million.

8. Equipment Retrofit Program improves reliability by targeting equipment prone to outages from animal interference, lightning, and clearance issues by upgrading the assets to modern design standards. The total capital cost for this program is $80.4 million.

9. Long Duration Interruption (LDI) Program relocates segments of main overhead feeder lines in hard-to-access areas to improve accessibility for utility trucks. The total capital cost for this program is $2.6 million.

10. TUG Program improves reliability by strategically identifying DEP's most outage prone overhead power line sections and relocating them underground to reduce the number of outages customers experience. The total capital cost for this program is $103.0 million.

11. Hazard Tree Removal Program maintains or improves reliability by identifying and removing dead, structurally unsound, dying, diseased, leaning, or otherwise defective trees that could strike electrical lines or equipment of the distribution system from outside the maintained right of way. The total capital cost for this program is $48.0 million.

12. Distribution Infrastructure Integrity Program identifies and mitigates risk factors such as end-of-service equipment, technology obsolescence, and damaged in-service distribution equipment. The total capital cost for this program is $366.1 million. *Id.* at 66-71.

.Witness Guyton testified that DEP's description of its distribution MYRP programs and associated exhibits reflect the detailed project information that Commission Rule R1-17B. *Id.* at 72. The projected annual net O&M benefits that Commission Rule R1-17B(d)(2)k requires reflect the operational O&M savings offset by the incremental cost to operate the new technology. *Id.* at 73. The O&M savings stem from fewer outages

resulting from reliability improvements and the reduction in vegetation management resulting from the undergrounding of overhead lines, for example, in the TUG program. *Id.* DEP netted these savings with the ongoing O&M costs associated with maintaining the added equipment installed under the SOG and Voltage Regulation programs. *Id.*

In his supplemental direct testimony, witness Guyton identified distribution MYRP project locations that DEP either added to or removed from the MYRP period and explained the reasons for such changes. *Id.* at 88-89. Witness Guyton provided updated project cost estimates for certain distribution MYRP projects and explained the basis of the updated cost estimates. *Id.* Witness Guyton testified that his direct testimony included 44 distribution projects (comprised of 301 distribution sub-projects at the location/task level) totaling $2.2 billion, while his supplemental direct testimony included 44 distribution projects (comprised of 297 sub-projects at the location/task level) totaling $2.0 billion representing an overall net reduction of $226.7 million across all the distribution MYRP projects. *Id.* Additionally, he testified that DEP and the Public Staff reached a consensus regarding the criteria pursuant to which DEP would update information regarding MYRP projects and their cost estimates. The updates to the distribution MYRP projects witness Guyton presented in his supplemental direct testimony meet those criteria. *Id.* at 90.

DEP removed three project locations from the MYRP period, including deferring the Franklinton 115kV location within the Substation and Line – Triangle North 262 MYRP Project totaling $0.9M to a later time outside the MYRP window, and moving both the Advanced Distribution Management System (ADMS) CVR project location, totaling $1.7M, and the ADMS Advanced Fault Location project, totaling $0.6M, outside the MYRP window. *Id.* at 91-92. Witness Guyton described cost updates to 148 total distribution MYRP projects. *Id.* at 92. Witness Guyton also explained that at the time of DEP's Application, the distribution MYRP projects were at various stages of the project management lifecycle under DEP's Project Management Center of Excellence (PMCoE) standards. *Id.* at 93. Under the PMCoE approach, as a project moves through the development cycle, DEP continues to refine the costs and project schedules based on project development, detailed design, and construction planning. *Id.* at 93.

Witness Guyton testified that the Substation and Line and Area Capacity projects comprise a significant percentage of the MYRP distribution projects. *Id.* at 94. When these projects were initially identified, a spreadsheet cost estimate was constructed based on past work scope completed for similar assets at similar locations primarily based on engineering analysis and data driven models *Id.* Planning and engineering activities that occurred after the filing of DEP's Application and engaged in as part of the PMCoE process provided the opportunity to refine the scope of work and cost estimates on 125 of the total 190 Substation and Line sub-projects at the location/task level in the MYRP based on actual circuit and equipment and site conditions. *Id.* at 94-95.

Guyton Supplemental Direct Exhibit 3 identifies the total estimated capital costs of the Distribution MYRP projects to be $1,970,915,190. Tr. Ex. vol. 10.

Public Staff witness Thomas recommended reduction of the project costs for four Area Capacity projects and one Facilities project to align with updated cost estimates. Tr. vol. 19, 218. Specifically, he recommended reduction of the cost estimates for the Wilmington 421 230kV Capacity, Wilmington Sunset Park 115kV #2 Capacity, Youngsville 115kV Capacity, Wake Tech 230kV Capacity, and Aberdeen Facilities projects. *Id.* Witness Thomas also recommended reduction of the cost estimates for the Area Capacity program by 5.0% as a financial incentive for DEP to maximize efficiencies for the Area Capacity and Substation and Line programs. *Id.* at 222-23.

Public Staff witness Metz raised multiple concerns about the MYRP projects, including outdated cost estimates, insufficient staffing levels to complete the projects on schedule, and the lack of coordination between business groups to increase project efficiencies. Tr. vol. 16, 461, 465-66, 481-83. Witness Metz recommended reducing the project contingency by half, arguing that DEP failed to justify the high contingency amount DEP budgeted for the projects. *Id.* at 491-92. Public Staff witness Lawrence recommended removal of the costs for the Electrification Charging Infrastructure (ECI) Program that would support the deployment of electric vehicles to DEP facilities and the homes of select DEP employees from the MYRP because DEP had not provided sufficient information or support for the program. Tr. vol. 21, 172-75.

NCJC, et al. witnesses Hill and Duncan made several recommendations related to DEP distribution planning. First, they recommended that the Commission initiate a working group to redesign DEP's CBA methodologies for selection of projects in the MYRP and that the Commission initiate an investigation into distribution system planning. Tr. vol. 21, 849, 874. Witnesses Hill and Duncan also recommended that the Commission require DEP to conduct non-wire (NW) pilot projects and that DEP update its MYRP cost estimates to account for federal funds available through the IRA and IIJA. *Id.* at 850-54, 879.

In his rebuttal testimony, DEP witness Guyton responded to the Public Staff's distribution related MYRP and base case testimony, and to NCJC, et al. witnesses Hill and Duncan's testimony. Tr. vol. 10, 97-98. Specifically, he: (1) described the process DEP used to select certain distribution projects for inclusion in the MYRP and provided specific, data-driven reasons why their selection was appropriate; (2) discussed the methodologies and procedures DEP used to develop cost and contingency estimates for distribution projects; (3) countered the argument that the Commission should reduce contingency components of the estimates for all distribution projects in the MYRP by 50.0%; and (4) addressed witness Thomas's recommendation that the Commission reduce certain distribution project estimates by 5.0%.

The Revenue Requirement Stipulation included certain modifications to DEP's MYRP distribution projects. Those modifications include: (1) inclusion of the 50.0% adjustment to the contingency amounts of the distribution projects as recommended by Public Staff witness Metz; (2) rejection of project efficiency adjustment to the MYRP revenue requirement but DEP agreement to leverage project efficiencies to the extent practical in the implementation of the MYRP; (3) removal of the costs of the Fleet Electrification Charge Infrastructure Project; (4) inclusion of the cost of Project Walter in

the MYRP; (5) agreement to discuss scope and content of proposed reporting on reliability O&M; (6) reduction of the Wilmington 421 230kV Capacity, Wilmington Sunset Park 115kV #2 Capacity, Youngsville 115kV Capacity, Wake Tech 230kV Capacity, and Aberdeen Facilities project cost estimates; and (7) reduction in the costs of the Substation & Line Targeted Undergrounding projects. Tr. Ex. vol. 7.

The Revenue Requirement Stipulation did not address the concerns raised by NCJC, et al. witnesses Hill and Duncan.

In response to the recommendations of NCJC, et al. witnesses Hill and Duncan, witness Guyton testified that the recommendations fail to acknowledge activities that are already underway, and for which Commission approval is therefore unnecessary. *Id.* at 105. Witness Guyton asserted that the recommendation of NCJC, et al. that the Commission initiate a working group to update DEP's CBA methodologies is unnecessary since DEP has demonstrated the current methodology, and no other intervenor disputed the current methodology or its usefulness in the current rate case. Tr. vol. 10, 149-50. He contends that witnesses Hill and Duncan also do not acknowledge specific improvements in the CBA methodology DEP used in the current rate case that DEP made in response to stakeholder feedback in DEP's last rate case. *Id.* at 150. Witness Guyton also asserted that the NW pilot projects witnesses Hill and Duncan suggest are unnecessary because DEP has already initiated other customer-solution NW approaches. Tr. vol. 21, 854-55. Witness Guyton points out that their recommendation that the Commission initiate distribution system planning is not necessary because the Commission has already initiated the ongoing ISOP stakeholder engagement efforts. *Id.* at 870. Similarly, witness Guyton asserts that their recommendation to require DEP to update MYRP cost estimates to account for federal funds available through the IRA and IIJA is unnecessary as DEP is actively pursuing grant funding opportunities for the benefit of customers. Tr. vol. 10, 151. Witness Guyton also points to DEP witness Abernathy's testimony, in which she testified that DEP requests that the Commission issue an accounting order authorizing deferral of all IRA and IIJA impacts, including benefits and costs, for addressing in a future filing. *Id.*

The Commission gives significant weight to the compromise agreements reflected in the Revenue Requirement Stipulation. The Commission is not persuaded that the recommendations of NCJC, et al. witnesses Hill and Duncan related to DEP's proposed MYRP distribution projects are necessary at this time. The majority of the recommendations of witnesses Hill and Duncan are related to distribution system planning that should be considered in other proceedings such as the CPIRP proceeding. With respect to witnesses Hill and Duncan's recommendation that the Commission require DEP to update its distribution MYRP investments to account for available federal funds, the Commission notes that the record demonstrates that DEP is pursuing such funds and re-emphasizes its direction to DEP to pursue such funds. As discussed later in this Order, impacts associated with the IIJA and IRA will be deferred, and the Commission declines to adopt Witness Hill and Duncan's recommendation related thereto.

After having carefully reviewed all the evidence in the record on DEP's distribution MYRP proposal in this docket, and based on that evidence, the Commission finds that DEP's

distribution MYRP projects satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a). The Commission further concludes that the evidence supports approval of the Revenue Requirement Stipulation's provision regarding these distribution MYRP projects.

Nuclear

DEP witness Ray testified in support of the nuclear projects DEP included in the proposed MYRP, the process DEP used to select the projects, and the method by which DEP calculated projected costs for the projects. Tr. vol. 16, 171-72. Witness Ray explained that DEP selected the projects based on their value in maintaining safe and reliable operation of the nuclear stations and on a high level of confidence in their cost estimates and schedule. Witness Ray stated that DEP based the projected costs on its long-range nuclear planning tool, which it updates regularly. *Id.* at 170. Witness Ray presented additional details regarding nuclear fleet-wide projects and the projects DEP planned for each of DEP's nuclear stations. *Id.* at 173-76; Application at 15-16, Tr. Ex. vol. 7. He concluded that DEP prudently and reasonably selected these projects as they will enable DEP to maintain the fleet in reliable and efficient condition for customers' benefit. *Id.* at 172. Witness Ray's Direct Exhibit 1 provided additional details regarding projected cost, schedule, scope, and justification for each nuclear MYRP project. Tr. Ex. vol. 16.

In his supplemental direct testimony, DEP witness Ray updated the information on the MYRP nuclear projects. Witness Ray testified that DEP did not include any new nuclear projects with its supplemental filing, but identified two nuclear projects that it was postponing until after the MYRP period and, therefore, removed from the MYRP. Tr. vol. 16, 179-80. Witness Ray explained the basis for updating MYRP project costs as agreed upon with the Public Staff and the method by which DEP developed the updated project costs. *Id.* at 181-83. Witness Ray's Supplemental Exhibits 1 and 2 provided updated in-service dates and projected costs for the nuclear MYRP projects. Tr. Ex. vol. 16

Public Staff witness Metz discussed the Public Staff's review of DEP's initial and supplemental MYRP filings and updates. Witness Metz testified that the Public Staff initiated multiple sets of discovery and participated in multiple meetings with DEP on the MYRP. Tr. vol. 16, 458. The Public Staff did not make any adjustments or raise any concerns with the need for, scope of, or projected costs for the nuclear MYRP projects. *Id.* at 478-81.

In his rebuttal testimony, DEP witness Ray noted that neither the Public Staff nor any other party recommended rejection or cost reduction for any nuclear projects DEP proposed for the MYRP. Tr. vol. 23, 289.

Based on the entire record in this proceeding, the Commission finds that DEP's projected nuclear MYRP capital investments satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a) and will be used and useful in the appropriate rate year. The Commission notes that no party offered any evidence to challenge any of the nuclear

MYRP projects. Therefore, the Commission concludes the evidence supports approval of the Revenue Requirement Stipulation's provisions regarding the nuclear MYRP projects.

Fossil/Hydro

In her direct testimony, DEP witness Turner outlined the projected natural gas, coal, and hydroelectric capital investments DEP included in the MYRP. Witness Turner described DEP's prioritization process for identification of the projects to include in the MYRP. Tr. vol. 12, 101-02. She explained that DEP applied its project management guidelines for project scope development and cost estimation. *Id.* at 102. Witness Turner presented additional details regarding the MYRP projects proposed for the natural gas, coal, and hydro generation fleets. *Id.* at 105-08; Application at 16, Tr. Ex. vol. 7. Witness Turner also testified to the importance of keeping DEP's remaining coal fired assets working efficiently to support customer's energy needs as DEP plans for those units' retirement and explained that DEP will continue to incur costs for these assets as appropriate and prudent to ensure that reliable cost-effective electricity remains available while DEP develops and implements replacement of the coal fleet. She noted that due to the continued importance of natural gas to DEP's resource mix, particularly during winter months and while DEP is developing and deploying energy storage capacity, DEP will continue to rely on its natural gas fleet as part of the diverse and dispatchable resource mix. *Id.* at 94-95. She concluded that DEP's decision to invest in these projects is prudent and reasonable as they will enable DEP to continue to provide safe, reliable, and affordable service to customers as well as comply with regulatory requirements. *Id.* at 105-06. Witness Turner's Direct Exhibit 1 provided additional details regarding projected cost, schedule, scope, and justification for each fossil/hydro MYRP project.

In her supplemental direct testimony, DEP witness Turner supported the additional fossil and hydro projects that DEP proposed to include in its MYRP. Tr. vol. 12, 112-15. She explained why certain projects that DEP removed from the MYRP were determined to be no longer necessary. *Id.* at 115-16. Witness Turner explained the basis for updated MYRP projected costs as agreed upon with the Public Staff and the method by which DEP developed the updated project costs. *Id.* at 116-17. Witness Turner's Supplemental Exhibits 1 and 2 provided updated in-service dates and projected costs for the fossil and hydro MYRP projects and cost, schedule, scope, and reasoning information for the newly added fossil and hydro projects. Tr. Ex. vol. 12.

Public Staff witness Metz testified that the Public Staff reviewed DEP's initial and supplemental MYRP filings and updates, initiated multiple sets of discovery, and participated in multiple meetings with DEP on the MYRP. Tr. vol. 16, 458, 478-81. Public Staff witness Michna testified that he did not dispute the inclusion of Steam Plant in Service projects in the MYRP, and that he agreed with DEP's philosophy of prioritizing unit reliability and resource adequacy in capital spending decisions. Tr. vol. 21, 302. Public Staff witness Thomas recommended a delay in the in-service date for the Blewett Falls fish passage project that would move the project from MYRP Rate Year 1 into MYRP Rate Year 2 due to previous and anticipated extensions of commencement of operations, and a reduction the projected cost for the project based on his review of the contractor

bid selection and internal funding approval processes, which he concluded resulted in significant excess contingency for the project. Tr. vol. 19, 208-13.

In rebuttal testimony, DEP witness Turner described how DEP's cost estimates for the Blewett Falls fish passage project, particularly the contingency allotted for the project, were based on the project's unique nature and challenges. Witness Turner disagreed with the delay of the project in service date to MYRP Rate Year 2, explaining that the timing for testing of the project is separate from the capital project construction, which according to current plans should go in service during Rate Year 1. Tr. vol. 12, 147-50.

The Revenue Requirement Stipulation accepts the Public Staff's recommended changes to the Blewett Falls fish passage project cost estimate and postponement of this project's in-service date to March 2025. Revenue Requirement Stipulation § III.33.e, Tr. Ex. vol. 7. Further, the stipulation accepts the Public Staff's recommendation for inclusion of the costs of the Blewett Falls fishing pier in the MYRP and removal from the historic test period. Revenue Requirement Stipulation § III.33.a, Tr. Ex. vol. 7. DEP witnesses Abernathy and Jiggetts and Public Staff witnesses McLawhorn and Metz supported these provisions in their settlement supporting testimony. Tr. vol. 13, 138-40, 262; Tr. vol. 16, 514.

Based on the entire record in this proceeding, the Commission finds that DEP's proposed natural gas, coal, and hydro MYRP projects satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a). DEP demonstrated that these projects are primarily in the normal course of business for maintaining the fossil and hydro fleets for reliability, safety, and regulatory compliance. In addition, DEP provided substantial evidence regarding the continued importance of the coal and natural gas fleets to its ability to continue to provide reliable service to customers and the need to continue to invest in the coal fleet until its retirement and in the natural gas fleet to reliably manage the transition away from coal. The Commission further concludes that the evidence supports approval of the Revenue Requirement Stipulation's provisions regarding these fossil/hydro projects.

Cybersecurity

In his Supplemental Direct Testimony, DEP witness Strasburger provided support for DEP's information technology (IT)/operational technology (OT) Cybersecurity project DEP will include in the MYRP. Tr. vol. 16, 184-88. Witness Strasburger explained that the purpose of the IT/OT Cybersecurity project is to assure safe and sustainable operations through proactive and effective cybersecurity design, implementation and operation of critical energy systems and their underlying technology. *Id.* at 186. He testified that the IT/OT Cybersecurity project will update OT governance and risk and compliance standards and processes, implement a new OT specific asset, patch and vulnerability management system, and deliver new OT cybersecurity threat logging and monitoring capabilities. *Id.* at 185-86. The project will also focus on expanding monitoring and threat response capabilities and will introduce proactive elements to reduce cybersecurity risks. *Id.* at 186. He noted that his Strasburger Exhibit 1 contained information regarding the IT/OT Cybersecurity project required by Commission Rule R1-17B(d)(2)j.(i)-(iii). He further testified that as DEP continues to see increased cyber threats against operational

assets, including potential geopolitical threats, cybersecurity becomes a larger component of DEP's energy transition and grid protection initiatives, and that the Commission should approve the MYRP IT/OT Cybersecurity project. *Id.* No other party offered any evidence regarding DEP's MYRP Cybersecurity project.

After having carefully reviewed the entirety of the evidence in the record on DEP's MYRP IT/OT Cybersecurity project, the Commission finds that the IT/OT Cybersecurity MYRP project satisfies the requirements set forth in N.C.G. S. § 62-133.16(c)(1)(a). DEP demonstrated that cybersecurity is becoming an increasingly critical component of its energy transition and grid protection initiatives, and that the IT/OT Cybersecurity project is reasonably necessary. Additionally, no party offered evidence to the contrary. The Commission further concludes that DEP put forth a reasonable plan to implement the IT/OT Cybersecurity project within the prescribed time period.

Battery Storage

DEP proposes a portfolio of MYRP battery energy storage projects. Tr. vol. 11, 22. The portfolio consists of six discrete and identifiable battery energy storage projects: (1) Riverside; (2) Warsaw; (3) Lake Julian; (4) Elm City; (5) Knightdale; and (6) Craggy. *Id.* DEP witnesses Tompson and Shearer (the Battery Energy Storage Panel) testified and detailed the projected cost, schedule, and scope for each MYRP project, as well as the reasoning for each project as Commission Rule R1-17B(d)(2)j requires. *Id.* at 21; *see also* Battery Energy Storage Panel Ex. 1, Tr. Ex. vol. 11. According to the Battery Energy Storage Panel, the proposed investments represent near-term investments that will play an integral role in the next phases of the energy transition. Tr. vol. 11, 21. Evidence appearing in Battery Storage Panel Exhibits 1-2 includes detailed information regarding projected cost, schedule, scope, and rationale supporting the investments. *Id.* Battery Energy Storage Panel Exhibit 2 also includes anticipated project timelines, including projected in-service month and year for each proposed project as Commission Rule R1-17B(d)(2)j requires. *Id.*

DEP's Battery Storage Panel testified as to the expected benefits associated with each proposed battery project including unique bulk power services. Tr. vol. 11, 23-25. The panel testified that battery resources are uniquely capable of serving multiple grid functions across generation, transmission, and distribution systems. *Id.* at 25. The panel testified that the Craggy, Lake Julian, and Riverside projects each comply with the Western Carolinas Modernization Project (WCMP) and support the Mountain Energy Act. *Id.* at 23-24. Additionally, the battery projects at Elm City and Warsaw both leverage and provide experience with surplus solar interconnection capacity, and they also utilize existing interconnection infrastructure thereby reducing development costs and project timelines. *Id.* at 24. Furthermore, the Knightdale battery project will be the largest battery DEP has installed and this size project provides the next phase of critical operating experience. *Id.* The Knightdale battery project will provide bulk system services including energy arbitrage and ancillary services with a grid scale battery system. *Id.* at 24-25.

Public Staff witness Thomas testified regarding DEP's proposed battery energy storage portfolio. Tr. vol. 19, 184-99. Witness Thomas recommended that DEP classify the Craggy battery project as 50.0% "Other Production Plant" and 50.0% "Transmission Plant," given that DEP sited and sized the project for a potential transmission deferral. *Id.* at 197. Witness Thomas noted that DEP has classified all battery storage projects as "Other Production Plant," with interconnection costs separated into either Transmission Plant or Distribution Plant, depending on where the facility interconnects to the grid. *Id.* at 196. For most of the projects, witness Thomas found this approach to be reasonable absent clear guidance from FERC. *Id.* For Craggy, however, witness Thomas testified that DEP identified Craggy as part of a first of a kind non-wires alternative study and sized and sited the project for a potential transmission deferral designed to alleviate a future DEP-West balancing area transmission constraint. *Id.* at 197. For those reasons, witness Thomas recommended reclassification of the Craggy battery project as 50.0% "Other Production Plant" and 50.0% "Transmission Plant." *Id.*

The Battery Energy Storage Panel rebutted witness Thomas' Craggy-related recommendation, asserting that the proposed project would not defer a transmission investment. Tr. vol. 11, 49. The panel explained that the Craggy battery would mitigate against certain delays in implementing the 230kV Craggy-Enka line project; however, it would not defer transmission investment entirely. *Id.* at 48. The panel further testified that DEP does not anticipate dispatching the Craggy battery for transmission deferral purposes – the proposed project remains cost-effective based on low interconnection costs in an area with limited generation resources. *Id.* The panel maintained that the originally proposed allocation of 100.0% Production for the project is reasonable. *Id.* at 49.

The Revenue Requirement Stipulation adopts the allocation factor by plant classification for the Craggy battery project, as proposed by DEP. Revenue Requirement Stipulation § III.33.c, Tr. Ex. vol. 7.

After careful review all the evidence in the record on DEP's MYRP proposal in this docket, and based on that evidence, the Commission finds that DEP's battery storage MYRP projects satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a). The Commission further finds that the evidence supports approval of the Revenue Requirement Stipulation's provisions regarding the battery storage MYRP projects.

Solar

DEP witness LaRoche addressed the need, rationale, and cost estimates for two solar development projects a solar project from the 2022 Solar Procurement Program DEP expects to be in service between 2025 and 2026 (2026 Solar Investment Project) and a 9.5 MW solar facility DEP proposes to place in service at the DEP Asheville Generating Plant site in Buncombe County by September 2025 (Asheville Solar Project). Application at 14; Tr. vol. 16, 113-18. Witness LaRoche stated that to identify the 2026 Solar Investment Project, DEP considered the solar investments that will result from the 2022 Carolinas Carbon Plan, the 2022 Solar Procurement Program Request for Proposals, and DEP's WCMP commitments. Tr. vol. 16, 113. Additionally, he testified that

DEP's most recent integrated resource plan (IRP) identified the need for new solar resources to reliably serve DEP's projected customer load. *Id.* at 114. Witness LaRoche also stated that N.C.G.S. 62-110.9 was a "key driver" of the 2026 Solar Investment Project, as that statute requires DEP and DEC to take all reasonable steps to achieve 70.0% carbon emission reductions by 2030 and carbon neutrality in North Carolina by 2050. *Id.* The WCMP, approved by the Commission on March 28, 2016, was also a primary regulatory driver of the program, as the Asheville Solar Project directly relates to and is a commitment stemming from the WCMP. *Id.* at 116.

Public Staff witness Thomas recommended that the Commission delay the in-service date for the Asheville Solar Project to March 2026. Tr. vol. 19, 181. Witness Thomas stated that he based this recommendation on DEP's history of delays with solar project completion as well as the potential for new challenges that may emerge during project development and construction. *Id.* at 181-82. Additionally, the Public Staff is concerned about the Asheville Solar project's costs, as the cost per kW is 50.0% higher than the cost per kW for the 2026 Solar Investment project. *Id.* at 181.

Regarding the delayed in-service date, DEP witness LaRoche testified in his rebuttal testimony that the use of historical delays is inappropriate, as blanket comparisons between past and future solar projects are not on an apples-to-apples basis. Tr. vol. 23, 262. For example, witness LaRoche noted that Public Staff witness Thomas cited DEP's delays in the Woodfin project to support his recommended delay but did not assess whether the same delays are likely to impact the Asheville Solar Project or whether DEP has taken steps to mitigate that risk. *Id.*

After having carefully reviewed the evidence in the record on DEP's Solar MYRP proposal in this docket, and based on that evidence, the Commission finds that DEP's solar MYRP projects satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a). The Commission concludes that the evidence supports approval of the Revenue Requirement Stipulation's provisions regarding the solar MYRP projects.

MYRP Implementation

Public Staff witness Metz testified to his concern regarding DEP's ability to complete the proposed MYRP projects within the three-year MYRP period. Based on his review of DEP's historic and projected 2023 staffing, Witness Metz asserted that DEP does not have a plan to increase staffing for planned MYRP projects while continuing to perform traditional work of the utility. Tr. vol. 16, 465-81.

In his rebuttal testimony, DEP witness Murray overviewed DEP's wholistic and comprehensive approach to project planning and execution while noting that neither the Public Staff nor any party recommended disallowance or rejection of any MYRP project based on generalized project execution risks or challenges. Tr. vol. 23, 313. Witness Murray discussed how Duke Energy's Project Management Center of Excellence (PMCoE) creates a common framework for managing projects across the enterprise and how DEP has successfully implemented prudent management processes historically.

While acknowledging that MYRP project execution will not be easy and that there likely will be unforeseen challenges that require DEP to, in some cases, modify planning MYRP projects to maximize benefits for customers, he explained that MYRP project execution is not a challenge that is fundamentally different than challenges inherent in DEP's historic capital project implementation and disagreed with the suggestion that DEP is not well prepared to successfully execute these projects. Tr. vol. 23, 312-18.

DEP witness Bowman also responded to the witness Metz's concerns regarding DEP's ability to execute on certain MYRP projects. Tr. vol. 21, 1211. She testified that DEP is confident in its ability to execute the MYRP projects and acknowledged DEP's obligation, as confirmed by the Commission, to continually assess the MYRP projects and ensure that customer benefits are maximized throughout the execution phase. *Id.* She explained that although DEP will encounter unforeseen challenges and circumstances, in all instances DEP will leverage its execution experience to maximize benefits for customers. *Id.*

After review of the evidence presented by DEP's various generation, transmission, and distribution witnesses, as well as the evidence presented by DEP regarding its processes, procedures, and project management experience the Commission finds that DEP has the obligation to prudently and reasonably implement the MYRP in a manner that benefits its customers. Any modification to the implementation of MYRP projects will be reported by DEP on a quarterly basis, as required under Commission Rule R1-17B(h(2)) and will be subject to audit in future base rate case proceedings. While the Commission recognizes the risk about which the Public Staff is concerned, the Commission determines, on the evidence presented, that DEP has demonstrated a reasonable plan to complete the MYRP projects within the prescribed time periods.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 30

Reporting Requirements

The evidence supporting this finding of fact is included in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Bowman, Abernathy, Jiggetts, and Guyton, and Public Staff witnesses Zhang, Boswell, McLawhorn, Metz, Nader, T. Williamson, and Thomas; the Revenue Requirement Stipulation; and the entire record in this proceeding.

Rider EC

In his testimony, Public Staff witness Nader testified that to ensure that the proposed Rider EC continues to be in the public interest, the Commission should require annual reporting on the impacts of Rider EC. Tr. vol. 21, 106. Witness Nader recommended that DEP should report the gross level of incentives DEP paid, the number of recipients, the amount of investment, load, and jobs associated with the incentives, and an overall marginal cost analysis of Rider EC to determine if the gross level of incentives DEP paid exceeds the marginal cost to serve the gross pool of participants. *Id.*

CIAC Reporting

In their joint direct testimony, Public Staff witnesses Zhang and Boswell stated that DEP was booking contributions in aid of construction (CIAC) related to interconnection agreements (IA) inconsistently. Witnesses Zhang and Boswell recommended that the Commission order DEP to review its CIAC policy to ensure that DEP properly accounts for CIAC and report the results of that review in the next general rate case. Tr. vol. 19, 39-40. In rebuttal, DEP witness Speros rebutted the notion that DEP was booking its CIAC related to IAs inconsistently but stated that DEP did not oppose in principle reporting to the Commission on its CIAC policy in the next general rate case. Tr. vol. 13, 63.

Vegetation Management Reporting

Public Staff witness T. Williamson recommended that the Commission require DEP to perform additional reporting requirements beyond the Vegetation Management Program Performance report DEP files annually. He recommended that DEP report on the additional following topics: (1) distribution vegetation management herbicide actuals, target, and variance for spending and miles; (2) distribution vegetation management number of miles of vegetated distribution lines that require trimming or herbicide treatment; (3) distribution vegetation management hazard tree program actuals, target, and variance for spending and tree counts; and (4) distribution vegetation management reactive/demand events, and the number of events worked annually. Tr. vol. 21, 217-18. In his rebuttal testimony, witness Guyton stated that DEP can provide the recommended additional distribution reporting requirements beyond the Vegetation Management Program Performance DEP files annually with two exceptions. Tr. vol. 10, 147.

Hot Springs CBA

In his testimony, Public Staff witness Thomas recommended the Commission direct DEP to perform an updated cost benefit analysis for Hot Springs. Tr. vol. 19, 194. He further recommended that DEP provide the updated cost benefit analysis with its operational report for the Hot Springs facility on October 31, 2023, in Docket No. E-2, Sub 1185. *Id.*

Discussion and Conclusions

The Revenue Requirement Stipulation establishes certain reporting obligations. Specifically, Paragraph 34 obligates DEP to report on Rider EC, subject to agreement of the Revenue Requirement stipulating parties regarding the scope and content of the report. Paragraph 35 obligates DEP to report on the CIAC issue in its next general rate case application. Paragraph 36 addresses a reporting on reliability O&M as discussed by Public Staff witness Metz, and a management reporting requirement as discussed by Public Staff witness T. Williamson, except for reporting on the two issues noted in the rebuttal testimony of DEP witness Guyton. In Paragraph 38, the Revenue Requirement stipulating parties agree to discuss the need for a report on the Hot Springs CBA as requested in the testimony of Public Staff witness Thomas. Besides the exceptions noted

in Paragraphs 34-38 of the Revenue Requirement Stipulation, Paragraph 39 indicates that DEP agrees to all reporting requirements proposed by the Public Staff.

No other party offered any evidence addressing the reporting obligations outlined in the Revenue Requirement Stipulation. The Commission concludes that the reporting obligations agreed-upon in Section IV of the Revenue Requirement Stipulation are reasonable. Based upon the record evidence and consistent with the Revenue Requirement Stipulation, the Commission finds and concludes that the reporting obligations outlined in Section IV of the Revenue Requirement Stipulation are approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 31

The evidence supporting this finding of fact is in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Hunsicker, Quick, and Jiggetts; the supplemental and settlement testimonies of Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

In prior DEP rate cases, including Dockets No. E-2, Sub 1023, E-2, Sub 1142, and E-2, Sub 1219, the Commission has approved a calculation of "storm normal" expenses based upon a 10-year average of storm costs, after reducing the costs associated with major storms, to include in rates. Witness Jiggetts explained the methodology for the calculation of storm normal in this case. Tr. vol. 14, 29-30. The resulting amount to include in rates per DEP's calculation is approximately $22.2 million. Jiggetts Partial Settlement Ex. 4, Tr. Ex. vol. 14.

No party disputes DEP's calculation of storm normal expenses to include in rates, and DEP witness Jiggetts testified that the Public Staff agrees with the amount as calculated by DEP. Tr. vol. 14, 58.

Accordingly, the Commission finds that the appropriate North Carolina retail normalized annual level of storm costs to include in DEP's rates in this case is $22.243 million.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 32-34

Distribution System Demand Response

The evidence supporting this finding is in the verified Application and Form E-1; the testimony and exhibits of DEP witnesses Jiggetts and Hunsicker; the testimony and exhibits of Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

In this case, DEP proposed to move the future costs associated with its DSDR energy efficiency program from the DSM/EE rider into base rates starting on the effective date for the new rates established in this proceeding as the Commission instructed in its Order from the 2019 Rate Case. Tr. vol. 13, 204. DEP witness Jiggetts explained that

DEP will continue to recover costs deferred to the regulatory asset before the effective date for new rates in this proceeding through the DSM/EE rider until they are fully amortized. *Id.* Public Staff witnesses Zhang and Boswell testified that DEP's proposal to recover the future DSDR costs in base rates is appropriate because all customers benefit from DSDR. Tr. vol. 19, 74.

No party opposed DEP's request.

Payment Navigator

The evidence supporting this finding is in the verified Application; the testimony and exhibits of DEP witnesses Jiggetts and Quick; and the entire record in this proceeding.

In her direct testimony, DEP witness Jiggetts stated that DEP proposed several new programs in this rate case to benefit customers, including the CAP, the Tariffed On-Bill program, and the Payment Navigator Program that DEP witnesses Harris and Quick also discussed in their testimony. If the Commission approves each program, DEP requests permission to establish a regulatory asset and defer to the account the incremental implementation and administration O&M costs related to the programs. Tr. vol. 13, 209.

DEP witness Quick described DEP's Affordability Ecosystem in her direct testimony. The Affordability Ecosystem is a multi-pronged approach to assist customers who have challenges in affording to pay their electric utility bills. The Affordability Ecosystem includes products and services, including bill pay assistance and weatherization programs, and DEP equips its customer service team to inform customers about opportunities to address their affordability challenges. Tr. vol. 7, 75. Consistent with DEP's Affordability Ecosystem, witness Quick requested approval of the Payment Navigator program, which DEP specifically designed to comprehensively support not only low-income customers in arrears on their bills, but all customers seeking assistance in managing their electric utility bills. *Id*. at 172. The Payment Navigator program is based on a pilot that DEP tested during the COVID-19 pandemic with customers seeking support in paying their electric bills. *Id*. at 175-77. As witness Quick described, in accordance with the Payment Navigator program, DEP proactively contacts customers who are struggling with arrearages to invite them to speak with a Payment Navigator specialist. A Payment Navigator specialist is a call center agent trained to empathetically handle more complex calls assisting customers who have fallen behind in their bills, and the specialist can take the necessary time to work with customers on obtaining the assistance they need. *Id.* at 177. Based on the customer's situation, the Payment Navigator specialist may tailor a unique set of recommendations to assist the customer in becoming current on payments and provide longer-term guidance on how to ease the customer's electric energy burdens by connecting the customer to assistance funding, referring them to energy efficiency or demand side management options, or enrolling them in programs like Budget Billing, Pick Your Own Due Date, and more. *Id.* at 78-79.

DEP witness Quick highlighted the positive feedback and insights that DEP received regarding the Payment Navigator pilot and the success that DEP had in referring customers to agencies for assistance, enrolling them in deferred payment arrangements, and recommending flexible billing programs. *Id.* at 79. During the pilot, by assisting customers to access this available funding, Payment Navigator helped customers obtain all the funding available to them from certain assistance agencies, in contrast to previous years when agencies' funds were not utilized. *Id*. at 175-76. Witness Quick also stated that during the pilot, DEP learned that about 50.0% of the customers that DEP contacted were not aware of the assistance available to them. She noted that some customers have difficulty reading and completing applications, and DEP learned during the Payment Navigator pilot that customers dropped out sometime during the application process and did not complete the applications. Witness Quick indicated that Payment Navigator specialists could benefit customers by working with them to complete the applications so that they can access all available funding. Tr. vol. 22, 132-33.

DEP witness Quick also testified that Payment Navigator would complement the CAP that DEP witness Harris described. She noted that CAP will directly benefit customers by reducing their monthly electric energy burden through a bill discount. After a customer enrolls in CAP, DEP can continue to work with the customer to understand the customer's needs and analyze what other products and services (such as Share the Light, Budget Billing, energy efficiency offerings, weatherization, and payment plans) are available to support the customer over the longer term. Tr. vol. 7, 80.

Witness Quick concluded by requesting that the Commission approve the Payment Navigator program and associated costs, which she estimated to be $3 million over the next three years. She noted that the deferral request that DEP witness Jiggetts describes in her testimony addresses the associated incremental O&M costs that the $3 million estimate includes. Witness Quick testified that DEP would not defer any capital costs associated with the program. *Id*. at 80-81

No party contested the implementation of the Payment Navigator program.

Customer Connect

In its Application, DEP requested recovery of the approximately $60 million North Carolina retail allocated capital investment associated with implementation of its Customer Connect project, the new customer engagement platform, and CIS. Tr. vol. 16, 71, 82. DEP witness Hunsicker testified that in November 2021, DEP implemented the Customer Connect platform including a CIS, which is a system that manages the billing, accounts receivable, and rates for DEP as a central repository for all customer information. *Id.* at 71-72. She explained that CIS links the consumption and metering process to payments, collections, and other downstream processes, including additional work order requests such as service connections and disconnections, outages, and trouble requests. CIS also manages customer profiles and integration of data to provide a holistic view of the customer and it should enable expected customer capabilities. *Id.* at 72-73. Witness Hunsicker explained that DEP developed its previous CIS almost 30 years

ago and the system could not efficiently support new capabilities, and thus required complex add-ons and manual performance of some complex billing functions. *Id.* at 71.

Witness Hunsicker explained that Customer Connect benefits customers by providing a modern, configurable billing system that allows DEP to keep pace more efficiently with changing customer expectations and needs. Improvements with Customer Connect include a customer-centric data model and more holistic customer data analytics capabilities, which allow DEP to better know its customers and the usage needs across the entire Duke Energy footprint and provide a more customized experience. She explained that since she first testified to the need for Customer Connect in the 2017 Rate Case, DEP has kept stakeholders informed of the status of the implementation and that, while no complex, enterprise-wide CIS implementation is without challenges, its Customer Connect implementation benchmark metrics compare favorably to industry benchmarks. *Id.* at 72.

No party contested DEP's request to recover its costs related to Customer Connect.

Discussion and Conclusions

No parties opposed DEP's requests related to DSDR, Payment Navigator, or Customer Connect. In *State ex rel. Utils. Comm'n v. Intervenor Residents*, 305 N.C. 62, 75-77, 286 S.E.2d 770, 778-79 (1982), the North Carolina Supreme Court held that the Commission can accept the uncontested evidence of a public utility regarding the reasonableness of its costs as satisfying the utility's burden of proof on the question of cost recovery. The Commission concludes that DEP has met its burden of showing that its proposals related to DSDR, Payment Navigator, and Customer Connect are just and reasonable.

More specifically, the Commission concludes that DEP's proposal to include future DSDR program costs in base rates starting with the effective date of the rates established in this proceeding to be reasonable and appropriate. Further, the Commission concludes that DEP's requested recovery of costs associated with its Customer Connect project is just and reasonable to all parties considering the evidence presented.

Finally, the Commission approves implementation of Payment Navigator and recognizes and appreciates the work of DEP to undertake this effort during the COVID-19 pandemic and to devote resources and expertise to connecting customers with assistance during the crisis. The Commission recognizes the customer benefits that arise, particularly in the context of those customers most in need, when DEP (and its affiliates) apply their specialized knowledge and resources in direct support of the customers. The Commission encourages DEP to continue to partner with assistance agencies across its service area and to proactively contact struggling customers to direct them to contact a Payment Navigator specialist for assistance in managing their electric utility bills.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 35

COSS Stipulation

The evidence supporting this finding is in DEP's verified Application and Form E-1; the COSS Stipulation; the testimony and exhibits of DEP witness Hager, Public Staff witnesses McLawhorn and D. Williamson, and CIGFUR witness Phillips; and the entire record in this proceeding.

Summary of Evidence

DEP Direct Testimony

Cost of Service Study Overview

In her testimony, DEP witness Hager described the purpose of a cost of service study (COSS) and how costs are assigned pursuant to such study. She explained that the COSS is used to align the total costs incurred by DEP in the test period with the jurisdictions and customer classes responsible for those costs. Tr. vol. 11, 82. Using the principle of cost causation, the COSS assigns or allocates DEP's revenues, expenses, and rate base to the regulatory jurisdictions and to customer classes that caused such costs to be incurred. *Id.* Costs are first grouped according to their function. *Id.* at 84. Functions include production (generation); transmission; distribution; and customer service, billing, and sales. *Id.* Functionalized costs are then classified based on the utility operation or service being provided and the related causation of the costs. *Id.* Typical classifications include demand, energy, and customer-related costs. *Id.* Finally, the functionalized and classified costs are allocated or directly assigned to the proper jurisdiction and customer class based on the way the costs are incurred (i.e., based on cost causation principles). *Id.* at 84-85. Once all costs and revenues are assigned, the COSS identifies the return on investment that DEP has earned for each customer class during the test period, and these returns can then guide rate design. *Id.* at 83.

The COSS Stipulation

On September 13, 2022, DEP, DEC, the Public Staff, CIGFUR, and CIGFUR III (the COSS Stipulating Parties) filed the COSS Stipulation with the Commission. Tr. vol. 11, 80. The COSS Stipulation provides that production and transmission demand costs are first allocated to the North Carolina retail jurisdiction using the 12 CP method, and then production demand costs are allocated within North Carolina retail rate classes using the Modified A&E method. *Id.* Because transmission demand does not have average or excess energy components, the transmission demand factors at the customer class level are equivalent to the 12 CP calculation. *Id.* The stipulation also provides that, for purposes of allocating production demand costs on a jurisdictional basis as well as to North Carolina retail rate classes, DEP will make an adjustment to exclude certain curtailable/interruptible loads if they were not curtailed at the twelve system peak hours during the test year. *Id.* By its terms, the COSS Stipulation only applies in the current rate

case, and COSS Stipulating Parties are free to advocate for different methodologies in future DEP cases. *Id.* DEP witness Hager testified that the stipulation is reasonable and that the Commission should approve it, noting that it was the result of the give-and-take inherent in coming to a settlement among parties with diverse views on the appropriate methodologies. *Id.* at 80-81. The COSS Stipulating Parties urge the adoption of the stipulation in this case as a fair and reasonable methodology for the allocation of costs. COSS Stipulation at 4-5, Tr. Ex. vol. 7.

The 12 CP Method

Under the COSS Stipulation, the 12 CP method will be used to allocate costs to the North Carolina retail jurisdiction. COSS Stipulation at 3, Tr. Ex. vol. 7. Witness Hager testified that in its previous rate case, DEP recommended, and the Commission approved, the summer coincident peak (Summer CP) method to allocate the fixed portion of production and transmission demand-related costs. *Id.* at 89. However, DEP now believes it is appropriate to move from Summer CP to 12 CP, which utilizes the average of the test year's twelve monthly peaks. *Id.* Witness Hager testified that DEP's integrated resource planning period has shifted away from an emphasis solely on summer peaks, and that by averaging the twelve monthly peaks, the 12 CP method is less volatile than a single coincident peak. She further testified that the 12 CP method is regularly used by other utilities and has been approved by state commissions and the FERC. *Id.* at 89-90.

The Modified A&E Method

The COSS Stipulation also proposes a Modified A&E method to allocate production demand costs across North Carolina retail customer classes. COSS Stipulation at 3, Tr. Ex. vol. 7. DEP witness Hager testified that the Modified A&E method adopted under the COSS Stipulation considers that generation facilities are needed to serve a utility's "average load" as well as its "excess or peak load" in assigning responsibility for the recovery of production demand-related costs. Tr. vol. 11, 81. The excess demand is the excess of a rate class' non-coincident peak (NCP) demands over its average demands. Under this method, all groups of customers are allocated some portion of the production plant investment and fixed expenses related to the generation of power. *Id.* at 96. A rate class' coincident peak demand is the class' load at the time of the system's peak demand, while a rate class' NCP is the maximum demand regardless of the time of occurrence. *Id.* Witness Hager explained that each customer class' non-coincident demand likely occurs at different times. *Id.* She noted that the A&E method is used in several jurisdictions including at least a third of the 30 utilities she examined and is a reasonable method for allocating demand-related production costs to the North Carolina retail classes in this case. *Id.* at 156, 81. However, DEP modified the method to conform the A&E allocators to the 12 CP method used at the North Carolina retail jurisdictional level. *Id.* at 97. In response to Commissioner Clodfelter's question, witness Hager testified that this method was used by Dominion in Virginia, but has never been used by Dominion in North Carolina. *Id.* at 130. Additionally, Witness Hager testified that since the sum of NCPs exceeds the coincident system peak, the excess components for each rate class were scaled down proportionally, such that the sum of their demand

matches the coincident system peak. *Id.* at 133. In response to Commission questions, DEP witness Hager stated that DEP did not use the 12 CP method for both jurisdictional and rate class allocation for this proceeding as it did in South Carolina, a difference which Witness Hager attributed to the COSS Stipulation. *Id.* at 134.

Removal of Certain Curtailable/Interruptible Loads

DEP witness Hager testified that, historically, DEP has allocated production fixed costs based on the demands served at its peak hour. *Id.* at 97. She testified that aligning firm load with firm capacity to serve that load is more consistent with the principle of cost causation than the previous method. *Id.* at 98. DEP does not plan for, and does not purchase capacity for, the curtailable load of customers. *Id.* Since DEP can curtail customers who take interruptible service so that their load does not contribute to the system peak, interruptible load does not factor in to how much the utility must invest in capacity to meet the system peak. *Id.* If the utility curtails all possible curtailable load in the test year during system peaks, there is no need for adjustments, as revenues and loads both reflect only firm load. *Id.* However, there can be a mismatch between revenues and loads if there is some non-firm load in the test year peaks. *Id.* Accordingly, DEP has removed non-curtailed non-firm load present during the test year peaks where its presence would create a mismatch with revenues. *Id.* This adjustment ensures a matching of firm load with firm load revenues. *Id.* This practice is also consistent with FERC precedent. *Id.* Witness Hager testified that this proposed method will eliminate the volatility of having load in one test year and out in the next test year. *Id.* at 100.

Adjustments were made to remove certain curtailable load at both the North Carolina retail jurisdiction level with the 12 CP method, as well as at the North Carolina retail rate class level with the modified A&E method. *Id.* at 101. The demand-related transmission costs were allocated to rate classes based on 12 CP demand, without adjustment for curtailable load. *Id.*

Distribution Costs

DEP witness Hager testified that most distribution investments are identified and then directly assigned to the state in which they are located. *Id*. Distribution costs identified as customer-related are allocated using customer allocation factors, and the remainder are designated as demand-related and allocated to customers based on NCP demand allocators. *Id.*

NCP allocators are developed to account for the different levels of the distribution system where customers may take service. *Id.* Witness Hager explained that NCP allocators are developed by taking the ratio of the non-simultaneous peak demands of the customers in each class whenever that peak occurred during the test period and comparing that to the sum of all customers' non-simultaneous peak demands. *Id.* She noted that several different NCP allocators are developed to account for the different levels of the distribution system where customers may take service (primary, secondary, etc.). *Id.* For example, only the NCP demand of customers taking service at secondary

voltage is included in the development of the NCP allocator used to allocate secondary distribution lines and poles. *Id.* at 101-02.

Further, witness Hager testified that NCP allocators are used for demand-related distribution investment because distribution facilities serve individual neighborhoods, rural areas, or commercial districts; they do not function as a single integrated system in meeting system peak demand. *Id.* at 102. The individual distribution system serving an area must be able to meet the peak demand in the area it serves, whenever the peak occurs. *Id.* Accordingly, Witness Hager testified that contribution to NCP is the appropriate measure of determining customers' responsibility for costs, because it best measures the factors that drive investment to support that part of the system. *Id.*

Energy Allocators

DEP witness Hager testified that energy-related costs, such as fuel costs and variable production costs at generating stations, reflect the variable cost of producing, transmitting, and delivering electricity. *Id.* at 102. She testified that these costs are allocated using DEP's kWh of generation and deliveries during the test period. *Id.* Witness Hager explained that kWh sales information is collected and adjusted for the level of losses attributable to each class and jurisdiction to determine the level of kWh at the generator attributable to that class or jurisdiction. *Id.*

Customer Allocators

DEP included operating expenses in FERC accounts 901-917 for allocation as customer-related costs that include meter reading, billing and collection, and customer information and services. Tr. vol. 11, 103. DEP has also included in this category a portion of distribution costs that it has identified as customer-related, such as meters and service drops (FERC accounts 369 and 370) and a portion of transformers (FERC account 368). *Id.* A portion of costs for distribution lines and poles (FERC accounts 364-367) were also identified as customer related. *Id.* The remaining distribution plant and associated costs were classified as demand-related, except for FERC account 363, Energy Storage Equipment – Distribution. *Id.*

Account 363, beginning in 2020, had a small balance of approximately $11 million related to batteries. *Id.* DEP witness Hager testified that storage battery equipment functionalized to distribution (FERC account 363) is allocated across customer classes using gross distribution plant excluding batteries. *Id.* This approach recognizes that batteries provide benefits to or support different parts of the distribution system. *Id.*

Witness Hager testified that a portion of distribution costs related to FERC accounts 364-68, including costs of poles, towers, fixtures, overhead and underground conductors, and transformers, are customer-related. *Id.* at 104. NARUC discusses using two methods for allocating these customer-related distribution costs: the Minimum System Method and the Zero-Intercept Method. *Id.* Witness Hager testified that both methods recognize that some portion of the distribution system is necessary to serve customers, regardless of whether the

customers take any energy from the system. *Id.* The Minimum System Method seeks to determine the minimum size distribution system that can be built to serve the minimum load requirements of customers. *Id.* This method develops the cost of the minimum set of distribution assets that are needed to serve customers, and allocates those costs based on the number of customers. *Id.* The Zero-Intercept Method, according to witness Hager, similarly allocates a portion of the same distribution accounts on the basis of the number of customers and seeks to identify the portion of distribution plant that is associated with no load using regression techniques. *Id.*

Witness Hager testified that DEP incorporated the Minimum System Method into its COSS and testified that this was appropriate for the allocation of customer-related distribution costs. *Id.* at 105. She explained that the Zero-Intercept Method is a more complex and time-consuming methodology. Witness Hager further explained that the Minimum System Method, which is sound and consistent with cost causation, produces results that are not materially different from the Zero-Intercept Method. *Id.* DEP's Minimum System Study allowed DEP to classify the distribution system into customer-related and demand-related portions. *Id.* She testified that because every customer requires some minimum amount of wires, poles, and other distribution infrastructure, every customer "causes" DEP to install some amount of distribution assets. *Id.* The concept used by DEP in developing its Minimum System study was to consider what distribution assets would be required if every customer had only a minimum level of usage. *Id.* This allows DEP to assess how much of its distribution system is installed simply to ensure that electricity can be delivered to each customer. *Id.* Once minimum system costs are identified, distribution costs over this amount and direct assignments of those extra costs are determined to be driven by demand. *Id.*

Witness Hager testified that the PBR Statute requires the use of the minimum system methodology to allocate distribution costs between customer classes. *Id.* at 106.

The Public Staff Testimony

Public Staff witness McLawhorn testified in support of the COSS Stipulation and discussed the stakeholder process that led to that settlement. Witness McLawhorn discussed the Commission's March 31, 2021, Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice issued in Docket No. E-7, Sub 1214, in which the Commission adopted the Second Agreement and Stipulation of Partial Settlement (Sub 1214 Partial Settlement). Tr. vol. 16, 398-99. The Sub 1214 Partial Settlement provided for an analysis of various cost of service methodologies in which DEP and DEC agreed to consult with the Public Staff and interested parties to analyze and develop cost of service studies based upon specific criteria, including the analysis of the various strengths and weaknesses of each respective methodology, and to file the resulting COSS with the Commission before DEP filed its next rate case. *Id.* at 399. As witness McLawhorn described, the stakeholders met several times throughout 2021, holding the final meeting on November 16, 2021. *Id.* On January 25, 2022, DEP and DEC filed the results of the COSS in Docket Nos. E-2, Sub 1219 and E-7, Sub 1214, as the Commission required. *Id.* at 400. Although the stakeholder process did not result in a consensus as to the appropriate cost of service allocation methodology to

utilize, it helped certain parties arrive at the COSS Stipulation that is before the Commission in this case. *Id.*

Public Staff witness D. Williamson also testified in support of the COSS Stipulation, including the results of his investigation on how the COSS influences the way DEP's base rate charges will reflect the requested revenue requirement changes. Tr. vol. 20, 133. As witness D. Williamson explained, it is important that the utility consider all costs in the COSS to ensure that it is reasonably able to recover its full cost to serve all customers, while also ensuring that all jurisdictions and customer classes bear the appropriate responsibility for the respective costs they impose upon the system. *Id.* at 149-50. In discussing the 12 CP methodology for jurisdictional allocations and the modified A&E methodology for NC retail allocations, witness D. Williamson confirmed that the use of different cost of service allocation methodologies may be unusual for a general rate case in North Carolina, but use of two methodologies does occur in some other jurisdictions. *Id.* at 152. In sum, witness D. Williamson recommended approval of the COSS Stipulation and DEP's use of the methodologies to which the parties agreed in the COSS Stipulation. *Id.* at 180.

CIGFUR Testimony

CIGFUR witness Phillips filed testimony in support of the COSS Stipulation. Witness Phillips testified that the COSS Stipulation is reasonable and that the Commission should approve it in its entirety. Tr. vol. 21, 477. Witness Phillips also testified that both the 12 CP and modified A&E methodologies are theoretically sound, reflect principles of cost causation as required by N.C.G.S. § 62-133.16(a)(1) and (b), and should be used for ratemaking in this proceeding. *Id.* at 474, 477. Witness Phillips further testified that DEP has appropriately allocated distribution system costs to customer classes in a manner consistent with N.C.G.S. 62-133.16(b), which requires the use of minimum system methodology by an electric public utility for the purpose of allocating distribution costs. *Id.* at 473. Witness Philips additionally testified about the relation between the excess component of the A&E method as it relates to additional capacity requirements. *Id.* at 479.

CUCA Testimony

CUCA is not a party to the COSS Stipulation. CUCA witness O'Donnell acknowledged that such settlements are a product of give-and-take settlement negotiations. Tr. vol. 21, 648. Despite this, witness O'Donnell testified that the results of any model should be viewed considering the economic impact that DEP rate increases will have on the economic drivers in North Carolina. *Id.* Witness O'Donnell recommended that if the Commission were to accept the modified A&E cost allocation method, then the Commission should set rates with the recognition that North Carolina is losing manufacturing jobs more than other southern states. *Id.* at 652-53. Witness O'Donnell questioned whether the time is right for DEP to transition to full implementation of the A&E method. *Id.* at 653. Nevertheless, he testified that CUCA does not oppose the COSS Stipulation. *Id.* at 648.

The Commercial Group Testimony

The Commercial Group is not a party to the COSS Stipulation. However, Commercial Group witness Chriss testified that for the purposes of this rate case, the Commercial Group does not oppose DEP's proposed production capacity cost allocation methodology. Tr. vol. 21, 520.

North Carolina League of Municipalities (NCLM)

The NCLM was the only party to cross-examine DEP witness Hager during the expert witness hearing on May 8, 2023. Tr. vol. 11, 113-58. NCLM questioned witness Hager as to whether a 20.0% increase in lighting rates in year one of the MYRP would be considered a "gradual" change. *Id.* at 117-20. In response, witness Hager testified that, while the change in cost of service methodology did lead to DEP's allocating more cost to the Lighting class, only a portion of that increase was driven by the change in cost of service methodology. *Id.* at 119. She also testified that the point of a cost of service study is to determine allocation of costs to customer classes, but that rate design ultimately uses the cost of service study to determine rates for customers. *Id.* at 120. Witness Hager acknowledged that this COSS allocates more costs to lighting. *Id.* at 119. But she also testified that this is reasonable because the COSS determined that this increase was consistent with cost causation principles, meaning that lighting customers are causing more costs to be incurred on the system. *Id.* at 120.

Further, NCLM questioned whether all parties participated in the COSS collaborative and in settlement discussions. *Id.* at 121-22. Witness Hager testified that DEP invited all entities that were parties to the previous rate case to participate in the COSS collaborative that led to settlement discussions, which then led to the COSS DEP uses in this case. *Id.* at 122. NCLM was a party to the prior case but did not participate in the COSS collaborative and did not offer any alternative cost of service methodology in this rate case.

Discussion and Conclusions

Although the COSS Stipulation is not unanimous, no other party to this proceeding has proposed an alternative cost of service methodology. Tr. vol. 11, 125.

Based upon the evidence presented in this case, including the evidence offered in support of the stipulation as well as the evidence elicited through cross-examination as discussed hereinabove, the Commission approves the COSS Stipulation. The Commission notes that the use of the diversified non-coincident peak demand to calculate the excess allocation portion of the Modified A&E methodology is a departure from both the method approved currently for DEP as well as the A&E method applied in South Carolina. Therefore, the Commission directs DEP to provide a more detailed justification for the use of a NCP demand over a coincident peak demand for any cost allocation purpose in future rate cases.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 36

TCA Stipulation

The evidence supporting this finding of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Abernathy and Bateman and Public Staff witness Metz; the TCA Stipulation; and the entire record in this proceeding.

As explained by DEP witness Maley, the Red Zone Expansion Plan transmission projects (RZEP Projects) included in DEP's MYRP consist of transmission upgrades needed to enable interconnection of additional solar generation on the DEP transmission system. DEP witness Abernathy testified as to the revenue requirement sought by DEP for the RZEP Projects, which involved allocation of all RZEP costs to DEP. In light of concerns expressed by the Public Staff in the Carbon Plan proceeding regarding the imbalance of transmission costs being incurred between DEC and DEP associated with the interconnection of new generation, DEP presented (but did not propose) an alternative allocation of RZEP costs as between DEC and DEP based on respective retail transmission demand load ratio share. Tr. vol. 13, 99-101. Witness Abernathy testified that DEP did not support this allocation but included the calculation in the event the Commission determined that such an allocation was more appropriate in light of the concerns of the Public Staff. *Id.* at 102.

While the Public Staff found merit in DEP's alternative proposal, Public Staff witness Metz recommended a different proposal that focused on the net energy transfers between DEP and DEC. Tr. vol. 16, 454-55. DEP witness Metz explained that the Public Staff's alternative proposal utilizes the non-firm transmission rate from the FERC-approved OATT of DEC, Duke Energy Florida, LLC (Duke Energy Florida), and DEP, which incorporates capital and ongoing O&M costs of the DEC and DEP transmission systems. He testified that DEP's alternative allocation only considers a discrete portion of each utility's system and does not consider the O&M costs. The OATT, updated annually and listed on the OASIS website, provides an established calculation for transmission system capital and O&M costs that is transparent and easily verifiable. *Id.*

DEP and the Public Staff resolved their differences on this issue and, as set forth in the TCA Stipulation, agreed to a pro forma adjustment of approximately $20 million to increase the revenue requirement in the DEC Rate Case and a corresponding decrease the revenue requirement in the instant proceeding.

DEC, also a party to the stipulation, DEP, and the Public Staff agreed to calculate the pro forma amount of transmission expense for DEC and transmission revenue for DEP by multiplying the net transfers from DEP to DEC under the JDA in 2022 by the DEP non-firm transmission rate from the FERC-approved Joint OATT of DEP, DEC and Duke Energy Florida. The stipulation makes clear that the adjustment is for North Carolina ratemaking purposes only and will neither change the terms or conditions of the JDA nor result in any accounting entries for DEP or DEC. The TCA Stipulation provides that the

adjustment will become effective on October 31, 2023, for both DEP and DEC and will terminate at the sooner of the effective date of rates in DEP's or DEC's next general rate case or the effective date of a full merger of DEP and DEC, unless the Commission orders otherwise. TCA Stipulation § II, Tr. vol. 7, 23.

DEP witness Bateman testified in support of the TCA Stipulation. Tr. vol. 14, 146. She testified that the TCA Stipulation is the result of substantial discovery and extensive negotiation among the stipulating parties and that it reflects a constructive near-term approach to addressing rate disparity concerns arising from the increasing net energy transfers from DEP to DEC under the JDA. *Id.* Public Staff witness Metz also testified in support of the TCA Stipulation. Tr. vol. 16, 517-18. Witness Metz testified that the TCA Stipulation addresses the growing level of net energy transfers and the subsequent rate disparity between DEP and DEC in North Carolina and explained that the adjustment will compensate DEP and DEC ratepayers for the use and annual maintenance of each utility's transmission system for energy transfers under the JDA. *Id.*

The Commission concludes that the TCA Stipulation itself, along with the expert testimony discussed above, is credible evidence and is entitled to substantial weight in the Commission's ultimate determination on this issue. No party offered evidence opposing the TCA Stipulation, and the Commission concludes that the TCA Stipulation, as supported by the testimony cited above, establishes a reasonable method to align costs with cost causation principles. Utilization of this method appropriately balances DEC and DEP benefits to the least cost dispatch of their respective systems. Accordingly, the Commission concludes that the provisions of the TCA Stipulation are in the public interest and are just and reasonable to all parties in this proceeding. Therefore, the TCA Stipulation is approved for the purposes of DEP's Application in this proceeding. The Commission notes that all parties have an opportunity in the pending DEC PBR proceeding in Docket No. E-7, Sub 1276 to address the DEC impacts of the TCA Stipulation before the Commission addresses the TCA Stipulation in that proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS FOR FACT NOS. 37-38

PIMs Stipulation

The evidence supporting these findings and conclusions is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Bateman and Stillman, Public Staff witnesses D. Williamson and Thomas, AGO witness Nelson, and CIGFUR witnesses Phillips and Gorman; the PIMs Stipulation; and the entire record in this proceeding.

PIMs

DEP initially proposed the following PIMs in its Application: (1) Peak Load Reduction, (2) Low-Income/Affordability, (3) Reliability, and (4) Renewables Integration and Encouragement. Tr. vol. 14, 91-99.

As filed, the Peak Load Reduction PIM encouraged DEP to reduce peak load, based on the estimated winter peak kilowatt reduction resulting from new customer enrollment in DEP's dynamic and time differentiated rate programs. *Id.*

The Low-Income/Affordability PIM provided incentives for DEP to encourage voluntary contributions to its existing "Share the Light" Fund, which provides financial assistance to customers who are struggling to pay their energy bills, through a structure that establishes graduated shareholder contributions and shareholder bonus matching contributions to fund health and safety repairs for low-income residences based upon target levels of contributions to the Share the Light Fund. *Id.*

The Reliability PIM held DEP accountable to maintain service reliability as measured by SAIDI (excluding Major Event Days (MEDs)). This PIM features graduated penalties DEP shall distribute to customers for failure to maintain SAIDI below tiered threshold levels that DEP will base upon historic averages adjusted for statistical confidence levels and increased outages due to additional grid work that DEP expects during the MYRP. *Id*.

The Renewables Integration and Encouragement PIM involved three metrics to incent and reward DEP. The Distributed Energy Resource (DER) Integration Metric A provided graduated rewards to DEP for exceeding targets for the number of net-metered DER customers interconnected to the DEP system. *Id.* at 104. The Large Customer Renewable Program Encouragement Metric B provided an incentive for DEP to design, obtain approval of, and subscribe customers to new renewable programs that meet these customers' desires for access to clean energy resources. *Id.* at 106. The Residential Customer Shared Solar Program Encouragement Metric C encouraged DEP to subscribe residential customers to new shared solar programs. *Id.* at 107.

In addition to the PIMs, DEP also proposed three tracking metrics in the areas of customer service, carbon dioxide (CO2) emissions, and beneficial electrification. The proposed customer service tracking metric supported maintaining adequate levels of customer service per N.C.G.S. § 62-133.16(d)(2)j. *Id*. at 113. The proposed CO2 emissions tracking metric would report progress towards compliance with the CO2 reduction requirements of S.L. 2021-165 and the Carbon Plan. *Id.* at 113-14. Finally, the third metric proposed to report on incremental load from EVs. *Id.* at 114.

Public Staff witnesses D. Williamson and Thomas expressed concerns with each PIM, beginning with the metric DEP proposed in the Peak Load Reduction PIM. Tr. vol. 18, 390. The Public Staff testified that time of use (TOU) customers have complete control over whether they act on price signals and shift their load, and enrollment in TOU rates does not directly correlate to winter peak load reductions across DEP's footprint. The Public Staff notes that DEP's TOU report suggests a modest winter peak load reduction for customers who could be presumed to be early adopters or have a greater awareness of energy usage, but there is no guarantee that this level of winter peak load reductions will occur with greater enrollment. *Id.* at 390. The Public Staff also testified that, as DEP is already receiving a performance incentive for its DSM and EE programs through its

DSM/EE rider, a winter peak load reduction PIM should have to demonstrate incrementally greater savings above those being observed through DSM and EE programs, particularly for customers who are on TOU rates and participate in DSM or EE programs. *Id.* at 391.

The Public Staff expressed concerns regarding the Low-Income/Affordability PIM, primarily based on the fact that the Share the Light Fund is not a regulated activity, and the impacts of this PIM would not be reflected in the annual PIM rider. The Public Staff testified that while customer contributions are an input in the calculation of this PIM, shareholders presently have great discretion to adjust the amount of their overall contributions to the Share the Light Fund. *Id.* at 392.

Regarding the Reliability PIM, which targets reliability by tracking DEP's SAIDI score, the Public Staff expressed concern that because benchmarking for the tiered performance structure proposed by DEP is based on five years of historical SAIDI data, consideration of any expected advancements in reliability that will occur as a result of grid investments included in the proposed MYRP is foreclosed. In addition, the Public Staff expressed the concern that the five years of historical performance data includes data that were collected before DEP's GIP investments were placed into service. *Id.* at 393.

Finally, the Public Staff testified as to concerns with the Renewables Integration and Encouragement PIM. *Id.* at 394-96. With respect to Metric A, the Public Staff testified that Net Energy Metering (NEM) adoption is largely outside of DEP's control, that NEM adoption has been steadily increasing over time as individual customers make individual financial decisions, that two recent Commission orders that have not been incorporated into the forecast or financial structure of this proposed PIM that have the potential to skew the adoption rates above what DEP has already forecast, and that the new NEM rate schedules involve customer enrollment in certain TOU rates, which links this metric to the Peak Load Reduction PIM. *Id.* at 394-96. With respect to Metrics B and C, the Public Staff expressed concerns that DEP has complete control over all renewable program capacity available to large customers and that a capacity limit that is set below anticipated enrollment requests could result in DEP easily surpassing the enrollment thresholds. Additionally, the Public Staff testified that existing large customer programs have been popular without an incentive, and the Public Staff noted that performance data on which Metric B and Metric C are based are linked to new programs and there is therefore insufficient data for determining whether a financial incentive is necessary. *Id.* at 396.

In light of the Public Staff's concerns, the Public Staff proposed three modified PIMs in response to the PIMs DEP proposed. The Public Staff proposed a Time-Of-Use Enrollment PIM, a Customer Reliability PIM, and a Renewable Interconnections PIM, which involve both modifications to DEP proposals as well as new proposals. *Id*. at 396-97.

In response to DEP's proposed Low-Income/Affordability PIM, NCJC, et al. witness Howat and Sierra Club witness Colton expressed concerns with the effectiveness of the proposed PIM as designed in advancing a policy goal of low-income energy affordability.

Id. at 205, 252. Both witnesses filed a suggestion to include a tier structure under this PIM for consideration. *Id.* at 211.

CIGFUR witness Gorman's direct testimony expressed concern regarding DEP's proposed Reliability PIM. Tr. vol. 21, 459. Witness Gorman proposed expanding the PIM to include a metric for measuring and ensuring the maintenance of adequate power quality and the avoidance of power quality incidents. *Id.* Commercial Group witness Chriss raised similar concerns about the Reliability PIM, stating that DEP should restructure the PIM to hold itself accountable for poorly performing circuits. *Id.* at 509.

AGO witness Nelson proposed a Carbon Reduction PIM as an alternative to Metrics B and C of the Renewables and Integration PIM. *Id.* at 165. Witness Nelson expressed concern that the PIMs Stipulation does not incentivize DEP to lower emissions at least cost. *Id*. at 90. DEP witness Stillman and Public Staff witness Thomas expressed concerns with a Carbon Reduction PIM's compatibility with S.L. 2021-165. *Id.* at 435, 468-69; Tr. vol. 23, 209-11.

CUCA witness O'Donnell and NCJC, et al. witness Posner proposed conceptual fuel cost PIMs. Tr. vol. 21, 671, 1104. Witness O'Donnell's proposed fuel cost PIM would attempt to manage fuel costs and volatility and encourage selection of generation resources based on fuel costs. *Id*. at 671.

DEP witnesses Bateman and Stillman explained how the carbon reduction requirement in N.C.G.S. § 62-110.9 is an aggregate requirement on DEC and DEP, meaning that the law does not require DEP to independently reduce its CO2 emissions by 70.0%. *Id.* at 211.

DEP, the Public Staff, and CIGFUR resolved their differences of opinions on PIMs proposed in this proceeding in the PIMs Stipulation. PIMS Stipulation, Tr. vol. 7, 23.

DEP's PBR Policy Panel provided testimony in support of the PIMs Stipulation. Tr. vol. 14, 131. The PBR Policy Panel testified that the resolution reached represents a balanced approach to achieving policy goals in DEP's first PBR Application. Tr. vol. 15, 17, 70. DEP witness Stillman testified as to how the settled PIMs originated from the North Carolina Energy Regulatory Process (NERP) PBR Working Group, were informed by DEP's prefiling PIM stakeholder process, and evolved over discussions with the stipulating parties. Tr. vol. 14, 132-33. DEP witness Bateman testified that the Commission must examine DEP's PIMs proposals in the context of the entire MYRP. Tr. vol. 15, 15. Witness Bateman testified that DEP took a conservative approach in its first PBR Application so that DEP, customers, and the Commission could gain experience with the operation and implementation of PIMs. *Id.* at 69. DEP witness Stillman explained DEP's approach to designing the PIMs around the 1.0% cap in N.C.G.S. § 62-133.16 and stated that DEP deliberately chose only a select number of PIMs that meet the maximum number of policy goals. *Id.* at 65.

Public Staff witnesses D. Williamson and Thomas also provided testimony in support of the PIMs Stipulation. Tr. vol. 18, 424-25. Witnesses D. Williamson and Thomas testified that the PIMs Stipulation benefits ratepayers by providing improved compliance with N.C.G.S. § 62-133.16 and that each PIM in the stipulation appropriately targets a specific policy goal from N.C.G.S. § 62-133.16. They further testified that the PIMs Stipulation will benefit ratepayers through improved operational efficiencies, cost savings, and reliability of electric service over the course of the MYRP. *Id*.

The parties to the PIMs Stipulation did not achieve an agreement on the Low Income/Affordability PIM. The PIMs Stipulation includes the three PIMs described below; the PIMs are described with specificity, including thresholds, tiers, penalty and reward amounts, and projections of costs in PBR Policy Panel Settlement Exhibits 1, 3, and 4. Tr. Ex. vol. 14.

Time Differentiated and Dynamic Rate Enrollment PIM

DEP Witness Stillman testified that the Peak Load Reduction PIM was renamed as the Time Differentiated and Dynamic Rate Enrollment PIM (TOU Enrollment PIM) and was revised to provide DEP with a $5 incentive for every new customer enrolled in an eligible program. Tr. vol. 14, 135. Witness Stillman testified that this PIM targets and advances operational efficiency and cost savings and encourages DEP to design and seek approval of dynamic and time-differentiated rate designs. *Id*. at 93. Witness Stillman further testified that this PIM is an upside only PIM, with a shared savings-like structure that would distribute 30.0% of the total peak reduction joint benefit to DEP and 70.0% to customers. *Id.* at 135.

At the expert witness hearing, witness Stillman further explained that the purpose behind this PIM is to encourage DEP to develop and expand the use of TOU rates to help address peak load growth. *Id.* at 169-71. This PIM should encourage customers to adapt to new rate designs and subsequently shift their usage from high to low usage periods. *Id.* at 169. Witness Stillman testified that current subscribership to these programs is low, in the range of about 1.5% of residential customers, so one of the purposes behind this PIM is to encourage more customers to subscribe to TOU programs. *Id.* at 171. Witness Stillman also stated that DEP had statistically significant results demonstrating that customers that have participated in these rate designs have adapted and shifted their usage from on peak periods to off peak periods. *Id.* at 170. In response to concerns about insufficient data to measure impact on load due to enrollment in TOU programs, witness Stillman testified that the PIMs Stipulation addresses this concern and explained that DEP will conduct a broader Evaluation, Measurement, and Verification study on system benefits once there is sufficient participation in DEP's TOU rate schedules to achieve statistical significance. Tr. vol. 15, 38-39.

Public Staff witnesses Thomas and D. Williamson testified that the parties designed the TOU Enrollment PIM to increase the customer base subscribing to TOU rates to continue to ascertain how TOU rates impact load reduction. Tr. vol. 18, 459. Witness D. Williamson explained that it is appropriate to reward DEP for increasing the

number of TOU customers to mitigate energy usage during peak periods when the grid is stressed, so that DEP can better operate and improve operational efficiencies of the grid. *Id.* at 460. Witness Thomas also explained that the parties based the $5 per customer reward amount on savings per customer from a previously conducted TOU Report. *Id.*

Reliability PIM

DEP witness Stillman offered direct settlement testimony in support of DEP's Reliability PIM, which is designed to facilitate maintaining or improving service reliability in compliance with N.C.G.S. § 62-110.9(3). Tr. vol. 14, 136-37. DEP's Reliability PIM would be measured by SAIDI, excluding MEDS. As originally proposed, DEP's Reliability PIM provided for graduated penalties based on DEP's failure to maintain SAIDI below certain threshold tiers based upon five-year historic averages, adjusted for statistical confidence levels, and increased outages due to expected grid work. Tr. vol. 14, 91-92.

At the expert witness hearing, witness Stillman explained that as part of the PIMs Stipulation, DEP agreed to revise the metric for this PIM to account for projected SAIDI improvement during the MYRP period due to expected grid investments. Tr. vol. 15, 41-43.

Renewables Integration and Encouragement PIM

DEP witness Stillman testified that DEP designed Metric A of the Renewables Integration and Encouragement PIM to incent rooftop solar and to provide DEP with an incentive to determine the most effective way to encourage adoption. Tr. vol. 15, 53. This metric was modified as part of the PIMs Stipulation to base the incentive tiers on the three-year rolling average of net metered interconnections. Tr. vol. 23, 194-95. Metric A would provide an incentive of up to $4 million to DEP if the number of net metered interconnections for each rate year exceeds the applicable preceding three-year rolling average by at least 25.0%. Tr. vol. 15, 50.

DEP witness Stillman testified at the expert witness hearing that the only difference between Metric B as proposed by DEP and the PIMs Stipulation is a decrease in the reward amount. Tr. vol. 15, 57. As filed, Metric B of the Renewables Integration and Encouragement PIM supports large commercial and industrial (C&I) customers, educational institutions, and local governments who have corporate goals related to electricity and are increasingly seeking access to renewable energy and programs. Tr. vol. 14, 106; Tr. vol. 23, 195-96. As witness Stillman explained, this component of the Renewables Integration and Encouragement PIM was proposed in response to feedback received from large customer representatives. Tr. vol. 14, 138; Tr. vol. 21, 460-61; *See* CIGFUR witness Gorman Direct Ex. 7; Tr. Ex. vol. 21. Public Staff witness Thomas testified that the reduction in the reward amount for Metric B, considering the PIMs Stipulation as a whole, helped to alleviate the Public Staff's concerns that DEP would be overly rewarded for the independent financial decisions of large commercial and industrial customers. Tr. vol. 18, 466-67.

Revised Metric C of the Renewables Integration and Encouragement PIM in the PIMs Stipulation is based on the recommendations of the Public Staff, addresses utility-scale interconnections, and is designed to increase operational efficiency by incentivizing interconnections above DEP's estimated annual limits. Tr. vol. 14, 139. This component includes incentive tiers and minimum MW thresholds for utility-scale interconnections in each MYRP rate year. *Id*. at 139. DEP witness Stillman testified that Metric C responds to recommendations from the Public Staff to develop a PIM to incentivize DEP to focus on utility-scale interconnections. Tr. vol. 15, 60. He further stated that the reward will not be possible until DEP exceeds the interconnections the Carbon Plan already required under the Carbon Plan. *Id*. at 63. The Public Staff also testified that the intent of Metric C is to incent DEP to be more efficient in the interconnection process. Tr. vol. 18, 472.

Tracking Metrics

DEP witness Stillman provided direct testimony stating that DEP selected the tracking metrics it proposed to quantitatively measure and monitor outcomes and/or utility performance that, although not tied to financial incentives or penalties, address DEP's progress in furthering important policy goals. He further stated that tracking metrics can provide useful information in evaluating potential future PIMs. Tr. vol. 14, 113-14.

In the PIMs Stipulation, the stipulating parties agreed to three tracking metrics. The first agreed-upon tracking metric is the proposed metric on customer service as DEP proposed in its initial testimony. DEP witness Stillman testified that under the customer service tracking metric DEP will provide a quarterly update during the rate year of the rolling 12-month call center answer rate and the average speed of answer. Tr. vol. 14, 140-41. Witness Stillman testified that this tracking metric is appropriate because customers often communicate with DEP about service and billing issues by telephone, it allows greater public access to the data, and it supports maintaining adequate levels of customer service. *Id.*

The second tracking metric is the proposed metric on beneficial electrification of EVs as DEP initially proposed. Witness Stillman explained that this metric requires DEP to report beneficial electrification from estimated incremental load from EVs and will provide data in an area of material public policy interest. *Id.*

The third tracking metric the PIMs Stipulation includes requires DEP to report the 10 worst performing circuits on an annual basis, including an analysis of the cause of each circuit's performance. DEP witness Stillman testified that the stipulating parties have agreed to confer on a definition for the metric for a worst performing circuit and file an update with the Commission on an agreed-upon metric no later than 60 days after issuance of the Commission's order in this proceeding. Tr. vol. 14, 141. Witness Stillman explained that the stipulating parties included this tracking metric in the PIMs Stipulation due to the importance of reliability and the information this reporting will provide to interested parties. Tr. vol. 15, 43.

Discussion and Conclusions

Upon review of the testimony of DEP, the Public Staff, and CIGFUR witnesses regarding the PIMs Stipulation, the Commission concludes that the PIMs Stipulation is the product of give-and-take negotiations between DEP, CIGFUR, and the Public Staff to achieve PIMs and metrics that are consistent with N.C.G.S. § 62-133.16 and strike an appropriate balance.

The Commission must give full consideration to a non-unanimous stipulation itself, along with all evidence presented by non-stipulating parties in determining whether the stipulation's provisions should be accepted. *CUCA I*, 348 N.C. at 466; *CUCA II*, 351 N.C. at 231. The Commission has considered the testimony of the parties to this proceeding on the PIMs, as cited above, and notes that some of the non-stipulating parties' recommendations and modifications are addressed by the PIMs Stipulation. For example, with the inclusion of the worst-performing-circuit tracking metric, certain intervenor recommendations on reliability PIMs are accounted for outside of an express PIM, and data on reliability and circuit performance will be gathered as a result. PIMS Stipulation § III.2, Tr. Ex. vol. 7.

As this is the first PBR application considered by the Commission and, therefore, the first set of PIMs to be adopted, the Commission concludes that it is reasonable and appropriate to take measured steps to implement PIMs and tracking metrics as allowed for under N.C.G.S. § 62-133.16. The PIMs and the tracking metrics set forth in the PIMs Stipulation achieve this measured approach and are balanced, reasonable, and consistent with the requirements of the PBR Statute, encourage behavior that is sought by customers, and could provide meaningful operational and financial benefits to customers. Therefore, the Commission concludes that the PIMs Stipulation is entitled to substantial weight. Accordingly, the Commission concludes that the PIMs and tracking metrics set forth in the PIMs Stipulation should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 39

Power Quality Stipulation

The evidence supporting this finding of fact is in the direct testimony of DEP witnesses Stillman and Guyton; the supplemental direct testimony of CIGFUR witness Phillips in support of partial settlement; the Power Quality Stipulation; and the entire record in this proceeding.

The Power Quality Stipulation provides that DEP and CIGFUR will work together to identify up to 13 industrial customer premises with DEP-owned transmission to distribution retail substations that DEP exclusively or primarily dedicates to the respective CIGFUR member (Eligible Premises). Subject to a feasibility review, DEP will install power quality monitoring technology for each Eligible Premises and meet with the identified CIGFUR members at least once annually to review the data from the power quality monitoring technology. Power Quality Stipulation at 3; Tr. Ex. vol. 7.

In support of the Power Quality Stipulation, CIGFUR witness Phillips testified that the stipulation will help satisfy the requirement of N.C.G.S. § 62-110.9 to maintain or improve reliability as utilities implement the Carbon Plan. Tr. vol. 21, 495. Witness Phillips testified that the Commission has recognized the well-documented reliability risks that inverter-based resources pose. *Id*. at 496-97.

Witness Phillips further testified that the pilot program the parties outline in the Power Quality Stipulation will allow DEP to mitigate the reliability risks associated with inverter-based resources. *Id*. at 497-98. Specifically, it would allow DEP to: (1) proactively monitor power quality as utilities implement the Carbon Plan; (2) gather and share data analytics with the Public Staff and the Commission; (3) determine whether power quality incidents are the result of an individual circuit or customer problem, or potentially part of a larger trend; (4) diagnose potential power quality issues and, pursuant to review, implement solutions to address any such issues; and (5) take a proactive approach to customer service and service quality. *Id.*

With respect to the cost of the pilot program, DEP witness Stillman stated in cross examination that the Power Quality Stipulation does not set a cost cap. Tr. vol. 15, 76. He estimated that the cost of installing the power quality monitoring technology would be approximately $10,000 to $25,000 per meter, while the total number of meters needed for this pilot was not specified. *Id.* at 75. He further stated that the cost of implementing solutions, as contemplated in the Power Quality Stipulation, will depend on the cause of the specific power quality issue for each premises. He added that the lessons learned from the pilot program will help the whole system, because the more meters that are installed, the more DEP will learn about where the power quality issues are arising. In acknowledging that DEP intends to seek cost recovery on a cost of service basis, witness Stillman stated in direct testimony that the pilot program will help DEP to understand the system and power quality issues better, and that it will ultimately be to the benefit of all customers. Tr. vol. 21, 474-76.

The Commission notes that no party introduced evidence in this docket suggesting that industrial customers are experiencing degraded power quality issues due to inverter-based resources. In addition, the Commission notes that the pilot program as the parties propose in the Power Quality Stipulation would be available for participation to only 13 CIGFUR members, and that DEP would recover the costs, with no cost cap, on a cost of service basis from all DEP ratepayers. This method would result in the cross subsidization of these industrial customers by all ratepayers, including residential customers.

The Commission acknowledges the effort required to craft a pilot program and a mutually agreeable stipulation. A well-designed pilot program focused on improving power quality for individual customers and for the entire system has merit and could provide benefits for all ratepayers. It is premature, based on the information provided in the Power Quality Stipulation, for the Commission to approve the pilot program as contemplated between the two parties absent additional details, including information regarding parameters for a feasibility review, participant eligibility, and cost, and absent an opportunity for interested parties to undertake a thorough review of the proposal and

provide comments to the Commission. Particularly with respect to pilot programs, the Commission needs sufficient information to ensure that the program is properly scoped and bounded. The Commission therefore concludes that the record evidence does not support approval of the power quality pilot program.

However, DEP may file an application for a power quality pilot program with the Commission in a new docket that addresses the concerns noted by the Commission, should it so choose.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 40-41

Affordability Stipulation/CAP

The evidence supporting these findings of fact is in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Harris, Bateman, and Stillman, Public Staff witnesses D. Williamson and Thomas, NCJC, et al. witnesses Howat and Posner, and Sierra Club witness Colton; the Affordability Stipulation; and the entire record in this proceeding.

Summary of Evidence

Low-Income/Affordability PIM

DEP's PBR Policy Panel testified in support of DEP's proposed Low-Income/Affordability PIM. Tr. vol. 14, 91. The PBR Policy Panel testified that the Low-Income/Affordability PIM would: (1) target and advance cost savings; (2) reduce low-income energy burdens; and (3) encourage carbon reductions. *Id.* at 94. The PBR Policy Panel testified that the proposed PIM would advance the identified policy goals by providing DEP with an incentive to promote voluntary contributions to the Share the Light Fund. *Id.* at 101.

Public Staff witnesses Thomas and D. Williamson recommended that the Commission deny DEP's proposed Low-Income/Affordability PIM. Tr. vol. 18, 418. The Public Staff expressed concern that the PIM fails to meet some of the Public Staff's guiding principles for the development of PIMs because the Share the Light Fund is not a regulated Company activity and DEP's annual PIM rider would not reflect the impacts of the PIM. *Id.* at 392.

Sierra Club witness Colton recommended that the Commission reject DEP's proposed Low Income/Affordability PIM and adopt Sierra Club's alternative proposal. Witness Colton expressed concerns that DEP's proposed Low-Income/Affordability PIM would insufficiently measure and promote the advancement of the PIM's stated goals and was not adequately in DEP's direct control. *Id.* at 295-300, 313. Alternatively, Sierra Club witness Colton recommended that the Commission require DEP to adopt a series of "outcome" metrics to measure DEP's performance and the accomplishment of program objectives. *Id.* at 293.

NCJC, et al. witness Howat recommended that the Commission reject DEPs Low-Income/Affordability PIM given his concerns that the originally proposed Share the Light Fund contributions would not directly advance low-income energy burden reductions and that there was no explicit commitment to measure potential low-income energy burden reductions attributable to the Low-Income/Affordability PIM. Witness Howat instead recommended that the Commission direct DEP to implement an alternative Energy Burden Reduction PIM based on a reduction in involuntary residential non-pay disconnections over a four-year period in the service territory zip codes with the highest disconnection ratios. Tr. vol. 18, 224. Additionally, he recommended that the Commission implement reporting requirements. *Id.* at 230. NCJC, et al. witness Posner echoed many of the same concerns as witness Howat and ultimately recommended that the Commission reject the Low-Income/Affordability PIM and advised the Commission to adopt NCJC, et al. witness Howat's Energy Burden Reduction PIM instead. Tr. vol. 21, 1103.

In rebuttal testimony, DEP's PBR Policy Panel reiterated DEP's position that the PIM strikes the appropriate balance between encouraging outcomes sufficiently within DEP's control and providing meaningful funding to address low-income issues. Tr. vol. 23, 186.

Customer Assistance Program

In its Application, DEP requested approval of the CAP and two new tariffs, the CAP Rider and the Customer Assistance Recovery Rider (CAR Rider). DEP witness Harris testified that the CAP proposal, initially developed in the Low-Income Affordability Collaborative (LIAC) docket, is designed to assist low-income customers who are facing affordability challenges. Witness Harris described the program structure, framework, and reasoning behind the program. Tr. vol. 12, 204-05. Under the CAP, eligible customers would automatically receive a $42 monthly bill credit for a 12-month period. Tr. vol. 12, 205.

Regarding CAP eligibility, witness Harris explained that customers who are eligible for and receive funds from either the Low Income Energy Assistance Program (LIEAP) or the Crisis Intervention Program (CIP) would qualify for assistance under the CAP. DEP would automatically enroll eligible customers into CAP using a list of customers provided by the North Carolina Department of Health and Human Services (DHHS). Tr. vol. 12, 207. Moreover, DEP could re-enroll customers in CAP for another 12 bill cycles if they are re-certified as LIEAP or CIP eligible after expiration of the initial enrollment. Tr. vol. 12, 215.

Witness Harris testified that in addition to the $42 bill credit on their next 12 monthly bills, DEP will also refer CAP customers to other income-qualified weatherization and energy efficiency services that can assist customers with reducing energy usage. Tr. vol. 12, 215. DEP would spread the costs for the $42 CAP credit among all customer classes, excluding lighting schedules, through the CAR Rider. Residential customers would pay approximately 86.0% of the CAR Rider on a per kWh basis, with non-residential customers paying the approximately 14.0% remaining on a per bill basis. Tr. vol. 12, 215. The CAR Rider would have a rolling recovery factor that DEP would true-up annually to reflect the actual amount of CAP credits paid. Tr. vol.12, 207.

Public Staff witness D. Williamson recommended that the Commission: (1) approve the CAP proposal for a three-year term; and (2) require that DEP, as part of the CAR Rider proceeding, file a report addressing several issues and metrics, including the number of CAP recipients, CAP administration costs, and observed impacts of CAP on arrearage management and disconnections for nonpayment. Tr. vol. 20, 147. Witness D. Williamson noted that the Public Staff would prefer a clear legislative requirement directing the development of a program like CAP; however, he also noted that the Commission has broad authority to determine whether programs utilities design to address affordability issues are in the public interest. Tr. vol. 20, 146. Witness D. Williamson highlighted that in the Commission's Order for the 2019 Rate Case, the Commission exercised this authority by requiring that parties collaborate on developing programs that would serve the public interest and address affordability challenges for low-income customers. Tr. vol. 20, 146-47.

Sierra Club witness Colton testified that absent a program like CAP, electric bill affordability in the DEP service territory would significantly deteriorate given the increased rates proposed in the proceeding. Tr. vol. 18, 274. Witness Colton concluded that the general policy underlying DEP's CAP proposal was reasonable. Tr. vol. 18, 275. Witness Colton proceeded to make modest recommendations to the CAP proposal to advance the achievement of affordable electric bills for low-income households. Among his recommendations, witness Colton emphasized the importance of defining an affordable bill burden as a percentage of a household's income. Tr. vol. 18, 252. Witness Colton maintained that an affordable bill burden is a range and not a point, and it is appropriate, in principle, to measure affordability by reference to bills as an affordable percentage of income – regardless of the ultimate burden target the Commission deems appropriate to adopt. Tr. vol. 18, 266. Witness Colton recommended modifying the proposed across-the-board flat bill credit to a tiered, percent of bill discount. Tr. vol. 18, 276. As proposed, witness Colton's alternative program design seeks to achieve affordable bills as a percentage of household income and reduce affordability disparities between customers at different income levels, measured by the Federal Poverty Guidelines. Tr. vol. 18, 281-84.

NCJC, et al. witness Howat provided observations and analysis regarding the variances between CAP and Consensus Proposal 24 from the LIAC, the hallmarks of effective bill payment assistance programs, low-income energy usage, and burdens. Witness Howat ultimately recommended that the Commission adopt a tiered discount affordability program. Tr. vol. 18, 203-22.

CIGFUR witness Phillips testified that the costs of the proposed CAP that DEP would recover though the CAR Rider should only be recovered from residential customers, and that the creation of a new cross-subsidy benefitting residential customers at the expense of non-residential customers contradicts the express directive of the PBR Statuteto minimize interclass cross-subsidization by the greatest practicable extent possible by the end of the MYRP period. Tr. vol. 21, 482.

The Affordability Panel of DEP witnesses Barnes, Harris, and Quick responded to the affordability-related testimony and recommendations proposed by the Public Staff and

other intervenors. Witness Barnes described DEP's Affordability Ecosystem as a multi-pronged approach resulting from the LIAC's findings. Witness Barnes explained that bill payment assistance represents one lever for addressing affordability challenges, and she pointed to energy efficiency programs as another major component in DEP's Affordability Ecosystem. Tr. vol. 22, 84. Witness Barnes further disputed witness Colton's claim of LIAC's adoption of an energy burden threshold, distinguishing LIAC's target electric energy burden from CAP from witness Colton's 5.0% definition of total home energy. Tr. vol. 22, 85. Witness Barnes testified to DEP's willingness to participate in an evaluation study of North Carolina customers that would inform findings for adopting an electric energy burden threshold for Duke Energy's North Carolina customers. Witness Barnes stated that providing the zip-code level data intervenors requested would violate DEP's Code of Conduct, which prohibits disclosing aggregated non-public customer data. Tr. vol. 22, 87. DEP witness Quick testified that while DEP tracks participants in the Winter Moratorium that Commission Rule 12-11(1) established, it does not routinely collect and track customers' income status. Tr. vol. 22, 88. Due to the complexity and costs that would be added to the work of DEP's call center representatives from collecting, validating, and tracking such sensitive information, she disagreed with recommendations that DEP should collect such data and instead endorsed DEP's continued work with state or assistance agencies with the necessary experience and expertise to assist customers. Tr. vol. 22, 89.

DEP witness Harris testified that DEP agrees with the Public Staff's testimony and recommendations related to the CAP and does not oppose the proposed annual report. Tr. vol. 22, 90-91. Harris disagreed with CIGFUR witness Phillips' conclusion regarding interclass cross subsidization and stated that the program will put downward pressure on all rates. Tr. vol. 22, 91. He further testified that DEP would be amendable to a tiering feature for future versions of the CAP. Witness Harris explained that the auto-enrollment mechanism, which is a core design feature of CAP, cannot currently support tiering. Tr. vol. 22, 92-93. Further, witness Harris disagreed with recommendations that DEP, DHHS, or other organizations provide another intake service for CAP, explaining that the estimated operating costs from a third party would increase the total cost of operating CAP by a factor of almost 11. Tr. vol. 22, 93. Witness Harris testified that using a percentage discount, rather than a dollar amount, would reduce the incentive for energy efficiency investments, reduce the financial incentives for customers to respond to dynamic rate designs, and make the program's costs less predictable. Tr. vol. 22, 94.

Affordability Stipulation

On May 4, 2023, DEP, DEC, Sierra Club, NCJC, et al., and the Public Staff filed the Affordability Stipulation. Pursuant to the terms of the Affordability Stipulation, DEP will withdraw the Low-Income/Affordability PIM and, instead, a shareholder contribution of $16 million to benefit income-eligible customers will be made as follows: $10 million in support of health and safety repairs that would allow for energy efficiency and weatherization upgrades to homes; and $6 million for the Share the Light Fund, which offers customers bill payment assistance. Tr. vol. 22, 99-100. In addition, DEP and DEC agree to collect and annually report the monthly payments ratio, which is the number of residential payments remitted divided by

the number of active residential accounts. DEP and DEC will file this data annually in Docket No. M-100, Sub 179. Furthermore, pursuant to the terms of the Affordability Stipulation, DEP would establish its CAP program as a three-year pilot. If the Commission approves CAP, DEP agrees to convene a stakeholder engagement process to consider CAP data, metrics, and future CAP program features. The Affordability Panel, the Public Staff, Sierra Club witness Colton, and NCJC, et al. witness Howat each provided testimony supporting the Affordability Stipulation. Tr. vol. 18, 326-66.

Considering all testimony and evidence along with the Affordability Stipulation, the Commission finds that the provisions of the Affordability Stipulation are reasonable and should be approved for the following reasons.

The Commission gives significant weight to the testimony of DEP witnesses Harris, Barnes, and Quick, and Public Staff witness D. Williamson regarding the Affordability Stipulation and DEP's CAP proposal. As Public Staff witness D. Williamson and DEP witness Harris highlighted in their testimony, the Commission has broad authority to set rates in the public interest. Tr. vol. 20, 146; Tr. vol. 13, 22. The question of whether the Commission should approve the CAP proposal and corresponding tariffs as outlined in the Affordability Stipulation is largely a public policy issue requiring a balancing of costs and benefits to DEP customers. The Commission established the LIAC in the 2019 Rate Case and tasked the collaborative with addressing affordability issues for low-income residential customers.

The statute authorizing performance-based regulation emphasizes reducing interclass subsidies and reducing low-income energy burdens. N.C.G.S. 62-133.16(b) requires the minimization of interclass subsidies to the greatest extent practicable by the end of the multiyear rate period. Further, N.C.G.S. § 62-133.16(d)(1) requires the Commission to consider whether the PBR application, in its entirety, "assures that no customer or class of customers is unreasonably harmed" by the proposal. N.C.G.S. § 62-133.16(d)(2) provides that the Commission may consider whether the PBR application "reduces low-income energy burdens." The Commission concludes that DEP reasonably designed the CAP proposal to meet and balance these statutory directives.

The Commission finds that the Affordability Stipulation advances the objective of reducing low-income energy burdens without causing unreasonable harm to any customer or class of customers. The Commission gives substantial weight to the DEP testimony that: (1) although the CAP causes a small interclass subsidy, residential customers primarily fund it; and (2) there is potential for the program to put downward pressure on rates for all customers, by having fewer stranded costs from disconnected accounts and arrearages, which would otherwise be passed on to the general body of ratepayers in the next general rate case.

The Commission approves the CAP as a limited-term pilot, which will allow the Commission, the Public Staff, DEP, and other parties, over time, to examine whether the CAP credit meets the public policy objectives and whether the CAP results in rates that are unreasonably discriminatory or preferential to certain customer classes. As such, the

Commission finds that it is reasonable for DEP to launch the CAP and implement the corresponding tariffs associated with the CAP proposal for a period of three years as set forth in the Affordability Stipulation.

Affordability – Next Steps

The Commission appreciates the consensus achieved by the parties in the Affordability Stipulation. Several provisions in the Affordability Stipulation provide for reporting of information. In order to examine whether the CAP meets public policy objectives, the Commission determines that it is necessary to provide guidance on these requirements.

Stakeholder Group and Report

In the Affordability Stipulation, the stipulating parties agree to convene a stakeholder engagement process to (i) consider data and reporting issues that may be necessary for the CAP, (ii) consider metrics and inputs used to assess the CAP pilot, and (iii) agree to update the Commission on the stakeholder process. The Commission directs DEP to convene this stakeholder group within 90 days of the issuance of this Order. The stakeholder group shall include the stipulating parties to the Affordability Stipulation. DEP is also directed to invite members of the LIAC to join the stakeholder group. Further, the Commission directs that the group meet at least quarterly, and that no later than 6 months after the issuance of this Order, the group must agree upon the data and information that will be provided in an annual report that will be filed each year the CAP is effective. The Commission directs that the annual report shall include, but shall not be limited to, the following information:

1. How many customers enrolled in the CAP by zip code.

2. How many dollars given in assistance by zip code.

3. Percentage of total customers enrolled in the CAP by zip code.

4. Percentage of total customers enrolled in the CAP that have had disconnections.

5. Identification of the zip codes which have the highest number of residential nonpayment disconnections.

6. Range, average, and median bill size for customers enrolled in the CAP.

7. Recommendations relating to potential changes in the CAP that would have the potential to improve the program during the pilot or as part of a subsequent program.

DEP is directed to inform the Commission if it is unable to report any of the above listed data.

The Commission notes that in Paragraph 2 of Section II the Affordability Stipulation, DEP and DEC agree to collect and report data regarding health and safety repairs that are made with shareholder funds. The Commission directs that the following information shall be provided and filed semiannually regarding these funds:

1. Dollar amount given in weatherization help to customers by zip code.

2. Dollar amount given to energy efficiency help to customers by zip code.

3. Percentage of customers that receive CAP and receive weatherization and/or EE assistance by zip code.

The report shall also identify the most frequent types of health and safety repairs that may be necessary and required to enable customers to qualify for weatherization programs.

Tiered Customer Assistance Program

The Commission further notes that the Affordability Stipulation states that parties agree to explore "a tiered customer assistance program based on income levels if that feature can be incorporated into the design of the CAP." In order to address affordability challenges in the state the Commission finds that it is necessary to direct the stakeholder group to develop a tiered program. Further, DEP is directed to file a report relating to the feasibility and proposed structure of a program the later of (i) 18 months after the entry of the order in this proceeding, or (ii) when there is one year of data from the CAP Rider. DEP shall also provide a report to the Public Staff and the Commission every six months after the entry of an order in this proceeding which summarizes the ongoing work of the stakeholder group, and which identifies any challenges as well as opportunities for improving the CAP program. DEP shall also seek from the Commission any waivers necessary or required to obtain or provide the zip code related data set forth in this Order as well as any zip code level data necessary or required to design a tiered customer assistance program.

Tracking Metrics

The Commission further finds that in order to inform future PIMs, DEP is directed to report on the following tracking metrics related to Affordability in the same manner as the tracking metrics agreed to the PIMS Stipulation:

1. The average Disconnect for Non-Payment (DNP) percentage of active residential customers over the last 12 month period.

2. The ratio of the average annual residential customer bill (1,000 kWh of usage per month) divided by the annual federal poverty income level for family of four according to the Federal Poverty Guidelines.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 42-48

Objectives of Rate Design

The evidence supporting these findings of fact is in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Reed and Byrd, Public Staff witnesses Williamson and Nader, Commercial Group witness Chriss, Kroger Co. and Harris Teeter witness Bieber, DoD-FEA witness Blank, CIGFUR witnesses Phillips and Gorman, AGO witness Nelson, and CUCA witnesses O'Donnell and Heilig; the Partial Revenue Requirement Stipulation; and the entire record in this proceeding.

DEP witness Reed testified that she used the cost-of-service information prepared by DEP and examined by DEP witness Hager to design rates. Tr. vol. 11, 176. Witness Reed testified that she also reviewed and considered the rates of return across the customer classes derived from the COSS when designing rates. *Id.* Finally, witness Reed noted that she reviewed DEP's Advanced Metering Infrastructure (AMI) data to examine customers' usage characteristics and to determine relationships between energy and demand, both on a coincident peak and non-coincident peak basis that might prove pertinent to the design of DEP's rates, including the development of new TOU periods. *Id.* at 176-77.

Witness Reed stated that one objective of DEP's proposed rate design is to achieve the necessary increase in rates to collect the total revenue requirement. *Id.* at 177. Witness Reed also stated that another DEP objective is to gradually align the cost to serve customers within its residential, general service, and lighting rate schedules. *Id.* Witness Reed also noted that DEP's goal is to design rates that reflect the costs that a customer causes DEP to incur. *Id.* With respect to the rate increases proposed in this case, witness Reed stated that the base rate increase has been allocated to the rate classes by base rate amounts. *Id.* at 180. Witness Reed claimed that this allocation methodology aims to distribute the increase equitably to the classes while maintaining each class's deficiency or surplus contribution to return. *Id.*

In his direct testimony, DEP witness Byrd testified that DEP, as ordered by the Commission, participated in a year-long Comprehensive Rate Design Study (CRDS) with external stakeholders to develop DEP's future pricing and rate design options. *Id.* at 231. Following this engagement, DEP proposed several rate design changes to incorporate stakeholder requests and input. *Id.* at 232.

DEP witness Reed testified in detail regarding changes that DEP proposes to the residential rate schedules, the SGS rate schedules, the MGS rate schedules, the LGS rate schedules, the seasonal and intermittent rate schedules, and to the lighting rate schedules. Tr. vol. 11, 183-202. DEP witness Reed also testifies in detail regarding the

proposed revisions to DEP's service riders, which are offered to reflect special customer needs and requirements. Her testimony describes how the riders have been revised to better reflect cost of service. *Id.* at 202-06.

Having considered the record evidence on the issue of rate design, the Commission concludes that the objectives of DEP's rate design – which are to: (1) achieve the necessary increase in rates to collect the total revenue requirement; (2) further align the cost to serve customers within DEP's residential, general service, and lighting rate schedules; and (3) design rates that reflect the costs a customer causes DEP to incur – are reasonable. Further, the Commission concludes that DEP's proposed allocation of the approved revenue increase to the customer classes is reasonable to all parties, considering the evidence presented and is approved for the purposes of this proceeding. Finally, for the foregoing reasons, the revisions to the rate schedules and to the service riders proposed by DEP in this proceeding are reasonable and are approved as proposed, unless otherwise specifically addressed hereinafter in this Order.

Subsidy Reduction

DEP evaluated rates of return across customer classes emanating from DEP's COSS. Tr. vol. 11, 179. DEP witness Reed testified that the historical per books rate of return indices as measured by the ratio of class rate of return to retail rate of return, shows that over a lengthy period, residential customers have been subsidized. She testified that his historical subsidy has, in the past, been beyond the range of reasonableness, which DEP defines as class rates of return within 10.0% of the total Company rate of return. *Id.* She also testified that an updated comparison through the test period now shows significant convergence of the class rate of return over all classes towards the band of reasonableness demonstrating the success of the strategy of gradually reducing the subsidy/excess by 10.0%. *Id.* at 180-81.

DEP witness Reed explained that in designing rates, the base rate increase was allocated to the rate classes by rate base amounts and that this allocation method distributes the increase equitably to the classes while maintaining each class's deficiency or surplus contribution to return. *Id.* at 18.

DEP witness Reed testified that, in this proceeding, DEP is also recommending a variance reduction of 10.0% to help reduce interclass subsidies to better align each rate class to the average rate of return. *Id.*

CIGFUR witness Phillips testified that he disagreed with DEP's proposed 10.0% subsidy reduction and instead recommended that a 25.0% subsidy reduction, consistent with DEP's last rate case proceeding, be the minimum reduction for this proceeding. Tr. vol. 21, 483. Witness Phillips testified that a subsidy reduction of 50.0% or even 100.0% would be preferable. *Id.* Witness Phillips claimed that LGS customers are subsidizing other rate classes by approximately $47.7 million under current rates, that the proposed 10.0% subsidy reduction does not adequately correct this cross-subsidization, and that LGS customers should receive a rate reduction to eliminate the subsidy. *Id.*

Witness Phillips also stated that DEP's proposed 5.8% LGS rate increase will "continu[e] the large subsidy paid by these customers". *Id.*

DoD-FEA witness Blank also took issue with DEP's proposed 10.0% subsidy reduction and stated that DEP's proposed allocation of base rate revenue increases deviates substantially from its COSS results. *Id.* at 310. Witness Blank claimed that DEP's proposed rate increases result in the LGS class subsidizing other classes, particularly the residential class. *Id.* at 326. Witness Blank argued that the use of any variance, even a higher variance than DEP's proposed 10.0%, will not alleviate the subsidization faced by the LGS class, will still lead to rate increases for LGS and LGS-TOU rate classes, and will lead to rate increases "well above a level that I would be comfortable with," for rate classes farther away from cost-based rates. *Id.* Therefore, witness Blank recommended that the Commission reject the use of a variance reduction approach, even at a higher level (e.g., 25.0%) than the 10.0% DEP proposed. *Id.*

On rebuttal, witness Reed testified that the proposed 10.0% subsidy reduction "balances the rate increases requested … so that no rate class receives a disproportionate increase [due to] the proposed changes to the cost-of-service methodology [shifting] costs among rate classes." Tr. vol. 11, 264. Specifically, witness Reed explained that if DEP had employed witness Phillips' recommended 25.0% subsidy reduction the proposed increase to the residential class would increase from 9.9% to 10.4% and the proposed increase to the Lighting class would increase from 19.9% to 24.9%. *Id.* at 265. Witness Reed stated that DEP's 10.0% subsidy reduction proposal applies the concept of gradualism to align revenues collected from each class with cost causation from DEP's class cost of service study (CCOSS) but that DEP does not intend it to signal that DEP will limit future subsidy reductions to 10.0%. *Id.*

During the expert witness hearing, in response to cross-examination by CIGFUR, CUCA, and DoD-FEA, witness Reed acknowledged that other customer classes have historically subsidized residential customers. *Id.* at 324, 360, 386-87. However, witness Reed explained that DEP intends for the 10.0% subsidy reduction to move the rate increase for each rate class toward parity with the rate of return while avoiding harm to certain classes. *Id.* at 387-88. Moreover, witness Reed reiterated that in determining the 10.0% subsidy reduction, DEP attempted to balance the change in cost-of-service with the requested rate increases so that certain rate classes would not be overly burdened with a rate increase. *Id.* at 326. Witness Reed further explained that employing a 25.0% subsidy reduction "would really harm certain [customer] classes." *Id.* at 388.

During the expert witness hearing, witness Reed also asserted that DEP's proposed 10.0% variance reduction was consistent with N.C.G.S. § 62-133.16. *Id.* at 318-21, 330. During cross-examination by CIGFUR, witness Reed acknowledged that N.C.G.S. § 62-133.16 requires DEP to minimize interclass subsidization. However, witness Reed emphasized that the statute only requires DEP to minimize interclass subsidization "to the greatest extent practicable," which is what it has done. *Id.* As witness Reed explained in response to cross-examination by the NCLM, this is particularly true given that the PBR Statute also requires the Commission to consider the possibility for

rate shock. Tr. vol. 12, 14. As such, witness Reed testified that DEP appropriately considered "competing priorities" such as cost causation, rate shock, and gradualism in proposing the 10.0% variance reduction. Tr. vol. 11, 320-21.

Based on the evidence in the record, the Commission agrees that a variance reduction of 10.0% is reasonable for application in this proceeding. In reaching this conclusion, the Commission gives significant weight to the testimony of witness Reed that a 10.0% subsidy reduction helps move towards eventual rate parity and minimize interclass subsidization, including but not limited to the historic subsidization of the residential class, while considering and incorporating other important factors. Additionally, the Commission recognizes that witness Phillips' argument in support of a greater variance reduction raises a legitimate concern, but concludes that, a variance reduction is not the only issue that a utility must consider when designing rates. The Commission also declines to accept witness Blank's recommendation to completely disallow a variance reduction. The Commission has historically approved a variance reduction for DEP and witness Blank has offered no compelling evidence warranting a departure from this prior practice. Accordingly, the Commission finds that a 10.0% subsidy reduction is just and reasonable and consistent with the PBR Statute, moves rates closer to cost for all customer classes and is less likely to lead to rate shock than a larger subsidy reduction.

Migration Adjustment

DEP witness Reed testified that during the rate design process, DEP analyzed rate migration, which occurs when customers change from their current tariff to a tariff that is more cost-effective for them. Tr. vol. 11, 181. Witness Reed claimed that, due to the introduction of new tariffs, the redesign of other tariffs to better align with system costs, and the ability of DEP's new Customer Connect billing system to perform rate comparisons and suggest the best rate for customers, DEP recommends a migration adjustment to the residential, MGS, and LGS classes. *Id.* at 181, 265-66. Specifically, DEP requests a migration adjustment to residential and MGS classes for customers who would save 10.0% or more annually and to the LGS class for customers who would save 5.0% or more annually. *Id.* at 181, 266. Witness Reed noted that this proposal would result in a $12 million migration adjustment for the residential class in Rate Year 0, an approximately $8 million migration adjustment for the MGS class each rate year, and an approximately $1.2 million migration adjustment for the LGS class each rate year. *Id.* at 181-82. Witness Reed noted that DEP is only requesting a migration adjustment for the residential class in Rate Year 0 and not Rate Years 1, 2, or 3 because under the MYRP a migration adjustment is unnecessary due to the Residential Decoupling Mechanism. *Id.* at 181-82, 370. In contrast, witness Reed testified that the proposed migration adjustment for the MGS and LGS classes will carry forward in each rate year including Rate Year 0 and Rate Years 1, 2 and 3 under the MYRP. *Id.* at 182. Witness Reed explained that the primary driver for the migration adjustment requests for the MGS and the LGS classes is the realignment of TOU windows to system costs which allows customers to respond to more economically efficient price signals. *Id.* Witness Reed's Direct Exhibits 4, 4_1, 4_2, and 4_3 provided the requested migration amounts. *Id.* Tr. Ex. vol. 11.

DoD-FEA was the only party to challenge DEP's requested migration adjustment. DoD-FEA witness Blank requested that the Commission deny DEP's proposed migration adjustment because it artificially increases DEP's base revenue recovery to account for an amount of lost future revenue that is not known or measurable. Tr. vol. 21, 314. Witness Blank argued that the migration adjustment presumes customers will switch rate schedules when they understand potential utility bill savings even though customers choose rate schedules for reasons beyond those a simple bill analysis suggests. *Id.* Witness Blank argued that the relative risk between rate designs and anticipated events that may affect future demand and usage influences actual customer choice. *Id.* Witness Blank argued that DEP's migration adjustments assume that customers will switch rate schedules and does not account for customer risk aversion, which may impact their willingness to switch even when potential utility bill savings are possible. *Id.* Witness Blank acknowledged that some migration will likely occur but argued that it is reasonable for DEP to bear such risk since it is a short-term risk that it can remedy during its next rate case when it better knows customer behavior. *Id.* at 314-15. Witness Blank also noted that future changes to customer electricity usage and billing are "an overall unknown," including potential increases that expanding EV ownership or a rise in the number of homes using electric heating could drive. *Id.*

In rebuttal testimony, DEP's Rate Design Panel, witnesses Byrd and Reed, disagreed with witness Blank's contention that the migration adjustment accounts for lost revenue that is unknown and unmeasurable. Tr. vol. 11, 266-68. The Rate Design Panel testified that in determining the migration adjustment, actual customer billing data was used to calculate actual savings on customer bills. *Id.* at 267. Specifically, the Rate Design Panel explained that for each participant in the rate class, individual customer bills were calculated on their current rate schedule at proposed rates and at other available rate schedules in their rate class at proposed rates. *Id.* at 266. The net annual savings from individual customers saving more than the threshold were then aggregated to determine the migration adjustment amount. *Id.* The Rate Design Panel further stated that DEP considers its proposed 10.0% and 5.0% savings thresholds to be conservative estimates of anticipated migration levels. *Id.* During cross-examination by the DoD-FEA, witness Reed explained that the proposed migration adjustment is a "conservative estimate" because it only considered "structural savers" – i.e., customers that would automatically save money simply by transitioning to a different rate schedule – and does not include customers below the savings threshold that may want to switch or customers that may save money through behavioral changes. *Id.* at 372, 376.

The Rate Design Panel also testified that the availability of several tools that will help customers switch to the best rate mitigates witness Blank's concerns regarding the migration adjustment. *Id.* at 267-68, 373. First, customers who have 12 months of usage history will have access to DEP's Rate Comparison Tool – an online tool (part of Customer Connect) that leverages historic interval data to determine a customer's best rate. *Id.* at 267. Second, customers may also contact DEP's Call Center Representatives to request a rate comparison. *Id.* Third, LGS class customers can also utilize their Large Account Managers. Tr. vol. 11, 267, 373. As witness Reed explained during cross-examination by

the DoD-FEA, these Large Account Managers help LGS customers both manage their complex rates and determine the best rate. *Id.* at 373.

The Commission concludes that DEP's proposed migration adjustment is just and reasonable considering the evidence of record in this proceeding. The Commission is not persuaded by DoD-FEA witness Blank that the lost revenues for which the migration adjustment is intended to compensate are unknown and unmeasurable. DEP witness Reed offered convincing testimony that the Rate Design Panel calculated the migration adjustment based on actual customer billing data and that the 10.0% and 5.0% savings thresholds are reasonable, conservative estimates of DEP's migration exposure. The Commission also considers witness Reed's testimony, describing how the Rate Comparison Tool, Call Center Representatives, and Large Account Managers will mitigate migration concerns and help customers switch to rates that may allow them to lower their bills, to be an adequate response to witness Blank's concerns. The Commission therefore accepts DEP's proposed migration adjustments and finds they should be approved as DEP proposed them for the purposes of this proceeding.

Customer Growth and Weather Normalization

DEP witness Reed testified that she provided the retail sales and number of customers to DEP witness Jiggetts for use in calculating the pro forma adjustment for growth in customers. Tr. vol. 11, 173. Witness Reed explained that to arrive at the appropriate number of customers served and the attendant annualized sales levels at the end of the test period, DEP used a combination of regression analysis and a customer-by-customer approach. *Id.* at 173-74.

In her supplemental direct testimony, witness Reed testified that DEP had agreed with the Public Staff to periodically update the Customer Growth Analysis to extend the results to the end of the pro forma period. *Id.* at 223. As such, witness Reed testified that DEP had updated the Customer Growth Analysis through December 31, 2022, for informational purposes only, as DEP witness Jiggetts' Supplemental Direct Testimony Exhibit 4 Pro forma NC1040 demonstrates. Tr. Ex. vol. 13.

CIGFUR witness Gorman testified that DEP's sales projection for residential and SGS customers in the base period is unreasonably low. Tr. vol. 21, 405, 425-26. Witness Gorman claimed that DEP bases its pro forma adjustments on weather normalized use per customer in a single year, which does not reflect how customers' usage can vary due to customer behavior, introduces uncertainty, and does not provide a reasonable projection of likely future customer electricity usage. *Id.* at 426. Witness Gorman recommended that DEP instead use a four-year average projected use per residential customers normalized sales projection. *Id.* at 428.

On rebuttal, the Rate Design Panel disagreed with witness Gorman's claim that DEP's residential weather normalized sales were too low. Tr. vol. 11, 268. The Rate Design Panel testified that DEP bases energy usage projections for the residential and SGS customer classes on historical actual weather normalized sales, which means that

DEP uses kWh sales over the test year and extended period and applies monthly factors based on 30 years of historical weather data to normalize sales for weather. *Id.* The Rate Design Panel also testified that witness Gorman was incorrect in his claim that DEP's pro forma adjustments are based on weather normalized use per customer in a single year. *Id.* The Rate Design Panel explained that the true-up of DEP's test year and extended period estimate of number of customers is based on the best fit of seven different regression models and that the analyses use four, three, two, and one-year time periods for projections. *Id.* at 268-69. The regression analysis that is best aligned with the data (highest statistical "R" value) is then selected. *Id.* at 269. Finally, the Rate Design Panel disagreed with witness Gorman's recommendation that DEP use a four-year average projected use per Residential customer normalized sales projection; the method currently used has been thoroughly vetted by the Public Staff and has been approved by the Commission in prior rate cases. *Id.* Moreover, the Rate Design Panel explained that if the Commission approves DEP's request for an MYRP, residential revenues will be decoupled. *Id.*

The Commission concludes that DEP's proposed weather normalization and customer growth adjustment are reasonable in light of the evidence presented. The Commission, therefore, rejects witness Gorman's recommendation because his proposal does not appear to provide a meaningful improvement over DEP's current methodology. Moreover, the Commission concludes that the evidence in this case does not support a departure from a customer normalized sales projection methodology that the Public Staff has scrutinized and the Commission has approved previously.

Updated Time of Use Periods

DEP witness Byrd, in his direct testimony, testified that DEP is proposing updated and aligned TOU periods across its tariffs that contain time-differentiated pricing for residential and non-residential customers. Tr. vol. 11, 233. Specifically, DEP is proposing to refresh TOU periods as follows (peak periods do not include weekends or holidays):

- On-Peak (Summer) – 6:00 p.m. – 9:00 p.m.
- On-Peak (Non-Summer) – 6:00 a.m. – 9:00 a.m.
- Discount (Summer) – 1:00 a.m. – 6:00 a.m.
- Discount (Non-Summer) – 1:00 a.m. – 3:00 a.m. and 11:00 a.m. – 4:00 p.m.
- Summer consists of the months May – September
- Non-Summer consists of the months October – April.

Id. at 234. Witness Byrd testified that the impacted rate schedules include Residential Service Time-of-Use Schedule R-TOU, Residential Service Time-of-Use Demand Schedule R-TOUD, SGS-TOUE, SGS Time-of-Use Schedule SGS-TOU

(renamed Schedule MGS-TOU), LGS-TOU, LGS-RTP, and the Large Load Curtailable Rider LLC. *Id.* at 241. Schedules R-TOU-CPP and SGS-TOU-CPP already use these proposed periods and will not be impacted. *Id.*

Witness Byrd explained that DEP's existing TOU periods, established decades ago, are no longer appropriate and increasingly do not align with DEP's current and anticipated system needs. *Id.* at 235. Witness Byrd stated that the new TOU periods will benefit customers and advance several policy goals. *Id.* at 241. Specifically, witness Byrd testified that the new TOU periods will properly align price signals to cost differences that exist across different seasons and hours, thereby encouraging peak load reduction and efficient system usage; provide the opportunity for economic use of new technologies, such as smart energy management devices, energy storage, and EVs; and encourage flexible consumption during times of low system costs, providing incentives for distributed energy resource adoption. *Id.* at 234, 241-42. Witness Byrd testified that the TOU periods proposed were taken directly from observations of the Cost Duration Model (CDM) and were discussed and evaluated at length with stakeholders during the CRDS. *Id.* at 235-36. Moreover, witness Byrd notes that the proposed TOU periods have already been approved by the Commission for two of DEP's current tariffs: R-TOU-CPP and SGS-TOU-CPP. *Id.* at 235.

The AGO was the only party that recommended any revisions to DEP's proposed TOU periods. AGO witness Nelson recommended that DEP shift its proposed Summer On-Peak period one hour earlier to 5:00 to 8:00 p.m. Tr. vol. 18, 89. Witness Nelson claimed that this Summer On-Peak period would better reflect system costs during each year of the CDM output (2021, 2026, and 2030). *Id.* at 86. Witness Nelson was particularly concerned with DEP's use of the 2030 CDM output and argued that DEP should not weight it as heavily as 2021 and 2026 output when designing current rates since it is farthest in the future and therefore the most uncertain. *Id.* at 89.

In his rebuttal testimony, DEP witness Byrd disagreed with the AGO's position that DEP should shift the Summer On-Peak period to 5:00 to 8:00 p.m. Tr. vol. 11, 269. Witness Byrd reiterated that DEP discussed and evaluated the proposed 6:00 to 9:00 p.m. Summer On-Peak period at length with stakeholders during the CRDS; DEP based the proposal on observations from the CDM; and the peak period balances several factors, including system costs through 2030 and customer experience. *Id.* at 270. In response to the AGO's concerns regarding DEP's forward-looking approach in designing the new TOU periods, witness Byrd explained that it is important that DEP revise its TOU periods now, before many residential customers are on TOU rates, to minimize disruption once more customers are on TOU rates and have established behavioral patterns. *Id.* at 304. Additionally, witness Byrd explained that TOU periods that consider expected system evolution are appropriate because they will be durable and can last for several years. *Id.* Moreover, witness Byrd testified that if the Commission adopted witness Nelson's recommendation to shift the Summer On-Peak period to 5:00 to 8:00 p.m., customers on Rate Schedules R-TOU-CPP and SGS-TOU-CPP – under which the Summer On-Peak period is 6:00 to 9:00 p.m. – would experience a change in TOU periods after having only been on these rate schedules for a short period. *Id.* at 270. As such, given the recent approval of Rate Schedules R-TOU-CPP and SGS-TOU-CPP, shifting the Summer On-

Peak period to 5:00 to 8:00 p.m. would presumably alter these customers' expectations of TOU period stability. *Id.* Finally, witness Byrd testified that the proposed 6:00 to 9:00 p.m. Summer On-Peak period better aligns with the anticipated increased levels of solar generation on the system, as contemplated in the Commission's Carbon Plan, which will shift the net peak to later in the afternoon. *Id.* at 270-71.

The Commission declines to adopt witness Nelson's recommended change to shift the Summer On-Peak period to 5:00 to 8:00 p.m. DEP witness Byrd offered convincing testimony that it would not be reasonable to shift the Summer On-Peak period to 5:00 to 8:00 p.m. given that the CRDS analyzed the 6:00 to 9:00 p.m. Summer On-Peak period,, DEP based the proposal on the CDM, and the Commission has already approved the Summer On-Peak period for DEP's Rate Schedules R-TOU-CPP and SGS-TOU-CPP. In addition to ensuring proper price signaling and encouraging customer adoption of new technologies, the evidence strongly indicates that DEP's modernized TOU periods will improve price and cost causation alignment. Accordingly, the Commission concludes that DEP's new TOU periods should be approved as proposed.

Residential

The residential rate class includes the following rate schedules: Residential Service Schedule RES, Residential Service Time-of-Use Demand Schedule R-TOUD, Residential Service Time-of-Use Schedule R-TOU, and Residential Service Time-of-Use with Critical Peak Pricing Schedule R-TOU-CPP. Tr. vol. 11, 184.

DEP witness Reed testified that DEP proposes to re-open and modify Residential Rate Schedule R-TOUD to modernize the TOU periods and to update the demand charge structure to better reflect cost causation. *Id.* Witness Reed explained that the CRDS addressed R-TOUD tariff redesign and that the modified tariff will provide customers with more choices regarding their energy consumption. *Id.* at 185. Additionally, witness Reed testified that in response to feedback from customers, DEP also proposes to expand the applicability of residential rates to include detached garages, barns, or other structures that are at the same service address as a separate, primary residential account. *Id.* at 187. Witness Reed testified that if the Commission approves the expansion, DEP will allow existing customers to move from a general service schedule to a residential schedule for detached structures at the same premises as the residential account. *Id.* at 188. Further, witness Reed testified that while DEP's unit cost study justifies an increase to the monthly Basic Customer Charge to better reflect customer-related costs and minimize customer cross-subsidization, DEP is not proposing to raise the Basic Customer Charge in this proceeding. *Id.* at 186. Specifically, witness Reed testified that DEP is proposing to maintain the monthly residential Basic Customer Charge for the R-TOUD, R-TOU, and R-TOU-CPP rate schedules at $16.85. *Id.* Reed Direct Exhibits 6, 6_1, 6_2, and 6_3 illustrate the Basic Customer Charges for the major customer classes for the proposed rate years. *Id.* at 170. Tr. Ex. vol. 11.

In his direct testimony, AGO witness Nelson recommended that the Commission explore making TOU rates default for the residential class. Tr. vol. 18, 111-12. Witness

Nelson argued that DEP's default residential rate schedule – Schedule RES – includes a non-time-varying energy rate that does not send accurate price signals to residential customers, thereby causing more costs to be incurred by customers and DEP during peak hours. *Id.* at 110-11. As such, witness Nelson argued that providing DEP with an incentive to get residential customers on a TOU rate is inappropriate and costly. *Id.* at 111. Instead, the Commission should explore other avenues for expanding residential TOU rates, such as making TOU rates default for the residential class. *Id.* at 111-12.

In his direct testimony, Public Staff witness Williamson testified that while he generally supports the proposed changes to the rate schedules, he proposed a few minor modifications. Tr. vol. 20, 172. Specifically, witness Williamson recommended that the Commission approve DEP's proposal to allow detached garages, barns, and other structures on the same residential premise to be served under a residential rate schedule. *Id.* at 173-75. However, witness Williamson recommended that DEP notify all SGS customers of this change through bill insert or separate mailing. *Id.* at 175, 180. Additionally, regarding DEP's Basic Customer Charge, witness Williamson recommended that DEP set the Basic Customer Charge for Schedules R-TOU and R-TOUD at the same $14.00 per month rate as Schedule RES. *Id.* at 173, 180.

DoD-FEA witness Blank also testified regarding DEP's proposed rate increase for the residential class. Tr. vol. 21, 322-23. Specifically, witness Blank recommended that DEP's proposed rate increase for the residential class not exceed 1.25 times the overall retail base revenue increase. *Id.*

In their rebuttal testimony, the Rate Design Panel disagreed with witness Nelson's recommendation to make TOU rates default for the residential class. Tr. vol. 11, 281. Witnesses Reed and Byrd testified that the choice to switch to a TOU rate should be with the customer because TOU rates only yield system benefits if customers respond to price signals and shift load away from peak periods. *Id.* During the expert witness hearing, witness Reed explained that forcing a residential customer to switch to a TOU rate could be harmful and result in higher bills if they cannot manage their energy usage in response to price signals. *Id.* at 312. Therefore, witness Reed testified that DEP's preferred approach to expanding TOU rate adoption is to make TOU rates more appealing and encourage voluntary adoption. *Id.* at 281, 311.

In response to the Public Staff's recommendations relating to the residential class, the Rate Design Panel accepted the Public Staff's proposal to notify all SGS customers through bill insert or a separate mailing about the expanded applicability of residential rates to include detached garages, barns, and other structures that are at the same service address as a separate, primary residential account. *Id.* at 283. DEP also accepted the Public Staff's proposal to set the Basic Customer Charge for Rate Schedules R-TOU and R-TOUD at $14.00. *Id.* at 280.

The Rate Design Panel also disagreed with witness Blank's recommendation to cap the rate increase for the Residential class. *Id.* at 282. The Rate Design Panel explained that witness Blank's rate increase proposal would shift the rate increase for the LGS class to other

customer classes which is not in line with the need to balance cost causation alignment, gradualism, and the avoidance of rate shock. *Id.* During the expert witness hearing, witness Reed explained that by shifting the rate increase from the LGS class to other customer classes, including the residential class, witness Blank's rate increase proposals benefit the LGS class at the expense of all other customer classes, including rate increases of over 100 percent for some classes. *Id.* at 385-86, 390.

In light of the parties' testimony and all the evidence presented, the Commission concludes that DEP's proposed rate design for the residential rate class, including the Public Staff modifications to which DEP agreed, is just and reasonable. The Commission agrees with witnesses Reed and Byrd that the decision to switch to a TOU rate should be with the customer. Additionally, the Commission accepts the Public Staff's testimony regarding the appropriateness of modifying the Basic Customer Charge for Schedules R-TOU and R-TOUD to be set at the same $14.00 rate as Schedule RES. This is the same Basic Customer Charge the Commission approved in DEP's last rate case, when it found that it appropriately balances the needs to offer rates that more clearly reflect actual cost causation, minimize subsidization, and provide proper price signals to customers in the rate class, while also moderating the impact of rate increases on low-usage customers. *See* 2019 DEP Rate Order 203. Accordingly, the Commission concludes that the Basic Customer Charges as set forth in Reed Exhibits 6, 6_1, 6_2, and 6_3 are just and reasonable and are therefore approved.

Medium General Service (MGS) and Large General Service (LGS)

The MGS rate class includes all nonresidential customers with demand requirements from 30 kW to 1,000 kW and consists of the following rate schedules: MGS, SGS-TOU (proposed to be renamed MGS-TOU), SGS (Thermal Energy Storage) Schedule GS-TES, Agricultural Post-Harvest Processing (Experimental Thermal Energy Storage) Schedule APH-TES, Church Time-of-Use Schedule CH-TOUE, Church and School Service Schedule CSE, and Church and School Service Schedule CSG. Tr. vol. 11, 190. The LGS class includes all nonresidential customers with demand requirements of 1,000 kW or greater and consists of the following rate schedules: LGS, LGS-TOU, and LGS (Real Time Pricing) Schedule LGS-RTP. *Id.* at 194.

In her direct testimony, DEP witness Reed described the proposed rate design for the MGS and LGS rate schedules[9]. *Id.* at 190-93. Witness Reed testified that DEP is proposing to increase the Basic Customer Charge for the MGS and LGS classes to better reflect the cost of serving these customers. *Id.* at 190. Specifically, witness Reed stated that DEP proposes to increase the Basic Customer Charge for the MGS class for all rate years from $28.50 to $30.00 per month for single-phase service, or $39.00 if the customer requests three-phase service and/or is on Schedule SGS-TOU (MGS-TOU). *Id.* at 190-91. Additionally, DEP proposes to increase the Basic Customer Charge for the LGS class for all rate years from $200.00 to $210.00 per month. *Id.* at 194.

[9] Note that DEP's proposed changes to Schedule LGS-RTP are discussed *supra*.

DEP witness Byrd testified explaining DEP's proposal to change the demand charge structure for renamed Schedule MGS-TOU and Schedule LGS-TOU. *Id.* at 243-45. Specifically, witness Byrd stated that DEP proposes a three-part demand structure consisting of the following components: a Base Demand Charge, designed to recover distribution costs, which DEP would apply to the higher of either (1) a customer's highest maximum demand across all periods over the previous 12 months, or (2) 50.0% of the Contract Demand; a Mid-Peak Demand Charge, designed to recover off-peak and discount allocation of production and transmission costs, which DEP would apply to a customer's maximum demand during off-peak or on-peak periods but excluding discount periods; and a Peak Demand Charge, designed to recover peak allocation of production and transmission costs resulting from the customer's contribution to system demand during peak hours, which DEP would apply to a customer's measured on-peak demand. *Id.* at 243-44. Witness Byrd explained that the proposed three-part demand structure will improve price transparency and better align with cost causation based on both the size and timing of customer demands and is meant to work in tandem with DEP's proposed TOU periods. *Id.* at 244.

Additionally, witness Byrd testified that, in response to stakeholder feedback during the CRDS, DEP evaluated the alignment of bills and pricing to cost causation. *Id.* at 245. Witness Byrd stated that this analysis showed that shifting a portion of fixed cost recovery from energy charges to demand charges improved alignment to cost causation across a wide spectrum of customer energy usage profiles with very little impact on customer bills. *Id.* Witness Byrd stated that as a result of this evaluation DEP witness Reed proposed that DEP institute pricing that reflects slightly higher recovery through demand charges for TOU rates. *Id.*

Kroger Co. and Harris Teeter witness Bieber testified regarding DEP's proposed MGS-TOU rate design. Tr. vol. 21, 694-702. In his direct testimony, witness Bieber acknowledged that DEP's proposed MGS-TOU rates "improve alignment between the charges and the underlying embedded costs," but noted that they are "...still substantially lower than the demand unit cost." *Id.* at 694. Witness Bieber recommended "moderate" and "revenue-neutral" changes to DEP's proposed MGS-TOU energy and demand charges that he contends will improve the alignment between the rate component and the underlying costs while employing the principle of gradualism and mitigating intra-class rate impacts. *Id.* at 697-98. Specifically, witness Bieber recommended that DEP's proposed three-part demand charges each be increased by an additional 20.0% and that the proposed off-peak energy charge be reduced by a corresponding amount. *Id.* at 698. If the Commission determines that an even more gradual approach to align rates with DEP's underlying costs is appropriate, witness Bieber provided an alternative recommendation: that MGS-TOU Base Demand Charge, Mid-Peak Demand Charge, and Peak Demand Charge each be increased by proportionally so that the sum of the three charges is no less than 60.0% of the unit cost of demand from DEP's proposed COSS for the corresponding rate year, with a corresponding adjustment to the off-peak energy charge so that the modification is revenue neutral. *Id.* at 700.

Commercial Group witness Chriss also expressed concern that DEP's proposed MGS-TOU rate design does not reflect the underlying cost to serve and as a result shifts cost

responsibility within the rate classes. *Id.* at 527-28. Witness Chriss claimed that DEP has not fully aligned the proposed MGS-TOU demand charges with the underlying demand-related costs. *Id.* at 527. Witness Chriss testified that collecting demand-related costs through an energy charge is inconsistent with cost causation principles and results in a shift in demand cost responsibility from lower load factor customers to higher load factor customers, which will overpay for demand-related costs DEP incurs through providing service to them. *Id.* at 528. Witness Chriss also claimed that DEP would benefit by recovering more demand-related costs through a demand charge instead of through the energy charge since it would be less susceptible to weather-related and other fluctuations in usage, resulting in greater revenue certainty and more stable utility earnings. *Id.* at 528-29. Witness Chriss testified that, for the purposes of this case, the Commercial Group does not oppose DEP's proposed rate levels for MGS-TOU at DEP's proposed revenue requirement, if there is a decrease from the proposed revenue requirement, the Commercial Group recommended that DEP apply such decrease proportionately to the energy charges to better align costs to the cost of service. *Id.* at 529.

In his direct testimony, AGO witness Nelson also took issue with DEP's proposal to increase the level of fixed costs it recovers through demand charges. Tr. vol. 18, 20, 93-101. Witness Nelson testified that DEP has not sufficiently demonstrated that its approach to increasing cost recovery through demand charges will improve alignment with cost causation or that it will result in superior price signals. *Id.* at 94-97. Specifically, witness Nelson claimed that the way DEP categorizes electric system costs as fixed and not fixed does not account for many power system characteristics and "reflects an oversimplification of cost classification…over-emphasizes short-term costs [and] revenue collection and de-emphasizes long-term asset avoidance and system efficiency". *Id.* at 95. Accordingly, witness Nelson recommended that DEP increase energy charges for Schedules MGS-TOU and LGS-TOU to a level that is above marginal cost while maintaining strong price ratios between On-Peak, Off-Peak, and Discount periods to send price signals to customers, and correspondingly decrease demand rates to reflect the revised energy rates. *Id.* at 93, 97, 99. Witness Nelson also recommended that DEP propose Critical Peak Pricing (CPP) rate options for MGS and LGS customers since they can contribute to lower costs and improved system reliability. *Id.* at 93, 101-06. Witness Nelson claimed that while well-designed TOU rates can improve alignment with system costs, they are not precise enough to sufficiently incentivize load shifting during critical peak events. *Id.* at 102-05. Witness Nelson testified that CPP tariffs provide utilities with the ability to flexibly identify peak load events and incentivize customers to shift load during short, but highly impactful, periods of system load. *Id.* at 102.

CUCA witness O'Donnell testified regarding DEP's proposed LGS-TOU rate design. Tr. vol. 21, 655-60. Overall, witness O'Donnell claimed that the LGS-TOU rate design is "overly complex", not beneficial to the LGS class, and would benefit DEP, not energy consumers. *Id.* at 657-59. Witness O'Donnell also testified that he did not agree with DEP's proposals to implement a Mid-Peak Demand Charge, which is "not consistent with the realities of how much manufacturing happens in North Carolina," noting that when manufacturers are "on they are on for as long as it takes," meaning they are not typically able to shutdown mid-production to avoid peak times. *Id.* at 655-56. Witness O'Donnell stated that he objected to the inclusion of a ratchet in the Base Demand Charge, which

he argued could lock customers into an overly expensive and unrepresentative demand charge if their peak demand occurs during an on-peak period. *Id.* at 658-59. As such, witness O'Donnell recommended removal of the Mid-Peak Demand Charge and the ratchet from the Base Demand Charge. *Id.* at 655-56, 659.

In their rebuttal testimony, the Rate Design Panel disagreed with the intervenors' various adjustments to DEP's proposed MGS and LGS rate design. Tr. vol. 11, 271-79. Specifically, DEP disagreed with witness Bieber's recommendation to increase the MGS-TOU three-part demand charges by an additional 20.0% and to reduce the proposed off-peak energy charge by a corresponding amount. *Id.* at 271-72. The Rate Design Panel explained that while witness Bieber's proposal is directionally aligned with DEP's approach, it does not sufficiently consider gradualism and would lead to materially adverse outcomes, such as rate shock, for lower load factor customers. *Id.* at 272. In contrast, the Rate Design Panel testified that DEP's approach to slightly increasing demand charges and correspondingly decreasing energy charges better balances gradualism with alignment to cost-of-service. *Id.*

Additionally, while DEP disagreed with witness Chriss' recommendation that DEP allocate any decreased revenue requirement proportionately to the energy charges on Schedule MGS-TOU, the Rate Design Panel noted that DEP is willing to balance lowering energy and demand, as appropriate, to meet the revenue requirement; ensure that it treats both low load factor and high load factor customers equitably; and provide that rate change shifts occur gradually. *Id.* at 271. The Rate Design Panel also testified that DEP agrees with witness Chriss that demand charges should align with demand-related costs. *Id.* at 276. However, the Rate Design Panel explained that DEP must also balance alignment to cost causation with gradualism. *Id.* at 277. As such, the Rate Design Panel testified that DEP's proposed rates, which reflect higher fixed cost recovery through demand charges, result in improved alignment to cost-of-service while also including necessary gradualism in order to avoid potential adverse impacts to lower load factor customers. *Id.*

Additionally, the Rate Design Panel rebutted witness Nelson's argument that DEP should increase cost recovery through energy charges and correspondingly decrease demand charges for Schedules MGS-TOU and LGS-TOU. *Id.* at 272. The Rate Design Panel explained that contrary to witness Nelson's recommendation, DEP proposed a modest increase in fixed cost recovery through demand charges relative to such recovery through energy charges. *Id.* The Rate Design Panel testified that DEP's proposal to increase cost recovery through demand charges both improves alignment to cost-of-service and provides meaningful price signals to encourage system beneficial behavior. *Id.* The Rate Design Panel explained that witness Nelson's suggestion would penalize higher load factor customers, who more consistently use fixed assets and require less cost to serve per unit of energy, and thus increase subsidization between customers with varying load factors. *Id.* at 273. The Rate Design Panel further explained that witness Nelson's proposed rate design would encourage more consistent consumption reduction throughout the month and weaken price signals that are meant to reduce consumption at peak times, thereby increasing the strain on the grid and subsequently increasing the

need for investments, ultimately increasing costs for all customers. *Id.* at 274. In contrast, the Rate Design panel testified that DEP's proposed rate design would encourage targeted behavioral modification to reduce demand during the times when additional demand would drive more fixed cost investments. *Id.*

Further, in response to witness Nelson's recommendation that DEP adopt a CPP rate option for MGS and LGS customers, the Rate Design Panel claimed that a CPP rate was unnecessary. *Id.* at 276. The Rate Design Panel noted that during the CRDS, stakeholders generally favored new hourly pricing options relative to CPP options. *Id.* Additionally, the Rate Design Panel stated that DEP's MGS and LGS rate design proposals offer suitable and sufficient options for customers with flexible loads. *Id.*

The Rate Design Panel also testified that it disagreed with witness O'Donnell's recommended changes to DEP's Mid-Peak Demand Charge and Base Demand Charge under Schedule LGS-TOU. *Id.* at 277-79. The Rate Design Panel explained that DEP's proposed Mid-Peak Demand Charge plays an important role in collecting significant amounts of fixed costs associated with non-peak production and transmission assets. *Id.* at 278. Similarly, the Rate Design Panel testified that the Base Demand Charge is carefully designed to reflect certain system costs under the CDM and to recover costs for distribution assets that remain constant year-round and are close to the customer, and thus appropriately utilizes a ratchet. *Id.* The Rate Design Panel explained that customers that exhibit consistent loads year-round, including some manufacturing customers, benefit from the ratchet feature because demand charges would be higher overall without such a feature. *Id.* at 278-79. Moreover, as witness Byrd testified during the hearing, the Base Demand Charge reduces bill volatility for customers by allocating and recovering costs through "very consistent charges". *Id.* at 364-65. The Rate Design Panel also disagreed with witness O'Donnell's characterization of the LGS-TOU rate as overly complex because customers taking service under Schedule LGS-TOU are generally sophisticated and capable of understanding rate design. *Id.* at 279. Moreover, as described in the CRDS, DEP's proposed tariffs appropriately balance simplicity and understandability with alignment to cost-of-service. *Id.*

DEP, the Commercial Group, and Kroger Co. and Harris Teeter entered into the MGS Partial Rate Design Stipulation resolving some of the issues in this proceeding between the parties. The MGS Partial Rate Design Stipulation provides that 75.0% of the reduction in revenue requirement, as determined by final Commission order, applicable to Rate Schedule MGS-time-of-use (TOU), should be applied to energy rates. The MGS Partial Rate Design Stipulation also provides that Kroger Co. and Harris Teeter agree to withdraw its proposal that DEP study the possibility of, and propose, a multi-site aggregate commercial rate. Finally, the MGS Partial Rate Design Stipulation provides that Kroger Co. and Harris Teeter does not oppose the Revenue Requirement Stipulation or the PIMs Stipulation.

DEP and CIGFUR entered into the LGS Partial Rate Design Stipulation, resolving some of the issues in this proceeding between the parties. The LGS Partial Rate Design Stipulation provides that any increase in energy charges resulting from an increase in

DEP's revenue requirement to be recovered from the LGS, LGS-TOU, and LGS-Real Time Pricing (RTP) rate schedules, as determined by final Commission order, shall be limited to a percentage that is less than half of the approved overall increase percentage to the LGS, LGS-TOU, and LGS-RTP classes, respectively, exclusive of any decrements for the LGS, LGS-TOU, and LGS-RTP rate schedules. The LGS Partial Rate Design Stipulation also applies to any customers currently taking service under an LGS, LGS-TOU, or LGS-RTP rate schedule that switch tariffs to either the High Load Factor tariff or Hourly Pricing (HP) tariff, in the event the Commission approves such tariffs in this proceeding.

Schedule LGS-RTP is a historical rate option that provides DEP's LGS customers with exposure to marginal pricing above a Customer Baseline Load (CBL) threshold. Tr. vol. 11, 251. Schedule LGS-RTP is currently available to customers with a load of 1,000 kW or greater and is capped at 85 nonresidential customers. *Id.* In his direct testimony, DEP witness Byrd testified that DEP proposes to freeze Schedule LGS-RTP to new applicants but grandfather current customers. *Id.* Specifically, witness Byrd testified that DEP will close Schedule LGS-RTP to new applications beginning October 1, 2023, and discard the waitlist to join schedule LGS-RTP. *Id.* at 338-39. Witness Byrd explained that DEP proposes to freeze Schedule LGS-RTP because it is administratively burdensome and does not contain ongoing CBL adjustments, creating scalability issues by allowing incremental load to remain on marginal pricing indefinitely. *Id.* at 251.

Additionally, witness Byrd testified that freezing Schedule LGS-RTP is appropriate considering the new Schedule HP proposed by DEP. *Id.* Witness Byrd explained that DEP created Schedule HP in response to stakeholder and customer requests during the CRDS for a more flexible marginal price rate with expanded availability. *Id.* at 248. Like the LGS-RTP, witness Byrd stated that Schedule HP will be available to customers with a load of 1,000 kW or greater. *Id.* at 249. Under Schedule HP, DEP will reestablish the CBL, which defines the level above which DEP will bill all kWh at the hourly energy prices, every four years based on a customer's 12-month usage history, with modifications to reflect price-responsiveness during times of grid constraints. *Id.* at 249. Witness Byrd explained that this new approach to reestablishing CBLs will restrict marginal prices to only four years for growing loads that are not consistently price-responsive, resulting in embedded cost recovery from such loads after the periodic CBL reestablishment. *Id.* Witness Byrd stated that the newly proposed CBL management is average kW and kWh by TOU period. *Id* at 250. Schedule HP will include a margin adder of $6.00 per megawatt-hour to account for day-ahead pricing uncertainty and provide some fixed cost recovery from the marginal energy purchases. *Id.* Witness Byrd testified that DEP proposes Schedule HP without a participation cap due to the durability and scalability of the new program design. *Id.*

DoD-FEA witness Blank recommended that the Commission deny DEP's request to freeze the LGS-RTP rate because DEP has not demonstrated a need to close the rate. Tr. vol. 21, 336-37, 341. Witness Blank testified that LGS-RTP is fully subscribed and that by freezing the rate DEP would prevent the possibility of a new customer replacing a departing LGS-RTP customer, which may provide a "financial windfall" to DEP. *Id.* at 336. Additionally, witness Blank argued that DEP should not close LGS-RTP because

Schedule HP is "categorically different" from Schedule LGS-RTP and therefore is not a suitable replacement for the LGS-RTP tariff. *Id.* at 336, 338. Witness Blank did not express any concerns with Schedule HP. *Id.* at 337-38.

In rebuttal, the Rate Design Panel disputed witness Blank's recommendation that the LGS-RTP rate should remain open. Tr. vol. 11, 284-88. In response to witness Blank's concerns that a departing LGS-RTP customer could provide a windfall to DEP, the Rate Design Panel testified that it does not anticipate that an existing RTP customer would switch to a non-RTP rate because under such scenario, a customer would be voluntarily switching to a higher rate. *Id.* at 285. The Rate Design Panel explained that witness Blank's imagined scenario is unrealistic because customers taking service under LGS-RTP are generally sophisticated and large and would not normally leave the rate for a less attractive option. *Id.* Rather, the Rate Design Panel testified that to the extent attrition occurs on LGS-RTP, the customer would likely be leaving DEP's service territory or otherwise switching to a lower-cost rate, thus lowering DEP's revenues. *Id.*

The Rate Design Panel also disagreed with witness Blank that Schedule HP is not a suitable substitute for LGS-RTP. *Id.* The Rate Design Panel testified that several similarities exist between Schedule LGS-RTP and Schedule HP. *Id.* Specifically, the Rate Design Panel stated that both the LGS-RTP tariff and Schedule HP: (1) are available to customers with a load of 1,000 kW or greater; (2) have energy priced at a marginal rate above a CBL threshold; and (3) contain incremental demand charges and an incentive margin. *Id.* at 285-86. Furthermore, the Rate Design Panel stated that the differences between LGS-RTP and Schedule HP demonstrate that Schedule HP is superior to LGS-RTP. *Id.* at 286. For instance, since under Schedule HP DEP will reestablish CBLs every four years and reduce them using a method that recognizes the benefits of price-responsiveness during times of grid constraints, loads DEP presently serves under the CBL could have exposure to marginal pricing after consistent price-responsive behaviors—a customer benefit that does not exist under the LGS-RTP tariff. *Id.* at 286. The Rate Design Panel explained that these adjustments are appropriate because loads that customers can reduce during times of system peak consistently over several years reduce the need for additional peaking resources and lower costs overall for the grid. *Id.* Similarly, a CBL reestablishment every four years ensures that loads that are not price responsive eventually move under the CBL and receive pricing under embedded costs, which is appropriate as such loads begin to drive investments in additional capacity assets. *Id.* at 286-87. Additionally, because of the reduced administrative burden and four-year CBL reestablishment, the Rate Design Panel testified that DEP was able to offer Schedule HP without a participation cap. *Id.* at 287. Finally, the Rate Design Panel explained that Schedule HP will more effectively serve as an economic development tool than the LGS-RTP tariff since Schedule HP is not capped and thus prospective new customers can confidently expect to be able to sign on to the rate if they wish to do so. *Id.* In summary, the Rate Design Panel stated that while several core elements in Schedule HP mirror Schedule LGS-RTP, the proposed improvements in Schedule HP relative to the LGS-RTP tariff yield a more scalable, durable, and accessible rate option for customers. *Id.* at 287-88.

During the expert witness hearing, witness Reed elaborated on the administrative burdens associated with Schedule LGS-RTP. *Id.* at 381-85. Specifically, witness Reed explained that Schedule LGS-RTP requires creation of a CBL and calendar mapping that reflect an individual customer's operations. *Id.* at 381-82. Witness Reed testified that under such processes, DEP sets a CBL for every hour of every day in Excel and must then update this data both annually and every time there is a change in scheduled shutdown days. *Id.* at 381-82. Witness Reed also described the administrative burden of manually billing and calculating the RTP bill for customers. *Id.* at 382. Witness Reed further noted that it takes two full-time personnel to manage Schedule LGS-RTP. *Id.* In contrast, witness Byrd testified that Schedule HP is much simpler and more scalable than Schedule LGS-RTP. *Id.* at 385. For example, witness Byrd explained that Schedule HP uses a CBL management approach that is already in place for DEC's hourly pricing program. *Id.* at 250, 385. This process of CBL management will eliminate the need for the administratively burdensome calendar mapping and special days process currently in use for the existing RTP rate. *Id.* at 250. Instead, after establishment of an initial CBL, DEP will automatically reestablish every four years. *Id.*

At the reconvened hearing on July 24, 2023, Public Staff witness D. Williamson testified regarding the Public Staff's concerns with the LGS Partial Rate Design Stipulation. Specifically, Public Staff witness D. Williamson testified that the Public Staff opposes the stipulation on the basis that it constricts the rate designer's ability to appropriately figure out how the revenue requirement that would get assigned to that class should be allocated between the energy and demand components of the rates. Tr. vol. 24, 89. He testified that while the stipulation might move in alignment with the cost of service, the stipulation, in the Public Staff's position, inappropriately predetermines how cost is apportioned between energy and demand components. *Id.* He explained that rate designers, not parties to the proceeding, should apportion costs among the various components of rates as rate designers have a better understanding of load shapes individual classes, specifically with respect to all customers in the class. He explained the Public Staff's position that, for this reason, the rate designer is in the best position to adequately price energy, demand, the customer charges. *Id.* at 92- 93. Ultimately, he concluded that the rate designer is in the best position to ensure that rates are designed to recover costs from customer classes most in alignment with the costs incurred by the utility to serve each class. *Id.* at 94. He also concluded that rates designed to be in alignment with cost causation are just and reasonable. *Id.* at 95. Ultimately, he testified that the Public Staff recommends that the Commission not approve the stipulation in order to allow rate designers to do their work. He testified that if the rate designer reaches the same conclusion on rate design as that set forth in the stipulation, then the Public Staff would support it. *Id.* at 97.

DEP witness Byrd testified that the LGS Partial Rate Design Stipulation would not involve any interclass subsidy and that the dynamic of allocating the revenue requirement between the energy and demand components of the rate impacts only the specific rate schedule for the customer class. *Id.* at 74. DEP witness Byrd testified that the possibility of moving capacity-related costs to the demand component of the rate was discussed during the Comprehensive Rate Design process. He testified that:

> At a high level, [DEP] looked at cost of service and determined that it would be appropriate to increase the amount of fixed costs recovered through demand charges relative to energy. We wrote about that in the roadmap, and so the Company proposed in this case -- our original proposed rates, particularly for LGS-TOU, increased the amount of fixed cost recovery through demand charges.

Id. at 75.

DEP witness Byrd testified that while the stipulation would not result in any interclass subsidization, there might be a slight bill impact to customers within the class, based on load factor but this impact is in alignment with cost of service. *Id.* at 77-78, 83-84. CIGFUR II witness Collins confirmed that the LGS Partial Rate Design Stipulation would not cause an interclass subsidy. Tr. vol. 24, 72.

Considering the parties' testimony and the evidence the parties presented, the Commission concludes that DEP's proposed rate design for the MGS and LGS rate classes, including the modifications agreed to in the MGS Partial Rate Design Stipulation and the LGS Partial Rate Design Stipulation, is just and reasonable. The Commission concludes that DEP's proposed Basic Customer Charge increases, including Basic Customer Charges of $30.00 for the MGS class and $210.00 for the LGS class, strike an appropriate balance that provide rates that accurately reflect cost causation, minimize subsidization, and provide proper price signals to customers in the MGS and LGS rate classes, while also moderating the impact of such increase on lower-load factor customers.

In addition, the Commission concludes that the MGS Partial Rate Design Stipulation and LGS Partial Rate Design Stipulation are the products of arm's-length negotiations between parties who took opposing positions on these subjects in their prefiled testimony. The Commission also finds that the MGS Partial Rate Design Stipulation and LGS Partial Rate Design Stipulation reduce the number of contested issues the parties present to the Commission for resolution regarding rate design. Both stipulations address only intra-class issues, not inter-class issues, and focus on increasing the amount of fixed cost recovery through demand charges as opposed to energy, which is consistent with DEP's COSS. The Commission acknowledges the concern of the Public Staff regarding rate design and the preference that the rate designer not be constrained by agreements between the utility and certain customers regarding the apportionment of costs between demand and energy components of the rates. Specifically, the Commission takes note of the concern that this may give rise to "winners and losers" within a particular customer class and appreciates the Public Staff's vigilance for all customers within a class. The Commission is persuaded by DEP witness Byrd that the LGS Partial Rate Design Stipulation does not result in an interclass subsidy and impacts customers within the class only slightly and in a manner that aligns with cost causation. The Commission notes that no party presented any evidence that the MGS Partial Rate Design Stipulation results in any interclass subsidization, involves inter-class allocation of revenue requirement, or is not in alignment with DEP's COSS. Therefore,

the Commission concludes that the MGS Partial Rate Design Stipulation and LGS Partial Rate Design Stipulation are reasonable and should be approved. However, in recognition of the concerns raised by the Public Staff, the Commission approval in this proceeding shall not be taken as an indication that the Commission generally looks favorably on rate design settlements, and the Commission will scrutinize rate design settlements between the utility and any customer or customer group going forward, with the objective of achieving just and reasonable rates for all customers.

Testimony from witnesses Reed, Byrd, Bieber, and Chriss indicates that the change to the MGS-TOU rate design agreed to in the MGS Partial Rate Design Stipulation is reasonable and based on cost causation. The Commission notes that the Partial Rate Design Stipulation provision relating to MGS-TOU energy rates applies only to the MGS-TOU rates proposed in this rate case. This provision does not bind DEP to any particular rate design structure in future rate cases and does not limit its ability to study alternative rate designs. Furthermore, testimony from witnesses Reed, Byrd, and Phillips indicates that the change to the LGS rate design agreed to in the LGS Partial Rate Design Stipulation is reasonable and based on cost causation. The Commission observes that the LGS Partial Rate Design Stipulation provision relating to LGS energy rates applies only to the LGS, LGS-TOU, and LGS-RTP rates proposed in this rate case, and any customers currently taking service under Rate Schedules LGS, LGS-TOU, or LGS-RTP that subsequently switch to either the HLF tariff or the HP tariff. This provision does not bind DEP to any particular rate design structure in future rate cases and does not limit DEP's ability to study alternative rate designs.

Additionally, the Commission concludes that DEP's proposal to freeze Schedule LGS-RTP to new customers effective October 1, 2023, is reasonable. The Commission further concludes that DEP's proposed Schedule HP is reasonable. The Commission declines to adopt witness Blank's recommendation to keep LGS-RTP open to new customers after DEP's proposed freeze date. Witness Reed offered convincing testimony that keeping LGS-RTP open is unduly burdensome and unnecessary given DEP's new Schedule HP. Accordingly, the Commission agrees with DEP that it is appropriate to freeze LGS-RTP. Additionally, the Commission rejects witness Blank's characterization of Schedule HP as "categorically different" than Schedule LGS-RTP. The Commission concludes that though Schedule LGS-RTP and Schedule HP contain several core similarities the differences between the two rate schedules indicate that Schedule HP will be more effective and efficient than Schedule LGS-RTP.

The Commission declines to adopt witness Nelson's recommended modifications to DEP's proposed MGS and LGS rate designs. The Rate Design Panel offered convincing testimony that it is appropriate to increase the level of fixed costs recovered through demand charges in this proceeding since doing so will improve alignment to cost causation across the range of customer load factors while also providing meaningful price signals. In contrast, the Commission finds that witness Nelson's proposal will likely result in subsidization between customers with varying load factors and weaken price signals. The Commission also rejects witness Nelson's request that the Commission adopt a CPP

rate at this time given the design of the MGS-TOU and LGS-TOU rates and the introduction of new hourly pricing options.

The Commission also declines to adopt the recommendation of witness O'Donnell to remove the Mid-Peak Demand Charge and the ratchet from the Base Demand Charge on the grounds that these charges are based on a rate design that more accurately reflects DEP's cost of service and provides customers with flexible loads the opportunity to shift consumption patterns and reduce costs.

Small General Service (SGS)

The SGS rate class includes all nonresidential customers with demand requirements below 30 kW and consists of the following rate schedules: SGS, SGS-TOUE, and SGS-TOU-CPP. Tr. vol. 11, 188.

In her direct testimony, DEP witness Reed described the proposed rate design for the SGS rate schedules. *Id.* at 188-89. Witness Reed testified that DEP is proposes to increase the Basic Customer Charge for the SGS class to better reflect the cost of serving these customers. *Id.* at 189. Specifically, witness Reed stated that DEP proposes to increase the Basic Customer Charge for the SGS class for all rate years from $21.00 to $22.00 per month for all SGS schedules to minimize the percentage increase in bills for customers with low monthly usage and to maintain a similar overall proposed increase for customers within the SGS class. *Id.* Witness Reed testified that DEP proposes to keep the Base Customer Charge at $22.00 per month for all rate years. *Id.* Witness Reed also testified that DEP proposes retaining the current kWh energy block structure, with the second block being approximately 18.0% less than the first block kWh energy rate. *Id.* Witness Reed stated that SGS energy rates are adjusted to recover the requested revenue increase. *Id.*

In his direct testimony, AGO witness Nelson recommended that DEP revise Schedule SGS-TOU-CPP. Tr. vol. 18, 105-06. Witness Nelson claimed that as currently designed, Schedule SGS-TOU-CPP does not appear to provide any tangible benefit in comparison to DEP's default TOU option under Schedule SGS-TOUE and, that in fact, Schedule SGS-TOU-CPP would be costlier for customers. *Id.* Witness Nelson claimed that Schedule SGS-TOU-CPP has higher rates across every time period, serving as a strong disincentive for customers to enroll and provide grid services during critical peak events. *Id.* at 106. He testified that DEP had previously acknowledged that "there is a pricing concern with SGS-TOU-CPP" and that as of February 2023 only a single customer had enrolled in the tariff. *Id.* As such, witness Nelson argued that DEP should redesign SGS-TOU-CPP so that customers who opt for the rate over the default TOU option have opportunities to save if they respond appropriately to critical peak events. *Id.*

DoD-FEA witness Blank also testified regarding DEP's proposed rate increase for the SGS class. Tr. vol. 21, 323. Specifically, witness Blank recommended that DEP maintain its proposed rate increase for the SGS class at $469,000 or 8.16%. *Id.*

In their rebuttal testimony, the Rate Design Panel acknowledged that there is a pricing concern with SGS-TOU-CPP. Tr. vol. 11, 282. As such, the Rate Design Panel stated that DEP will adjust the pricing on SGS-TOU-CPP to be more competitive relative to Schedule SGS-TOUE to encourage adoption of the more dynamic tariff. *Id.* Regarding witness Blank's recommendation on the proposed increase to the SGS class, the Rate Design Panel testified that witness Blank's rate increase proposal would shift the rate increase from the LGS class to other classes, contrary to DEP's goals of alignment to cost causation, gradualism and the avoidance of rate shock. *Id.*

Considering the parties' testimony and the evidence presented, the Commission concludes that DEP's proposed rate design for the SGS class, subject to modification in its compliance filing, is just and reasonable. The Commission concludes that DEP's proposed Basic Customer Charge increase to $22.00 per month for all SGS schedules strikes an appropriate balance that provides rates that accurately reflect cost causation and thus, minimizes subsidization and provides proper price signals to customers in the SGS customer class. Additionally, the Commission agrees with the Rate Design Panel that DEP should make a compliance filing to adjust the pricing on SGS-TOU-CPP to be more competitive and to encourage adoption of the tariff. Further, the Commission declines to adopt witness Blank's proposed revenue adjustments to the SGS class because his proposal would result in greater subsidization and does not align with the principles of gradualism or cost causation.

Lighting

DEP provides outdoor lighting service under the following rate schedules: Area Lighting Service Schedule ALS, Street Lighting Service Schedule SLS, and Street Lighting Service (Residential Subdivisions) Schedule SLR. Tr. vol. 11, 198. DEP also provides lighting service under Sports Field Lighting Service Schedule SFLS, Traffic Signal Service (Metered) Schedule TFS, and Traffic Signal Service Schedule TSS. *Id.* at 197.

In her direct testimony, DEP witness Reed testified in support of DEP's proposed changes to its Lighting class schedules. *Id.* at 197-202. With respect to outdoor lighting, witness Reed testified that DEP has adjusted the rates in the proposed outdoor lighting schedules to achieve a combined outdoor lighting revenue target and to reduce or eliminate the difference between the monthly rates in the Area and Street Lighting Service Schedules for similar fixtures and poles/posts. *Id.* at 198. Witness Reed explained that because the current SLS class has a significantly lower return than DEP realizes under Schedule ALS, DEP recommends a higher increase for Schedules SLS and SLR. *Id.* Witness Reed also testified that DEP proposes to freeze Schedule SLR to new applicants to align with DEC's outdoor lighting offering. *Id.* at 201. Witness Reed explained that DEP will continue to serve existing customers under Schedule SLR until such time as they move to another schedule and new customers can take service under Schedules SLS or ALS, as applicable. *Id.*

In their direct testimonies, NCLM witnesses Saffo and Mann testified that DEP's proposed increases for the Lighting class are far too high and have the potential for rate

shock. Tr. vol. 21, 761-62, 765, 777-78, 783. Witness Mann testified that the proposed increases for Lighting class customers are almost triple the average increase in the base rate, and almost double the average increase across the MYRP period. *Id.* at 762. Witness Mann also asserted that DEP's proposed Lighting class rate increases will force municipalities in North Carolina "to choose between cutting services and programs or raising property taxes on citizens," since one of the most significant costs for municipalities is street lighting. *Id.* at 766. Witness Saffo described DEP's 30.0% rate increase to the Lighting class over three years as "the opposite of gradual". *Id.* at 779. Witnesses Saffo and Mann requested that the Commission carefully review proposed rate increases for services to municipalities to be assured that DEP has taken all steps to minimize any rate increases. *Id.* at 765, 783.

In his direct testimony, Public Staff witness D. Williamson recommended approval of DEP's proposed changes to Schedule SLR, including the accompanying amendments to its Outdoor Lighting Service Regulations. Tr. vol. 20, 176-77. However, witness D. Williamson recommended that DEP notify all Schedule SLR customers of this change by bill insert or separate mailing. *Id.* at 177.

In their rebuttal testimony, the Rate Design Panel recognized that the Lighting class is facing a large rate increase but explained that a change in cost-of-service methodology primarily drives the proposed increase. Tr. vol. 11, 283-84. The Rate Design Panel testified that to mitigate some of the increase, DEP proposes to limit the reduction in the subsidy to 10.0% as opposed to the 25.0% it implemented in prior rate cases, resulting in a 19.9% increase instead of a 24.9% increase for the Lighting class. *Id.*

Regarding Public Staff witness D. Williamson's recommendation regarding Schedule SLR, the Rate Design Panel testified that DEP is willing to notify all Schedule SLR customers of its proposal to freeze the rate schedule, including the accompanying amendments to DEP's Outdoor Lighting Service Regulations, via bill insert or separate mailing. *Id.* at 284.

During the expert witness hearing, DEP witness Reed reiterated that the COSS indicated that the Lighting class should have received a substantial increase. Tr. vol. 12, 16. To mitigate this increase to the lighting class, witness Reed stated that DEP is proposing to reduce the subsidy reduction to 10.0%. *Id.* Witness Reed explained that the reduction from 25.0% to 10.0% amounts to approximately $4 million in savings to the lighting class. *Id.* While witness Reed acknowledged the substantial rate increase to the Lighting class, she explained that DEP needs to recover its revenue requirement and that DEP has limited options to shift these costs to other customer classes. *Id.* at 18. Witness Reed explained that, to the extent possible, she levelized the rate increase between the rate schedules within the lighting class. *Id.*

Considering the parties' testimony and the evidence the parties presented, the Commission finds that DEP's proposed rate design for the Lighting class, with the modification Public Staff witness D. Williamson suggested and DEP agreed to, is just and reasonable for the purposes of this proceeding. The Commission concludes that the rate

increase for the Lighting class is due to the change in cost-of-service methodology and, while substantial, reflects actual cost causation. As such, while the Commission gives some weight to the testimony of NCLM witnesses Saffo and Mann and acknowledges that the rate increase to the Lighting class may prove to be burdensome, it also recognizes the need for rates to reflect cost causation and thus approves DEP's proposed rate design for the lighting class.

Service Riders

In his direct testimony, DEP witness Byrd described DEP's proposed new service riders – Economic Development Rider (Rider EC) and Non-Residential Solar Choice Rider (Rider NSC) – that DEP intends to offer so it may expand the rate options available to customers. Tr. vol. 11, 230. Witness Byrd testified that proposed Rider EC and Rider NSC stemmed from discussions with stakeholders during the CRDS. *Id.* at 247, 253.

Witness Byrd testified that Rider EC will be available to customers: (1) with new load exceeding 1,000 kW with a minimum load factor of 40.0%; (2) that have applied for and received economic assistance from either the state or local government or another public agency; and (3) that meet certain employment and investment minimums relative to the size of the new load. *Id.* at 253. However, witness Byrd stated that new loads that are predominantly for serving EV charging are exempted from Rider EC's employment and load factor requirements and may participate for new load sizes above 500 kW, and that existing customers considering plant investments with possible relocation outside of DEP's service territory may qualify for Rider EC by meeting the investment and employment thresholds, but their new load calculation will exclude reductions associated with the removal of historic equipment or processes. *Id.* at 253-54. Witness Byrd stated that in light of new Rider EC, DEP proposes to close its existing Economic Development Rider (Rider ED) and Economic Redevelopment Rider (Rider ERD) to new applicants. *Id.* at 257. Witness Byrd explained that customers DEP currently serves under Rider ED and Rider ERD will continue to take service under these riders until completion of their existing contracts. *Id.*

Witness Byrd testified that Rider EC contains several improvements to Rider ED. *Id.* at 254-55. First, witness Byrd explained that Rider EC will provide more flexibility for customers to tailor benefits based on both electric grid and regional economic benefits associated with the participant's investment and load characteristics. *Id.* at 252-53. For example, Rider EC will consider the following criteria in developing appropriate benefit levels on an individual customer basis: peak monthly demand; average monthly load factor; DEP's incremental costs to serve; the number of new full-time employees; economic multiplier; and the total new capital investment of the customer. *Id.* at 254. Second, witness Byrd testified that in contrast to Rider ED, under which participants are required to begin taking credits 18 months after the first date service is supplied under the contract (the ramp up period), Rider EC allows participants to wait to take credits until 36 months after the first date of service, recognizing that some industries require significant start-up time for new facilities and that an 18-month ramp up period may constrain their ability to take advantage of Rider EC's benefits. *Id.* at 254-55. Third, witness Byrd testified that unlike Rider ED, which provides benefits that steadily decline

over a five-year period on a rigid schedule, Rider EC allows benefits up to 10 years, with possible differences across the years as determined by the project merits. *Id.* at 255. For example, witness Byrd stated that DEP will require projects receiving greater levels of benefits for longer periods to meet higher thresholds of investment and employment. *Id.* Finally, witness Byrd explained that Rider EC provides a reduction of up to 75.0% of the applicable demand charges on the monthly bill, while Rider ED provides a reduction in demand charges that would require modification in order to align it with DEP's proposed demand charge structure redesign. *Id.* Overall, witness Byrd explained that Rider EC will enable DEP to improve its ability to compete for, attract, and retain customers that are adding jobs and making capital investments in its service territory, ultimately reducing the prices all customers pay and promoting the prosperity of the citizens and businesses in North Carolina. *Id.* at 252-53, 255-56.

With respect to Rider NSC, witness Byrd testified that, as a result of DEP's proposed new TOU periods and the new three-part demand charge structure, DEP proposes new Rider NSC to implement several changes for non-residential customers who seek to pursue self-generation through NEM. *Id.* at 246. Witness Byrd stated that to be eligible for Rider NSC, customers must take service under a general service rate schedule that includes TOU periods. *Id.* Witness Byrd explained that because DEP's TOU periods include the proposed modified demand charge structure, this eligibility requirement ensures price alignment with system utilization and cost causation. *Id.* at 246-47. Additionally, witness Byrd stated that Rider NSC will be available to customers with NEM systems that do not exceed the lesser of 100.0% of the customer's contract demand or 5,000 kW. *Id.* at 247. Moreover, under Rider NSC, DEP proposes eliminating the standby charge for customers with a capacity factor of 60.0% or less. *Id.* Finally, unlike Rider NM, energy exported would be netted against imports during the same TOU period and excess energy exported would be credited at an average avoided cost rate calculated using the Net Energy Credit calculation proposed by DEC and DEP in Docket No. E-100, Sub 175. *Id.*

With the advent of Rider NSC, witness Byrd testified that DEP is proposing that all new non-residential NEM applications take service under Rider NSC and that current Rider NM be frozen to new customers beginning on October 1, 2023. *Id.* at 248. Accordingly, witness Byrd explained that only existing non-residential NEM customers served under Rider NM prior to the availability of Rider NSC would continue service under Rider NM. *Id.* Witness Byrd stated that existing NEM customers could continue service under Rider NM until they request service under Rider NSC or until September 30, 2033, at which point all non-residential NEM customers receiving service under Rider NM will be moved to Rider NSC or another appropriate tariff, as available at that time. *Id.*

In his direct testimony, Public Staff witness Nader testified that Rider EC is in the public interest and not unduly discriminatory, will assist in preventing job loss. and fairly balances costs and benefits. Tr. vol. 21, 104-06. Witness Nader explained that Rider EC mitigates the potential for further loss of economic activity in communities that the state has already designated as economically distressed by targeting new investment in load, employment, and economic activity. *Id.* at 104-05. Witness Nader also stated that

requiring participants to demonstrate that they have received state or local assistance conveys a sense of fairness between the costs to non-participants and the benefits to participants. *Id.* at 105. Moreover, witness Nader testified that the retention of jobs is critical given the competitive pressures manufacturing and large energy customers experience, and Rider EC should assist with keeping jobs in economically distressed communities. *Id.* Witness Nader also noted that Rider EC's longer ramp-up period and extended period of access should help ensure that system load and employment will remain in communities for some time. *Id.* Finally, witness Nader testified that the Public Staff is "reasonably satisfied" that the costs and benefits of Rider EC are balanced and fair. *Id.* at 106. However, to ensure that Rider EC continues to be in the public interest, witness Nader recommended that the Commission require annual reporting of the impacts of Rider EC. *Id.* At a minimum, witness Nader stated that DEP should report the gross level of incentives paid, the number of recipients, the amount of investment, load, and jobs associated with the incentives, and an overall marginal cost analysis of Rider EC to determine if the gross level of incentives paid exceeds the marginal cost to serve the gross pool of participants. *Id.*

With respect to Rider NSC, Public Staff witness Nader recommended that DEP's proposed 5,000 kW cap on installed capacity be eliminated. *Id.* at 108. Witness Nader testified that by requiring all non-residential NEM customers to subscribe to a TOU schedule and the proposed three-part demand structure, the full fixed cost of service should be recovered regardless of system size, thereby mitigating the risk for material cross-subsidization. *Id.* Witness Nader also argued that large non-residential customers that seek to install on-site generation will be subject to the capital funding limitations of their own businesses, serving as another limitation to prevent generation in excess of site load from being installed. *Id.* at 108-09. Although witness Nader found DEP's concerns regarding reliability if the installed capacity limit were increased to be valid, but he testified that these concerns could be addressed though customer generator controls and communication. *Id.* at 109.

Regarding Rider NSC. AGO witness Nelson recommended that: (1) customers have the option to enroll in Rider NSC for a contract term of up to five years, with the option for annual renewal thereafter; and (2) DEP permit customers enrolling in a rate that does not include a demand charge to retain their renewable energy credits (RECs). Tr. vol. 18, 108. Witness Nelson explained that providing an option for customers to enroll for a term length of up to five years balances the need to provide customers with rate certainty with the imperative to ensure that tariffs adapt to reflect evolving grid dynamics. *Id.* at 108-09. Additionally, witness Nelson argued that DEP's requirement that customers who do not enroll in rates containing a demand charge cede RECs to DEP appears arbitrary and would unduly harm or discourage the participation of SGS customers who do not currently have the option of enrolling in demand-based rates. *Id.* at 110.

Although not raised by DEP in this proceeding, Public Staff witness D. Williamson recommended that DEP analyze the standby service being offered under Riders 7 and 57 in his direct testimony. Tr. vol. 20, 178-79. Witness D. Williamson claimed that the rates and terms of service under Riders 7 and 57 likely do not cover the costs incurred to serve

customers. *Id.* at 178. Additionally, witness D. Williamson argued that keeping Riders 7 and 57 – which only serve five large industrial customers – closed to all other customers and allowing only five customers to benefit results in an unduly discriminatory rate design. *Id.* Therefore, witness D. Williamson recommended that the Commission require DEP, prior to filing its next rate case or PBR application, to analyze the impact of transferring the five customers currently taking service under Riders 7 and 57 to other standby service riders. If the analysis shows that viable options to do so exist, witness D. Williamson recommends that DEP propose a transition period in its next general rate case or PBR proceeding to temper any potential rate shock that doing so may cause the customers currently taking service under Riders 7 and 57. *Id.* at 179.

On rebuttal, the Rate Design Panel testified that it did not agree with Public Staff witness Nader's recommendation for elimination of the 5,000 kW cap on Rider NSC. *Id.* at 291. The Rate Design Panel explained that the 5,000 kW limit strikes a reasonable balance between stakeholders' requests during the CRDS for larger system sizes and DEP's concerns regarding grid operations and reliability. *Id.* The Rate Design Panel noted that DEP's proposed 5,000 kW limit for Rider NSC represents a 500.0% increase over Rider NM. *Id.* Moreover, the panel testified that DEP's proposed Schedule HP would allow customer generating systems above the 5,000 kW limit for Rider NSC. *Id.* Importantly, the Rate Design Panel explained that the larger the NEM system, the more complicated the interconnection study due to the of the unpredictability of their output to the grid. *Id.* DEP witness Byrd, during the expert witness hearing, testified that the sort of unpredictability in output (which becomes a bigger problem in the context of larger systems) has the potential to create large swings in load, which poses reliability challenges. Tr. vol. 12, 32. Accordingly, given the sizable move from 1,000 kW to 5,000 kW and operational considerations associated with going beyond 5,000 kW, witness Byrd testified that DEP believes it is inappropriate to remove the cap. *Id.* at 74.

In response to witness Nelson's recommendations with respect to Rider NSC, the Rate Design Panel testified that it did not agree with his recommendation. Tr. vol. 11, 292-93. Specifically, the Rate Design Panel explained that it did not agree with witness Nelson's recommendation that DEP permit customers to enroll in Rider NSC for a term of up to five years because DEP merely intends that the specific tariff language it proposes for Rider NSC – that "[t]he Customer shall enter into a contract for service under this Rider for a minimum original term of one (1) year, and the contract shall automatically renew thereafter . . . ." – correspond to and align with the core tariff language. *Id.* at 292. Additionally, the Rate Design Panel testified that it did not agree that DEP should permit its customers enrolling in a rate that does not include a demand charge to retain their RECs since DEP's retention of RECs from systems is a long-standing practice in North Carolina and DEP is not proposing any changes to this practice in this proceeding. *Id.* The Rate Design Panel further noted that currently effective Rider NM similarly requires DEP customers to cede RECs if they receive service under a schedule other than a TOU schedule with demand rates. *Id.* at 292-93.

Finally, in response to Public Staff witness D. Williamson's recommendation that DEP analyze the standby service DEP is offering under Riders 7 and 57, the Rate Design

Panel testified that the DEP does not oppose analyzing the effects to customers' bills of moving Riders 7 and 57 customers to another standby service rider or closing Riders 7 and 57 and moving customers to other available standby service options in a manner that lessens rate shock. *Id.* at 293.

During the expert witness hearing, DEP witness Byrd provided further support for Rider NSC. Witness Byrd testified that stakeholders discussed Rider NSC at length during the CRDS and that it captures stakeholders' proposals and feedback. Tr. vol. 11, 340-42, 347. Witness Byrd reiterated that Rider NSC better reflects cost causation. *Id.* at 351, 355. Witness Byrd, in response to questions from Commissioner Clodfelter, elaborated on DEP's justification for allowing it to retain RECs for customers who are not served under a TOU rate. Tr. vol. 12, 38-39. Witness Byrd explained that while DEP's Residential Solar Choice Rider (Rider RSC) allows customers to retain their RECs regardless of rate schedule, there are differences between Rider NSC and Rider RSC that justify the disparate treatment. *Id.* at 39. Specifically, witness Byrd stated that certain components of Rider RSC – e.g., CPP netting, non-bypassable charges, monthly grid access fee, and the monthly minimum bill – do not appear in Rider NSC and, therefore, the differences in REC retention are appropriate. *Id.*

DEP witness Byrd also provided further support for Rider EC during the expert witness hearing. In response to questions by Chair Mitchell, witness Byrd elaborated on the differences between Rider EC and Rider ED. Tr. vol. 12, 63. Witness Byrd testified that Rider EC is much more flexible than Rider EC and allows DEP to provide a more tailored incentive structure based on demand over a longer period. *Id.* Additionally, witness Byrd testified that Rider EC's 36-month ramp up period, as compared to the 18-month ramp up period under Rider ED, results in a more competitive offer to prospective customers considering sites in North Carolina. *Id.* at 63-64. Overall, witness Byrd testified that Rider EC is a more competitive and flexible offer that will put North Carolina in a better position to attract potential customers. *Id.* at 64-65.

Based on the evidence in the record, the Commission concludes that DEP's proposed new Rider EC, with the reporting obligation witness Nader suggested and DEP agreed to, is reasonable and should therefore be approved. The Commission views DEP's proposed Rider EC as an effort to attract economic development in North Carolina and concludes that implementation of the rider is in the public interest. As with other economic development tariffs this Commission has previously approved, approval of Rider EC is based in part on an evaluation of the expected economic benefits resulting from the tariff. The Commission has considered the goal of attracting new economic development in North Carolina as well as the impact of Rider EC on non-participating ratepayers and concludes that Rider EC strikes the appropriate balance between the two. The Commission agrees with witness Byrd that Rider EC will result in broad state and regional benefits by enabling DEP to assist North Carolina and local communities when competing for projects. The Commission gives substantial weight to the testimony of witness Byrd that Rider EC represents an improvement from Rider ED and that it is, therefore, appropriate for DEP to close existing Rider ED and Rider ERD.

The Commission also concludes, considering the evidence, that DEP's proposed new Rider NSC is reasonable and should therefore be approved. The Commission finds that Rider NSC is appropriate given DEP's new TOU periods and three-part demand structure and will help ensure price alignment with system utilization and cost causation. In arriving at this conclusion, the Commission gives weight to the testimony of DEP witness Byrd. The Commission is not persuaded by Public Staff witness Nader's recommendation that DEP eliminate the 5,000 kW cap on nameplate capacity. The Commission also gives weight to the operational and reliability concerns expressed by DEP. By increasing the cap from the existing 1,000 kW to 5,000 kW, DEP will gain more experience with larger systems, and this experience can be used to inform the Commission regarding the operational and reliability challenges and mitigative measures that can be adopted in future proceedings in the context of increasing the system limit. Therefore, the Commission rejects the Public Staff's recommendation to remove the 5,000 kW limit under Rider NSC. In addition, the Commission rejects the recommendations of AGO witness Nelson on the grounds that his proposals are inconsistent with past Commission practice. Finally, the Commission finds it reasonable to freeze Rider NM to new customers as of October 1, 2023, and allow existing NEM customers to continue service under Rider NM until they request service under Rider NSC or until September 30, 2033.

The Commission further requires before filing its next rate case, to DEP shall analyze the impacts of transferring customers receiving service under Riders 7 and 57 to other standby service riders and, if that analysis reveals viable options for transferring these customers, DEP shall move these customers to other standby service riders over a reasonable transition period and in a manner that lessens or avoids rate shock.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 49-51

Cost of Capital

The evidence supporting these findings is in DEP's verified Application and Form E-1; the testimony and exhibits of the public witnesses; the testimony and exhibits of DEP witnesses Morin and Newlin, Public Staff witness Walters, CUCA witness O'Donnell, DoD-FEA witness Reno, NCJC, et al. witness Ellis, Commercial Group witness Chriss, CIGFUR witness Gorman; and the entire record in this proceeding.

Cost of Equity Capital

Summary of Evidence

DEP's rate of return expert, Dr. Roger Morin, recommended a rate of return on common equity of 10.4% with a capital structure consisting of 53.0% common equity and 47.0% debt. The recommendations of intervenor expert rate of return witnesses are as follows:

Witness Walters/The Public Staff	9.45%[10]
Witness O'Donnell/CUCA	9.25%[11]
Witness Reno/ DoD-FEA	9.3%
Witness Ellis/NCJC, et. al	6.00%

Neither Commercial Group witness Chriss, nor CIGFUR witness Gorman, performed an independent expert rate of return on common equity analysis. Rather, both witnesses confined their rate of return testimony to commenting on average rates of return awarded to electric utilities over various time periods.

As is often the case with rate of return on common equity, the testimony is voluminous. Below, the Commission summarizes the prefiled testimony of the various witnesses, and addresses testimony it received at the hearings in its discussion of its findings and conclusions.

DEP Direct and Supplemental Testimony

In his direct testimony, DEP witness Morin recapped the regulatory framework under which a regulated entity's rates should be set, which is that the entity should have a fair opportunity to recover its prudently incurred costs, including taxes and depreciation, plus a fair and reasonable return on its invested capital. The allowed rate of return must necessarily reflect the cost of the funds obtained, that is, investors' return requirements. In determining a company's required rate of return, the starting point is investors' return requirements in financial markets. A rate of return can then be set at a level sufficient to permit a company the fair opportunity to earn a return commensurate with the cost of those funds. Tr. vol. 8, 31-32. Witness Morin noted that while the cost of debt is observable in the marketplace, the cost of equity – that is, investors' required rate of return on this source of financing – is more difficult to estimate. *Id.* Witness Morin concluded that the Commission's decision should allow DEP to earn a rate of return on common equity that is commensurate with returns on investments in other firms having corresponding risks; sufficient to assure confidence in DEP's financial integrity, and sufficient to maintain DEP's creditworthiness and ability to attract capital on reasonable terms. *Id.* at 32-34.

Witness Morin reiterated that the aggregate return required by investors is "the cost of capital," which he described as "the opportunity cost, expressed in percentage terms, of the total pool of capital employed by the utility." *Id.* at 34. He noted further that public utilities (or their publicly traded parent companies) must compete for capital, and that the price of capital is set in the same manner as it is set for other input factors of production – by supply and demand. *Id.* at 35.

[10] Witness Walters recommends a 20-basis point downward adjustment in rate of return on equity, to 9.25%, if DEP's MYRP is approved, and 9.45% otherwise.

[11] Witness O'Donnell recommends a 25-basis point downward adjustment in rate of return on equity, to 9.0%, if the MYRP is approved, and 9.25% otherwise.

Witness Morin testified that the focus is and must be on the investor and the investor's expectations. As witness Morin explained, "[t]he market required rate of return on common equity, or cost of equity, is the risk-adjusted return demanded by the equity investor. Investors establish the price for equity capital through their buying and selling decisions in capital markets." *Id.* at 38.

In estimating a fair rate of return on common equity for DEP, witness Morin applied three cost of capital methodologies, the Discounted Cash Flow (DCF) methodology, the Capital Asset Pricing Model (CAPM) methodology, and the Risk Premium methodology, all of which are market-based methodologies designed to estimate the return required by investors on the common equity capital committed to DEP. *Id.* at 39. Witness Morin stressed that multiple methodologies must be employed in the estimation of the cost of equity. As he noted:

> No one single method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data.
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> * * *
>
> As a general proposition, it is extremely dangerous to rely on only one generic methodology to estimate equity costs. The difficulty is compounded when only one variant of that methodology is employed. It is compounded even further when that one methodology is applied to a single company. Hence, several methodologies applied to several comparable risk companies should be employed to estimate the cost of common equity.

Id. at 39-40.

He noted that the three methodologies he utilized, DCF, CAPM, and Risk Premium, are "broad market-based methods available to measure the cost of equity," and are all "accepted and used by the financial community and firmly supported in the financial literature." *Id.* at 40. Witness Morin utilized two sub-variants of each broad methodology, for a total of six studies.

In his direct testimony, witness Morin recommended a rate of return on common equity of 10.2%, which was the midpoint of the range of mathematical results from the six cost of capital studies he conducted. *Id.* at 26, 130. In his supplemental testimony, he updated all six of his studies, and provided the below comparison:

Method	Direct ROE	Supplemental ROE
DCF Value Line Growth*	9.9%	9.3%
DCF Analysts Growth*	9.3%	9.3%

CAPM*	10.8%	11.0%
Empirical CAPM*	11.1%	11.2%
Historical Risk Premium*	10.2%	10.8%
Allowed Risk Premium	10.2%	10.5%

* ROE estimate includes an adjustment for flotation costs.

Id. at 132. His updated rate of return on equity recommendation of 10.4% is again the midpoint of the range of these mathematical results.

For his supplemental testimony, witness Morin used the same proxy group as in his direct testimony, and the same methodologies in his studies as he had used in his direct testimony, but with updated capital markets data. The increase in his recommended rate of return on equity was largely the result of an increase in interest rates. As he noted, as of the time of his updated analysis, the level of U.S. Treasury 30-year long-term bond yield forecast is 4.3%, versus 3.7% when he prepared his direct testimony. *Id.* at 130. He noted further that the increase in forecast interest rates increases the CAPM, the empirical approximation to the CAPM (ECAPM), Historical Risk Premium, and Allowed Risk Premium results in his direct testimony. *Id.* at 33, 131. Finally, while his DCF modeling showed a slight decrease, the DCF results did not offset the increase in interest rates. *Id.* Dr. Morin concluded that the "net result of these capital market changes is a small increase in the cost of common equity." *Id.* at 131.

In his direct testimony DEP witness Morin also surveyed the current risk environment, describing a paradigm shift in the electric utility industry's risk profile. He described a "perfect storm" environment, in which "the industry is experiencing declining demand growth, rising operating costs, rising capital costs, while at the same time the industry is beset by lower allowed returns," and noted that as a result "[i]t is not surprising that investor risk perceptions have escalated" in this setting. *Id.* at 89.

Witness Morin attributed this increase in industry risk to four major challenges facing electric utilities: (1) declining growth in energy consumption due to improvements in energy science and productivity; (2) the need for record amounts of capital to replace aging infrastructure, improve reliability, and deliver renewable generation; (3) higher business risks, including the emergence of "prosumers," that is, customers (residential, commercial, industrial) who are both consumers and producers as a result of the increase in distributed generation; and (4) rising operating costs due to rising inflation and supply chain bottlenecks. *Id.* at 91-93. He concluded with the observation that "[g]iven the new paradigm shift in the industry, it is transparent that state regulatory support, including adequate returns on equity, will be instrumental to ensure ongoing capital attraction in the utility sector at reasonable costs." *Id.* at 93.

Finally, witness Morin surveyed economic conditions in North Carolina. He considered key macroeconomic factors such as GDP growth, employment data, and household income levels in North Carolina and DEP's service territory relative to the aggregate U.S. economy. *Id.* at 95. He opined that the economic conditions remain highly correlated with national conditions, such that they were reflected in the analyses used to

determine the cost of equity. *Id.* at 103. He noted that economic conditions in North Carolina continue to improve from the COVID-19 pandemic, and they continue to be strongly correlated to conditions in the broader U.S economy. *Id.* He further noted that unemployment at the state level continues to fall and remains highly correlated with national rates of unemployment, and that GDP growth also remains well correlated with U.S. GDP growth. *Id.* Median household income in North Carolina has grown at a rate consistent with the rest of the U.S. and remains strongly correlated with national levels. *Id.* Witness Morin concluded that, "the correlations between state-wide measures of economic conditions noted by the Commission in Docket No. E-22, Sub 479 remain strongly in place and, as such, they continue to be reflected in the models and data used to estimate the cost of equity capital." *Id.*

Intervenor Testimony (rate of return experts)

The intervenor rate of return on common equity expert witnesses generally criticized DEP witness Morin's analysis that resulted in his recommended 10.4% rate of return on common equity. In addition, they performed their own analyses as outlined below.

Direct Testimony of Public Staff witness Walters

Public Staff witness Walters used nearly the same proxy group of electric utilities relied on by DEP witness Morin, except that he excluded two utilities, FirstEnergy and MGE Energy. Tr. vol. 16, 248. He performed DCF, Risk Premium, and CAPM analyses for his proxy groups of electric utilities. *Id.* at 242. Witness Walters developed his DCF growth rate by relying on a consensus of professional securities analysts' earnings growth estimates, averaging the growth rate forecasts from Yahoo Finance, MI, and Zack's. *Id.* at 252-53. Public Staff witness Walters recommended a rate of return on common equity of 9.45% based on a capital structure of 52% common equity and 48% long-term debt. *Id.* at 247, 284. In the alternative, he recommended a rate of return on common equity of 9.25% if the Commission grants DEP's MYRP and PBR application. *Id.* at 288.

Public Staff witness Walters applied the DCF model, Risk Premium Model, and CAPM that yielded the following results:

Discounted Cash Flow (DCF) – 9.0% Recommended DCF Result

	Mean	Median
Constant Growth – Consensus Analyst	9.01%	9.03%
Constant Growth – Sustainable Growth Rate	8.83%	8.47%
Multi-Stage Growth	7.91%	7.89%

Risk Premium Model – 9.9% Recommended Risk Premium Result

Projected Treasury Yield (3.700%)	9.74%	
	A-rated	Baa-rated
13-week Average Utility Bond Yield	9.93%	10.22%
26-week Average Utility Bond Yield	10.04%	10.34%

Capital Asset Pricing Model (CAPM) – 9.5% Recommended CAPM Result

	Current VL Beta	Historical VL Beta	Current MI Beta
D&P Normalized Method	9.22%	8.46%	8.69%
Risk Premium Method	10.72%	9.72%	10.02%
FERC DCF	9.78%	8.92%	9.18%

Id. at 264, 71, 83-84.

In his DCF analysis, witness Walters used the average of the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ending on February 10, 2023. *Id.* at 251. For his constant growth model, he used the most recently paid quarterly dividend as reported in ValueLine and an expected growth rate based on a consensus of professional securities analysts' earnings growth estimates as a proxy for investors' dividend growth rate expectations. *Id.* at 251-53. For his sustainable growth model, he estimated the long-term growth rate based on DEP's current market-to-book ratio and on Value Line's three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances. *Id.* at 256. His Multi-Stage growth model relied on inputs from three growth periods: (1) a short-term growth period consisting of the first five years; (2) a transition period, consisting of the next five years (6 through 10); and (3) a long-term growth period starting in year 11 and extending into perpetuity. *Id.* at 258. For the short-term growth period, he relied on the consensus of analysts' growth projections described above in relationship to his constant growth DCF model. For the transition period, he reduced or increased the growth rates by an equal factor reflecting the difference between the analysts' growth rates and the long-term sustainable growth rate. For the long-term growth period, he assumed each company's growth would converge to the maximum sustainable long-term growth rate. *Id.* at 259. Lastly, while not his typical practice, he provided DCF models using historical growth inputs, which resulted in DCF estimates ranging from 7.91% to 9.89%. *Id.* at 265.

Witness Walters' risk premium model is based on two estimates of an equity risk premium: the difference between the regulatory commission-authorized returns on common equity and (1) contemporary U.S. Treasury Bonds, and (2) contemporary Moody's "A" rated utility bond yields. He evaluated these premia over the period of 1986-2021 on an overall average and rolling five- and 10-year basis. *Id.* at 266-67. In addition, he evaluated the average spread between Treasury bonds and A- and Baa-rated utility

bonds. *Id.* at 269. Finally, witness Walters added what he deems an appropriate premium in the third quartile of the rolling five-year average risk premia (6.04%) to his projected Treasury bond yields (3.7%), which produces a return on equity of 9.74%. Additionally, witness Walters applies a similar methodology to utility bond yields to estimate an equity risk premium of 4.63%.[12] He adds this to the 13- and 26-week average A- and Baa-rated utility bond yields. *Id*. at 270-71.

Witness Walters' CAPM analysis used the Blue Chip Financial Forecasts' projected 30-year U.S. Treasury bond yield of 3.7% for the risk-free interest rate. *Id.* at 274. He used the Value Line beta estimates of 0.89, the historical average Value Line beta since 2014 of 0.76, and the adjusted beta estimates provided by Market Intelligence's Beta Generator Model of 0.80 for his proxy group. *Id.* at 275. Witness Walters used two versions of the constant growth DCF model to develop his estimates of the market risk premiums. *Id.* at 278. He used the 6.85% average of his estimated market risk premiums of 6.4% and 7.3%. *Id.* at 279. He testified that his 6.85% market risk premium is a reasonable, if not a high-end estimate. *Id.* at 281.

Witness Walters concluded that the appropriate equity cost rate for DEP based on companies in his proxy group is in the 9.0% to 9.9% range, recommending the midpoint of 9.45%. *Id.* at 284. However, witness Walters testified that DEP's PBR application would shift risk from shareholders to ratepayers by reducing regulatory lag. *Id.* at 285. As such, he recommended a 9.25% rate of return on common equity, should the Commission grant DEP's MYRP and PBR application. *Id.* at 288. Witness Walters also testified as to current capital market conditions as of the date of his testimony in April 2020. He stated that the authorized rates of return on common equity for electric utilities have declined over the last several years. *Id.* at 222.

Direct Testimony of CUCA witness O'Donnell

CUCA witness O'Donnell proposed a rate of return on common equity of 9.25% (without regard to DEP's MYRP proposal), based upon DCF modeling and CAPM methodologies, as well as a comparable earnings approach. Tr. vol. 21, 627. Witness O'Donnell primarily relied upon the DCF model and testified that it is superior to the others because it has a direct and immediate link to stock prices. *Id.* at 602-03. Witness O'Donnell's DCF analysis results range from 8.7% to 9.7% with an overall result of 9.25%. *Id.* at 614. His CAPM analysis ranged from 7.25% to 8.25% with a midpoint of 7.75%. *Id.* at 626. His Comparable Earnings Analysis (CEA) ranged from 9.5% to 10.5% with a midpoint of 10.0%. *Id.*

Witness O'Donnell, like Public Staff witness Walters, made a downward adjustment to his rate of return on common equity recommendation in the event the

[12] Witness Walters states in his testimony that he adds 5.33%, but the math in his narrative indicates 4.63% was used, and 4.63% is supported by Exhibit CCW-12.

Commission approves DEP's MYRP. The downward adjustment would take his rate of return on equity recommendation from 9.25% to 9.0%. *Id.* at 627.

Direct Testimony of DoD-FEA Witness Reno

DoD-FEA witness Reno recommended that the Commission approve a rate of return on common equity of 9.3% and reject DEP's requested 10.4%. *Id.* at 349-50. She conducted her analysis by deriving average expected market returns for a proxy group of regulated electricity companies with risk comparable to DEP. *Id.* at 362. Her analysis applied two DCF models, CAPM, and ECAPM, as well as a Comparable Earnings Model. Witness Reno summarized her model results in her Table 7, reproduced below:

Table 7. ROE Estimates (%)

DCF Methodology	30-Day Stock Price	90-Day Stock Price	Average
Constant-Growth DCF (EPS Growth)	9.57	9.54	
Constant-Growth DCF (DPS, EPS and BVPS)	9.19	9.11	
Sustainable Growth DCF	8.42	8.35	
DCF Range:	**8.35**	**9.57**	**8.96**
CAPM & ECAPM Methodology	**CAPM**	**ECAPM**	
Capital Asset Pricing Model (Lg. Stock ERP, 30-yr T-Bond Rate)	10.42	10.63	
Capital Asset Pricing Model (Supply-Side ERM, 30-yr T-Bond Rate)	9.32	9.49	
Capital Asset Pricing Model (D&P Normalized Rate)	8.83	9.00	
CAPM Range:	**8.83**	**10.63**	**9.73**
Comparable Earnings Methodology			
Comparable Earnings Model (Historical ROE)	10.26		
Comparable Earnings Model (Adjusted ROE)	11.10		
Comparable Earnings Model (VL Forecasted ROE 25-27)	11.00		
CEM Range:	**10.26**	**11.10**	**10.68**
Summary			
DCF-Based ROE Average			8.96
DCF-CAPM-Based ROE Average			9.35
All-Model ROE Average			9.79
	Min	**Max**	**Midpoint**
ROE Range	8.96	9.57	9.26
Recommended ROE (%)			**9.30**

Id. at 395.

Witness Reno's recommended rate of return on equity of 9.3% represents the midpoint of her constant-growth DCF outcomes (her primary method) and is supported by the average of her DCF and CAPM methods of 9.35%. The average of all of witness Reno's models is 9.79%. *Id.* at 373.

Direct Testimony of NCJC, et al. witness Ellis

NCJC, et al. witness Ellis recommended a rate of return on common equity of 6.0%, based on the minimum required to maintain DEP's current A2 credit rating. *Id.* at 1071. Witness Ellis criticized DEP witnesses for their conflation of the rate of return on capital and the cost of capital, arguing that such confusion has led to excessive authorized returns. *Id.* at 940-42. He testified that his analysis relies on the premise that rate of return on common equity and capital structure are interrelated and cannot be determined separately. *Id.* at 1055-60.

Witness Ellis' analysis relies on the DCF and CAPM to estimate the cost of capital. *Id.* at 937. His analysis yielded the following results:

Multi-Stage Discounted Cash Flow: 6.25%

Capital Asset Pricing Model: 5.8%

Id. at 939.

He opined that the multi-stage DCF model should be used instead of the constant growth DCF model because it allows for more realistic cash flow projects, yielding more accurate results. *Id.* at 990. He testified that his CAPM analysis eliminates the upward biases seen in Witness Morin's CAPM analysis. *Id.* at 997.

Witness Ellis testified that rate of return on common equity and capital structure are interrelated and must be addressed together. *Id.* at 1056-57. He recommended along with his 6.0% rate of return on common equity that the Commission set DEP's capital structure at 58.0% equity and 42.0% debt and indicated that this combination would maintain DEP's credit rating. *Id.* at 1071.

Intervenor Testimony (other experts)

As noted above, both Commercial Group witness Chriss and CIGFUR witness Gorman provided rate of return on common equity-related testimony but did not perform any ROE analysis.

Direct Testimony of Commercial Group witness Chriss

While he did not provide a rate of return on common equity analysis in his testimony, witness Chriss for the Commercial Group testified that DEP's proposed rate of return on common equity was significantly higher than rates of return previously approved

by the Commission from 2019 to the present. *Id.* at 513-14. Likewise, witness Chriss indicated that DEP's proposed ROE is significantly higher than most reported rate of return on common equity decisions by utilities commissions from 2019 to the present. *Id.* at 515-17. He testified that according to S&P Global Market Intelligence, 141 decisions were rendered during that time frame, with results ranging from 7.36% to 10.6%, with the median authorized ROE at 9.5%. *Id.* at 515. Removing distribution-only utilities and distribution service rates from the analysis, he testified that the average rate of return on common equity for vertically integrated utilities authorized from 2019 through the time of his direct testimony filing was 9.61%. *Id.*

Direct Testimony of CIGFUR witness Gorman

CIGFUR witness Gorman proposed that the Commission adjust DEP's authorized return on equity to reflect the current industry average of 9.6%. *Id.* at 405. He testified that for vertically integrated utilities, the authorized rate of return on common equity was around 9.53% in 2021, 9.69% in 2022, and currently holds around 9.6% for 2023. *Id.* at 409. He testified further that a fair ROE and a lower-cost, more balanced ratemaking capital structure would lower DEP's cost of service and support the implementation of more competitive rates. *Id.* at 411. He further testified that the proposed 10.4% ROE significantly exceeds the authorized returns on equity for other regulated utilities companies, which have been sufficient to maintain credit and provide utilities access to capital under reasonable terms and prices. *Id.* at 450-51.

DEP Rebuttal Testimony

In his rebuttal testimony, DEP witness Morin responded to criticism by intervenor ROE witnesses and commented upon deficiencies in their analyses. While he testified that he agrees with several of the views and procedures presented by witness Walters and witness O'Donnell, he noted that their recommendations understate the appropriate ROE for DEP. Tr. vol. 8, 139, 171. Particularly, he reasoned that their recommendations lie outside of the zone of currently authorized rates of return on common equity for vertically integrated electric utilities in the United States, which have averaged 9.7% in the past and have trended upward in more recent decisions in response to the surge in interest rates and inflation. *Id.* at 139, 169. He further noted that neither witness Walters, nor witness O'Donnell, nor witness Reno explained why or how DEP's cost of equity capital has decreased since it was awarded a rate of return on common equity of 9.6% in its last rate case in 2021, given a surge in interest rates and inflation that each of them acknowledged in their testimony. *Id.* at 223.

Witness Morin further disputed the contentions of witnesses Walters, O'Donnell, and Reno that the adoption of a performance-based ratemaking statute in North Carolina, including multi-year rate plans, should result in a lower rate of return on common equity for DEP. *Id.* at 135. He noted that the peer group of electric utilities also includes other risk-mitigating mechanisms, taken account in the use of the proxy group's financial data. *Id.* As such, further adjustment on the basis that an MYRP reduces risk amounts to double counting and should be rejected. *Id.*

Witness Morin additionally challenged the findings of the intervenors individually. While he noted that they shared quite a bit of common ground in their analyses, witness Morin testified that Public Staff witness Walters' recommended rate of return on common equity lies outside of the zone of currently authorized rates of return on common equity for vertically integrated utilities and opined that if his results were amended to reflect proper data inputs to the financial models, his results would exceed 10.0%. *Id.* at 139-67. He offered the following seven points of disagreement. *Id.* at 140.

Witness Morin criticized witness Walters' reluctance to accept flotation costs, explaining that the parent-subsidiary relationship does not eliminate the cost of stock issuance. *Id.* at 142. He disagreed with witness Walters' DCF technique, explaining that his sustainable growth rate approach was illogical and inconsistent with empirical evidence. *Id.* at 143-46. He testified that witness Walters' multi-stage DCF should not be given any weight by the Commission, as it is predicated on the idea that utilities grow at the same rate as the general macro-economy. *Id.* at 148. He wholly rejected witness Walters' use of the historical Value Line beta estimates and Vasicek-adjusted betas, explaining that their use is not standard and the extent to which market participants rely on them is unclear. *Id.* at 153-54. He argued that witness Walters' CAPM underestimates the appropriate cost of capital. *Id.* at 159-60. In challenging witness Walters' risk premium analysis, witness Morin testified that it fails to recognize the inverse relationship between risk premium and interest rates. *Id.* at 160-61. Finally, witness Morin disagreed with witness Walters' criticisms of his testimony, noting that nothing presented would cause him to alter any of his recommendations or methodologies. *Id.* at 167.

At the outset, witness Morin identified two fundamental flaws in CUCA witness O'Donnell's testimony, noting that his proposed 9.25% rate of return on common equity would be one of the lowest in the industry and that it is the result of a defective DCF analysis. *Id.* at 168-71. While witness Morin agreed with parts of witness O'Donnell's analysis, he identified six specific areas of disagreement over the appropriate data inputs for the CAPM and DCF models. *Id.* at 172. He explained that witness O'Donnell's recommended rate of return on common equity is outside the zone of currently authorized rate of return on common equity for vertically integrated electric utilities in the United States and that of his own sample of companies, noting that the currently authorized returns for his peer companies average nearly 10.0%, and the expected returns for these companies from his own Value Line data shown on Exhibit KWO-4 are in the range of 10.6% – 11.1%. *Id.* at 172-73. He asserted that two of witness O'Donnell's dividend yield estimates are understated because they are based on stock prices reaching back several months in the past, thus violating the notion of market efficiency. *Id.* at 173. Witness Morin raised concern with witness O'Donnell's choice of DCF growth rates, finding his reliance on 12 different rates, including historical growth rates, sustainable growth rates, and analysts' forecasts arbitrary and inconsistent with empirical evidence. *Id.* He further questioned witness O'Donnell's reliance on historical growth rates in his DCF model, explaining that the substantial changes occurring in the electric utility industry make use of those rates questionable. *Id.* at 174.

While he agreed with parts of witness O'Donnell's CAPM analysis, witness Morin argued that witness O'Donnell's risk-free rate assumption is too low. *Id.* at 182. Witness Morin also testified that witness O'Donnell's denunciation of analysts' growth forecasts as unreasonable proxies for the DCF growth rate is without foundation and inconsistent with empirical finance literature on the subject. *Id.* at 192.

Witness Morin challenged DoD-FEA witness Reno's analysis, particularly her exclusive reliance on her Constant Growth DCF. *Id.* at 196. He reiterated his concerns about using the sustainable growth methodology due to its inherent circularity and encourages the rejection of the 90-day stock price DCF in violation of the Efficient Market Hypothesis, leaving only two DCF results from her analysis to consider. *Id.* at 198. He agreed with witness Reno's decision to give little weight to the Kroll 6.0% normalized market risk premium (MRP), as well as her comparable earnings analysis results. *Id.* at 198-99. Finally, he disputed witness Reno's criticisms of his own analyses, noting that her risk premium analysis uses a group with a nearly identical beta risk estimate and that her opposition of a flotation allowance disregards the fact that the parent-subsidiary relationship does not eliminate the costs of a new issue of stock. *Id.* at 199-200.

Witness Morin highlighted the limited analysis performed by Commercial Group witness Criss and CIGFUR witness Gorman. *Id.* at 201. He testified that witnesses Criss and Gorman determined their recommendations merely by averaging what other regulators have allowed in 2022. *Id.* He criticized the circular nature of their recommendations and noted the large deviations among the utilities included in their proposed averages. *Id.* at 202. He encouraged the Commission to disregard their testimonies as not germane and to exercise a mind of its own rather than relying on the actions of other Commissions. *Id.* at 203.

Witness Morin wholly rejected the testimony of NCJC, et al. witness Ellis, describing his approach as "non-mainstream, far-fetched, and unorthodox for both methods he uses to estimate the cost of capital." *Id.* at 204. He described witness Ellis' recommendation as draconian and described the adverse consequences to DEP's creditworthiness, financial integrity, capital raising ability, and its customers, should the Commission adopt it. *Id.* He also identified witness Ellis' inconsistencies and contradictions, such as his challenging the validity of the same consensus economic forecasts he relies on to make his recommendations. *Id.* at 205. Witness Morin challenged witness Ellis' differentiation of cost of capital and rate of return and dismissed his position on the use of Market-to-Book ratios in utility regulation. *Id.* at 206-07. In addition to challenges to witness Ellis's recommendations, witness Morin offered a myriad of criticisms to the application of his methodologies. He explained that witness Ellis' misuse of geometric averages rather than arithmetic averages produces results clearly contrary to the most basic financial theory. *Id.* at 210-12. He further identified multiple other instances where witness Ellis' methods deviate from academic state of the art practices, including his rejection of the constant growth DCF analysis and his condemnation of Value Line beta estimates. *Id.* at 205, 214, 219.

Law Governing the Commission's Decision on Rate of Return on Equity

Rate of return on equity is often one of the most contentious issues to be addressed in a rate case. The baseline for establishment of an appropriate rate of return on common equity is the constitutional constraints established by the decisions of the United States Supreme Court in *Bluefield Water Works & Improvement Co. v. Public Service Commission*, 262 U.S. 679 (1923) (Bluefield), and *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591 (1944) (*Hope*), which establish:

> To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting [an ROE], the Commission must still provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital.

Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, *Application by Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-7, Sub 1146 , at 50 (June 22, 2018); *see also State ex rel. Utils. Comm'n v. Gen. Tel. Co.,* 281 N.C. 318, 370, 189 S.E.2d 705, 738 (1972) (General Telephone). As the North Carolina Supreme Court held in *General Telephone*, these factors constitute "the test of a fair rate of return declared" in *Bluefield and Hope*. *Id.*

The rate of return on equity is, in fact, a cost – the return that equity investors require represents the cost to the utility of equity capital. In his dissenting opinion in *Missouri ex rel. Southwestern Bell Telephone Co. v. Missouri Public Service Commission*, 262 U.S. 276 (1923), Justice Brandeis remarked upon the lack of any functional distinction between the rate of return on equity (which he referred to as a "capital charge") and other items ordinarily viewed as business costs, including operating expenses, depreciation, and taxes:

> Each is a part of the current cost of supplying the service; and each should be met from current income. When the capital charges are for interest on the floating debt paid at the current rate, this is readily seen. But it is no less true of a legal obligation to pay interest on long-term bonds . . . and it is true also of the economic obligation to pay dividends on stock, preferred or common.

Id. at 306 (Brandeis, J., dissenting). Similarly, the United States Supreme Court observed in *Hope*, "[f]rom the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business . . . [which] include service on the debt and dividends on the stock." 320 U.S. at 591, 603.

The North Carolina Supreme Court has long recognized that the Commission's subjective judgment is a necessary part of determining the authorized rate of return on common equity. *See, e.g., State ex rel. Utils Comm'n v. Public Staff-N.C. Util's. Comm'n*, 323 N.C. 481, 490, 374 S.E.2d 361, 369 (1988) (*Public Staff*). Likewise, the Commission has noted that such determination is not made by application of any one simple mathematical formula:

> Throughout all of its decisions, the [United States] Supreme Court has formulated no specific rules for determining a fair rate of return, but it has enumerated a number of guidelines. The Court has made it clear that confiscation of property must be avoided, that no one rate can be considered fair at all times and that regulation does not guarantee a fair return. The Court also has consistently stated that a necessary prerequisite for profitable operations is efficient and economical management. Beyond this is a list of several factors the commissions are supposed to consider in making their decisions, but no weights have been assigned.
>
> The relevant economic criteria enunciated by the Court are three: financial integrity, capital attraction and comparable earnings. Stated another way, the rate of return allowed a public utility should be high enough: (1) to maintain the financial integrity of the enterprise, (2) to enable the utility to attract the new capital it needs to serve the public, and (3) to provide a return on common equity that is commensurate with returns on investments in other enterprises of corresponding risk. These three economic criteria are interrelated and have been used widely for many years by regulatory commissions throughout the country in determining the rate of return allowed public utilities.
>
> In reality, the concept of a fair rate of return represents a "zone of reasonableness." As explained by the Pennsylvania commission:
>
> > There is a range of reasonableness within which earnings may properly fluctuate and still be deemed just and reasonable and not excessive or extortionate. It is bounded at one level by investor interest against confiscation and the need for averting any threat to the security for the capital embarked upon the enterprise. At the other level it is bounded by consumer interest against excessive and unreasonable charges for service.
> >
> > As long as the allowed return falls within this zone, therefore, it is just and reasonable. . . . It is the task of the commissions to translate these generalizations into quantitative terms.
>
> Charles F. Phillips, Jr., The Regulation of Public Utilities, 3d ed. 1993, pp. 382 (notes omitted).

Order Granting General Rate Increase, *Application of Carolina Power & Light Co., d/b/a Progress Energy Carolinas, Inc., for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-2, Sub 1023, at 35-36 (May 30, 2013), *aff'd, State ex rel. Utils. Comm'n v. Cooper*, 367 N.C. 444, 761 S.E.2d 640 (2014) (2013 DEP Rate Order).

Moreover, in setting rates the Commission must not only adhere to both the United States and North Carolina Constitutions, but as held by the North Carolina Supreme Court, it must set rates as low as possible consistent with constitutional law. *Public Staff*, 323 N.C. at 490, 374 S.E.2d at 370. Further, the North Carolina General Assembly has provided that the Commission must also set rates employing a multi-element formula set forth in N.C.G.S. § 62-133. The formula requires consideration of elements beyond just the rate of return on common equity element, and it inherently necessitates that the Commission make many subjective determinations, in addition to the subjectivity required to determine the rate of return on common equity. The subjective decisions the Commission must make as to each of the elements of the formula can and often do have multiple and varied impacts on all of the other elements of the formula. In other words, the formula elements are intertwined and often interdependent in their impact to the setting of just and reasonable rates.

The fixing of a rate of return on the cost of property used and useful to the provision of service (as determined through the end of the historic 12-month test period prior to the proposed effective date of a requested change in rates and adjusted for proven changes occurring up to the close of the expert witness hearing or projected in accordance with the provisions of N.C.G.S. § 62-133.16(c)(1)(a)) is one of several interdependent elements of the statutory formula to be used in setting just and reasonable rates. North Carolina General Statute § 62-133(b)(4) provides, in pertinent part, that the Commission shall:

> [f]ix such rate of return on the cost of the property . . . as will enable the public utility by sound management [1] to produce a fair return for its shareholders, *considering changing economic conditions and other factors* . . . [2] to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and [3] to compete in the market for capital funds on terms that are reasonable and that are fair to its customers and to its existing investors. [Emphasis added.]

N.C.G.S. § 62-133(b)(4).

The North Carolina Supreme Court has interpreted the above-emphasized language as requiring the Commission to make findings regarding the impact of changing economic conditions on customers when determining the proper rate of return on common equity for a public utility. *Cooper I*, 366 N.C. at 495, 739 S.E.2d at 548. The Commission must exercise its subjective judgment so as to balance two competing rate of return on common equity-related factors – the economic conditions facing DEP's

customers and DEP's need to attract equity financing on reasonable terms in order to continue providing safe and reliable service. 2013 DEP Rate Order at 35-36. The Commission's determination in setting rates pursuant to N.C.G.S. § 62-133, which includes the fixing of the rate of return on common equity, always takes into account affordability of public utility service to the using and consuming public. The impact of changing economic conditions on customers is embedded in the analyses conducted by the expert witnesses on rate of return on common equity, as the various economic models widely used and accepted in utility regulatory rate-setting proceedings take into account such economic conditions. 2013 DEP Rate Order at 38. Further,

> [t]he Commission always places primary emphasis on consumers' ability to pay where economic conditions are difficult. By the same token, it places the same emphasis on consumers' ability to pay when economic conditions are favorable as when the unemployment rate is low. Always there are customers facing difficulty in paying utility bills. The Commission does not grant higher rates of return on common equity when the general body of ratepayers is in a better position to pay than at other times . . . .

Id. at 37.

Economic conditions existing during the modified test year, at the time of the public hearings, and at the date of the issuance of the Commission's order setting rates will affect not only the ability of the utility's customers to pay rates but also the ability of the utility to earn the authorized rate of return during the period the new rates will be in effect. However, in setting the rate of return on common equity, just as the Commission must assess the impact of economic conditions on customers' ability to pay for service, it likewise must assess the effect of regulatory lag on DEP's ability to access capital on reasonable terms. The Commission sets the rate of return on common equity considering both of these impacts taken together in its ultimate decision fixing a utility's rates.

Thus, in summary and in accordance with the applicable law, the Commission's duty under N.C.G.S. § 62-133, as well as N.C.G.S. § 62-133.16, is to set rates as low as reasonably possible to the benefit of the customers without impairing DEP's ability to attract the capital needed, at reasonable rates, in order to provide safe and reliable electric service and recover its cost of providing service.

Discussion and Conclusions

Two basic issues relating to ROE are presented in this case. First, the Commission must, based upon the evidence presented, select the appropriate ROE for DEP. Second, the Commission must determine whether a downward adjustment to that ROE is appropriate in light of North Carolina's adoption of PBR, in particular, the potential for an MYRP, and the Commission's approval of DEP's PBR Application, as modified by this Order. For the reasons set forth herein, the Commission determines that: (1) the appropriate ROE to be awarded to DEP in this case is 9.8%, and (2) downward adjustment to otherwise applicable ROE is not warranted in view of (a) the widespread

acceptance of alternative regulation throughout the United States, and (b) a comparison of North Carolina's alternative regulation program as promulgated by the PBR Statute and other states' alternative regulation. The Commission is persuaded that that comparison shows, as DEP witness Bateman testified, that North Carolina is not "less risky, in terms of regulatory framework, than other states on average across the country." Tr. vol. 15, 96.

Setting the Rate of Return on Common Equity

As is the norm, the expert witnesses for DEP, the Public Staff, and other intervenors differ widely in their ROE recommendations.[13] A summary of the model outputs of the various witnesses illustrates this divergence (bold indicates a point estimate, while parenthetical figures below are the range of model outcomes provided by the witness):

	DCF (Constant Growth*)	CAPM	Risk Premium	Comparable Earnings	Overall
Morin (DEP Supp.)	9.3%	11.0%-11.2%	10.5%-10.8%	Not Performed	10.4%
Morin (DEP, Direct)	9.3%-9.9%	10.8%-11.1%	10.2%	Not Performed	10.2%
Walters (The Public Staff)	**9.0%** (8.47%-9.03%)	**9.5%** (8.46-10.72%)	**9.9%** (9.74-10.34%)	Not Performed	9.45%
O'Donnell (CUCA)	**9.25%** (8.7-9.7%)	7.25%-8.25%	Not Performed	Not relied upon 9.5%-10.5%	9.25%
Reno (DoD-FEA)	**9.3%** (9.11%-9.57%)	8.83%-10.63%	Not Performed	10.26%-11.1%	9.3%
Ellis (NCJC, et. al.)	6.25%	5.8%	Not Performed	Not Performed	6.0%
Gorman (CIGFUR)					9.6%

[13] The Commission places little weight on the rate of return on equity testimony of Commercial Group witness Chriss and CIGFUR witness Gorman as neither actually performed any rate of return on equity analysis, beyond looking to average authorized rate of return on equity awards by utility commissions, including this Commission. While looking to such industry average data can be beneficial, it does not substitute for the rigorous analysis the law and the Commission demand in setting the allowed rate of return on equity.

*Although Public Staff witness Walters and DoD-FEA witness Reno performed multi-stage and sustainable growth DCF models, they did not rely on their outputs. As such, the figures above exclude those results. NCJC, et. al. witness Ellis's 6.25% is the result of a multi-stage growth DCF analysis.

As is also typical of rate of return on equity testimony, the various expert witnesses rely on many of the same models to inform their cost of equity estimates. However, the results of these models vary due to differences of opinion on the appropriate inputs. In the following pages, the Commission will weigh and consider the inputs in order to narrow the range of reasonable outcomes. Further, while DoD-FEA witness Reno and CUCA witness O'Donnell primarily rely upon their DCF results, it has been the Commission's long-standing practice to consider and place weight on multiple models in order to protect against any one model's skewing the outcome in times when it may be less indicative of the true cost of capital. The Commission also notes that DEP witness Morin's figures above, with the exception of his Allowed Risk Premium measure, include a flotation cost adjustment of approximately 0.2%. Tr. vol. 8, 53-54, 73, 75, 78.

The Commission, for reasons discussed below, concludes that a flotation cost adjustment is not warranted in this case. As such, the following discussion excludes them from consideration in setting the allowed return on equity.

Discounted Cash Flow Model

Despite the wide range of overall recommendations provided by the expert witnesses, with the exception of NCJC, et al. witness Ellis's 6.25% result, the recommended results of the DCF models form a relatively tight band from 9.0% to 9.3%. While the remaining witnesses disagreed on the appropriate growth adjustment to apply to the dividend yield, a 30-basis point window of outcomes reflects consensus regarding an appropriate model output for the DCF model. This remains the case even after removing DEP witness Morin's 20 basis point flotation cost adjustment.

The Commission concludes that NCJC, et al witness Ellis's outcome of 6.25% is an outlier and should be ignored. Apart from being more than 300 basis points below any rate of return on equity ever approved by this Commission for DEP, it is scarcely 200 basis points above DEP's embedded cost of debt, a premium that is clearly insufficient to compensate investors for the added risks associated with equity ownership relative to a debtholder's claim on the same enterprise. Further, NCJC, et al witness Ellis is alone in his reliance on a DCF method other than the constant growth DCF model. In contrast, DoD-FEA witness Reno and Public Staff witness Walters both conducted a multi-stage DCF model, and subsequently ignored or discounted those results. Tr. vol. 16, 264; Tr. vol. 21, 395.

As a result of their relatively narrow band of 9.0% to 9.3%, the Commission concludes that the DCF analyses of DEP witness Morin, CUCA witness O'Donnell, Public Staff witness Walters, and DoD-FEA witness Reno, are credible, probative, and entitled to substantial weight.

Risk Free Rate

A key input to both the risk premium and CAPM models is the risk free rate. On cross examination, DEP witness Morin testified that, due to a decline in interest rates between the time of filing of his supplemental testimony and the hearing, his recommended rate of return on equity would have been 0.2% lower if recalculated. *Id.* at 323-324. The Commission appreciates DEP witness Morin's candor in this regard and understands that, due to the dynamic nature of financial markets, model outcomes calculated on any given day would reflect the inputs available on that day, and as such would change from day to day. With or without this correction, however, DEP witness Morin's preferred measure of the risk free rate that he used in his supplemental testimony, 4.3%, based on projections, diverges meaningfully from the actual 30-year Treasury rate both at the time of filing and during the hearing. DoD-FEA witness Reno reports the 30-day average yield on the 30-year Treasury bond was 3.79% as of February 28, 2023. Tr. vol. 21, 382. NCJC, et al. witness Ellis uses the January average of 3.66%. Tr. vol. 21, 939. DEP witness Morin himself reports the yield to be between 3.9% and 4.0% as of the date of the hearing. Tr. vol. 8, 324. CUCA witness O'Donnell uses the range of yields over the prior 12 months of 2.42% to 4.4%, and Public Staff witness Walters uses his own projected value of 3.7%. Tr. vol. 16, 274; Tr. vol. 21, 625.

In support of his use of projected interest rates, DEP witness Morin testified that,

> Cost of capital models, including both the CAPM and DCF models, are prospective (i.e., forward-looking) in nature and must take into account current market expectations for the future because investors price securities on the basis of long-term expectations, including interest rates. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using data that reflects the expectations of actual investors in the market.

Tr. vol. 8, 60.

The Commission considers the single best indicator of "the expectations of actual investors in the market" to be the yield they are willing to accept on the bonds they own. Where this information is available, either in the form of current yields or forward yields based upon the same, the Commission will continue to prefer using these rates to projections offered by market commentators.

DEP Witness Morin's direct testimony relied upon a risk free rate of 3.7%, and in response to a question from Chair Mitchell, he confirms that had he relied on the same 3.7% rate in his supplemental testimony, the outputs would have largely been in-line with the model outputs from his direct testimony (i.e. 20 basis points lower than his supplemental testimony). As a result, the Commission will place somewhat more emphasis on DEP witness Morin's direct testimony than his supplemental testimony with regard to his CAPM and Risk Premium Model outcomes.

Capital Asset Pricing Model (CAPM)

The wide range of results for the CAPM from the various intervenors shed light on the importance of the underlying inputs to the model. Of primary importance are the assumed risk free rate, market risk premium and beta, as the model's output is the sum of the former and the product of the latter two. As discussed above, a risk free rate in the range of 3.7% to 3.9% reasonably aligns with prevailing 30-year Treasury yields at the time of the hearing, and with the exception of CUCA witness O'Donnell, the expert witnesses have each provided models utilizing this input. CUCA witness O'Donnell, for his part, utilized a range of yields that cover the considerable variability of the measure over the 12 months prior to his testimony (2.42% to 4.4%). Tr. vol. 21, 625. While not exactly a match, it would indicate that top half of his indicated range overlaps with the others on the basis of risk free rate.

Turning next to beta, the witnesses diverge considerably. DEP witness Morin was adamant that a beta of 0.89, reflecting the current Value Line average for the proxy group. Public Staff witness Walters also employed this figure, along with average betas going back to 2014 (0.76) and betas from Market Intelligence's Beta Generator. The Commission agrees with DEP witness Morin that using stale betas is incorrect and prefers the current Value Line average, as they better reflect current market fundamentals. The Commission also accepts DEP witness Morin's rationale for rejecting the Vasicek adjusted betas from Market Intelligence. CUCA witness O'Donnell appeared to agree with DEP witness Morin, and used a 0.88 beta for the proxy group, sourced from Value Line. Tr. vol. 21, 625. Similarly, DoD-FEA witness Reno relied upon a Value Line beta of 0.89. *Id.* at 384. NCJC, et al. witness Ellis rejected the Value Line beta because Value Line considers five years of trailing data, meaning it continues to reflect the effects of pandemic-related market turmoil and asserted that they do not reflect current investor risk perceptions. *Id.* at 1010. Instead he offers several alternatives, including from providers that allow users to modify beta calculation parameters. *Id.* at 1012. On rebuttal, DEP witness Morin testified that Value Line betas are widely used and well-known to investors, that Diana Harrington's work established them as consistently the best at predicting ensuing betas, and that NCJC, et al. witness Ellis's preferred alternatives are inferior. Tr. vol. 8, 213-14. The Commission accepts DEP witness Morin's rebuttal of NCJC, et al. witness Ellis on this point and finds reassuring the reliance of other intervening witnesses on Value Line betas in its determination of the appropriate beta.

The MRP, the last variable in the CAPM model, reveals a wider range of assumptions made by the intervening witnesses. DEP witness Morin used 8% in his initial testimony (composed of a historical MRP of 7.4% and a prospective MRP of 8.5%, averaged), and 7.3% in his supplemental testimony, each reflecting an expected market return of 12%. DEP witness Morin opined that an MRP in the range of 6.0% to 8.0% is a reasonable estimate of the cost of equity for CAPM and that the historical MRP approach is simple and difficult to improve upon. Tr. vol. 8, 71. Witness Walters utilized both a historical approach and DCF approach to estimate the MRP, yielding results of 7.9% and 6.85% respectively, and implying expected market returns of 11.6% and 10.52%. Witness Walters also utilized a method from Kroll that provides a normalized risk-free rate of 3.89% and an MRP of 6.0%. Tr. vol. 16, 278-

82. DEP witness Morin accepted witness Walters' first two estimates, but rejected the Kroll based estimate for several reasons, namely that Kroll is a highly selective source, that it lacks transparency, and falls at the bottom of a range indicated by Kroll's own analysis to be a reasonable estimate of the MRP. Tr. vol. 8, 156. Witness Reno used estimates from Kroll of 7.46% (historic arithmetic average) and 6.22% (Ibbotson-Chen supply side model). She also used a 6.0% Kroll recommended U.S. ERP paired with a normalized risk-free rate of 3.5%. Tr. vol 21, 382-83. Witnesses O'Donnell (3.5% to 4.5%) and Ellis (3.98%) offered substantially lower MRP estimates. Tr. vol. 21 939, Exhibit KWO-5; Tr. vol. 21. Witness Morin noted that these estimates are below several widely used estimates of the MRP for U.S. Stocks, that witness O'Donnell did not rely upon the CAPM, and that NCJC, et. al. witness Ellis incorrectly used geometric means in generating his MRP. Tr. vol. 8, 181-83, 210. The Commission agrees that the MRP rates of witnesses Ellis and O'Donnell are unreasonably low and should be ignored.

Witnesses Morin, Reno and Walters all seemed to agree that an estimate for the MRP within a range of 6.0% to 8.0% is reasonable. The Commission agrees.

In light of the foregoing, the Commission finds that a CAPM with inputs in the range of 3.7% to 3.9% for the risk free rate, a beta 0.89, and an MRP of 6.0% to 8.0% is a reasonable outcome. Witness Morin's use of an 8% MRP and 3.7% risk free rate from original testimony, when combined with the updated beta of 0.89 results in a CAPM rate (without flotation costs) of 10.82%. Witness Walters provided three estimates utilizing the current Value Line beta (9.22%, 9.78% and 10.72%), averaging 9.91%, while witness Reno's estimates using Value Line beta (but excluding the estimate which used a normalized risk free rate of 3.5%) were 9.32% and 10.42%, averaging 9.89%. Averaging the 9.9% results from the intervenors, with witness Morin's 10.82% modified result yields an estimated cost of equity of 10.35%. Thus, the Commission concludes that an estimate of 10.35% is a reasonable outcome for the CAPM model.

Empirical CAPM (ECAPM)

In this case, both DEP witness Morin and DoD-FEA witness Reno supported inclusion of an ECAPM result. The ECAPM, according to witness Morin, corrects for the fact that the CAPM under-predicts observed returns when beta is less than one. Public Staff witness Walters took issue with witness Morin's use of an adjusted beta as published by Value Line because the adjustments made in his ECAPM model are mathematically the same as adjusting beta. Tr. vol. 16, 306-07. In rebuttal, witness Morin testified that adjusted betas and ECAPM correct different problems, and that as a result, both are needed. NCJC, et. al. witness Ellis opposed the ECAPM on the grounds that it is not used elsewhere in finance and is not supported by updated research. Tr. vol. 21, 1038. Witness Morin contended the ECAPM is discussed in most finance textbooks, including one cited by witness Ellis. Tr. vol. 8, 217.

The Commission agrees with witness Walters's contention that mathematically, the Blume adjusted betas provided by Value Line achieve the same end. However, it finds witness Reno's support for using these same betas in the ECAPM persuasive and is

further persuaded by witness Morin's testimony that both adjustments are needed because they correct for different things.

As witness Reno and witness Morin's ECAPM calculations were both approximately 20 basis points higher than their CAPM calculations, reflecting the Commission's CAPM conclusions above, the Commission accepts an ECAPM estimate of the rate of return on equity of 10.55% as reasonable.

Together with the results of the CAPM, a combined CAPM range of 10.35% to 10.55% will be used to calculate the required rate of return on equity in this case.

Risk Premium Model

The last major method relied upon by the cost of equity expert witnesses are the Risk Premium methods. DEP witness Morin utilized two variations of this approach. The first compares actual returns of the S&P Utility Index with contemporaneous Treasury returns and applies the 4.3% risk free rate. As with his other methods, he also applied a flotation cost adjustment. His second RPM represents the historical premium of allowed ROEs to the risk free rate. This method does not employ a flotation cost adjustment, as it assumes allowed ROEs factor that in. While the Commission has previously relied upon such models, and finds them credible, as mentioned above, the Commission finds that a risk free rate of 4.3% is overstated, and will instead rely upon witness Morin's Risk Premium Models as provided in his direct testimony, which used 3.7% risk free rate. Those results, after removing the adjustment for flotation costs, averaged 10.1%. The Commission finds this result credible, probative, and entitled to substantial weight.

Public Staff witness Walters also provided a risk premium method based on authorized returns for electric utilities. Witness Walters compares 37 years of authorized returns for electric utilities against contemporaneous bond yields and uses this method to estimate a return on equity of 9.9%. The Commission has given substantial weight to this method in the past and does so in this case as well. Taken together with the 10.1% RPM result of witness Morin, the Commission finds there is credible and probative evidence supporting an RPM-based cost of equity ranging from 9.9% to 10.1%.

Comparable Earnings Method

Although no witness relied upon a comparable earnings method in formulating their recommended rate of return on equity, CUCA witness O'Donnell and DoD-FEA Reno calculated results of 9.5% to 10.5% and 10.26% to 11.1% respectively. The Commission finds these results generally support its decision regarding rate of return on equity in this case.

Indicated Range Prior to Adjustments

In light of the foregoing, the Commission has identified a zone of reasonableness of 9.75% to 10%, reflecting the average of the ranges identified above. The Commission will next examine the proposed adjustments offered by the witnesses.

Flotation Cost Adjustment

Flotation costs are the expenses of issuing equity, such as printing fees, underwriter fees, attorney fees, and other similar fees. Tr. vol. 8, 337. DEP, itself, does not issue equity; instead, equity issuances are made by its publicly traded parent, Duke Energy.

Duke Energy issued no equity during the test year. Duke Energy forecasts there will be no common equity issued from 2023 through 2027. Public Staff Cross Examination Morin – Direct and Rebuttal, Ex. 10. Tr. Ex. vol. 9. DEP witness Newlin testified that "we've said publicly that the holding company is not planning to issue common stock until 2027 at the earliest." Tr. vol. 9, 111.

Flotation costs may not be recovered under these circumstances for the following two separate and independent reasons. First, it would be "unjustified" to cause customers to overpay DEP approximately $48 million dollars towards flotation costs when, in fact, no equity was or will be issued from 2021 through 2027. See, Order Approving Partial Settlement Agreement and Stipulation, Deciding Contested Issues, Approving Water and Sewer Investment Plan, Granting Partial Rate Increases, and Requiring Customer Notice, *Application by Aqua North Carolina, Inc. for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All Its Service Areas in North Carolina and for Approval of a Water and Sewer Investment Plan*, No. W-218, Sub 573, at 62 (June 5, 2023) (2022 Aqua Rate Case).

Second, the recovery of flotation costs is not allowed under North Carolina law where there is no evidentiary support. 2022 Aqua Rate Case at 61-62. The North Carolina Supreme Court in *State ex rel. Utilities Commission v. Public Staff,* 322 N.C. 689, 370 S.E.2d 567 (1988), reversed and remanded the ROE portion of the Commission's Order dated October 31, 1986, Docket No. E-7, Sub 408 for Duke Power Company. The Supreme Court directed the Commission on remand to reconsider the proper rate of return on Duke Power's common equity and also support its conclusion on flotation costs with specific findings. There was no evidence in that case that Duke Power intended to issue new stock for the next three or four years. On remand, the Commission issued its second E-7, Sub 408 Order, reassessed the evidence, and issued new findings of fact and conclusions. The Commission concluded that 13.2% was a fair rate of return on Duke Power's equity and there was a 0.1% increment in the approved 13.2% ROE to cover future stock issuance costs. On the second appeal, the Supreme Court held that the Commission's inclusion of the "stock" issuance increment is not supported by substantial evidence in view of the whole record. *State ex rel. Utils. Comm'n. v. Public Staff*, 331 N.C. 215, 218 (1992). The Supreme Court concluded the Commission's inclusion of a 0.1% ROE increment for purported future financing costs in the approved ROE was not based upon substantial evidence in view of the whole record. The Supreme Court stated:

> As we noted on the first appeal, an 0.1% upward increment in Duke's rate of return on common equity costs ratepayers $ 4.2 million annually in additional rates. Historically, Duke's average costs per issuance of stack

> was $ 3.2 million. In light of the whole record on this issue, particularly in the absence of any evidence that Duke intended to issue stock in the immediate future, there is simply no substantial evidentiary support for the Commission's addition of a 0.1% increment to Duke's rate of return on common equity to cover future stock issuance costs.

State ex rel. Utils. Comm;'n v. Public Staff, 331 N.C. 215 at 221-22.

The Supreme Court further stated and ruled:

> On the first appeal of this case, we questioned whether the record supported *any* adjustment whatever in the rate of return for purported future stock issuance, or financing, costs. We said:
>
> > Since *no* evidence was introduced that Duke intends to issue new stock for the next three or four years, and because there was no evidence regarding the probable cost of a prospective issuance, we question whether the record supports *any* financing cost adjustment. *State ex. rel. Utilities Commission v. Public Staff*, 322 N.C. at 700, 370 S.E.2d at 574 (emphasis added). We are not satisfied, for the reasons alluded to in our first opinion, that the record supports no such adjustment in the common equity rate of return.

Id. at 221.

As in that case, there was and is no plan to issue equity in the present case. Accordingly, there is no evidence to support DEP's request to increase its ROE by 20 basis points for flotation costs. Therefore, the Commission rejects DEP's inclusion of 20 basis points in its ROE request to cover flotation costs.

Downward Adjustment Due to MYRP

N.C.G.S. § 62-133.16(c)(1)(a) requires the Commission to consider any increased or decreased risk to either the electric public utility or its ratepayers that may result from having an approved MYRP.

Public Staff witness Walters and CUCA witness O'Donnell both made specific mathematical downward adjustments in their ROE recommendations to account for what they perceive as the less risky environment DEP now operates in as a result of the passage of the PBR Statute. Witness Walters's downward adjustment was 20 basis points, taking his ROE recommendation from 9.45% to 9.25%. Tr. vol. 16, 288. Witness O'Donnell's downward adjustment was 25 basis points, taking his ROE recommendation

from 9.25% to 9.0%[14]. Tr. vol. 21, 627. Inasmuch as the Public Staff's recommendation is more fully explained in witness Walters's testimony, the Commission will address it, but the same factors described in this discussion apply with equal force to the recommendations of witnesses O'Donnell and Reno.

While asserting that there were other reasons to support a downward adjustment, witness Walters conceded that "the only stated adjustment for [DEP's] ROE is based on the MYRP." Tr. vol. 16, 336. Further, the actual quantification of the recommended downward adjustment was not performed by witness Walters at all. Instead, he simply adopted the Public Staff's methodology applied in the recent water utility cases, the 2022 Aqua Rate Case., and the general rate case proceeding for Carolina Water Service North Carolina in Docket No. W-354, Sub 400 (the 2022 CWSNC Rate Case). See Order Approving Partial Settlement Agreement and Stipulation, Deciding Contested Issues, Granting Partial Rate Increase, Approving Water and Sewer Investment Plan, and Requiring Customer Notice, *Application by Carolina Water Service, Inc. of North Carolina for Authority to Adjust and Increase Rates and Charges for Water and Sewer Utility Service in All Service Areas of North Carolina and Approval of a Three-Year Water and Sewer Investment Plan*, No. W-354, Sub 400 (Apr. 26, 2023); *See also* Order Approving Partial Settlement Agreement and Stipulation, Deciding Contested Issues, Approving Water and Sewer Investment Plan, Granting Partial Rate Increases, and Requiring Customer Notice, *Application by Aqua North Carolina, Inc., for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All Its Service Areas in North Carolina and for Approval of a Water and Sewer Investment Plan*, No. W-218, Sub 573 (June 6, 2023). In footnote 29 of his direct testimony, witness Walters linked to the Public Staff testimony filed in those two water utility cases to support quantification, noting that the "Public Staff has previously argued that approval of multi-year mechanisms that reduce the risk borne by water and wastewater utilities should result in a 20-basis point reduction in the allowed ROE." *Id.* at 287. The Commission did not accept the Public Staff position in either of the proceedings cited by witness Walters, and this downward adjustment is contrary to Commission's reasoning in the Orders in the 2022 Aqua Rate Case and the CWSNC Rate Case. Further, there is substantial evidence introduced in this case supporting DEP's position that no downward adjustment is warranted. Accordingly, the Commission rejects the downward adjustment theory.

In the Commission's Order in the 2022 CWSNC Rate Case, the Commission addressed and rejected the Public Staff's requested 20 basis point downward adjustment in otherwise applicable ROE and its holding was read into the record by Dr Morin:

> [T]he Commission is persuaded that this type of mechanism is prevalent across the country and within the proxy group. Although a WSIP is intended to reduce regulatory lag, the existence of similar mechanisms across the country and in the states where the proxy group utilities operate indicates

[14] DoD-FEA witness Reno did not make a specific downward adjustment to her rate of return on equity recommendation due to DEP's MYRP proposal but indicated that she had taken the MYRP proposal into account in setting rate of return on equity.

> that the comparative risk reduction associated with a WSIP[15] for CWSNC, in this case, is zero.

Tr. vol. 9, 20-21 (emphasis added)[16].

The Commission's conclusion is in line with witness Morin's academic work on this subject, which is summarized in his most recent book, Modern Regulatory Finance, published in late 2021. *See* DEP Redirect Morin Direct and Rebuttal Ex. 1. Tr. Ex. vol. 9. At the hearing in this proceeding Witness Morin summarized the three reasons why he asserts the presence of risk-mitigating mechanisms should not result in a reduction in the cost of equity as presented on pages 58-59 of his Direct and Rebuttal Exhibit 1. *Id.*

First, witness Morin asserts that the ROE in a rate case is being set based upon a proxy group of comparable companies, and the use of a proxy group takes into account similar risk mitigating mechanisms that are pervasive in the industry, so "the addition of any discreet adjustment would be unwarranted double counting of the effect of these mechanisms." DEP Redirect Morin Direct and Rebuttal Ex. 1 at 58, Tr. Ex. vol. 9. In sum he states that the "current market data reflects or embeds the presence of risk mitigators." Tr. vol. 9, 17. Second, he states that empirical studies in peer-reviewed academic journals have examined the impact of risk mitigators on the cost of equity, and the results show that there is no impact. *Id.* at 17-18. Third, risks that are diversifiable are not considered relevant in cost of capital estimates for investors, because by definition they can be eliminated through diversification, and risk mitigators are in fact diversifiable. *Id.* at 18.

DEP witness Morin, quoting from his book, summarized that a downward adjustment would be "double counting" as the "market-derived returns are estimated for market information on the cost of common equity for other comparable companies, which already incorporates the impacts of these mechanisms." Tr. vol. 9, 17-18 (quoting DEP Redirect Morin Direct and Rebuttal Ex. 1 at 59), Tr. Ex. vol. 9.

The Commission is persuaded that DEP has proven, by the greater weight of the evidence, that the impact of alternative ratemaking mechanisms like the PBR Statute is already incorporated into the analysis and a downward adjustment in otherwise applicable ROE would be inappropriate "double counting."

DEP Late-Filed Exhibit (LFE) No. 11 and LFE No. 14 illustrate the prevalence of alternative ratemaking mechanisms. DEP LFE No. 11 is a map demonstrating that alternative ratemaking mechanisms are widespread throughout the United States. In fact, of the 51 jurisdictions depicted (the 50 states plus the District of Columbia), only five have no alternative ratemaking mechanism in place. By contrast, 36 (over 70%), have two or more such mechanisms, including North Carolina, which has two (MYRP and

[15] A "WSIP" (Water and Sewer Investment Plan) is the water utility analog to an MYRP for electric utilities.

[16] The Commission reiterated this holding, in identical language, in its recent Order in the 2022 Aqua Rate Case. See Order at 62.

decoupling). The other eleven states have a single mechanism, either a future test year or specific capital trackers. The exhibit validates DEP witness Bateman's observation that in the United States:

> [A]lternative ratemaking regulation is the norm and, therefore, contrary to Witness Walters's assertion, implementation of a MYRP does not warrant a reduction to the Company's ROE since this change simply makes North Carolina's ratemaking practices more aligned with the rest of the country. Notably, every single company in Witness Walters's proxy group operates either entirely or partially in states that have adopted alternative regulation.

Tr. vol. 23, 159-60.

LFE No. 14 shows the 23 electric utility holding companies in witness Morin's peer group used in connection with his ROE recommendation and the alternative ratemaking mechanisms in the applicable jurisdiction. Tr. vol. 8, 349. The LFE illustrates witness Morin assertion that "the proxy group companies all operate in … states [that have alternative ratemaking mechanisms], and more than one state in many cases." *Id.*

DEP witness Bateman compared the alternative ratemaking mechanisms available in North Carolina under the PBR Statute with similar mechanisms available in other jurisdictions. DEP witness Bateman stated that "the focus should not be on whether DEP has a Multiyear rate plan, but rather, how the North Carolina PBR framework compares to alternative regulation in other states in terms of risk to the utility." Tr. vol. 23, 160. Witness Bateman asserted that "North Carolina's framework places more risk with the utility than the frameworks in some other states." *Id.* She provided numerous examples of how North Carolina's framework places risk on the utility. As an example, she compared states with formula rates and riders for significant capital investments that allow for true-ups of costs increases to North Carolina's PBR mechanism under which she contends electric utilities bear "all the risk of and financial impact associated with cost increases on projects in between rate cases." *Id.* Witness Bateman also stated that unlike the PBR Statute many other states' MYRP mechanisms provide for fully forecasted growth of both capital and associated O&M expense. Tr. vol. 15, 91-92. Finally, she noted that ESM in North Carolina's PBR Statute is asymmetrical in that it assures that customers receive 100% of earnings once the utility's earnings exceed 50 basis points of its allowed ROE, but the utility does not receive an earnings boost if it underearns. *Id.* at 92-93; Tr. vol. 23, 160-61; *See also* DEP Redirect Bateman Stillman Direct and Settlement Ex. No. 1, Tr. Ex. vol. 16.

Witness Bateman concluded her review with the observation that she saw nothing that makes North Carolina "less risky, in terms of the regulatory framework than other states on average across the country." Tr. vol. 15, 96.

The Commission agrees with DEP witnesses Bateman and Morin and concludes that substantial evidence supports the reasonableness of a rate of return on equity ranging from 9.75% to 10.0%, without a downward adjustment due to the MYRP. The

Commission is persuaded by the evidence that similar types of mechanisms are prevalent across the industry as well as within the proxy group. The Commission is also persuaded that elements of the North Carolina statute are distinguishable as compared to other jurisdictions, as pointed out by witness Bateman, in terms of allocation of risk between utility and customers. The Commission is mindful that one of the objectives of the MYRP is to reduce the lag in recovery experienced by the utilities, which, in theory, benefits the utility. However, the Commission concludes that given the utility has entered a capital intensive period of time as it manages the transition of its system, it is critical that the utility be in a position to access capital on reasonable terms and the Commission concludes that the availability of the MYRP makes DEP competitive in terms of its ability to access capital on reasonable terms.

Regarding the obligation in accord with the holding in *Cooper I* to inform its selection of a rate of return on equity within that range, the Commission will next address the impact of changing economic conditions on customers.

In this case, all parties had the opportunity to present the Commission with evidence concerning changing economic conditions as they affect customers. The testimony of DEP witness Morin and Public Staff witness Walters addresses changing economic conditions at some length. Witness Morin provided detailed data concerning changing economic conditions in North Carolina, as well as nationally, and concluded that the North Carolina-specific conditions are “highly correlated” with conditions in the broader national economy. As such, witness Morin testified that changing economic conditions, both nationally and specific to North Carolina, are reflected in his rate of return on common equity estimates.

Public Staff witness Walters generally agreed with DEP witness Morin that as of the time of the filing of his testimony, economic conditions had improved in North Carolina. As the Commission has noted, customer impact due to changing economic conditions is embedded in ROE expert witness analyses. Witness Morin’s analysis, which the Commission credits and to which the Commission gives weight, also indicates that even though the North Carolina and U.S. economies have contracted, economic conditions in North Carolina continue to be highly correlated to conditions nationally, and, therefore, continue to be reflected in the analyses used to determine the rate of return on equity.

The point is to see whether the econometric data relied upon by ROE expert witnesses captures the effects and impacts of changing economic conditions upon customers and the Commission concludes that, based on the evidence presented in this case, it does.

Based upon the general state of the economy and the need for the continuing affordability of electric utility service, and after weighing and balancing factors affected by the changing economic conditions in making the subjective decisions required, the Commission concludes that the rate of return on common equity of 9.8% will not cause undue hardship to customers even though some will struggle to pay the increased rates.

Indeed, affordability, especially for low-income customers, was a special focus of DEP and the intervening parties to this proceeding. As noted above, the Commission established the LIAC in its April 16, 2021, Order in the 2019 Rate Case and tasked the LIAC with addressing affordability issues for low-income residential customers. The efforts of the LIAC are apparent in this case and include the Affordability Stipulation as previously discussed in this Order. The provisions in the Affordability Stipulation, which includes the development of the CAP pilot, directly benefit customers with the least ability to pay in the current economic environment. In addition, as previously discussed in this Order, through the Payment Navigator program proposed in this proceeding, DEP will work closely with customers in need of assistance with managing bills and will connect those customers with sources of support and funding, based on the unique situation of the customer. While these programs will not ease the burden that electricity rates will place on certain of DEP's customers, the Commission expects these programs to provide a meaningful level of support to eligible customers. The Commission takes these facts into account in approving the 9.8% return on equity. However, the Commission also concludes, based on the evidence of record, that efforts to address energy burden and support for customers need assistance with their bills are but nascent. The LIAC allowed DEP and its stakeholders to generate data that illustrates the depth and breadth of the challenge in North Carolina. Work must continue to reach these customers and provide meaningful support both in terms of assisting customers use energy more efficiently so that bills are reduce and in terms of providing support to those customers when they are in need of bill assistance. The Commission recognizes the difficulties attendant to solving for these issues but emphasizes that the utility must continue this work. As has been previously expressed by this Commission, the electric utilities must pursue every opportunity presented by federal funding made available by the IRA and other federal legislation to support customers in need. The Commission has confidence that DEP, the Public Staff and stakeholders will identify such opportunities for customers and will develop programs that take advantage of every federal dollar that is available for customer support.

Considering the changing economic conditions and their effects on DEP's customers, the Commission recognizes the financial difficulty that an increase in DEP's rates may create for some of DEP's customers, especially low-income customers. The Commission is mindful that, as shown by the evidence, relatively small changes in the rate of return on common equity have a substantial impact on a utility's base rates. Therefore, the Commission has carefully considered changing economic conditions and their effects on DEP's customers in reaching its decision regarding DEP's approved rate of return on common equity.

The Commission also recognizes that provisions in S.L. 2021-165 may intensify the risks facing DEP as it continues to navigate the challenges associated with the change in the mix of electric generating resources and with new load patterns, including ensuing the continued reliable operation of the electric system, and to work toward the requirements of N.C.G.S. § 62-110.9. As DEP witness Bowman asserted,

> [I]t is simply indisputable that the tasks currently before the Company—implementing the energy transition within the construct of the Carbon Plan while simultaneously evolving nearly every aspect of its business and pursuing a complex merger—are unprecedented, imposing new and unique execution risks on the Company across all phases and aspects of its business that are inarguably more far-reaching and complex than anything the Company has ever pursued in the past.

Tr. vol. 21, 1200-01.

The need to invest significant sums to serve its customers requires DEP to maintain its creditworthiness in order to compete for large sums of capital on reasonable terms. And, in addition, as recent years have demonstrated, macroeconomic, geopolitical, extreme weather, public health, and other exogenous events beyond DEP's control may necessitate – and indeed have necessitated – the need for DEP to access and invest significant sums during atypical and volatile market conditions. The Commission takes note of DEP witness Newlin's testimony that, particularly in light of DEP's present credit metrics, ROE is one predicate (capital structure being another predicate, discussed in detail below) to the level of creditworthiness necessary to efficiently access the capital markets on reasonable terms during all market cycles, including periods of high volatility, which access ultimately lowers borrowing costs passed through to customers during such time. Tr. vol. 9, 112-13; Tr. vol. 22, 206-07.

The Commission must weigh the impact of changing economic conditions on DEP's customers against the benefits that those customers derive from DEP's ability to provide safe, adequate, and reliable electric service 24/7/365, regardless of macroeconomic, geopolitical, environmental, and public health events. Safe, adequate, and reliable electric service is essential to the well-being of the people, businesses, institutions, and economy of North Carolina. The Commission is mindful of the burden that electricity rates will place on many of DEP's customers and the contribution of the ROE to those rates, but the Commission must balance the burden against DEP's being in a position to access capital: (1) on reasonable terms; and (2) in moments when DEP most needs capital in order to provide reliable service.

The Commission concludes in the exercise of its independent judgment and discretion that a 9.8% rate of return on common equity is supported by the evidence and should be adopted. The hereby approved rate of return on common equity appropriately balances the benefits received by DEP's customers from DEP's provision of safe, adequate, and reliable electric service in support of the well-being of the people, businesses, institutions, and economy of North Carolina (which benefits are symbiotically linked to DEP's ability to compete in the capital markets to access capital on reasonable terms that will be fair to ratepayers) with the difficulties that some of DEP's customers will experience in paying DEP's adjusted rates. The Commission further concludes that a 9.8% rate of return on common equity will allow DEP to compete in the market for equity capital, providing a fair return on investment to its investor-owners. Accordingly, the Commission concludes, taking into account changing economic conditions and their

impact on customers, that the approved rate of return on common equity will result in the lowest rates constitutionally permissible in this proceeding.

Capital Structure

Summary of Evidence

In his direct testimony, DEP witness Newlin proposed using a capital structure of 53% members' equity and 47% long-term debt. Tr. vol. 9, 94. Witness Newlin testified that DEP's "specific debt/equity ratio will vary over time, depending on a variety of factors, including among other things, the timing and size of capital investments and payments of large invoices, debt issuances, seasonality of earnings, and dividend payments to the parent company." *Id.* As of December 31, 2021, DEP's capital structure was 53.9% common equity and 46.1% long-term debt. *Id.* at 95.

Witness Newlin discussed the current credit ratings and forecasted capital needs of DEP and emphasized the importance of DEP's continued ability to meet its financial objectives. *Id.* at 87. He noted that DEP faces substantial capital needs over the next several years so as to provide cost-effective, safe, reliable, and increasingly cleaner electric service to its customers well into the future, so DEP must therefore appeal to debt and Duke Energy's equity investors to attract the capital it needs. *Id.* at 98-99. He explained that investors – both debt and equity – have a variety of investment opportunities available to them and require a return commensurate with the risk they incur, warning that they will invest elsewhere if they feel the expected return provided by a company for a given amount of risk is inadequate. *Id.* at 86. He further explained that lower credit quality weakens a company's attractiveness as an investment opportunity relative to companies with higher credit quality and similar return profiles. *Id.* at 86-87. As such, witness Newlin testified it is critically important that DEP maintain strong, investment-grade ratings to assure its financial strength and flexibility and ensure access to capital on reasonable terms. *Id.* at 96.

Discussing DEP's financial objectives, witness Newlin addressed specific objectives that support financial strength and flexibility, including maintaining 53% common equity for DEP on a financial capitalization basis; ensuring timely recovery of prudently incurred costs; maintaining sufficient cash flows to meet obligations; and maintaining a sufficient return on equity to fairly compensate shareholders for their invested capital. *Id.* at 97-98. He further testified that the ability to attract capital (both debt and equity) on reasonable terms is vitally important to DEP and its customers, and each of these specific objectives helps DEP both to maintain its investment-grade credit ratings and to meet its overall financial objectives. *Id.* at 87-88.

Intervenor witnesses disputed witness Newlin's recommendation. Public Staff witness Walters, CUCA witness O'Donnell, and DoD-FEA witness Reno all testified that DEP's proposed 53/47 capital structure exceeded the equity ratio for all proxy group companies. Tr. vol. 16, 245 (Walters); Tr. vol. 21, 592 (O'Donnell); Tr. vol. 21, 360 (Reno). The testimony of witnesses Walters and Reno also noted that the 53/47 recommendation

was inconsistent with DEP's observed capital structure at various points in time. Tr. vol. 16, 246 (Walters); Tr. vol. 21, 360 (Reno). Witnesses O'Donnell, Reno, and Gorman testified that the 53/47 proposal exceeded the average capital structure authorized by other utility commissions. Tr. vol. 21, 360 (Reno); Tr. vol. 21, 593-94 (O'Donnell); Tr. vol. 21, 405, 408 (Gorman).

These witnesses' capital structure recommendations were as follows: Walters — 52/48 (Tr. vol. 16, 247); O'Donnell — 50/50 (Tr. vol. 21, 568); Reno — 52/48 (Tr. vol. 21, 360); and Gorman — 52/48 (Tr. vol. 21, 405).

NCJC, et al. witness Ellis took a different tack, recommending a capital structure of 58% equity and 42% debt. Tr. vol. 21, 1071. As noted above in connection with the Commission's discussion of ROE evidence, witness Ellis testified that ROE and capital structure are interrelated and must be addressed together. *Id.* at 1056-57. Accordingly, his 58/42 capital structure recommendation goes hand-in-hand with his 6.0% ROE recommendation. *Id.* at 1071. He indicated that this combination would minimize customer costs while meeting investor return expectations. *Id.*

In his rebuttal testimony, DEP witness Newlin took issue with the intervenor witness recommendations. He observed that the reliance of witnesses Walters, O'Donnell, and Reno on capital ratios of proxy group companies was misplaced, because the proxy companies are all publicly traded holding companies, not utility operating companies. Tr. vol. 22, 169. He testified that it is inappropriate to compare DEP's capital structure to the holding company capital structures, because the risk profiles are very different. *Id.* at 170. The appropriate comparison is to other utility operating companies. Witness Newlin performed that comparison for witness Morin's proxy group, which was essentially the same for the other rate of return on equity expert witnesses and presented the results in Newlin Rebuttal Exhibit 1. Tr. Ex. vol. 22. The results show that the average capital structure for operating utilities is 53.3% equity/46.7% debt – consistent with DEP's proposal. Tr. vol. 22, 172. He pointed to the Commission's previous rejection of the use of parent company structures as opposed to operating company structures in determining the operating utility's appropriate equity/debt ratio. *Id.* at 172-73.

Witness Newlin further testified that witnesses Walters's and Reno's comparisons of DEP's proposed capital structure with DEP's actual capital structure at a specific point in time are inappropriate. *Id.* at 173. He explained that it is reasonable to expect DEP's capital structure to fluctuate above and below the target equity ratio, and that merely selecting a point in time is not representative of how DEP intends to capitalize its business in the long-term. *Id.* at 174. Moreover, the specific points in time utilized by witness Walters rely on a surveillance report which includes current maturities of long-term debt which are excluded for ratemaking purposes. *Id.*

Witness Newlin disputed the manner in which witnesses O'Donnell, Reno, and Gorman compare DEP's proposed capital structure with allowed common equity ratios granted by other state regulators, noting that their presentations are overly simplistic and

misleading. *Id.* at 175. He explained that their considerations fail to give proper weight to trends of rising equity components not reflected in their historical observations. *Id.* at 176.

Witness Newlin also presented an analysis of the intervenor capital structure recommendation with the lowest equity ratio component, proposed by witness O'Donnell. He noted that selection of an optimal capital ratio requires balance between affordability and access to the capital markets. He noted that a strong capital structure and adequate ROE provide the balance sheet protection and cash flow generation to support high credit quality. This in turn creates financial flexibility to efficiently access the capital markets on reasonable terms during all market cycles, including periods of high volatility, which ultimately lowers borrowing costs passed through to customers. *Id.* at 180. He testified that witness O'Donnell fails to consider the impact his 50/50 capital structure recommendation would have on DEP's credit metrics and potentially its credit ratings. *Id.* Witness Newlin then presented an analysis showing the negative impact upon DEP's credit ratings of the 50/50 recommendation, concluding the recommendation along with witness O'Donnell's ROE estimate would further stress DEP's already distressed credit metrics and cash flows, with negative consequences to DEP's credit ratings and cost of debt. *Id.* at 181-88.

Witness Newlin also criticized witness Ellis' 6.0% rate of return on equity/58% equity layer recommendation, noting that with an ROE that low DEP would not be able to effectively compete for capital. *Id.* at 193. Witness Newlin presented a table showing alternate ROE comparisons of southeastern utilities, as follows:

Table 4: Authorized ROE Comparison of Peer Utilites in the Southeast since 2020

Regulated Utility	State	Docket/Case No.	Year of Order	Current Authorized ROE
Virginia Electric and Power	NC	E-22, Sub 562	2020	9.75%
Alabama Power Company	AL	reported by S&P, under RSE mechanism	2021	11.88%(1)
Dominion South Carolina	SC	2020-125-E	2021	9.50%
Duke Energy Carolinas	NC	E-7, Sub 1214	2021	9.60%
Georgia Power	GA	44280	2022	10.50%(2)
Florida Power & Light	FL	20210015 - ROE Trigger	2022	10.80%(3)
Duke Energy Florida	FL	20220143-EI	2022	10.10%(4)
Tampa Electric Co.	FL	20220122-EI	2022	10.20%(5)
Duke Energy Progress	SC	2022-254-E	2023	9.60%
Average				**10.21%**

Source: S&P Capital IQ, Past Rate Cases pulled on April 4, 2023.

(1) Alabama Power has a formula rate mechanism that allows for annual adjustments, and they have a variety of mechanisms to allow for the inclusion of new plant. Under this mechanism, they are allowed a relatively high ROE (S&P reported 11.88% in year 2021) that is balanced against limited annual rate adjustments with certain caps.

(2) Authorized retail ROE set under the 2022 Alternative Rate Plan approved by the Georgia Public Service Commission and evaluated against a range of 9.50% to 11.90%. Any retail earnings above 11.90% will be shared with Georgia Power retaining 20%, 40% applied to reduce regulatory assets, and 40% directly refunded to customers.

(3) ROE Trigger increased authroized ROE to a midpoint of 10.80% from 10.60%

(4) Originally approved ROE band was 8.85% to 10.85%. The ROE band will increase by 25 basis points beginning in 2023 as a result of the average 30-year U.S. Treasury rate increasing by more than 50 basis over a six-month period.

(5) Originally approved ROE band was 9.00% to 11.00%. The ROE band will increase by 25 basis points beginning in 2023 as a result of the average 30-year U.S. Treasury rate increasing by more than 50 basis over a six-month period.

Id. at 195.

Finally, witness Newlin provided an overview of market dynamics since DEP's last rate case, noting the dramatic changes in economic conditions, including persistently high inflation, geopolitical issues like the war in Ukraine, and bank failures. *Id.* at 196. The Federal Reserve has responded to inflation by dramatically raising short term interest rates, and long term rates have also spiked and remain volatile. He noted that this heightened level of market volatility and uncertainty has led to an unprecedented number of zero issuance days in the primary debt capital markets. Witness Newlin stressed the value during these times of high credit quality and strong investment-grade credit ratings, which allow Companies to not only access the market, if needed, but also provide flexibility to wait for more optimal market conditions. *Id.* at 196-97. In his testimony summary witness Newlin noted that DEP's existing strong investment grade credit ratings constitute a form of insurance against downgrades that will be the likely consequence of weakening DEP's financials and noted further that downgrades only work to the detriment of DEP and its customers. *Id.* at 201.

Discussion and Conclusions

For the reasons set forth herein, the Commission approves DEP's proposed capital structure of 53.0% equity and 47.0% long term debt.

The Commission is not persuaded by witness Ellis' recommendation. In the Commission's view, his testimony on capital structure is far outside the mainstream, just as it was for ROE. While the Commission appreciates – and no party disputes – witness Ellis's point that capital structure and rate of return on equity are related, the Commission is concerned that an ROE so low, even if connected to a high equity ratio, will render DEP at a severe disadvantage when competing for capital. The Commission is concerned that DEP will not find many equity investors willing to invest in an electric utility that runs nuclear plants and faces significant challenges and capital needs with respect to spearheading S.L. 2021-165's energy transition with a 6.0% rate of return on equity, no matter what the equity ratio – especially when, as indicated by DEP Redirect Newlin Rebuttal Exhibit 2, those same investors can invest in much less risky utility bonds yielding 5.24%. Tr. vol. 23, 47; Tr. Ex. vol. 22.

Turning next to the recommendations of the other witnesses, the Commission notes while witnesses Gorman, Reno, and Walters support use of the stipulated equity later from DEP's prior rate case, much of their testimony in support of lowering the equity layer from DEPs request is premised upon comparisons to the capital structures of publicly traded holding companies. The Commission has repeatedly rejected the use of holding company capital structures in the past. *See, e.g.,* Order Granting General Rate Increase and Approving Amended Stipulation, issued on December 7, 2009 in Docket No. E-7, Sub 909, 27-28. Moreover, witness Newlin persuasively establishes that DEP's proposed 53/47 capital structure is right in line with the capital structures of the utility operating companies that are subsidiaries of the holding companies in Dr. Morin's proxy group, which is essentially the same as all of these witnesses' proxy groups. *See* Newlin Rebuttal Ex. 1, Tr. Ex. vol. 22.

The seemingly slight difference between DEP's 53/47 proposal and the Public Staff's 52/48 proposal masks consequential impacts. Those impacts persuade the Commission that 53/47 is the optimal structure that appropriately balances affordability and DEP's access to capital on reasonable terms. With DEP's credit metrics as stressed as they are, further downward pressure in the form of a reduced equity layer and increased debt is decidedly not in the best interests of either DEP or its customers.

The credit stressors experienced by DEP are in some respects being felt industry wide. In his direct testimony, witness Morin referenced the "perfect storm" facing electric utilities like DEP: (1) slowing or even declining electricity growth in energy consumption; (2) at a time in which record amounts of new capital must be raised to replace aging infrastructure, improve reliability, and deliver renewable generation; (3) coupled with the need to implement a transition away from fossil fuel (particularly coal) and toward renewables, including electrification of the transportation sector; and (4) and layering on further the need to build new transmission infrastructure to strengthen the grid against

weather events increasing in frequency and ferocity, as well as new renewable generation resources. Tr. vol. 8, 91-92.

As witness Bateman testified, DEP faces multiple risks on multiple fronts including risks associated with investment and new technologies; risks associated with operating a system that must be "on" 24/7/365 with new types of generation, including increasing amounts of solar; and risks associated with getting the retirement of existing coal generation "just right." Tr. vol. 15, 97-98. These risks all highlight the execution and operational risks facing DEP in connection with the mandates of S.L. 2021-165. Witness Bowman addressed this issue as well, as noted in the return on equity discussion above. Moving forward, these risks impose upon DEP the obligation to navigate a fast-changing landscape to secure ready access to capital upon reasonable terms, to ensure that it can make the necessary capital investments to ensure reliable and affordable service to its customers.

Credit rating agencies have noted these stressors, both on a national and a DEP-specific basis. On the national front, Moody's published in November 2022 an industry-wide report highlighting the agency's revision of the entire regulated utility sector outlook from stable to negative. *See* DEP Redirect Newlin Direct Ex. 3, Tr. Ex. vol. 10. The report highlights that the industry as a whole is confronting numerous financial pressures at a time when Moody's expects "the sector to maintain elevated capital spending focused on reducing carbon emissions to make progress toward net zero goals and overall system reliability" – precisely the execution risks DEP faces in connection with the mandates of S.L. 2021-165.

Specifically regarding DEP, Moody's has taken two very recent actions, both of which highlight the immediate credit metric challenges DEP faces. First, in April 2023 Moody's published a "Ratings Action" report (DEP Redirect Newlin Direct Exhibit 1) affirming DEP's A-level rating but at the same time issuing an explicit warning with regard to the principal credit metric utilized by Moody's, the ratio of Funds From Operations (FFO) to debt (FFO/Debt)[17]. Tr. Ex. vol. 10. In its April 2023 Ratings Action Moody's indicated that it was raising its FFO/Debt downgrade threshold for DEP from 20.0% to 21.0%, meaning that while it had in the past forecast a potential downgrade in DEP's credit rating if the FFO/Debt metric stayed below 20.0% on a sustained basis, it was now forecasting a potential downgrade if the metric stayed below 21.0% on a sustained basis. This is a particularly worrisome development because, as Company witness Newlin pointed out during his direct testimony, DEP's FFO/Debt ratio has been below 21.0% for a number of years. Tr. vol. 9, 17-18. In other words, DEP is already operating below the Moody's raised downgrade threshold and has already been doing so on a sustained basis. *Id.* at 18-19.

Between witness Newlin's appearance on direct on May 5 and his appearance on rebuttal on May 16, Moody's issued its May 2023 updated Credit Opinion regarding DEP, replacing its Credit Opinion issued in March 2022 (introduced into evidence as both Public

[17] In Moody's parlance FFO/Debt is called "preworking capital cash flow to debt" (Tr. vol. 9, 115), or "CFO pre-WC to debt." Both FFO and CFO pre-WC mean the same thing and are a measure of cash flow. *Id.*

Staff Cross-Examination Morin Direct and Rebuttal Exhibit No. 15 and DEP Redirect Newlin Direct Exhibit 2). Tr. Ex. vol. 10. In the updated Credit Opinion, Moody's explicitly referenced as factor that could lead to a downgrade the FFO/Debt ratio "remaining below 21% in 2023." DEP Redirect Newlin Rebuttal Ex. 1, 2; *see also* Tr. vol. 23, 36-37. Accordingly, Moody's not only alluded to its raised download threshold, but pointedly referenced 2023 – this very year.

The potential for downgrade is not a theoretical issue. The actions by Moody's beginning with its sector outlook publication in November 2022, running through its April 2023 raising of DEP's downgrade threshold, and culminating with its May 2023 updated DEP Credit Opinion are a series of escalating warnings.

Witness Newlin noted in his testimony that to ensure reliable and cost-effective service, and to fulfill its obligations to serve customers, DEP must continuously plan and execute major capital projects, and must be able to operate and maintain its business without interruption and refinance maturing debt on time, regardless of financial market conditions, even (and perhaps especially) in times of market volatility. Tr. vol. 9, 102. Customers benefit from DEP's financial strength, because its strong investment-grade credit ratings provide DEP with greater access to the capital markets on reasonable terms during such periods of volatility. *Id.* Responding to questions from Chair Mitchell, witness Newlin recounted a recent example of market dislocation, resulting from the collapse of Silicon Valley Bank, in which other Duke Energy subsidiaries were able to time entry into the market for the benefit of their customers, and he noted that only a "utility with good strong credit quality is able to do that." Tr. vol. 22, 207. He similarly alluded to market dislocation at the initial stages of the COVID-19 pandemic when Duke utilities were able to flexibly maintain market access when other utilities were unable to access the credit markets. *Id.* at 208. And widening credit spreads between higher- and lower-rated utilities mean that downgrade will have cost consequences for customers even if DEP were able to achieve access to the capital markets. *Id.* at 205; tr. vol. 23, 45-48.

Witness Newlin likened the flexibility derived from DEP's existing strong investment grade credit ratings as "a form of insurance against downgrades that will be the likely consequence of weakening the Company's financials," and noted that "downgrades only work to the detriment of DEP and its customers." Tr. vol. 22, 201 (emphasis in original). He cautioned against the Commission's taking action to weaken this insurance policy, "perhaps with unintended consequences." *Id.* The Commission heeds this warning, and the escalating series of warnings from Moody's, and finds that now is decidedly not the time to weaken DEP's credit profile and invite a credit downgrade. DEP must attract capital on reasonable terms in order to finance investment needed for the continued reliability of the system. Weakening DEP's capital structure or awarding too-low an ROE will make attraction of necessary capital that much more difficult – and certainly more expensive.

Accordingly, the Commission accepts witness Newlin's recommendation that DEP's capital structure be composed of 53.0% equity and 47.0% long term debt.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 52-56

COVID Deferral

The evidence supporting these findings of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Bowman, Quick, Abernathy, Speros (together as a panel), and Jiggetts, Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

Deferral Docket

In August of 2020, DEP and DEC (together, Duke) jointly petitioned the Commission for approval of orders for regulatory accounting purposes authorizing both Companies to establish a regulatory asset to account for incremental costs resulting from the unprecedented COVID-19 Pandemic and declared State of Emergency, so that such costs can be deferred pending further action by the Commission in the next general rate case filed by DEP and DEC. Joint Petition of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC for Approval of Accounting Orders to Defer Incremental COVID-19 Expenses, Docket Nos. E-2, Sub 1258 and E-7, Sub 1241 (August 7, 2020) (Covid Deferral Docket). DEC and DEP each requested permission to create a regulatory asset to defer costs associated with customer fees waived, bad debt expenses, employee stipends and safety-related costs, remote work costs, and other costs, including overtime and related call center costs.

The Public Staff filed comments the Covid Deferral Docket opposing Duke's request, arguing among other things that Duke had not substantiated a need for a deferral of the costs enumerated and recommending the Commission deny the request. Further, the Public Staff stated that if the Commission allowed Duke to defer costs, Duke should offset such costs with COVID-related savings such as federal tax credits and reductions in operating expenses.

The Commission granted the request to defer incremental costs and waived customer fees associated with the COVID-19 Pandemic for recovery in a future proceeding in its December 21, 2021 Order Approving Deferral Request (Deferral Order), in Docket Nos. E-2, Sub 1258, E-7, Sub 1241. The Commission noted the unique nature of the request, the severity of the ongoing pandemic, and the fact that many of the actions taken by the Companies were in part due to government mandates imposed upon Duke intended to ease both the financial and public health impacts of the pandemic on North Carolina and its citizens who might likely have been displaced from their homes. Deferral Order at 13.

The Commission determined that it would be patently unfair to penalize Duke by not allowing an opportunity to justify recovery of these costs in a future rate case and the Commission concluded that the costs allowed to be recovered may be amortized over a period of time determined in the future rate cases.

Although the Commission allowed Duke to include carrying costs on the deferred amounts for accounting purposes, the Commission concluded that the rate of that return, if any, and the amount to which that return is applied will be subject to determination in that future rate case.

Summary of Evidence

DEP Direct and Supplemental Testimony

In the present proceeding, DEP now seeks recovery of its deferred incremental COVID-related costs. In her direct testimony, DEP witness Jiggetts presented DEP's request. Witness Jiggetts explained that DEP deferred and requests to recover: (1) customer fees waived, (2) bad debt charge-offs, (3) employee stipends to cover unplanned expenses associated with the COVID pandemic, (4) costs related to employee safety, (5) costs related to remote work, and (6) miscellaneous costs, such as employee overtime. Tr. vol. 13, 197-99. Witness Jiggetts maintained that the costs included in the deferral are reasonable and prudent costs that were incurred as DEP provided its essential public service during the pandemic. *Id.* at 199.

In her direct testimony, DEP witness Quick explained the efforts DEP undertook to support its customers throughout the pandemic and the return to normal billing practices. Tr. vol. 7, 81-83. Witness Quick explained that DEP suspended service disconnections and waived fees for card payments, walk-in pay location payments, late payment charges, and insufficient funds. *Id.* at 81. Witness Quick also detailed how DEP worked with assistance agencies and customers on an individual basis to connect qualifying customers with assistance funding where possible. *Id.* Witness Quick described DEP's expanded outreach campaign efforts and, in particular, detailed the ways in which DEP adapted its customer operations resources to provide a more tailored experience for customers and utility assistance agencies. *Id.* at 82.

DEP witness Speros testified in support of DEP's bad debt calculation. Tr. vol. 13, 51-52. Witness Speros explained that the moratorium on disconnections and late payment fees led to an increase in the number and amounts of past due accounts outstanding, which in turn lead to increased bad debt expense. *Id.* Witness Speros testified that the deferred bad debt expense was calculated as the total amount of incremental bad debt expense exceeding the amount already being recovered in base rates from the period starting in March 2020 through the capital cut-off date in this case. *Id.* at 52. Witness Speros also explained that DEP is continuing to incur impacts to business operations from the pandemic, namely that charge-offs related to COVID delinquencies are ongoing and will continue to be. *Id.* at 53.

Witness Jiggetts explained that DEP's additional deferred expenses include employee safety-related costs, costs for remote work, employee stipends, and other miscellaneous costs. Tr. vol. 13, 197. She explained that because DEP is an essential service provider, it was not an option for some of DEP's employees to remote work. Witness Jiggetts further explained that DEP provided, and will continue to provide,

employees with the appropriate personal protective equipment, and incurred additional incremental costs for increased cleaning and sanitation supplies, health care, as well as for testing and temperature checks. *Id.* at 198. For those employees who could work from home, witness Jiggetts testified that DEP incurred additional costs for remote work, including costs for expanded conference line capacity, increased network bandwidth, other required information technology improvements, expanded video conferencing licenses, and increased company cellular telephone and data usage. *Id.* at 198-99. Lastly, for certain eligible employees, witness Jiggetts stated that DEP provided a one-time cash payment of $1,500 to help with unplanned expenses associated with COVID-19. Witness Jiggetts also clarified that DEP seeks to recover other expenses related to overtime costs needed to implement COVID-19 guidelines to ensure employee safety and increased costs due to expected increased call volume at call centers when normal billing practices resume. *Id.* at 199.

Witness Jiggetts testified that the proposed new rates requested in this proceeding include recovery of costs deferred from March 2020 through April 2023, and that the adjustment normalizes revenues for waived late fees that will be collected going forward, amortizes the deferred costs over a three-year period, adjusts test year expenses to include certain incremental employee costs that were previously deferred and includes the deferral balance, net of one year of amortization and deferred taxes, in rate base. *Id.* In her third supplemental direct testimony, witness Jiggetts updated DEP's amortization amount for the COVID deferral to include actual amounts realized through March 31, 2023.[18] Tr. vol. 13, 247.

The Public Staff Direct and Supplemental Testimony

In their direct testimony, Public Staff witnesses Zhang and Boswell recommended that the Commission adjust DEP's revenue requirement to remove DEP's proposed COVID deferral due to significant questions regarding the eligibility, accuracy, and reasonable quantification of the costs included in the deferral and the savings and cost offsets DEP chose not to net against the COVID expenses. Tr. vol. 19, 65. Witnesses Zhang and Boswell commented that during their review of several major O&M expenses they found COVID-related cost savings in employee expenses and printing which were not netted again the deferred COVID costs. They stated that DEP was offsetting these savings against reduction in customer load, unfavorable weather, and excess storm costs, none of which were the causation of the savings. *Id.* at 66.

Witnesses Zhang and Boswell noted that DEP received the following credits and delayed payments as a result of the pandemic: (1) Employee Retention Credit (ERC); (2) delayed payment of employer portion of social security tax; and (3) Accelerated Alternative Minimum Tax (AMT). *Id.* at 67. The witnesses explained that Section 2301 of the federal CARES Act created a refundable ERC of up to $5,000 per eligible employee taken against the employer's share of the Social Security Tax on Qualified Wages paid from March 13, 2020, through December 31, 2020. *Id.* Witnesses Zhang and Boswell

[18] See fn. 2.

further stated that the CARES Act amended Title 26 of the Internal Revenue Code to allow the entire AMT credit carryforwards to be refundable to taxpayers in either the 2018 or 2019 tax year. Witnesses Zhang and Boswell noted that DEP reported that the AMT credits were generated by non-regulated operations of Duke Energy and, as such, were not attributable to DEP. *Id.* at 68.

Witnesses Zhang and Boswell testified that DEP is unable to provide any and all costs savings associated with the pandemic; thus, the Public Staff cannot calculate an appropriate amount for deferral. Additionally, the witnesses expressed concerns regarding the types of charges deferred reiterating the same concerns the Public Staff expressed in its comments filed in the Deferral Docket. *Id.* at 69. With regard to the employee stipends, witnesses Zhang and Boswell testified that this one-time payment, does not appear to include a verification by DEP as to the expenses paid, and constitutes goodwill to some employees on the part of DEP, not a cost that should be borne by ratepayers. *Id.*

Witnesses Zhang and Boswell rebutted DEP's assertion that its call center costs have increased, instead testifying that based on the Public Staff's review of the call center volumes and labor costs, including overtime, over the last five years, the volume and costs has been steady, with costs and volume declining in 2021 and 2022. *Id.* at 69. They testified, concerning costs for remote work, that while DEP incurred some additional costs with the initial rollout, remote work is now part of DEP's regular work offerings, and DEP has not offset any of these increased costs with associated decreases in office expenses. The witnesses removed the costs associated with safety personal protection equipment because DEP indicated that the amount included in the original filing will not be an ongoing amount. *Id.* at 71. Witnesses Zhang and Boswell also removed the overtime for the call center as their review indicated the level sought by DEP was not above the amounts already included in DEP's cost of service. *Id.* They also expressed concern regarding the reserve percentage DEP is utilizing to estimate its bad debt expense because DEP is still collecting a portion of the uncollectible amount through various collection agencies. *Id.* at 70.

In their supplemental and settlement testimony, Public Staff witnesses Zhang and Boswell again recommended removal of DEP's COVID deferral from the revenue requirement and updated their recommended removal amount to account for amounts included by DEP through February 28, 2023. *Id.* at 89. The witnesses again reiterated that the Public Staff opposes DEP's recovery of its deferred expenses because it did not net its COVID-related cost savings against the actual costs incurred. *Id.* at 93.

DEP Rebuttal Testimony

On rebuttal, DEP's COVID Panel, consisting of witnesses Bowman, Quick, Abernathy, and Speros, all testified to provide further detail and context for DEP's pandemic response and COVID-related costs incurred. Tr. vol. 21, 1263-64. The Panel stated that the vast majority of the deferred costs DEP seeks to recover result directly from customer inability to pay and the governmental response to that inability to pay. They

explained that non-payment ordinarily would have been met by discontinuance of service, but actions both of the Governor of North Carolina and the Commission removed service disconnection as an option for DEP. *Id.* at 1264.

Witness Bowman detailed DEP's initial and ongoing response as an essential service provider. Witness Bowman explained DEP's actions in response to federal, State, and Commission direction, including Governor Cooper's executive orders and the Commission's moratorium on disconnections. *Id.* at 1266-67. Witness Bowman also provided a brief background on the Deferral Docket and the Commission's Deferral Order, which approved DEP and DEC's request to establish a regulatory asset for the purposes of deferring the incremental costs associated with the COVID-19 pandemic for final determination in a future rate case. *Id.* at 1268. She stated that the Deferral Order also required DEP to periodically file reports to update the Commission concerning the actual amounts deferred. *Id.* DEP witness Quick details the ways in which DEP adapted its customer support operations to serve the unique needs of customers associated with the pandemic. *Id.* at 1272-76.

DEP witness Abernathy included in her portion of the prefiled COVID Panel rebuttal testimony a chart detailing the deferred costs as of March 17, 2023, the date DEP's second supplemental testimony was filed:

Deferred Incremental COVID-19 Costs	**$ in Millions**	**% of total**
Customer fees waived	$27.1	29.1%
Bad debt expense	$57.3	61.6%
Employee safety related costs	$4.0	4.3%
Costs for remote work	$0.6	0.7%
Employee stipends	$0.7	0.8%
Other (primarily call center costs)	$3.3	3.5%
Total Incremental COVID-19 Costs deferred	$93.0	100.0%
Accrued carrying costs	$12.0	
COVID Deferral projected balance as of rates effective	$105.0	

Id. at 1280.

According to DEP, the requested $105.0 million in deferred incremental COVID-related costs translates to approximately 124 basis points, excluding any impacts from lost revenues. *Id.* Witness Abernathy testified that as of the filing of the third supplemental testimony (April 18, 2023) the projected balance as of the date rates would go in effect had grown to approximately $107 million, mainly because of an increase in the amount of bad debt expense. *Id.* at 1307. She commented that the spike in bad debt expense occurred in connection with the expiration in March 2023 of 12-month repayment plans DEP automatically enrolled customers into as of the time (March 2022) when the extended winter moratorium on disconnection finally ended. *Id.* at 1353.

Witness Abernathy explained that over 90% of the deferred costs are attributable to waived customer fees and bad debt expenses. She notes that these incremental costs were primarily the result of government-issued moratoriums imposed on DEP. *Id.* at 1282. Witness Quick explained that DEP waived approximately $27 million in customer fees, launched extensive outreach campaigns to bring awareness to the available customer assistance, expanded the eligibility for the Winter Moratorium and extended its length. *Id.* at 1272-73. The COVID Panel testified that the remaining categories of expense are also clearly pandemic-related, in that they were incurred in order for DEP, as a provider of an essential service, to fulfill its obligation to continue operation 24 hours a day, seven days a week despite the pandemic. Witness Bowman stated that more than 40% of DEP's workforce had to show up, in person, at work, at power plants and other facilities, or to repair damage following storms. *Id.* at 1319. She noted that in doing so those employees had to be furnished with protective gear, cleaning supplies, sanitizing supplies, and COVID testing services and nursing case management. Further, witness Bowman testified that DEP installed barriers at the workstations located at various operating plants so employees would not transmit the coronavirus. *Id.* at 1321. Witness Abernathy stated that these costs are captured in the category "employee safety related costs." *Id.* at 1281.

The COVID Panel testified regarding the challenges faced by DEP's customer service representatives, who ordinarily would work in call centers but had to transform themselves essentially overnight into a virtual workforce working from their homes – homes that in large measure were not set up with home-office facilities – while simultaneously dealing with childcare and other family-related issues exacerbated by the pandemic. They noted that costs associated with these challenges are captured in the employee stipends, which were distributed to hourly-paid call center employees costs related to the pandemic such as increased childcare, home-office equipment, and home internet access.[19] *Id.* at 1282, 1325-26. They explained that the stipends served as an inexpensive means of retaining essential employees, as witness Quick noted, "to try to keep them and help them through this unprecedented time that we were all going through … just a way of really supporting our hourly employees at the call center." *Id.* at 1326. The COVID Panel testified that DEP also incurred costs related to remote work generally, such as expanded conference line capacity, increased network bandwidth, other required information technology improvements, expanded video conferencing licenses, and increased company cellular telephone and data usage. *Id.* at 1281-82.

Regarding regulatory treatment of COVID-19 costs in other jurisdictions, the COVID Panel testified that as of the time the reply comments were filed in the Deferral Docket (November 30, 2020) commissions in 32 states and the District of Columbia had permitted cost deferral in response to requests from regulated utilities subject to their jurisdiction. They stated that since then, several state commissions have begun to allow recovery of deferred costs. They noted that the Georgia Public Service Commission

[19] Call center-related costs are also captured in the "call center" category, which relates to incremental increases in workload and the need to retain outside vendors as the centers began to "return to normal" following the easing of the shutdown moratoriums. Tr. vol. 21, 1277-79.

recently permitted recovery of approximately $25 million in deferred COVID-related costs over a three-year amortization period.[20] *Id.* at 1270.

In response to the Public Staff's testimony that DEP's request for cost recovery of incremental deferred COVID-related costs should be denied because DEP has not offset these costs with COVID savings, the COVID Panel testified that the Deferral Order requires only that DEP track the costs being deferred. The Panel did note that in South Carolina DEP was required to track and report quarterly both COVID-19 related savings and net lost revenues (NLRs) on a South Carolina retail basis in 2020. *Id.* at 1288. The Panel stated that because of this South Carolina requirement, DEP has tracked incremental savings due to COVID and provided these amounts to the Public Staff. They explained that DEP's estimates included two categories of expenses that resulted in financial savings attributable to the COVID-19 pandemic. First, DEP experienced reduced employee expenses as compared to budget, primarily related to reductions or elimination of travel and expenses associated with normal operations while DEP's employees were required to work remotely and adhere to travel restrictions, etc. Second, DEP experienced reduced printing and postage costs while the various government-imposed moratoriums were in place and DEP was not disconnecting customers and thus not mailing required notifications. *Id.* at 1289.

The COVID Panel stated that in 2020, DEP estimated approximately $4.5 million, on a North Carolina retail basis, in O&M expense savings attributable to COVID-19. DEP estimated NLRs in 2020 to be approximately $28 million, on a North Carolina retail basis, compared to budget, more than offsetting the savings reductions that the Public Staff suggests. *Id.* The COVID Panel maintained that the negative impact of NLRs was ignored by the Public Staff in its testimony.

The Covid Panel also addressed the assistance provided by the federal CARES Act. With respect to the accelerated AMT, the COVID Panel maintain that the Public Staff's argument that this credit should impact the COVID-19 deferral is simply incorrect as "not a single dollar of the AMT refunds is attributable to DEP; rather, the refunds all relate to other subsidiaries of Duke Energy Corporation". *Id.* at 1291. Regarding the delay in payment of the social security tax for the period April through December 2020, the COVID Panel noted that this was only a temporary deferral from the government and was fully paid by December 31, 2022. *Id.* They stated that although the Public Staff believes that DEP should have offset the COVID deferral for the working capital impacts of the delay in payment, witnesses Boswell and Zhang did not provide a quantification of their estimate of that amount. The COVID Panel estimates that the carrying cost benefit between April 2020 and December 2022 was approximately $2 million on a North Carolina Retail basis. *Id.* Related to the ERC, the COVID Panel stated that DEP filed for ERCs under the CARES Act and that all claims have been filed attributable to its operations from March 13, 2020, through September 30, 2021. The COVID Panel contended that even if these

[20] See Order Adopting Settlement Agreement as Modified, Docket No. 44280 (December 20, 2022); see also Direct Testimony of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson, Docket No. 44280, at 46-47 (June 24, 2022).

benefits to DEP (excluding the AMT which is not a benefit attributable to DEP) should be netted against costs, they should in that case also be netted against NLRs. The Panel maintained that these benefits do not overcome NLRs even when added to the $4.5 million DEP estimates is COVID-related savings. *Id.* at 1292.

Witness Abernathy maintained that the Public Staff's recommendation is one-sided and asymmetrical in its focus on DEP's apparent savings but omits any discussion of NLRs. *Id.* at 1271. Witness Abernathy explained that in 2020, DEP faced challenges in addition to the pandemic, such as mild weather that also resulted in substantially lower than projected revenues. She also testified concerning increased expense due to higher-than-normal storm restoration costs. Witness Abernathy testified that when faced with the prospect of revenue loss and in keeping with its focus on managing O&M expenses for the benefit of customers, DEP, as a routine part of its business, identifies and implements a suite of cost mitigation measures. *Id.* at 1271.

Witness Abernathy testified that total O&M cost reductions for 2020 amounted to $62 million on a North Carolina retail basis. *Id.* at 1295. She further testified that revenue impacts from COVID and mild weather amounted to $71 million on a North Carolina retail basis, and when added to an additional impact ($14 million) related to storm costs, the total is $85 million, an amount that was not contested by any party. *Id.* at 1294-95. Witness Abernathy then observed that "revenue impacts plus storm costs on the one hand, and the cost savings on the other, are opposite sides of the same coin – but, as shown by my illustration, the reduced revenues and storm impacts ($85 million) outstrip cost savings ($62 million) by a significant amount – approximately $23 million." *Id.* at 1295.

In response to the Public Staff's testimony regarding incremental call center costs, the DEP COVID Panel explained that, although average workload hours decreased during the Commission-ordered disconnection (Q2 and Q3 2020), DEP could not capture the potential savings associated with reduced workload during this timeframe in light of the uncertainty of when DEP would return to normal, making it such that reducing staffing would not have been prudent; and its view that reducing staffing in the short term, only to have to restaff a few months later, would not have been cost-effective. DEP witness Quick clarified that while overall call volume declined in 2021 and 2022, the average handling time per call increased as DEP's customers experienced changing needs following the return to normal. *Id.* at 1276.

Witness Abernathy also testified regarding the various invoices and ledgers DEP provided the Public Staff of its COVID-related expenses and savings. *Id.* at 1284-86. She described in detail the data DEP provided in response to the Public Staff data requests and in support of its COVID cost recovery request. *Id.* Witness Abernathy stated that the Public Staff did not dispute the actual amounts of the costs deferred and requested for recovery. *Id.* at 1286-87. She noted that for bad debt expense, the Public Staff only expressed concerns with DEP's calculation and the reserve percentages used.

Witness Speros provided additional testimony in support of DEP's bad debt expense and calculation. Witness Speros testified to the process that DEP undertook to

develop the reserve percentages, explaining that the reserve percentages are calculated by taking the net charge-off amounts divided by the aged receivable balance utilizing the historical data from 2018 and 2019. *Id.* at 1297. Witness Speros explained that DEP reviews the aging schedules and works with various internal teams to determine if there are any unusual changes or fluctuations in collections and write-offs that could impact the reserve calculation, and that based on these reviews, DEP determines if the balance in the loss reserve is reasonable as stated or if an adjustment is required. Witness Speros also testified that DEP compiles quarterly data on aged receivables, the balance of the loss reserve, and the current write-offs compared to forecast are then summarized and discussed with management. *Id.* at 1298. Witness Speros also clarified how customers on payment plans are treated for purposes of charge-off accounting. *Id.* He stated that customers on payment plans are actively working with DEP and are therefore viewed as having less risk of charging off than the typical delinquent customer. He noted that consistent data is available related to payment plans and a more accurate assessment can be taken by looking at the trends of customer defaults on their payment plans. Witness Speros explained that the percentage is calculated using the dollars defaulted on payment plans divided by total dollars of payment plans. *Id.*

Witness Abernathy testified that DEP has proposed to continue the deferral of bad debt expense until the next rate case. She stated that if the reserve percentages used to calculate bad debt expense do not result in actual charge offs, this will be reflected in future bad debt expense. *Id.* at 1286. Therefore, the continuation of the deferral should resolve any Public Staff concerns about the correct percentages to use. She noted that if the Commission does not approve continuation of the bad debt expense deferral, then test year bad debt expense should be increased by approximately $42 million to reflect a current level of bad debt expense using 2022 actual expense. *Id.* at 1286-87.

Testimony Presented at the Expert Witness Hearing

At the expert witness hearing, Public Staff witnesses Zhang and Boswell responded to questions on cross-examination and from Commissioners about their recommendation to disallow all COVID-related expenses included in DEP's deferral. Witness Boswell testified that part of the reason why the Public Staff removed the expense was because it could not determine what level should be included. Tr. vol. 19, 139. Public Staff witness Boswell stated that the Public Staff struggled to receive information from DEP and that underlying the difference of opinion between the Public Staff and DEP is the respective views on COVID savings. *Id.* Witness Boswell further stated that it is unreasonable to offset COVID-related savings against other costs, such as storm and weather costs, as DEP has proposed. *Id.* at 140. In response to a hypothetical question on deferral approval from Commissioner Duffley, witness Boswell testified that an appropriate amortization period would be around ten or fifteen years, akin to storm recovery, instead of the three years proposed by DEP. *Id.* at 141.

The COVID Panel also responded to questions from Commissioners related to DEP's deferral request. Witness Abernathy began by providing the final amount of the requested deferral in this proceeding – $107 million through DEP's third supplemental

update. Tr. vol. 21, 1307. Witness Speros explained that DEP has a structured and well-documented approach for tracking its COVID-related impacts, and further clarified that DEP's bad debt expense consists of two components: actual charge-offs, and a reserve adjustment based on the level of accounts receivable. *Id.* at 1310-11. Witness Abernathy explained DEP's methodology for the quantification of net lost revenues but reiterates that DEP has not requested recovery for lost revenues, *Id.* at 1316, 1343, and witness Bowman provided testimony related to the costs incurred in order for DEP to continue to operate as an essential service provider. *Id.* at 1319. Witness Bowman explained that 40% of DEP's workforce had to continue work as before, even in light of potential nonpayment due to the disconnection moratorium in place at the time, and that in no instance did DEP stop providing its services. *Id.* at 1319-20. Witness Bowman further testified that this period extended from March of 2020 until August of 2022. *Id.* at 1321. Witness Bowman explained that this continuation of service came at a cost to DEP as it ensured safety protocols were in place and followed and procured adequate protective gear for DEP's employees. *Id.*

Concerning the amortization period of the deferred costs, witness Bowman indicated its preference for a shorter amortization period stating DEP's preference for a three-year amortization but stated that DEP would likely be willing to slightly extend the recovery period. She testified that, if extended, DEP would prefer the amortization period be in a three-year increment, such as six years, to keep in sync with the MYRP. *Id.* at 1327.

Public Staff witness Boswell testified that "the Company meticulously … [accounted for] the costs associated with COVID." Tr., vol. 19, 161. Witness Boswell further testified that, while the Public Staff would have liked to provide the Commission with a recommendation on recovery of COVID costs, "[t]ruthfully … we couldn't determine what level should be put in there." *Id.* at 138. Witness Boswell noted that the Public Staff had issued numerous data requests and participated in several teleconferences with DEP seeking to formulate a recommendation. *Id.* She stated that "…since we couldn't come to a number, we thought it was just wiser to remove [the deferred COVID costs] altogether than to put a range for which that we didn't fully have support for." *Id.*

Witnesses Abernathy and Speros addressed the "savings" issue directly. Witness Speros noted that while costs can be (and were) directly tracked, the negative is not true – "savings" are not directly trackable; rather, they must be discerned through data analysis, namely by comparing actual expenditures with budgeted expenditures to get a sense of what DEP did not spend versus what it thought it would spend. Tr. vol. 21, 1345. He stated that at that point, the analyst can make a judgment based upon the type of expense and whether it is COVID-related. *Id.* Witness Abernathy confirmed that is precisely what DEP did to determine that the employee expense and printing/postage reductions discussed in her testimony, in fact, directly related to the pandemic. *Id.* at 1346. The witnesses maintained there is no reason that the Public Staff could not go through the same exercise, had it chosen to do so. They noted that the Public Staff had the data including "[a]nalysis of comprehensive actuals vs. budget information by O&M for function for 2020 (PS DR 138)" and that data was even supplemented outside of the formal discovery process. DEP Redirect COVID Panel Rebuttal Ex. 1, Tr. Ex. vol. 21. When

asked by Chair Mitchell if the Public Staff used any of this data provided by DEP to estimate COVID savings, witness Abernathy responded, "[n]o, they have not." *Id.* at 1350.

Concerning DEP's request to continue the COVID deferral for bad debt expenses, witness Abernathy testified (and her testimony is uncontradicted) that were the Commission to side with the Public Staff and refuse cost recovery and continued deferral, test year bad debt expense in this case would increase by approximately $42 million, increasing the revenue requirement in this case by that amount, an amount which no party to this proceeding has challenged. *Id.* at 1354-55; Tr. vol. 22, 13. Witness Abernathy testified that the revenue requirement associated with recovery of the deferred costs in this case is $41 million. Tr. vol. 21, 1307. She maintained that, not only is DEP's proposed approach the most reasonable and equitable, it is also the approach that results in the lower revenue requirement in this proceeding.

Further, as it relates to DEP's request for continuation of the COVID deferral, witness Quick explained that part of this request results from the payment plans that DEP offered at the expiration of the disconnection moratorium and the expansion of the Winter Moratorium. Tr. vol. 21, 1328-29. Witness Quick testified that this provided customers with flexibility and support to make disconnection a last resort. *Id.* at 1330. Witness Abernathy explained that this process has resulted in higher arrearages and testifies that DEP accordingly has not seen the completion or lack of completion of all the authorized payment plans, and therefore is unable to calculate an appropriate level of bad debt expense. *Id.*

Discussion and Conclusions

In the Deferral Order, the Commission expressly granted DEP's request that "estimated incremental costs of utility service that are proximately caused by the pandemic may be deferred pending a final determination on cost recovery in a future rate case," and also held that its decision was "without prejudice to the right of any party to take issue with the amount, if any, of the deferred costs to be allowed for ratemaking purposes, if such costs are included in future rate filings." Deferral Order at 13. Typically, the Commission's customary two-prong deferral test is applied in the context of a deferral request such that the nature of the costs and magnitude thereof need not be litigated in the subsequent cost recovery docket. The COVID deferral request was unique in the sense that the costs were unusually speculative, the length of time totally unknown, and the magnitude indefinite, leaving the Commission unable to evaluate the second prong in a meaningful manner in the COVID Deferral Docket. In its discretion, the Commission may in this proceeding undertake an analysis of the magnitude of the deferred COVID expenses that are now known and measurable, if the Commission determines such analysis is necessary in reaching its conclusion regarding cost recovery of COVID-related costs. The three main factors that the Commission generally finds relevant in its analysis of the second prong are: (1) the amount of the deferred costs; (2) DEP's earnings during the analogous timeframe; and (3) fairness and equity.

In prior deferral orders, the Commission has noted that it does not apply the two-prong test in a vacuum. Rather, the Commission considers all of the pertinent factors involved on a case-by-case basis and weighs the equities to arrive at a decision that is fair to the utility and its ratepayers, and that serves the public interest. The Commission may analyze the merits of deferral using not only the well-established two-prong test but also considering the totality of the underlying facts, circumstances, and equities of this case. In the case of the incremental COVID-related costs, the Commission determines that the two-prong test was met in that these costs are extraordinary in nature and, absent deferral, would have a material impact on the utility's financial condition. The Commission gives significant weight to DEP's calculation in this proceeding that the $105.0 million in deferred costs amount as of DEP's second supplemental filing would have a 124 basis point impact on earnings, excluding any impacts on lost revenues.

In this proceeding, the Public Staff noted that DEP has consistently achieved earnings in excess of its authorized ROE since before the COVID pandemic and maintained that DEP's earnings are a relevant factor for consideration in the Commission's decision concerning cost recovery. The Commission acknowledges that historically in assessing the appropriateness of cost-deferral requests, the Commission has based its decision, in large measure, on the impact that the costs would have on the level of earnings currently being achieved by DEP. The impact on earnings, typically, has been measured and assessed in terms of ROE, considered in conjunction with: 1) the ROEs realized and reported to the Commission in DEP's recent quarterly ES-1 reports, particularly the ROE reflected in DEP's most recent report; and 2) DEP's currently authorized ROE. In this proceeding, the Commission finds that the COVID pandemic was an unprecedented event – truly exceptional – much more so than unusually severe weather and other events for which costs have been allowed to be deferred in the past. In determining fairness and equity between customers and shareholders in this circumstance, the Commission must evaluate the totality of the situation.

The Commission recalls that during the state of emergency government officials were taking all necessary steps to slow the spread of the coronavirus by requiring people to social distance and stay at home to the greatest extent possible. The health and safety of North Carolina communities were affected by the efforts of all residents to stay home and socially distance to slow the spread of the coronavirus. Governmental actions were also implemented to help prevent hospitals from being overwhelmed with patients and to preserve human life. The seriousness of the circumstance was unprecedented. The Commission recognizes that it was crucial for DEP, as a provider of an essential service, to fulfill its obligation to its customers to continue operations 24 hours a day, seven days a week despite the pandemic. This vital requirement for DEP to continue to provide its customers essential electric utility service during this unprecedented event cannot be overemphasized. The Commission recognizes that DEP met its obligation to the Commission and the citizens of North Carolina. The Commission recognizes that for DEP to provide electric utility service to the citizens of North Carolina during the pandemic necessitated certain DEP employees to perform their job duties in the same manner as prior to the declaration of the state of emergency. As a result, many of DEP's employees

were not allowed the option to work from home to protect the health and safety of themselves and their families.

Government officials, including this Commission, sought to aid North Carolina citizens amidst a turbulent and challenging economic environment by issuing a state of emergency and various mandates and moratoriums. During the height of the turmoil caused by the pandemic, customers benefitted from the governmental mandates to waive customer fees and discontinue disconnections for non-payment. The pandemic lasted much longer than anyone anticipated. Businesses, families, and individuals benefitted from these mandates, particularly households that were struggling with financial issues resulting from the pandemic. Further, DEP, at this Commission's direction, provided customers with new, more favorable payment options and worked to connect eligible customers with available financial assistance from new and existing federal and state programs.

In reaching its decision concerning cost recovery of the incremental COVID-related expenses, the Commission sought to balance fairness and equity between customers and shareholders when: 1) determining the appropriate size or amount of the deferral for cost recovery in this proceeding; 2) applying the COVID-related savings; 3) determining whether a return should be allowed on the deferred costs during the deferral period and on the unamortized balance during the amortization period; 4) selecting the amortization period for cost recovery; and 5) deciding the timing of when amortization should begin.

In its examination of the deferred COVID-related costs for which to allow cost recovery, the Commission gives significant weight to the fact that the Public Staff, which extensively audited the deferred costs, did not find any of the costs to be unreasonable in amount and did not find that any of the costs were unrelated to the COVID-19 pandemic. As it did in the Deferral Docket, the Public Staff argues that COVID costs should be offset with COVID savings, and that, in its view, DEP has not adequately accounted for savings.

After careful consideration, the Commission concludes based upon the evidence presented that recovery in rates of DEP's deferred COVID-related costs pertaining to customer fees waived, bad debt expense, and employee safety related costs, are just and reasonable and should be approved. The Commission determines that it is appropriate to reduce these allowed costs by certain COVID-related expense savings for employee travel expenses, printing and postage costs, DEP's filed ERCs, and the carrying cost benefit of the delayed payment of the employer portion of social security tax. The Commission concludes that it is not appropriate to recover the carrying costs accrued during the deferral period or a return on the unamortized balance during the amortization period. Further, the Commission determines a six-year amortization beginning when rates become effective for this proceeding is appropriate. The Commission sets forth its reasons for these conclusions below.

Regarding the amount of costs deferred, DEP witness Abernathy testified that as of the filing of the Third Supplemental Testimony filed on April 18, 2023, the projected balance of deferred incremental COVID-19 costs as of the date rates would go in effect increased to

approximately $107 million, mainly because of an increase in the amount of bad debt expense that occurred in connection with the expiration in March 2023 of 12-month repayment plans DEP automatically enrolled customers into as of the time (March 2022) when the extended winter moratorium on disconnection finally ended. The Commission acknowledges that no party has challenged the expenses for which DEP now seeks recovery pursuant to the Deferral Order were COVID-related expenses. Instead, the fundamental disagreements between DEP and the Public Staff are: (1) whether certain deferred COVID expenses are appropriate for recovery from ratepayers; (2) whether the deferred COVID expenses should be offset by certain savings, benefits, credits, and overearnings; and (3) whether a return on the deferred costs during the deferral period and on the unamortized balance during the amortization period should be allowed.

The Commission notes that as indicated in the chart above provided by witness Abernathy, over 90% of the deferred costs were incurred from waived customer fees and bad debt expense. The Commission concludes that these two costs resulted directly from governmental action, including mandates from the Commission, and are appropriate for recovery from customers. Specifically, at the onset of the COVID-19 pandemic the Governor issued a proclamation of a state of emergency (Executive Order No. 116), and subsequent orders of the Governor and of the Commission imposed a moratorium upon DEP's ability to disconnect customers for nonpayment and required waiver of customer fees ordinarily imposed in connection with nonpayment, such as late fees, reconnection fees, and return check charges. As a consequence of these governmental actions, DEP was unable to use its customary tools to timely collect payments from customers. DEP's ability to charge certain customer fees such as late fees, reconnection fees, and returned check charges encourage customers to pay their monthly bills. Disconnection of electric service is a strong incentive for the customers to pay their bills timely. The DEP COVID Panel testified that the moratorium on disconnections and the suspension of late fees had an adverse impact on the level of bad debt expense in that DEP realized an increase in the number of past due accounts that ultimately caused a significant increase in bad debt expense.

In this proceeding DEP seeks to recover only the difference between the level of bad debt expense currently in rates and the amount of bad debt expense above that level resulting from actions taken during the pandemic. The Commission acknowledges that denial of the recovery of deferred waived customer fees and bad debt expense would deny DEP recovery of costs incurred for complying with Executive and Commission Orders. DEP was expected to continue to provide normal, uninterrupted electric service 24 hours per day, seven days a week, to all customers during this unprecedented event. Moreover, DEP was expected to continue to provide service to its customers who were not paying for such service for an extended period of time. The Commission concludes that these costs are reasonable for recovery from customers.

With respect to employee safety related costs, the Commission acknowledges that DEP incurred costs to provide its employees with the appropriate personal protective equipment to facilitate the continuation of work for customers in a safe manner. Additionally, DEP incurred incremental costs associated with cleaning supplies, health

care, as well as testing and temperature checks. As previously noted, to provide essential electric service, many of DEP's employees were not allowed the option to work from home. DEP witnesses testified that more than 40% of DEP's workforce had to show up, in person, at work, at power plants and other facilities, or to repair damage following storms. The Commission concludes that those employees had to be furnished with protective gear, cleaning/sanitizing supplies, and COVID testing services and nursing case management. Thus, the Commission concludes that these costs are reasonable and prudent costs to recover from customers.

Regarding the costs of remote work, in order to facilitate employees working remotely to protect their health and safety during the pandemic, DEP incurred incremental costs associated with expanded conference line capacity, increased network bandwidth, other required information technology improvements, expanded video conferencing licenses, and increased company cellular telephone and data usage. The Commission recognizes that many other businesses and state agencies in North Carolina were able to shift to fully or nearly full remote work to respond to the Governor's state of emergency and also incurred similar incremental costs to accommodate employees working remotely. The Commission notes that in the post-state of emergency work environment, remote work offerings continue either fully or on a hybrid basis for many businesses, state agencies, and utilities, including DEP. The Commission determines that although the pandemic may have initiated this category of costs, these costs are now largely ongoing in nature and not specific to the pandemic. Moreover, DEP has not offset the deferred costs of remote work with the associated decreases in office expenses such as utilities, office supplies, and other miscellaneous expenses related to employees working from the office. Thus, the Commission concludes that it would not be appropriate to recover the deferred costs of remote work from customers.

DEP provided certain eligible employees a one-time cash payment of $1,500 to help with unplanned expenses associated with COVID-19. DEP testified that the stipends were appropriate to support employees in providing service to customers and to avoid turnover and should be allowed as reasonable and prudent costs. The COVID Panel contended that DEP did not require expense verification associated with the employee stipends to avoid the extra administrative cost of reviewing receipts and validating usage by the employees that received the stipend. The Commission concludes that the one-time $1,500 stipends provided voluntarily by DEP to certain hourly employees should be considered voluntary goodwill and should not be recovered from customers. Usage of the stipends was not verified by DEP and that employees were free to spend the funds as they pleased, without oversight, and thus the Commission determines they should be excluded from cost recovery of deferred COVID expenses.

DEP witness Jiggetts testified that the other category of deferred costs includes overtime to implement COVID-19 guidelines to ensure employee safety and increased costs due to expected increased call volume at call centers when normal billing practices resume. Public Staff witnesses Boswell and Zhang contended that expenses associated with call center overtime should not be included in the ongoing COVID deferral given that the amount sought by DEP for call center overtime was not above the amounts already

included in DEP's cost of service. The Commission is persuaded that, because the amount sought by DEP for call center overtime was not above the amount already included in DEP's cost of service, these costs should not be recovered from customers.

Regarding COVID-related cost savings, the COVID Panel contends that the Deferral Order required only that DEP track the costs being deferred, but that nonetheless DEP was required to track and report COVID savings (specifically, reduced employee expenses such as reductions or elimination of travel and expenses associated with normal operations while employees were required to work remotely and adhere to travel restrictions, and reduced printing and postage costs) and NLRs on a South Carolina retail basis for 2020 and therefore did, and provided to the Public Staff, the incremental COVID savings and NLRs at a system level to which it applied allocation factors to derive the South Carolina retail amounts. According to the COVID Panel, DEP's COVID savings were largely realized in 2020 in the amount of approximately $4.5 million on a North Carolina retail basis, while DEP estimated the NLRs related to reduced load and demand in 2020 to have been approximately $28 million on a North Carolina retail basis, thereby more than offsetting the savings reductions that the Public Staff suggests.

Although not presented in filed testimony, in its proposed order the Public Staff maintained that a portion of the O&M savings DEP experienced in 2020 and 2021 – which includes any savings experienced by DEP related to remote work, and reduced expenses in employee travel, printing, and postage – should offset the deferred COVID costs DEP is now seeking to recover. The Public Staff contended that, with few exceptions, DEP stated it did not track how the O&M savings were derived, thus, there is no amount that the Public Staff could definitively identify as strictly COVID-related savings. In light of this, the Public Staff recommended that 50% of DEP's total non-fuel O&M savings in 2020 and 2021 should be offset against the deferred COVID costs sought for recovery. The Commission notes that in its proposed order, the Public Staff also recommended disallowance of the employee stipends and the increased call center costs but did not specifically object to cost recovery of any other category of DEP's deferred COVID-related costs.

The Commission acknowledges that DEP is not requesting rate recovery of the NLRs related to the COVID pandemic. Witness Bateman testified that DEP made a conscious decision not to request deferral of NLRs in the COVID Docket. Witness Bateman further testified that DEP did what it always does when faced with the prospect of lower than budget revenues, DEP absorbs revenue impacts through O&M savings. Witness Bowman explained that when faced with the prospect of revenue loss, DEP as a routine part of its business and in keeping with its focus on managing O&M cost for the benefit of customers, identifies and implements a suite of cost mitigation measures. Witness Abernathy testified that further complicating the picture in 2020, the prospect of revenue loss arose not only from the pandemic but also from mild weather. She noted that DEP responded to twin threats to its revenue stream, both the pandemic and mild weather, by instituting cost efficiency measures, which she described in detail. She testified that none of these "belt tightening measures" were included in the deferred costs. Witness Abernathy maintained that DEP did everything that it could to reduce costs and,

as a result, avoided the need to request a deferral of the NLRs. However, DEP was not able to offset both the incremental costs due to COVID-19, and the other unfavorable impacts in 2020, including the NLRs due to COVID. The end result is that deferral of incremental COVID-19 costs was required and requested, and the Commission gave its approval to that deferral. Witness Abernathy contends that none of the cost savings measures discussed above have been – or should be – used to offset the COVID-19 related incremental costs.

When asked by the Public Staff to identify the COVID-related savings, witness Abernathy testified that two categories of savings were identified: 1) reduced employee expense related to reduction in or elimination of travel, and 2) reduced printing and postage costs as a result of the disconnect moratoriums ordered by the Commission. The Commission concludes that these cost savings identified by DEP which were directly attributable to the pandemic should offset the amount of deferred COVID-related expenses. DEP witness Speros noted that while COVID-related costs can be and were directly tracked, the negative is not true – "savings" are not directly trackable; rather, they must be discerned through data analysis, namely by comparing actual expenditures with budgeted expenditures to get a sense of what DEP did not spend versus what it thought it would spend. He stated that the analyst can make a judgment based upon the type of expense as whether it COVID-related. Witness Abernathy confirmed that is precisely what DEP did to determine that the employee expense and printing/postage reductions were, in fact, directly related to the pandemic.

The Commission determines that the issue of COVID-related cost savings is intertwined with the issue cost savings resulting from the mitigation measures taken by DEP to address NLR. Furthermore, various events occurring in 2020 are entwined in the analysis - COVID, mild weather, and storm restoration costs. On the one hand, in its proposed order the Public Staff indicated there was no amount that the Public Staff could definitively identify as strictly COVID-related savings; thus, the Public Staff recommended that 50% of DEP's total non-fuel O&M savings in 2020 and 2021 should be offset against the deferred COVID costs sought for recovery. On the other hand, DEP, through witness Abernathy's testimony, maintained that none of DEP's cost saving measures to mitigate NLRs should be used to offset the incremental COVID-related costs. Witness Abernathy also maintained that savings related to the federal government assistance for which DEP filed ERCs and was granted a carrying cost benefit related to the delayed payment of the employer portion of social security tax. The Commission concludes that these measures taken by the federal government to assist companies and employers in weathering the impacts of the pandemic should inure to the benefit of customers. To balance the fairness and equity between customers and shareholders related to the COVID-19 pandemic and, in part, because the amount of COVID-related savings cannot be definitively identified, the Commission did not approve all deferred COVID-related expenses for cost recovery from customers. The Commission notes DEP's position on savings and the difficulties associated with calculating savings that are directly attributable to the pandemic. However, the Commission determines that the two types of savings identified by witness Abernathy are directly related to the pandemic and that the measures taken by the federal government to assist companies and employers during the pandemic which provided

benefits to DEP, directly relate to the pandemic. For these reasons, the Commission concludes that these costs should be netted against deferred COVID-related costs. In reaching this conclusion, the Commission gives weight to the testimony of witness Abernathy that expense savings resulting from DEP's normal cost mitigation measures to offset revenue shortfalls related to mild weather and in this case, the pandemic, should not be used to offset COVID-related expenses.

The Commission declines to approve DEP's request to recover approximately $12 million in accrued carrying costs on the deferred costs or to authorize a return on the unamortized balance of the COVID costs during the amortization period. In reaching this decision, the Commission is conscious of the fairness and equity factors inherently at play in considering how to appropriately balance the difficulties experienced by both the utility and ratepayers throughout the pandemic. DEP contends that inasmuch as the deferred costs are by definition not already in rates and were fronted by DEP's investors, the costs properly bear a return at DEP's weighted average cost of capital so as to ensure that DEP and its investors are made whole. The Public Staff recommends denial of any return on the allowed deferred expenses stating that interest has already been accounted for in the $27 million late payment fees of the deferred expenses at issue in this proceeding, and to allow an additional return would unfairly allow DEP to collect interest upon interest.

Taking into consideration the hardships caused by the pandemic on the residents and businesses in North Carolina, DEP's earnings reported in its E.S.-1 Report during the deferral period which were at or above the utility's authorized rate of return, and the totality of the hardships suffered by customers during the pandemic, the Commission concludes that the approximately $12 million included in DEP's request related to accrued carrying costs on the deferred costs or a return on the unamortized balance during the amortization period should not be recovered from customers through rates.

The Commission concludes that it is appropriate that cost recovery for the approved deferred COVID-related costs occur over a six-year amortization period. Due to the material amount of COVID-related costs approved for recovery, the Commission finds that the three-year amortization period requested by DEP would be burdensome for customers. The 12-year amortization period advocated by the Public Staff in its proposed order is unreasonably long in light of the Commission's decision herein to not allow carrying charges on the deferred costs. The Commission has customarily used a five-year amortization period for recovery of costs from customers for extraordinary events like storms. However, at the expert witness hearing, the COVID Panel stated DEP's preference that the amortization period be in a three-year increment, such as six years, to keep in sync with the MYRP. Thus, the Commission determines that a six-year amortization period reasonably balances the impacts to both DEP's customers and its shareholders.

The Commission determines that amortization of the deferred COVID-related costs should begin upon the effective date of new rates in this proceeding.

Regarding DEP's request to continue its deferral for incremental bad debt expense, the Commission determines that since DEP is still incurring incremental bad debt expense, it is appropriate for DEP to continue to defer those costs incurred after March 31, 2023. The Commission concludes that DEP's request to continue the deferral of the incremental bad debt, for future recovery, is just and reasonable, and should be approved. The Commission acknowledges the positions taken by the Public Staff in its proposed order related to this issue and agrees with the Public Staff's recommendation that any payments associated with the deferred bad debts should be credited on a monthly basis through the next general rate case but declines to accept the Public Staff's other recommendations related to call center overtime costs or an ongoing overearnings analysis during the deferral period. Thus, the Commission concludes that DEP should credit on a monthly basis through the next general rate case any payments associated with the deferred bad debts.

Finally, the Commission notes that its decision on deferral of the COVID-related costs is based on the particular facts of this case, and in particular, the unprecedented circumstances related to the pandemic, and should not be cited or relied on as precedent for future cost deferral decisions. The Commission evaluated the totality of the pandemic, taking into consideration the governmental mandates which removed DEP's tools to control bad debt expense, the necessity for DEP to provide uninterrupted electric service during the duration of the pandemic – even when many customers were not paying their bills, the benefit to customers and North Carolina as a whole of the governmental mandates, and DEP's financial standing as reported in its quarterly E.S.-1 Reports to the Commission for the duration of the deferral period. Considering all these factors and the entire evidence of record, the Commission concludes that its decision set forth herein is the most reasonable, fair, and equitable outcome for both customers and shareholders with respect to the COVID-19 pandemic.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 57

Inflation Adjustment

The evidence supporting this finding of fact is found in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witness Jiggetts and Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

Summary of Evidence

DEP Direct and Supplemental Testimony

DEP, through witness Jiggetts' direct testimony and exhibits, adjusted its annual non-labor and non-fuel O&M costs to reflect the increase in costs during the test period that occurred due to inflation. *See* Tr. vol. 13, 185. In supplemental direct testimony, witness Jiggetts testified that this inflation adjustment was updated to reflect inflation factors through December 31, 2022, and to remove the impact of the gains/losses on the sale of by-products. *Id.* at 222-23. This inflation adjustment factor was subsequently

updated in Jiggetts' second and third supplemental direct testimony, *Id.* at 232, 243, and finally in Settlement Testimony to arrive at a rate of 12.13%. Jiggetts Partial Settlement Ex. 4 at 109, Tr. Ex. vol. 14.

The Public Staff Testimony

Public Staff witnesses Zhang and Boswell recommend that the Commission adjust DEP's inflation factor to reflect a five-year average inflation rate through December 31, 2022. Tr. vol. 19, 44. Witnesses Zhang and Boswell further recommend that the inflation adjustment be modified to reflect the Public Staff's recommended adjustments removing aviation expenses, Board of Directors expenses, uncollectibles, and sponsorships and donations. *Id*. In supplemental testimony, witnesses Zhang and Boswell applied their recommended inflation adjustment to actuals through February 2023 to reflect the 61-month average recommended by the Public Staff. *Id.* at 90. Witnesses Zhang and Boswell testified that the increasing inflation rates seen in 2021 and early 2022 have already begun to decrease and that DEP's 2021 expenses already reflect some portions of the increase in costs due to inflation. *Id.* at 44-45. They further testified that the Public Staff does not find it appropriate to calculate ongoing rates for a minimum of the next three years based on years in which inflation was abnormally high. *Id.* at 45.

DEP Rebuttal Testimony

In rebuttal, DEP witness Jiggetts opposed the Public Staff's recommended adjustment. Tr. vol. 23, 93-97. Jiggetts testified that DEP's proposal does not project inflation of O&M expenses, but instead accounts for the impacts of inflation that have already been incurred from the test period to the end of the update period. *Id.* at 94. Witness Jiggetts further testified to DEP's methodology for calculating an inflation factor, stating that it has not changed from previous rate cases. *Id.* Witness Jiggetts testified that the Public Staff's assertion that any non-payroll O&M expenses updated beyond December 2021 would include impacts related to inflation is incorrect, and she explained that any O&M expenses that are updated through pro forma adjustments are excluded from the inflation adjustment. *Id.* at 94-95. Witness Jiggetts cited data from the U.S. Bureau of Labor Statistics that shows a continual upward trend for all inflation metrics. *Id.* at 96. Further, witness Jiggetts testified that while DEP disagrees with the Public Staff's adjustments removing certain expenses related to aviation, sponsorships, donations, lobbying, and Board of Directors expenses, DEP agrees that it would be appropriate to adjust the total O&M subject to inflation for that amount, to the extent that there are adjustments made to those expenses. *Id.* at 97.

Testimony Presented at the Expert Witness Hearing

At the hearing, witness Jiggetts testified to DEP's recommended inflation rate factor of 12.13%. Tr. vol. 13, 302. Witness Jiggetts explained that DEP uses a 13-month average to calculate its inflation factor, consistent with its methodology in the previous rate case. *Id.* at 302-03. She further explained that, in calculating the inflation factor, DEP is looking at the actual level of inflation, as reported by the U.S. Bureau of Labor Statistics,

through the March 31, 2023 cutoff date. *Id.* at 302. She testified that DEP compares that level of inflation to the costs actually incurred during the test year by looking at the 13-month average of the Bureau of Labor Statistics' data. *Id.* at 302-03. Using this approach, witness Jiggetts explained that inflation has increased to 12.13% through the March 31, 2023, cutoff period. *Id.*

Witness Jiggetts clarified that the test year used in the adjustment is historical, rather than prospective, and that the purpose of the adjustment is to adjust test year expenses to account for inflation as of the March 31 cutoff period. *Id.* at 304. Witness Jiggetts explained that DEP does not project inflation rates or factors. *Id.* at 304. Instead, the test year expenses are adjusted for known and measurable changes through the March 31 cutoff period. *Id.* at 303.

Public Staff witness Zhang testified that the Public Staff calculated its recommended inflation adjustment by averaging the inflation rate over the 61-month period from January 2018 through January 2023. Tr. vol. 19, 116-17. Witness Zhang further testified that averaging the inflation rate over that 61-month period with the average inflation of the consumer producer price index's published inflation resulted in a 61-month average inflation factor of 4.31%. *Id.* at 117. In response to cross examination by DEP, witness Boswell testified that she could not state for certain if the Public Staff's methodology had previously been used in any electric utility rate case. *Id.* at 128.

Discussion and Conclusions

The Commission concludes, based upon the evidence presented, that the rate factor adjustment proposed by DEP is just and reasonable. The Commission declines to adopt the 61-month average method advocated by the Public Staff and notes that per DEP's Late-Filed Exhibit No. 13, the Public Staff has previously proposed the same method that DEP employed in this proceeding. The Commission determines that the adjustment proposed by DEP, at 12.13%, captures actual inflation during the test period updated through March 31, 2023, in substantially the same manner that DEP has historically employed.

Specifically, the inflation adjustment (Adjustment No. NC2110 in witness Jiggetts' schedules) annualizes test period O&M expenses, excluding fuel, purchased power, and labor and benefit costs to reflect the change in test period costs through the March 31, 2023 cutoff date by an actually-experienced inflation factor. The adjustment captures actual inflation during this period in the same manner used in at least DEP's last seven general rate cases. DEP Late-Filed Ex. No. 13. As witness Jiggetts testified, DEP has proposed and the Commission has approved rates that were calculated using the method of determining the inflation adjustment used by DEP in this proceeding for many years, in all kinds of inflationary environments. While the Commission recognizes that, as the Public Staff points out, the period of time during which the updated test year occurred was coincident with unprecedented times, including the pandemic, the Commission is concerned that a departure from historical practice on this issue is not warranted, as adjusting for "known and measurable changes" is consistent with N.C.G.S. § 62-133(c)

and produces the just and reasonable result of putting DEP in a position of recovering its costs, and is fair to DEP and to customers regardless of the inflationary environment.

Upon consideration of all the evidence in this proceeding, the Commission concludes that DEP's proposed inflation adjustment to test year non-fuel and non-labor O&M costs is consistent with past practice, consistent with statutory law, derived using a method that is fair to customers and to the utility regardless of the inflationary environment, and is approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 58-60

Rate Case Expense

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the testimony and exhibits of DEP witnesses Jiggetts and Bateman; Public Staff witnesses Zhang and Boswell, and the Public Staff's cross exhibits of witness Jiggetts; and the entire record in this proceeding.

Witness Jiggetts testified that, in the current proceeding, DEP has included adjustment NC5020 related to rate case costs, amortizes over a three-year period the incremental rate case costs incurred and projected to be incurred for this docket, as well as costs incurred after the cut-off in the last rate case which have not yet been brought forth for recovery. Her testimony explained that over amortizations associated with rate case costs approved in Docket Nos. E-2, Subs 1023 and 1142 and severance costs approved in the 2019 Rate Case were used to offset the amount requested for recovery in this case. Tr. vol. 13, 176, 194.

With respect to costs associated with the 2019 Rate Case, witness Jiggetts explained that in the first partial settlement in the 2019 Rate Case (2019 First Partial Settlement), entered into by DEP and the Public Staff on June 20, 2020, DEP and the Public Staff settled on an agreed amount of rate case expense that would be recovered from customers. Tr. vol. 13, 332. She explained that the amount of rate case expense was estimated, at that time, to be $3.5 million, which represented the sum of actual expense incurred through February 2020 and estimated to be incurred through August 2020. Tr. vol. 13, 312. Witness Jiggetts testified that the projection of costs through August 2020 was based upon past, normal experience that DEP would have had with a rate case proceeding.

In response to a question from Commissioner Duffley, witness Jiggetts testified that DEP seeks to recover rate case costs in this case which exceed those agreed to in the 2019 First Partial Settlement with respect to rate case expense related to the instant proceeding, Witness Jiggetts updated adjustment NC5020 in her supplemental direct testimony and third supplemental direct testimony to reflect actual rate case expense amounts incurred by DEP. *Id.* at 224, 247.

Witness Jiggetts testified that over-amortizations associated with rate case expenses approved in Subs 1023 and 1142 and severance costs approved in the 2019 Rate Case were used to offset the amount requested for recovery in this case. Tr. vol. 13, 194. She testified that DEP requests that the remaining balance to be amortized over the three-year period. Tr. vol. 23, 78.

Public Staff witnesses Zhang and Boswell explained that they removed: 1) DEP's adjustment to include additional rate case expenses from the 2019 Rate Case that exceed the amount agreed to in the 2019 First Partial Settlement 2) the adjustment to include the unamortized portion of rate case expense in rate base; and 3) DEP's inclusion of over-amortized regulatory assets to offset rate case expense. Regarding the additional costs from the 2019 Rate Case, witnesses Zhang and Boswell testified that the 2019 First Partial Settlement reflected an agreed-upon amount for 2019 Rate Case expenses, and that this amount was ultimately incorporated into the revenue requirement approved by the 2019 Rate Case. As such, the Public Staff asserted that it is inappropriate to include 2019 Rate Case costs beyond those included in the Commission-approved revenue requirement from a general rate case that has been closed, and in which DEP did not request that additional costs be considered before the Commission issued its final order. Tr. vol. 19, 56-57.

Regarding DEP's adjustment to include the unamortized balance of rate case expense in rate base, witnesses Zhang and Boswell testified that the amortization of rate case expense should reflect a normalization of the costs associated with the filing of a rate case, based on an average of the number of years between rate case filings. In this case, witnesses Zhang and Boswell stated that rate case expense does not rise to the level of being extraordinary in nature and, as such, does not require rate base treatment. As with other over-amortizations in this proceeding, witnesses Zhang and Boswell asserted that the over-amortized amounts from the rate case expense and severance costs should be flowed back to ratepayers as a one-year rider and not used to offset other amounts. Tr. vol. 19, 57-58.

In her rebuttal testimony, witness Jiggetts asserted that DEP is not precluded from collecting additional amounts incurred from the 2019 Rate Case based on the 2019 First Partial Settlement. In her view, the 2019 First Partial Settlement does not contain any language capping rate case costs at a maximum amount or prohibiting DEP from asking for additional reasonably and prudently incurred actual expenses in a future rate case. While the amounts agreed to in the 2019 First Partial Settlement were based upon information available at the time the agreement was reached, witness Jiggetts stated that DEP's costs were ultimately higher as the proceedings for that case were delayed and extended, for reasons which could not have been foreseen, and that the Public Staff has made no assertion or forecasted any evidence showing that the additional 2019 Rate Case expenses were not reasonably and prudently incurred. Tr. vol. 23, 79-81.

Rejecting the Public Staff's recommendation that the unamortized rate case costs for this proceeding be removed from rate base, witness Jiggetts explained that DEP's investors have advanced the funds to cover these reasonably and prudently incurred

utility costs and, as such, DEP should be allowed to earn a return on this asset to reflect the earnings expected from its investors during the amortization period. Tr. vol. 23, 81-82.

At the expert witness hearing, witness Jiggetts testified that, to the best of her knowledge, DEP did not provide updates of its 2019 Rate Case expenses through May 2020 as the second settlement would have allowed, and that she was not aware of DEP's having requested to recover these amounts during the 2019 Rate Case expert witness hearing or at any point prior to the filing of this proceeding. Tr. vol. 13, 311-18.

Although not presented in prefiled testimony, in is proposed order, the Public Staff provided additional context concerning various events that occurred during the 2019 Rate Case related to the issue of rate case expense. On June 2, 2020, DEP and the Public Staff filed the First Settlement, in which DEP and the Public Staff agreed that certain rate case expenses as set forth in DEP's rebuttal testimony could be recovered (not in rate base) and that these expenses would be amortized over a five-year period. In DEP witness Kim Smith's testimony supporting the 2019 First Partial Settlement, she describes the settled issues (including rate case expense) as "resolve[d] . . . without the necessity of contentious litigation." 2019 Rate Case, Tr. vol. 14, 260. On July 31, 2020, DEP and the Public Staff filed the second partial settlement, in which the two parties agreed that DEP's updates covering expenses through May 31, 2020 (filed on July 2, 2020), could be included for recovery (pending and subject to the Public Staff's audit thereof), up to 75% of the difference (should the difference result in an increase in the revenue requirement) between DEP's February 2020 costs and May 2020 updates in recognition of the uncertainty regarding the effects of COVID. However, in its July 2, 2020 filing, which updated expenses through May 2020, DEP did not seek recovery of any additional rate case expenses. In addition, the Public Staff notes that the expert witness hearing for the 2019 Rate Case took place in August 2020, but the issue of recovery of 2019 Rate Case expense beyond that provided for in DEP's rebuttal testimony does not appear to have been raised to the Commission during the hearing, in DEP's proposed order, or in any other form during the pendency of the 2019 Rate Case.

According to the Public Staff, DEP had a reasonable opportunity in the 2019 Rate Case to come forth with additional rate case expenses, and it failed to do so. If DEP believed there were 2019 Rate Case expenses outside the confines of the 2019 Settlement Agreements, DEP should have raised this issue at the 2019 Rate Case expert witness hearing and sought the Commission's guidance on how to preserve the issue, but it failed to do so. The Public Staff asserts that just because DEP's 2019 Rate Case expenses were ultimately higher than expected due to COVID does not mean that the entire category of 2019 Rate Case expenses were not encompassed in the settlement agreements. Instead, this was an aspect of settlement that DEP did not foresee. However, the Public Staff asserts that the fact that DEP did not foresee the impact of its agreements is not justification to depart from the terms therein or deprive customers of the benefit of the Public Staff's bargain.

In their second supplemental testimony filed on June 27, 2023, Public Staff witnesses Zhang and Boswell updated rate case expenses to reflect the actual rate case expense incurred through March 31, 2023, as reflected in DEP's third supplemental filing.

Discussion and Conclusions

The Commission must decide on three issues relating to rate case expense: (1) recovery of rate case expense from DEP's 2019 Rate Case, as well as the recovery of rate case expense from the current proceeding; (2) whether rate case expense should be reflected in the rate base; and (3) the amortization period over which the expense should be recovered. As discussed below the Commission concludes that (1) DEP's request to recover costs incurred from the 2019 Rate Case which are above and beyond those provided for in the 2019 Settlement Agreements is approved; (2) the unamortized balance of rate case expense should not be reflected in the rate base; and (3) the amortization period over which the rate case expense should be recovered is three years. The issue regarding whether over-amortizations associated with rate case costs approved in Sub 1023 and severance costs approved in the 2019 Rate Case should be used to offset the rate case expense in this proceeding is discussed in other portions of this Order.

The Commission notes that 2019 First Partial Settlement reflected a settlement on the sum of actual rate case expense incurred through February 2020 plus expenses estimated to be incurred through August 2020. The Commission also notes, as DEP witness Jiggetts testified, that DEP did not update its rate case expenses through May 2020, as the second partial settlement in the 2019 Rate Case allowed. However, the Commission also notes the unusual, perhaps unprecedented, trajectory of the 2019 Rate Case. Specifically, the first partial settlement was entered into on June 2, 2020, and the second settlement was entered into on July 31, 2020. The consolidated hearing for DEC and DEP was held in late August 2020. The separate hearing for DEP was held in late September to early October 2020. Between the consolidated hearing and the individual hearing, DEP worked to put interim rates into effect and notified customers of same. On December 11, 2020, the Supreme Court issued its order in *State ex rel. Utils. Comm'n v. Stein*, 375 N.C. 870, 851 S.E.2d 237 (Dec. 11, 2020), effectively remanding the issue of cost recovery for coal combustion residuals (CCRs) back to the Commission. Subsequent to issuance of that decision, DEP engaged in settlement discussions related to CCR cost recovery. On January 25, 2021, the Coal Combustion Residuals Settlement Agreement (CCR Agreement), to which DEP and the Public Staff were parties, was filed in the 2019 Rate Case docket. On February 12, 2021, the Commission issued an order in the 2019 Rate Case docket re-opening the record to accept into evidence supporting testimony filed by DEP and the Public Staff. On February 17, 2021, the Commission issued an order requiring DEP to respond to certain questions from the Commission regarding the CCR Agreement. The final order in the 2019 Rate Case was issued by the Commission on April 16, 2021. Subsequent to the issuance of the order, DEP worked to establish rates in compliance with the Commission's order, provide notice to its customers of new rates and put those rates into effect on June 1, 2021. The 2019 Rate Case, initiated by application

filed in August 2019 made by DEP, culminated with rates' taking effect on June 1, 2021. This timing was impacted by events outside of DEP's control, namely the pandemic and the issuance of the Stein order by the North Carolina Supreme Court. As summarized by DEP witness Jiggetts:

> The actual hearings, the consolidated hearings, I believe, happened at the end of August of 2020. We had interim rates that went into effect in September of 2020. The individual hearing for DEP happened, I believe, late September, early October of 2020. The CCR settlement was essentially reached in January of 2021. The Order in that case came out in April of 2021. And then new rates went into effect in June of 2021.
>
> During that time frame, obviously, we had additional discovery that required, you know, questions and responses. We had the prep and the times for the hearings. So all of that, kind of, bled into the costs being more than what we initially estimated at the time of settlement in June of 2020.

Tr. vol. 23, 118.

The Commission understands and respects the Public Staff's strongly held position that the settlement agreements entered into during the rate case should govern and that DEP should be held to the terms of these agreements in order for customers to receive the benefit of the Public Staff's bargain. In general, the Commission agrees with the Public Staff that parties must be held to their agreements made in settlement, particularly in the interest of encouraging future settlements. Nevertheless, the Commission concludes that it would be unreasonable to deny DEP recovery of expenses incurred in the context of the 2019 Rate Case that were not reflected in the 2019 First Partial Settlement The Public Staff asserts that DEP could have raised the issue rate case expense during the August 2020 expert witness hearing, but it is not clear to the Commission that DEP could have reasonably anticipated, at that time, the additional work that would be required in the 2019 Rate Case. Thus, DEP's request to recover costs incurred related to the 2019 Rate Case which are above and beyond those provided for in the 2019 First Partial Settlement is approved. Further, the Commission concludes that these additional rate case costs in the amount of $5.384 million as shown on Public Staff Accounting Second Supplemental Exhibit I, Schedule 3-1(t), Line 4, should be amortized over a three-year period.

Regarding rate case expense for this proceeding, the Commission concludes that it is reasonable and appropriate to allow DEP to recover total costs of $6.551 million as shown on Public Staff Accounting Second Supplemental Exhibit I, Schedule 3-1(t), Line 1. Tr. Ex. vol. 24. As previously stated, the issue regarding whether over-amortizations associated with rate case costs approved in Sub 1023 and severance costs approved in the 2019 Rate Case should be used to offset the rate case expense in this proceeding is discussed in other portions of this Order.

The Commission notes that DEP has projected additional rate case expense to be incurred through the date rates will be effective for this proceeding in the amount of $2.526

million as shown on Public Staff Accounting Second Supplemental Exhibit I, Schedule 3-1(t), Line 6, and has requested that the Commission allow DEP to track these costs for possible recovery in a future general rate case proceeding. Tr. Ex. vol. 24. The Commission determines that, in the ordinary course of ratemaking, the rate case expense amount to be recovered from customers should be established in the current general rate case proceeding and not re-evaluated in a future rate case for recovery from customers. Generally, it has been past practice for the Public Staff and the utility to work together to estimate an appropriate amount of rate case expense for approval by the Commission to reflect the activities occurring after the agreed-upon update cutoff date to the conclusion of the hearing or through the preparation of proposed orders. The Commission finds that this practice has been an efficient and reasonable process with respect to determining the appropriate amount of rate case expense to recover from customers. As previously discussed, the Commission's decision in this case to re-evaluate in this proceeding the 2019 Rate Case costs to be recovered in rates is an exception to the Commission's historic practice due to the unusual circumstances occurring during the 2019 Rate Case. Therefore, the Commission denies DEP's request to track and seek future recovery of rate case costs for the present proceeding above the amounts approved herein.

Concerning DEP's adjustment to include the unamortized portion of rate case expense in rate base, the Commission gives significant weight to the Public Staff's testimony stating that the amortization of rate case expense should reflect a normalization of the costs associated with the filing of a rate case, based on an average of the number of years between rate case filings. The Commission notes that the 2019 First Partial Settlement expressly provided that the unamortized balance of rate case expense would not be included in rate base. The Commission concludes that DEP's request to include the unamortized balance of rate case expense in rate base is denied.

Regarding the amortization period over which the current rate case expense of $6.551 million, as netted against a portion of the over-amortization of rate case expenses approved in Sub 1023, should be recovered, the Commission determines that the amortization period over which the rate case expense should be recovered is three years, as this aligns with the MYRP timeframe. Accordingly, the Commission finds and concludes that the three-year amortization period is just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 61

Over-Amortizations

The evidence supporting this finding of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witness Jiggetts, Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

Summary of Evidence

In its Application, DEP requested permission to apply expiring over-amortizations as an offset to the deferral balances of costs that DEP believed were similar in nature, but which may not yet have been approved by the Commission. The requested offsets include: (1) the

coal combustion residuals (CCR) asset retirement obligation; (2) rate case expenses; (3) application of the over-amortization of severance costs to rate case expenses; (4) application of the over-amortization of early retired coal plants to the Asheville early retired coal plant; (5) application of the over-amortization of Hurricane Matthew to the Winter Storm Izzy proposed deferral; and (6) regulatory fees. Tr. Ex. vol. 7.

DEP Direct Testimony

In direct testimony, DEP witness Jiggetts supported adjustment NC5010, which removes from Test Period costs the amortization of various regulatory assets or liabilities that have been approved by the Commission in previous general rate case proceedings. Tr. vol. 13, 194. Witness Jiggetts testified that the amortization period for the items removed will expire before proposed new rates are effective, and thus should not be included in Test Period expenses on which new rates are based. *Id.* Witness Jiggetts explained that over-amortizations of the regulatory assets and liabilities have been applied to like kind expense recovery in this case. *Id.* Witness Jiggetts testified that DEP intends to apply the over-amortization of the early retired plant regulatory assets against the Asheville Coal plant regulatory asset allowed in the 2019 Rate Case, as an example, and she also testified that over-amortization associated with rate case costs as approved in Docket Nos. E-2, Subs 1023 and 1142 and severance costs approved in the 2019 Rate Case were used to offset the amount requested for recovery in this case. *Id.*

The Public Staff Testimony

Public Staff witnesses Zhang and Boswell recommended that the Commission remove DEP's proposed over-amortization offsets and return the expiring amortizations to customers as single rider over a period of one year with interest. Tr. vol. 19, 73. Witnesses Zhang and Boswell stated that, due to the complexities involved with the associated adjustments, the Public Staff will work with DEP to verify appropriate accounting for the removal of the regulatory assets from the calculation of rate base and propose their inclusion in a rider in their supplemental filing. *Id.* Witnesses Zhang and Boswell explained that currently, regulatory assets are handled on a case-by-case basis, with the recovery period determined by the Commission based on the specifics of the item to be recovered. *Id.* They testified that by offsetting the expiring amortizations against continuing amortizations, DEP is overriding the Commission's approved terms for recovery of the individual regulatory assets. Thus, witnesses Zhang and Boswell testified that the Public Staff recommends returning the over-amortizations to ratepayers through a one-year rider with interest to allow for the refund to customers while maintaining the terms of the Commission's previous approvals of the remaining regulatory assets. *Id.*

DEP Rebuttal Testimony

In rebuttal, DEP witness Jiggetts described each of the expired amortizations that DEP is proposing to offset against like costs: (1) coal ash;[21] (2) rate case costs;

[21] The over-amortization of coal ash costs is separately addressed earlier in this Order.

(3) severance; (4) early retirement of coal plants; (5) Hurricane Matthew; and (6) regulatory fees. Tr. vol. 23, 101-04. Witness Jiggetts explained how DEP's proposed treatment of the expiring amortizations is consistent with the Commission's 2018 Order in the 2017 Rate Case. *Id.* at 100-01; Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, Docket No. E-2, Sub 1142 (February 23, 2018) at 224. She stated that in that order the Commission previously addressed continuing amortizations of expired regulatory assets and liabilities in the context of coal ash costs. Tr. vol 23, 100. She further stated that in that order the Commission concluded:

> With regard to DEP's CCR costs from 2018 forward, DEP witness Bateman testified that DEP is requesting to establish a regulatory asset/liability account and defer to this account the portion in annual rates that is more than DEP's actual costs, or the amount in annual rates that is less than DEP's actual costs. In essence, the asset/liability account would be a tool used to true-up the difference in DEP's next general rate case. The Commission agrees with DEP's recommended approach, not only for CCR costs, but also for all cost deferral accounts…. [T]he Company should continue to record all amounts recovered as deferred costs in the specific regulatory asset account established for those deferred costs until the Company's next general rate case.

Id. at 100-101.

Witness Jiggetts also disagreed with the Public Staff's assertion that by offsetting the expiring amortizations against continuing amortizations, DEP is overriding the Commission's approved terms for recovery of the individual assets. *Id.* at 100. Witness Jiggetts maintained that DEP has complied with the 2018 DEP Order and has continued the amortization of the expired regulatory assets and liabilities and, in the context of this rate case, is applying those over-amortizations to the deferral balances of costs that are similar in nature, in compliance with the Commission's order. *Id.* at 101.

Witness Jiggetts' also explained the impact upon rates should the Commission adopt DEP's proposed treatment. *Id.* at 104. Witness Jiggetts testified that DEP's approach reduces deferred balances being addressed in the current case, and thereby reduces the base rate revenue requirement, all the while protecting the customers from the rate volatility created by a significant one-year rider. *Id.*

Testimony Presented at the Expert Witness Hearing

At the expert witness hearing, DEP witness Jiggetts answered questions from the Commission regarding the process by which DEP analyzed the rate impact of its proposed treatment of over-amortizations. Tr. vol. 14, 22. Witness Jiggetts walked through DEP's proposal with regard to both coal ash and Winter Storm Izzy. *Id.* at 22-23. Witness Jiggetts explained how applying DEP's proposed treatment to coal ash over-amortizations provides customers a benefit of approximately $3 million. *Id.* at 23. Witness

Jiggetts testified that for - Hurricane Matthew, the over-amortization completely covers what DEP is requesting to defer for Winter Storm Izzy, which means customers would never have to pay for that balance. *Id.* at 23-24.

Discussion and Conclusions

Over-amortization occurs when amortization expense collected in rates (as established in a prior rate case) exceeds the associated regulatory asset or liability. DEP defers such over-amortizations, and the issue in this proceeding is how to utilize such over-amortizations to benefit customers. DEP proposes to apply the over-amortizations to recovery of like kind expenses. The Public Staff proposes to flow the over-amortizations back to customers through a one-year Regulatory Asset/Liability Rider (Rider RAL). The Commission has reviewed the evidence and considered the testimony of the witnesses and determines that, for purposes of this proceeding, it is reasonable and appropriate to offset some, but not all, of DEP's previously approved regulatory assets that have been over-amortized against other regulatory assets.

DEP witness Jiggetts testified that the Commission previously addressed continuing amortizations of expired regulatory assets and liabilities in the context of coal ash costs in the 2018 DEP Order and that DEP's proposal in this proceeding to apply over-amortizations to like kind expenses is consistent with that order. DEP contends that the Commission's conclusion in the 2018 DEP Order that the asset/liability account would be a tool used to account for and subsequently true-up in the next general rate case the difference between the actual amount in annual rates for regulatory assets/liabilities and DEP's actual costs is consistent with its proposal that over-amortizations should be used as a true-up tool with respect to like costs, to be ruled on by the Commission in DEP's next rate case. The Commission disagrees with DEP's interpretation that the 2018 DEP Order approved any sort of offsetting of amortizations between one set of costs that had been approved by the Commission and another set of costs which had not been approved by the Commission for deferral.

The Commission notes that in the 2018 DEP Order cited to by DEP, the Commission allowed DEP to record a specific amount of revenue for its CCR costs as of September 1, 2017, and onward in a deferral account until its next general rate case, with a five-year amortization period. The Commission also stated in the 2018 DEP Order that, if DEP receives revenue for any deferred cost authorized in the 2017 Rate Case proceeding for a longer period of time than the amortization period approved by the Commission for that deferred cost, DEP should continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until DEP's next general rate case. In other words, the Commission directed in its 2018 DEP Order that the asset/liability account utilized for CCR costs be used as a tool to true-up the difference between the portion in annual rates that is more than DEP's actual costs, or the amount in annual rates that is less than DEP's actual costs, in DEP's next general rate case.

The Commission has addressed over-amortizations directly in another docket. In its February 21, 2019 Order Approving Joint Partial Settlement Agreement and Stipulation, Granting Partial Rate Increase, and Requiring Customer Notice, *Application by Carolina Water Service, Inc., of North Carolina for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All of its Service Areas in North Carolina, Except Corolla Light and Monteray Shores Service Area*, No. W-354, Sub 360 (2019 CWSNC Order), the Commission ordered that federal unprotected EDIT funds (a regulatory liability) should be returned to ratepayers through a levelized rider and not be offset through the remaining unamortized portion of a regulatory asset (in this instance, the overcollection in rates of federal income taxes related to the decrease in the federal corporate income tax rate), as the utility suggested. In ordering as such, the Commission explained that:

> [O]ffsetting [a] known and measurable [liability] against either unknown future regulatory assets, or regulatory assets previously approved by the Commission for recovery over a specified period, presents significant intergenerational issues and constitutes inappropriate ratemaking. . . . [T]he amortization period for each regulatory asset is approved by the Commission based upon its determination of what is fair and reasonable for the ratepayers with regard to the costs associated with that specific regulatory asset, or other specific factors taken into consideration by the Commission at the time of that approval. The Commission finds that choosing to simply offset the new . . . liability with the remaining unamortized portion of any regulatory asset would effectively override the Commission's prior decision as to the appropriate amortization period for the regulatory asset, by equalizing the remaining amortization period and the amortization period for the new . . . regulatory liability. And as CWSNC witness DeStefano testified, he is not aware of a situation wherein the Commission has approved such offsetting treatment. . . .
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> [D]eparting from this transparent process in the course of a general rate case simply to offset flowing through the benefit of reductions in an entirely separate category of costs (income taxes) is neither fair nor reasonable. Further, the Commission notes that for customers, a rider will be separately identified on their bills so they can see in dollars and cents the impact of the federal unprotected EDIT flow through. This transparency would not occur with the offsetting proposed by DEP.

2019 CWSNC Order at 55-56. The Commission considered the two costs to be in "entirely separate categor[ies] of costs" such that offsetting one with the other was not justified.

In the proceeding now before us, the Commission examines whether offsetting expiring over-amortizations with new or existing regulatory assets or expenses is justified or in the best interests of ratepayers, when the nature of the two events is similar or the same. The Commission notes that the Public Staff did not present any Commission

precedent, statutory, or rule that over-amortizations must be flowed back to customers via a one-year rider. DEP argues that its proposed approach reduces deferred balances and thereby reduces the base rate revenue requirement which provides a longer-term benefit to customers than the Public Staff's proposed one-year rider. Further, the Commission gives significant weight to the potential implications of the Public Staff's one-year rider proposal upon DEP's credit metrics. As indicated in DEP LFE No. 10, "[g]iven the magnitude of the reduction in cash flow resulting from the Public Staff's proposed $37 million one-year rider, the accelerated flowback puts additional downward pressure upon DEP's already-stressed credit metrics – specifically, the ratio of Funds from Operations (which is essentially a measure of cash flow) to Debt (FFO/Debt). The downward pressure is all the more acute in light of Moody's very recent decision to increase the FFO/Debt downgrade threshold to 21% (up from 20%)."

The Commission finds that DEP's proposal makes intuitive sense in some specific instances because it applies the over-amortization to an actual, Commission-approved cost of the same nature as identified in the course of a general rate case rather than "returning" the over-amortization only to turn around and collect revenue from customers for costs of the same type. However, the Commission determines that similar to the approval of deferral requests, the manner in which to address the true-ups related to over-amortizations in the utility's next general rate case should be determined on a case-by-case basis based on the specific circumstances existing at the time. The Commission finds that, in this specific rate case, DEP's simpler approach to reduce regulatory assets approved by the Commission in this rate case with over-amortizations related to previously Commission-approved regulatory assets is reasonable and appropriate as follows:

a. The over-amortization of rate case expense from Docket No. E-2, Sub 1023 of $1,112,000 should be applied to the balance of rate case expense in the Commission's Order in the 2017 Rate Case $530,000, which will eliminate that balance. The remaining $582,000 of over-amortization should be applied against rate case costs being requested in this proceeding.

b. The over-amortization of early retired plant in the amount of $13.8 million should be applied against the outstanding rate base balance for the Asheville early retired coal plant authorized in the 2019 Rate Case.

c. The over-amortization of Hurricane Matthew costs from the 2017 Rate Case in the amount of $17 million should be treated as follows: First, to recover 2022 incremental Winter Storm Izzy costs of approximately $15 million, and second, the remaining $2 million credit should be refunded to customers through a one-year rider with interest.

Based on the circumstances in this proceeding, the Commission concludes this treatment is reasonable and appropriate because the Commission has carefully reviewed and selected specific "same type" regulatory assets for which the over-amortizations are being applied. The Commission is very clear that same type Commission-approved costs

are being offset by over-amortizations related to same type previously approved regulatory assets. The specific information related to the same type of regulatory assets/liabilities is set forth herein in a manner that is transparent both to the parties and to customers. The Commission concludes that the approved offsetting of over-amortizations reduces deferred balances being addressed in the current case, and thereby reduces the base rate revenue requirement, provides a longer-term impact on rates to customers, protects customers from the rate volatility created by a significant one-year rider, and addresses the potential unfavorable implications of the Public Staff's significant one-year rider proposal upon DEP's credit metrics.

The Commission denies DEP's proposal to apply the over-amortization of severance costs from the 2019 Rate Case in the amount of $907,000 against the rate case costs being requested in this proceeding because these are two entirely separate categories of costs and as such, offsetting one with the other is not justified. The Commission rejects DEP's argument that the offset should be approved because severance costs are labor related, and the rate case costs primarily consist of labor related dollars. The Commission also rejects DEP's proposal that the over-amortization of regulatory fees in the amount of $68,000 should be addressed in a future proceeding but instead finds the over-amortization should be addressed in the present rate case. Thus, the Commission concludes that the over-amortizations related to the regulatory fees, the severance costs, and the remaining $2 million credit from the Hurricane Matthew amortization that DEP proposed to be used to fund the initial balance in the Storm Balancing Account, should be returned to customers through a levelized rider over a one-year period with a return at the weighted average cost of capital.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 62-66

Winter Storm Izzy and Storm Balancing Account

The evidence supporting these findings of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witness Jiggetts and Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

Summary of Evidence

DEP Direct Testimony

DEP witness Jiggetts testified as to the incremental O&M costs incurred as a result of Winter Storm Izzy. Tr. vol. 13, 210. She testified that DEP experienced extraordinary storm costs in response to Winter Storm Izzy in January 2022, incurring approximately $23.8 million on a North Carolina retail jurisdictional basis. *Id.* at 211. Witness Jiggetts testified that these amounts are not finalized and that invoices would continue to be received, validated, and paid over the next several months. *Id.* DEP requested to defer the incremental O&M expenses related to Winter Storm Izzy, less approximately $11 million of "normal storm range expense" as that term was defined in the 2017 Rate Case for a total deferral in this proceeding of approximately $12.8 million. *Id.* Witness Jiggetts

testified that, without approval of this deferral request, DEP would face earnings degradation of approximately 35 basis points. *Id.* According to witness Jiggetts, approval of this request would benefit DEP and its customers by helping to ensure investors' confidence in DEP and to assure access to needed capital on reasonable terms and equitable treatment as to deferred costs and revenues. *Id.*

DEP witness Jiggetts also testified as to DEP's request for approval of a new methodology for tracking storm costs incurred. Tr. vol. 13, 212. Witness Jiggetts testified that the regulatory asset approved for Hurricane Matthew storm costs in the 2017 Rate Case was fully amortized as of September 2021, and per the Commission's order in that case, DEP has continued to record the amortization and has a regulatory liability on its books. *Id.* Witness Jiggetts testified that DEP is seeking to use this existing regulatory liability to create a "balancing account" for storm costs going forward, starting with DEP's request to apply the excess amortization from Hurricane Matthew to the deferred costs for Winter Storm Izzy. *Id.* Witness Jiggetts explained that, to this end, Adjustment NC7010 establishes an average amount of incremental storm costs included in customer rates. *Id.* Witness Jiggetts testified that under DEP's proposal, each year, if the incremental storm expenses are over the average amount in rates, the difference would be deferred to the account; if the incremental storm expenses are under the average amount in rates, the difference would be contributed to the account. She testified that if the average amount included in customer rates approximates the average amount of storm expense going forward, the balancing account balance should fluctuate around zero and not require additional funding. *Id.* She further stated that if the account does require additional funding, this could be evaluated in a future rate case or storm securitization proceeding. *Id.* at 212-13. Witness Jiggetts testified that the Storm Balancing Account would allow DEP to recover its actual costs for storm restoration efforts and ensure that DEP does not make or lose money related to its storm restoration efforts. *Id.* at 213.

DEP witness Jiggetts also testified as to how she calculated a storm normal expense amount of $17.8 million based upon a ten-year average of storm costs, after removing costs associated with major storms, to be included in rates consistent with prior Commission orders. Jiggetts Supplemental Ex. 4, Tr. Ex. vol. 14.

The Public Staff Direct Testimony

Public Staff witnesses Zhang and Boswell did not make an adjustment to DEP's storm normalization calculation. Public Staff Accounting Ex. 1, Tr. Ex. vol. 19.

Witnesses Zhang and Boswell disagreed that DEP should be permitted to defer costs associated with Winter Storm Izzy, stating that the Public Staff maintains its position as articulated in its initial comments filed on March 15, 2017, in the 2017 Rate Case and Docket No. E-2, Sub 1131, that it is appropriate and reasonable that DEP only be allowed to defer the difference between its actual incremental O&M expense related to Winter Storm Izzy and a normal amount of $27.4 million on a North Carolina retail jurisdictional basis. Tr. vol. 19, 54. In light of the fact that DEP had, at the time it filed its Application in this proceeding, estimated the costs of Winter Storm Izzy to be approximately $23.8

million on a North Carolina retail jurisdictional basis, the Public Staff stated that the costs associated with this storm would not qualify for a deferral. *Id.* The Public Staff explained that, merely because the storm costs incurred in a given year are greater than $11 million (the normalized level from a prior rate case), it cannot simply be assumed that the larger expense is extraordinary in magnitude and therefore suitable for deferral. *Id.* Witnesses Zhang and Boswell stated that actual storm expenses included in the ten-year average spanned a wide range of annual amounts, from a storm amount as low as $4,901 to as high as $461.974 million, and, as such, at least $27.4 million should be considered an appropriate level of normal storm expense for purposes of consideration of DEP's $23.8 million in deferral costs. *Id.* at 54-55. In the event that the costs associated with Winter Storm Izzy exceed the $27.4 million North Carolina retail amount, the Public Staff suggested that DEP may file for a deferral or securitization, whichever is most beneficial to ratepayers. *Id.*

Additionally, the Public Staff did not agree with DEP's proposal to create a storm balancing account and stated that creating such an account would only serve to transfer all risk from DEP to ratepayers, including placing unaudited costs into a deferral for recovery. *Id.* at 53. The Public Staff stated that DEP already has ample opportunities to recover storm costs, whether that be through storm normalization, securitization, or deferrals, all of which may allow DEP to reasonably and appropriately recover actual audited storm costs. *Id.*

DEP Rebuttal Testimony

DEP witness Jiggetts testified on rebuttal that the Public Staff accurately summarizes DEP's intent in proposing the storm balancing account. Tr. vol. 23, 83. Witness Jiggetts explained that the Commission should implement a mechanism that results in DEP's neither making nor losing money because of storm restoration efforts. *Id.* Witness Jiggetts responded to the Public Staff's assertion that the storm balancing account would transfer risks from the utility to ratepayers and would include unaudited costs for recovery. *Id.* at 83-84. Witness Jiggetts testified that the base level of storm expense that must be exceeded before DEP can request deferral, as established in the 2017 Rate Case, has in practice been inequitable to DEP as the base level of storm expense is greater than the amount of storm normal expense included in base rates, which results in that difference being borne by shareholders. *Id.* at 84. Witness Jiggetts explained that when DEP's linemen repair and replace damaged lines and equipment after a storm event, the outcome is the restoration of utility service for DEP's customers. *Id.* Witness Jiggetts stated that it is DEP's position that these storm restoration expenses are a cost of service of the regulated utility that are reasonably and prudently incurred and should be recovered from customers. *Id.*

Witness Jiggetts also responded to the Public Staff's second assertion and explained that the deferral of the amounts to the balancing account does not preclude those amounts from being subject to audit or review by the Public Staff or the Commission. *Id.* at 86. Witness Jiggetts testified that deferrals, by their nature, are unaudited amounts when initially recorded, but that when the amounts in the balancing account are put forth for recovery or

return to customers in a future case or securitization, the activity and related balance will be subject to audit for reasonableness and prudency. *Id.*

In her third and final supplemental testimony, witness Jiggetts updated the storm normalization calculation to $22.2 million. Jiggetts Supplemental Ex. 4, Tr. Ex. vol. 14. In its exhibits to settlement testimony, the Public Staff similarly utilized $22.2 million for DEP's storm normalization calculation. Public Staff Accounting Ex. 1, Tr. Ex. vol. 19.

The Public Staff Supplemental and Settlement Testimony

In its supplemental and settlement testimony, the Public Staff testified that, based upon the updated numbers provided in witness Jiggetts' supplemental filings with regard to the costs of Winter Storm Izzy and other 2022 storms, it recommends that the costs incurred for Winter Storm Izzy be recovered through securitization. Tr. vol. 19, 91.

Testimony Presented at the Expert Witness Hearing

At the expert witness hearing, DEP witness Jiggetts explained the methodology for the calculation of storm normalization of $22.2 million in this case and testified that the Public Staff agreed with her storm normalization calculation. Tr. vol. 14, 29-30; 57-58.

Public Staff witnesses Zhang and Boswell explained at the expert witness hearing that, while the costs contained in DEP's initial filing did not rise to the level of warranting deferral, DEP's inclusion in a supplemental filing of costs associated with Hurricane Ian – when viewed together with Winter Storm Izzy costs – met the threshold warranting deferral or securitization of the costs. Tr. vol. 19, 150-51.

At the expert witness hearing, DEP witness Jiggetts described the mechanics of DEP's proposal for a storm balancing account and how it is accomplished using a visual aid. DEP Redirect Jiggetts Direct and Settlement Ex. 2, Tr. Ex. vol. 14. Witness Jiggetts explained how the exhibit shows that in Year 1 DEP experienced $25.65 million in storm restoration costs (apart from major storms where costs would ordinarily be deferred or securitized). Subtracting that amount from "storm normal" ($22.2 million) leaves an under-recovery of $3.45 million, which is deferred to the Storm Balancing Account, meaning that at its inception in this example, the account is a Regulatory Asset. In Year 2, however, DEP experiences only $10.15 million in storm restoration costs. After accounting for the existing balance in the account ($3.45 million) and Year 2's "storm normal" (again, $22.2 million), the balance in the account has now shifted to a Regulatory Liability of $8.6 million – that is, over the two year period in the example, DEP collected "storm normal" costs in rates amounting to $44.4 million, and experienced restoration costs associated with "normal" storms of $35.8 million, leaving a balance in the account of $8.6 million in favor of customers.

Witness Jiggetts clarified that the initial building block for the storm balancing account is the calculation of the storm normal expense, which is the amount already in rates. Tr. vol. 14, 27-31. Witness Jiggetts testified that, as originally approved by the

Commission in DEP's 2012 Rate Case, Docket No. E-2, Sub 1023, "storm normal" embeds average storm restoration costs in rates over a 10-year period, after excluding costs which would ordinarily be deferred or securitized. She explained that deferral or securitization applies to major storms, so the "storm normal" calculation is designed to have a baseline level of storm restoration cost in rates derived from a 10-year average. *Id.* at 28-30. In this case, the "storm normal" cost to be embedded in rates is $22.2 million, a figure with which the Public Staff agrees. *Id.* at 30.

Witness Jiggetts testified that, as proposed, the account would have a regulatory liability of approximately $2 million (in favor of customers), which would extinguish costs associated with Winter Storm Izzy but also lower returns, since the funds would be in rate base. Tr. vol. 14, 62-63. Witness Jiggetts stated that this regulatory liability position would continue until the next general rate case and, even though the balance in the account would change from year to year based upon storm costs actually experienced from a rates charged to customer perspective that the initial $2.27 million credit, would stay reflected in rates until DEP returns for a rate case proceeding. *Id.* at 63.

Discussion and Conclusions

As noted above, the Commission has approved DEP's calculation in this proceeding for the storm normalization expense to be included in rates.

The Commission stated in its Order in the 2017 Rate Case that both DEP and the Public Staff cite in support of their positions in this case with regard to the issues concerning the recovery of storm costs:

> The Commission's precedents do not require that ratepayers bear the entire cost of repairing the damage to a utility's system resulting from a major storm. Instead, deferrals of storm costs are limited to those costs that are beyond the normal range of fluctuation of storm costs from year (in this case, costs in excess of $27.4 million). In recent general rate cases, the Commission has also included in the utility's rates a storm cost allowance based on the average amount the company has incurred over a period of years (the storm cost allowance approved in Sub 1023 was $12.7 million per year). Costs may exceed an average, or normal, amount used to set rates in a general rate case; however, as long as those excess costs are within a normal range of variation, they should be presumed to be recovered through the utility's rates in effect at that time (given the fact that many expenses fluctuate from year to year).

Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, *Application by Duke Energy Progress, LLC, For Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-2, Sub 1142, at 127 (Feb. 23, 2018) (2017 Rate Case Order).

Based upon DEP's spending of $87.126 million on a North Carolina retail jurisdictional basis in 2022 on annual storm costs, which is above the annual threshold of $27.4 million on a North Carolina retail jurisdictional basis in annual storm costs that the Public Staff agreed is proper for seeking deferral or securitization, the Commission is satisfied that DEP has met the threshold warranting a deferral or securitization for Winter Storm Izzy and Hurricane Ian. As discussed herein, the Commission concludes that DEP should be allowed to recover the 2022 incremental Winter Storm Izzy costs of approximately $15 million, which amount was agreed to by the Public Staff, by applying a portion of the over-amortization of Hurricane Matthew costs in the amount of $17 million from the 2017 Rate Case. As stated elsewhere in this Order, the remaining amount of over-amortization of Hurricane Matthew costs, approximately $2.0 million, should be returned to customers through a levelized rider over a period of one year.

With regard to the proposed storm balancing account, the Commission described the position taken by DEP in the 2017 Rate Case proceeding (that all costs in excess of a normalized annual amount should be considered extraordinary and recovered on a deferred basis) as potentially "set[ting] a dangerous precedent for other categories of costs in the future." 2017 Rate Case Order at 130. More specifically, the Commission stated explicitly that:

> Under this approach, the Company would be assured of recovery of all its storm costs on almost a "true-up" basis, either through the presumed annual allowance in rates or through deferral and amortization. In effect, DEP's proposal would amount to a "tracker" system for storm cost recovery, similar to the riders established by the General Assembly in G.S. 62-133.2, 62-133.8 and 62-133.9 for fuel, REPS, and DSM/EE cost recovery. If DEP is allowed to implement such a system for recovery of its storm costs, other utilities may well seek to adopt a similar approach for any of various other expense items. In light of this concern, and the attendant shifting of more risk to customers, the Commission has generally been reluctant to approve cost tracker systems, except when they are required by statute.

Id.

In this case, and at this time, the Commission is unpersuaded by DEP's contentions that there is any reason to begin allowing, in essence, a true-up of storm costs where such recovery is not explicitly statutorily permitted. Further, the Commission continues to have concerns that DEP's proposed approach might set precedent for other categories of costs in the future. The Commission notes that any storm costs not eligible for securitization or deferral are presumed to be covered by DEP's authorized base rates. For these reasons, the Commission declines to approve a storm balancing account, at this time, as requested by DEP.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 67-69

The evidence supporting these findings of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Abernathy, Jiggetts, Harris, Quick, Bateman and Stillman, Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

IIJA/IRA

By Application and through the direct testimony of witness Abernathy, DEP requests to defer the estimated tax benefits, net of costs, associated with the IRA and IIJA. Tr. vol. 23, 151, 154.

With respect to the IRA, DEP witness Panizza discussed the two solar MYRP projects and six battery energy storage MYRP projects that are eligible for either Investment Tax Credits (ITC) or Production Tax Credits (PTC) made available under the IRA. Tr. vol. 16, 140-44. Witness Abernathy explained how DEP estimated the IRA benefits based on the best information available and that DEP's intention is for customers to receive the full benefit (net of costs) of the tax credits. Tr. vol. 23, 151. Witness Abernathy also testified that "the Company agrees [with the Public Staff] that a deferral of IIJA impacts is appropriate and supports the recommendation for the Commission to approve an accounting order to defer any incremental revenue requirement impacts, including benefits and costs related to IIJA, to be addressed in a future rate case." Tr. vol. 23, 154.

Public Staff accounting panel witnesses Boswell and Zhang, as well as Public Staff witness Thomas, testified in support of the requested deferral treatment of the IRA impacts. Tr. vol. 19, 77, 178-80, 195. Public Staff witness Nader provided similar testimony, recommending that the Commission treat the impacts associated with the IIJA consistent with those related to the IRA. Tr. vol. 21, 114.

Based on foregoing, the Commission concludes that DEP's request for an accounting order authorizing deferral of all IRA and IIJA related impacts, net of costs, as well as any difference between realized and estimated impacts included in DEP's filing is reasonable and should be approved.

Customer Assistance Program, Payment Navigator Program, and the Tariffed On-Bill Program

In her direct testimony, DEP witness Jiggetts explained that DEP has proposed several new programs in this case to benefit customers, including the CAP, Tariffed On-Bill program, and the Payment Navigator program (Customer Programs) and that DEP would incur certain implementation and administration costs that were not included in the test period, and which are not known and measurable at this point. She stated that should the Commission approve the Customer Programs, DEP requests permission to establish a regulatory asset and defer to the account the incremental implementation and

administrative O&M costs related to the programs for future recovery in rates. Witness Jiggetts also testified that DEP is proposing PIMs as part of its PBR application and that DEP requests to defer to this regulatory asset the implementation costs for the PIMs, including, without limitation, certain costs relating to marketing, administration, and the PIMs dashboard. Tr. vol. 13, 209.

DEP witnesses Bateman and Stillman testified that the PIMs dashboard had a capital cost estimate of $540,000, with estimated annual O&M costs of approximately $100,000, with DEP proposing to allocate 43.23% of these costs to DEP's North Carolina retail customers. Tr. vol. 14, 112.

Public Staff witnesses Zhang and Boswell testified that the proposed deferral of the costs associated with the implementation of the proposed Customer Programs and PIMs fails to meet either prong of the Commission's two-prong test for deferrals, and therefore DEP's request should be denied. Tr. vol. 19, 75-76. They further testified that because PIMS are designed to protect ratepayers and are required for approval of an MYRP, PIMs are part of DEP's normal course of business and should also be denied on that basis. *Id.* at 75-76.

In her rebuttal testimony, witness Jiggetts responded to the Public Staff's recommendation to deny DEP's request on the basis of the deferral test. Tr. vol. 23, 105. Witness Jiggetts testified that DEP's request is being included as a part of its general rate case proceeding and is not an "out of period" cost subject to the Commission's two-prong deferral test. Witness Jiggetts explained that even though the costs of implementing these programs are known and measurable, DEP did not adjust operating expenses in this case to include these incremental costs which are not captured in the historic test period. *Id.* at 106. Witness Jiggetts clarified that while PIMs will become a part of DEP's normal course of business as a result of the MYRP, the costs of that new normal course of business have not been included in operating expenses for recovery from customers. *Id.* Thus, witness Jiggetts explained that creation of a regulatory asset for deferral of the costs would allow DEP to postpone recovery of these costs until the Customer Programs are implemented and benefitting customers. *Id.*

At the expert witness hearing, responses to the Public Staff discovery requests were entered into the record in which DEP indicated that many of the costs associated with implementation of the PIMs were minimal. Public Staff Cross Examination Bateman Stillman Direct and Settlement Ex. 1, Tr. Ex. vol. 16.

The Commission has historically treated deferral accounting as a tool to be allowed only as an exception to the general rule, and its use has been allowed sparingly. Deferred accounting treatment is generally authorized by the Commission only in those instances where there was a clear and convincing showing that the costs in question were of an unusual or extraordinary nature and that, absent deferral, the costs would have a material impact on the company's financial condition. Requests for the use of deferral accounting have been historically considered by the Commission on a case-by-case basis and such decisions are based on the specific circumstances of the request.

The Commission considers program proposals such as the Customer Programs, to be a normal part of DEP's operations to provide benefits to customers with respect to billing and payment options and other customer service offerings pertaining to the provision of electric utility service. With respect to PIMs, the Commission acknowledges that this is the first time the Commission is considering PIMs in a general rate case proceeding; however, PIMs are now statutorily part of the normal course of business when a utility elects in its discretion to pursue an MYRP. Accordingly, DEP's request to defer these costs is denied. To the extent that there are ongoing O&M expenses associated with implementation of the PIMs and customer programs, DEP may seek cost recovery of actual expenses incurred during a future test period in its next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 70

Interconnection CIAC Regulatory Liability Recommendation

The evidence supporting this finding of fact is contained in DEP's verified Application and Form E-1; the Revenue Requirement Stipulation; the testimony and exhibits of DEP witness Speros and Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

Public Staff witness Metz explained that in relation to interconnection agreements (IAs), Contributions in Aid of Construction (CIAC) are funds provided to DEP by third party utility customers to pay for capital projects (usually new construction) typically requested by the third party. Tr. vol. 16, 452. Witness Metz testified that during his review of IAs between third party qualifying facilities (QFs) and DEP, he discovered that DEP had historically recorded QF developer CIAC payments as revenue rather than an offset to rate base. *Id.* Witness Metz stated that a QF developer is responsible for the cost of the network upgrades required for interconnection and that the costs are not socialized to all ratepayers unless otherwise permitted by law to ensure that the ratepayers are held harmless. *Id.* He explained that DEP performs a study to determine what network upgrades are necessary for the safe and reliable interconnection of the developer's project. DEP then charges the third-party developer for the construction costs of the identified network upgrades. *Id.* Witness Metz testified that ratepayers should be held harmless if the network upgrades are paid for in whole by the developer, plus any additional true up costs, once the project is online. *Id.* Witness Metz stated that the Public Staff attempted to determine the magnitude and resulting rate impact of this issue; however, more time was needed to audit, validate, and review this issue given the complexity. *Id.*

Witness Metz testified that DEP self-identified errors related to recording CIAC interconnection activity during a 2019 audit but deemed it as not material. *Id.* at 452-53. The audit findings stated that DEP's practice of recording CIAC from developers to the income statement as Other Revenue while charging costs incurred to complete construction to CWIP balance sheet accounts is incorrect. *Id.* at 453. To correct this issue, the audit findings instructed that the CIAC should be recorded to CWIP. *Id.* Witness Metz stated that DEP reviewed this topic again during a 2022 follow-up audit and that the audit

findings recognized that DEP's process improvements have strengthened tracking of the interconnection financial activity. *Id.* However, the audit findings determined that a comprehensive process documentation needs to be established to define roles and responsibilities and to ensure sustainability of the financial processes. *Id.* A deadline of June 2023 was established for DEP to prepare this documentation. *Id.*

Public Staff witnesses Zhang and Boswell testified that DEP booked these CIAC payments inconsistently, leaving the Public Staff unable to determine whether ratepayers were held harmless regarding the costs associated with these interconnections. Tr. vol. 19, 39. Witnesses Zhang and Boswell further testified that DEP changed its booking procedures for the fees received for interconnections at the beginning of 2022. *Id.* The Public Staff witnesses asserted that they were unable to determine the magnitude of the error, whether ratepayers have been harmed, and if so by how much or whether DEP's new procedures will alleviate the issues. Tr. vol. 16, 453; Tr. vol. 19, 39. Therefore, the Public Staff recommended that the Commission order DEP to produce all entries related to the IAs for all plant, depreciation, and collections so the Public Staff can determine whether ratepayers have been held harmless. *Id.* Additionally, the Public Staff recommended that a regulatory liability be established to record any instances in which DEP incorrectly recovered costs associated with IAs from ratepayers, to be flowed back to ratepayers with interest at DEP's weighted average cost of capital in the next DEP general rate case. *Id.* at 39-40. Witnesses Zhang and Boswell testified that since DEP had full control over its accounting systems and should have booked the amounts correctly, any items found to have been booked that should have been recovered from ratepayers should not be credited to the regulatory liability. *Id.* at 40. Witnesses Zhang and Boswell recommended that the Commission order DEP to review its CIAC policy and report the results of that review in the next general rate case. *Id.*

DEP witness Speros took exception to the Public Staff's recommendations and argued that the establishment of a regulatory liability has not been justified in this case. Tr. vol. 13, 60. Witness Speros explained that DEP has taken a number of steps to ensure CIAC associated with IAs is appropriately recorded on DEP's books. *Id.* He stated that this process begins with DEP's monthly reconciliation of associated liability accounts. *Id.* For Transmission projects, a monthly journal entry is made to credit capital projects for customer deposits based upon the cost incurred. *Id.* For distribution projects, quarterly journal entries are made to credit the capital projects for customers based upon costs incurred. *Id.* Witness Speros stated that DEP's project controls organization and finance organizations then work together to ensure that the current list of IA projects is appropriately analyzed so that proper journal entries are made, whether a debit or credit to the construction project. *Id.* Moreover, witness Speros explained that DEP continually works to improve its accounting processes, including the process for recording CIAC associated with IAs. *Id.* at 61. He commented that since 2019, DEP has taken steps to improve the processes in place for recording CIAC associated with IAs and made recent modification in 2022. *Id.* Witness Speros also explained that DEP has not been able to identify any interconnection costs associated with CIAC that ratepayers should not have been charged in DEP's last general rate case. Tr. vol. 13, 62.

Witness Speros also testified that the Public Staff's broad-based recommendation to order DEP to produce all entries related to IAs for all plant, depreciation, and collections is unnecessary to demonstrate that DEP's procedures are working properly. *Id.* at 61. In the alternative, DEP offered to work with the Public Staff in a collaborative fashion to facilitate their review and help identify information that would best provide a reasonable and efficient evaluation. *Id.* at 61-62. DEP also did not oppose in principle reporting to the Commission on its CIAC policy in the next general rate case. *Id.* at 63.

No other intervenors raised an issue regarding DEP's accounting for CIAC associated with IAs.

The initial Revenue Requirement Stipulation identifies as unresolved the issue of whether it is necessary for DEP to establish a regulatory liability to address CIAC for IAs as recommended by the Public Staff. As discussed below, the Commission concludes that the evidence in this case does not support the establishment of a regulatory liability to address CIAC collected by DEP from interconnection customers.

Fundamental to the establishment of a regulatory liability for CIAC related to IAs is a showing that the establishment of a regulatory liability is justified. In this case, the Public Staff offered very little in the way of justification to support the establishment of a regulatory liability. The Public Staff testified that it had found inconsistencies in the financial accounting of the CIAC related to IAs and that it was unable to determine whether ratepayers are being held harmless. Witness Metz acknowledged that the Public Staff needed more time to audit, validate, and review this issue given its complexity. Beyond these statements, the Public Staff witnesses were not in a position to demonstrate to the Commission the magnitude and rate impact on customers of this issue such that the establishment of a regulatory liability would be justified. Instead, the Public Staff requested that the Commission require DEP to produce all entries related to IAs for all plant, depreciation, and collections to allow the Public Staff to continue its audit of this issue beyond the conclusion of the present rate case proceeding.

The explanations provided by DEP witness Speros in his rebuttal testimony are informative as to the steps that DEP has taken to record CIAC for IAs in a manner that does not harm customers. As witness Speros explained, DEP has worked to improve its CIAC accounting procedures since 2019, with additional improvements made as recently as 2022. Further, as a result of the follow-up audit in 2022, a June 2023 deadline was established for DEP to document processes and define roles and responsibilities related to the financial accounting of CIAC related to IAs. The Commission determines that the requirement for DEP to construct this documentation should facilitate sustainability of DEP's improved financial processes. DEP should provide the Public Staff a copy of its documented processes related to this issue once the documentation is completed.

The Commission concludes that the Public Staff's proposal to establish a regulatory liability is not warranted at this time, given the uncertainty regarding the magnitude of the issue. In so concluding, the Commission gives weight to the testimony of witness Speros that

DEP has been unable to identify any interconnection cost associated with CIAC that ratepayers should not have been charged in DEP's last general rate case.

Based upon all of the evidence presented, the Commission concludes that the establishment of a regulatory liability is not justified by the record in this proceeding. DEP shall continue its work with the Public Staff regarding the documentation of its processes related to the recording of CIAC and shall report on the CIAC issue in its next general rate case application as required by the Revenue Requirement Stipulation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 71

Quality of Service

The evidence supporting this finding of fact is set forth in the testimony of DEP witnesses Guyton, Maley, and Quick and Public Staff witness T. Williamson.

DEP witnesses Guyton and Maley testified to the performance of the DEP transmission and distribution systems during the base period. Witness Maley testified that DEP's transmission system is reliable and well-maintained, and that DEP is seeking to continue transmission investments to facilitate the conversion of the transmission system to meet future demands. Witness Maley further indicated that DEP utilizes the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) metrics to measure outage durations and that these metrics over the base period showed a downward trend in outages (and therefore an upward trend in reliability). Witness Maley indicated that the transmission system also utilizes an Outages per Hundred Miles per Year – Sustained Automatic (OHMY-SA) metric which has further demonstrated the reliability of the DEP transmission system. Tr. vol. 10, 176-77. Witness Guyton testified that DEP's operational investments since its last rate case have allowed it to meet its operational performance and customer satisfaction goals and that it is providing safe and reliable service. *Id.* at 48. Witness Guyton also cited DEP's SAIDI and SAIFI scores as indicative of increasing system reliability in the form of reduced customer outages. He attributed this improvement in outage experience to ongoing grid improvements such as Self-Optimizing Grid improvements as well as ongoing vegetation management activities. *Id.* at 50.

In his direct testimony, Public Staff witness T. Williamson largely concurred with DEP's conclusions about improving service quality and attributed the stable to improving system performance to DEP's Grid Improvement Plan and vegetation management activities. Tr. vol. 21, 222. Witness T. Williamson also engaged in an in-depth analysis of DEP's service quality in which he examined various aspects of DEP's performance in initiating new service, providing normal day-to-day service, and restoration of service after outage events. *Id.* at 218-33. Witness T. Williamson also summarized various consumer statements of position filed with the Commission relative to this rate case. *Id.* at 233-35.

Regarding the initiation of new service, witness T. Williamson indicated that new service installations had almost doubled from 2015 through 2022 but that DEP's average

percentage of installations completed within 20 days had improved in recent years from historic averages and was in the low to mid 90s from 2020 forward. Witness T. Williamson also noted that the sheer number of new connections experienced by DEP in 2022 was having an impact on the ability to complete new installations quickly but that DEP still averaged to meet the 20-day goal 92.6% of the time in 2022. Witness T. Williamson also noted that "[t]he average business days to construct [new connections] has been consistently around the 10-day range and the average percent within 20 days has been consistently around the 95% range since 2019." *Id.* at 219-20. Regarding day-to-day service, witness T. Williamson reiterated that SAIDI and SAIFI scores have been trending downward since 2017 in part because of GIP program implementation which "provides a level of predictability concerning future service levels, to the benefit of customers. *Id.* at 222. Witness T. Williamson further testified that service reliability as measured by ASAI[22] has consistently measured more than 99.97% since 2013. *Id.* at 226. With respect to restoration of service after an outage, witness T. Williamson testified that DEP's Estimated Time to Restoration for service outages was met in 92% of Major Event Day outages. *Id.* at 232.

In her direct testimony, DEP witness Quick testified that in addition to DEP's primary responsibility of providing safe and reliable service, DEP understands that its customer base has diverse service needs and strives to recognize and accommodate them where possible. Tr. vol. 7, 67-68. She outlined the steps that DEP is taking to continue to improve customers' experiences and satisfaction. Tr. vol. 7, 65. With respect to DEP's customer care operations, witness Quick explained that they designed and continuously enhanced to ensure that customer inquiries are answered promptly and accurately. Customer calls are either processed in the Interactive Voice Response (IVR), allowing customers to self-serve, or by a call center specialist. Tr. vol. 7, 67. She also described how DEP uses social media channels to inform customers about reliability updates in their area and changes that could impact their bills. Additionally, in an emergency or major storm, DEP uses social media to communicate essential information to customers, making proactive posts to quickly warn as many customers as possible and engage with customers who have storm- or outage-related questions. Tr. vol. 7, 69-70.

Witness Quick also testified about the programs that DEP supports to help customers with the affordability of electric utility service. She noted the energy efficiency programs that help reduce energy usage and provide weatherization assistance. Tr. vol. 7, 71-73. She also detailed DEP's numerous efforts to support customers during the unprecedented COVID-19 pandemic. One example she gave was DEP's expansion and extension of the Winter Moratorium, a period from November until March every year where qualified customers are protected from disconnection for non-payment. DEP ensured the Winter Moratorium remained in place from November 2020 until March 2022, protecting approximately 48,000 eligible customers from disconnection during the initial and subsequent COVID-19 pandemic waves. Another example was the outreach campaigns to municipal leadership, community stakeholders, Chambers of Commerce, state agencies, food banks, and churches where

[22] ASAI is the ratio of the total number of customer hours that service was available during a given time period to the total number of customer hours demanded. Algebraically, this ratio is represented as follows: ASAI = 1 – (SAIDI/8760).

DEP communicated with customers to promote options for assistance and contacting DEP. Tr. vol. 7, 81-88.

Witness Quick further testified about recent digital enhancements to improve service to customers. She relayed that after receiving customer feedback, DEP improved its website by making interaction operations easier to locate in January 2022. Additionally, she described an interactive Transmission Map that details transmission projects planned across North Carolina, a planned vegetation management map, a feature alerting customers to estimated call wait times, the ability for customers to start and stop service online, and a digital, and a self-service enrollment option for payment arrangements. Moreover, witness Quick highlighted that DEP's digital enhancements made it easier for customers to report service interruptions. She also testified that DEP offers a fee mobile app that allows residential and small business customers to easily manage their account from anywhere in the United States. Witness Quick stated that since making these changes, customers are reporting higher satisfaction with their web experiences. Tr. vol. 7, 96-105.

In recognition of the policy of the State of North Carolina "to promote adequate, reliable and economical utility service" codified at N.C. Gen. Stat. § 62-2(2) and in accordance with the Commission's general supervisory authority established in N.C. Gen. Stat. § 62-32, and recognizing that the Commission found DEP's service quality to be "good" in the 2019 Rate Case and that the performance metrics for service rendered have not declined and, in some cases, have improved since that rate case, as is reflected in witness Williamson's testimony, the Commission concludes, based on the record in this proceeding, that the quality of service provided by DEP's is good. No other party presented evidence on DEP's service quality.

Additionally, no other party presented evidence critical of DEP's quality of service. Based on the foregoing, the Commission concludes that DEP provides adequate service to customers.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 72-73

Tax-Related Items

The evidence supporting these findings of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witness Jiggetts, Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

In its Application, DEP proposes to revise the EDIT-4 rider to return an additional $16.2 million for unprotected federal EDIT and $4.5 million for deferred revenues to customers over the remaining 2.7 years of the total five years to return the unprotected federal EDIT approved in the prior rate case. The two-year period for Deferred Revenues under EDIT-3 will expire in June of 2023; therefore, DEP is proposing to flow the additional amounts back to customers over the remaining life of the EDIT-4 rider in lieu of creating a new decrement rider. *Id.*

DEP witness Jiggetts supports this revision to the EDIT-4 Rider in her direct testimony and in Jiggetts Exhibit 3. Tr. vol. 13, 164. The Public Staff agrees with DEP's proposal to flow back the incremental amount to customers on a levelized basis over the remaining EDIT rider term; however, the levelized return rate used by the Public Staff reflects DEP's 3.88% cost of debt rate and a return on equity of 9.25% from December 31, 2022. Tr. vol. 23, 107.

In her third supplemental testimony, witness Jiggetts updated DEP's cost of debt to 4.03% as of March 31, 2023, and recalculated the proposed changes to the EDIT-4 Rider accordingly. Tr. vol. 13, 240, 242. In the initial Revenue Requirement Stipulation, the stipulating parties agree to an embedded cost of debt of 4.03%. Revenue Requirement Stipulation § III.1, Tr. Ex. vol. 7.

Based on the foregoing, the Commission concludes that DEP's proposal to revise the EDIT-4 Rider to return additional unprotected federal EDIT to customers over the remaining life of the EDIT-4 Rider, as supported by the Public Staff, is just and reasonable and should be approved. Further, the Commission finds and concludes that the levelized return rate should be based on the 4.03% embedded cost of debt agreed to by the stipulating parties in the initial Revenue Requirement Stipulation and the capital structure and rate of return on equity approved by the Commission in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 74-75

Equal Percentage Allocation, Base Fuel and Fuel-Related Factors and Fuel Cost Allocation

The evidence supporting these findings of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Hager, and Jiggetts, the testimony of Public Staff witnesses Lucas, and McLawhorn, and Zhang and Boswell, and the testimony of CIGFUR witness Phillips, and the entire record in this proceeding.

In its Application and Form E-1, the fuel rates presented by DEP were allocated to customer classes utilizing the equal percentage fuel adjustment.

Public Staff witness Lucas testified that DEP currently allocates fuel cost adjustments to customer classes based on an equal percentage change, meaning that fuel and fuel-related costs are recovered using a uniform percent increase or decrease per rate class such that each rate class will, on average, experience the same average monthly percent increase or decrease as the overall fuel and fuel-related cost change. Tr. vol. 20, 28. Public Staff witness Lucas testified that since 2008, DEP has allocated fuel cost increases on an equal percentage basis to each of its five customer classes as allowed by Session Law 2007-397. Tr. vol. 20, 28. He testified that the Public Staff first supported the use of equal percentage allocation in DEP's 2008 fuel adjustment proceeding, Docket No. E-2, Sub 929. He cited several reasons for the Public Staff's agreement to the equal percentage allocation, such as the uncertain economic times and

the large increase in fuel costs. *Id.* at 29-30. He noted that the equal percentage method of adjusting rates assisted industrial customers financially during the Great Recession and during a period of unprecedented increases in coal prices at the expense of other customers. Id. at 28-31. He testified that the distortion that can be created by equal percentage fuel adjustments is found in DEP's most recent 2022 fuel rider proceeding, in which fuel costs increased for all customer classes except LGS, which received a fuel rate decrease. Id. at 30-35. He explained that, for this reason, it is the Public Staff's recommendation that the Commission does not allow DEP to make equal percentage fuel adjustments but allow DEP to continue to offer voltage differentiated rates. *Id.*

Witness Lucas stated that N.C.G.S. § 62-133.16(b) requires the Commission to allocate the utility's total revenue requirement among customer classes based on the cost causation principle and minimize cross subsidies "to the greatest extent practicable." *Id.* at 33-35, 53, 103. Witness Lucas noted that the statute defines the cost causation principle to mean "establishment of a causal link between a specific customer class, how that class uses the electric system, and costs incurred by the electric public utility for the provision of electric service." *Id.* at 33.

Witness Lucas presented the current fuel rates adjusted to remove the equal percentage allocation method. *Id*. at 36. As set forth in his Table 4, the rates in cents per kWh, excluding the regulatory fee, are 2.647 for residential customers, 2.654, for SGS customers, 2.609 for MGS customers, 2.516 for LGS customers, and 2.511 for Lighting customers. *Id.* at 36.

In his direct testimony, CIGFUR witness Phillips provided support for the equal percentage methodology. Tr. vol. 21, 487-88. He testified that the methodology has been approved without objection by any party in every annual fuel charge adjustment proceeding since 2008 and that the method has served ratepayers well and should be continued to be utilized. *Id.* He further stated that the methodology levelizes over time any harsh impacts and results in equal percentage increases or decreases to all customers, which are fair, just, and reasonable. *Id.*

The Commission notes that in DEC's annual fuel proceeding, DEC and the Public Staff agreed that DEC should continue to utilize the equal percentage fuel adjustment for purposes of that case. *See* Agreement and Stipulation of Partial Settlement, Docket No. E-7, Sub 1282 (filed May 31, 2023). The Commission further notes that there is not a similar agreement filed in the DEP annual fuel proceeding in Docket. No. E-2, Sub 1321.

Based on all the evidence in this proceeding, the Commission concludes that use of the equal percentage method of allocating fuel and fuel related costs does not follow the cost causation principle. In reaching this conclusion, the Commission gave substantial weight to the testimony of the Public Staff regarding the cost causation principle set forth in N.C.G.S. § 62-133.16, as well as their demonstration of the distortion that can be created by equal percentage fuel adjustments. Further, the Commission finds that this change shall be implemented for fuel rider proceedings filed after the date of this Order, and shall not apply in DEP's pending fuel adjustment proceeding, Docket No. E-2, Sub 1321.

Base Fuel and Fuel-Related Cost Factors

DEP's Application explained that the rates set forth in the exhibits to the Application included a base fuel and fuel-related rate of Residential - 2.126 cents per kWh; SGS - 2.111 cents per kWh; MGS 2.169 cents per kWh; LGS- 2.019 cents per kWh; and Lighting - 1.682 cents per kWh, excluding the Experience Modification Factors as approved in Docket No. E-2, Sub 1272 and excluding regulatory fees.

Witness Jiggetts testified DEP made an adjustment (Adjustment No. NC2010) to test period fuel expense to match the fuel clause revenues included in pro forma Adjustment No. NC1010. Tr. vol. 13, 180-81. She explained that by matching the expenses to the revenue, the adjustment ensures that no increase is requested in this proceeding related to fuel and fuel-related costs that are recoverable through the fuel clause. *Id*. She further stated that DEP intended to update this pro forma adjustment once it received an order in its pending fuel case in Docket No. E-2, Sub 1292. *Id.*

In her supplemental direct testimony, witness Jiggetts explained that DEP had updated pro forma Adjustment No. NC2010 to include revisions to reflect the fuel rates approved under in Docket No. E-2, Sub 1292. Tr. vol. 13, 221.

In her second supplemental direct testimony, witness Jiggetts testified that DEP had made a new adjustment (Adjustment No. NC2020 to adjust the nonfuel component of purchased power expense to reflect the impacts of the Stipulation Regarding the Proper Methodology for Determining the Fuel Costs Associated with Power Purchases from Power Marketers and Others reached with DEP, DEC and the Public Staff in Docket No. E-7, Sub 1282. Tr. vol. 13, 235. She further explained that during the test year, 39% of purchased power energy costs were estimated to be non-fuel expense and appropriate for cost recovery through base rates. *Id.* Based on the stipulation, during the test year, 15% of energy costs from these power purchases is the appropriate percentage to be deemed as non-fuel costs and appropriate for cost recovery through base rates. This pro forma adjustment makes the required reduction to operating expense in the test year as agreed upon with the Public Staff. *Id*.

The Commission issued a final order in the Sub 1292 fuel rider proceeding on November 3, 2022. In the Sub 1292 order, the Commission concluded that, effective for service rendered on and after December 1, 2022, DEP shall adjust the base fuel and fuel-related cost factors in its North Carolina retail rates, as approved in the 2019 Rate Case, amounting to 2.080¢/kWh for the Residential class, 2.126¢/kWh for the SGS class, 2.228¢/kWh for the MGS class, 2.204¢/kWh for the LGS class, and 1.392¢/kWh for the Lighting class (all excluding the regulatory fee), by amounts equal to 0.728¢/kWh, 0.971¢/kWh, 0.352¢/kWh, (0.066¢)/kWh and 1.984¢/kWh, respectively, and further, that DEP shall adjust the resulting approved prospective fuel and fuel-related cost factors by EMF increments/(decrements) of 0.649¢/kWh for the Residential class, 0.449¢/kWh for the SGS class, 0.586¢/kWh for the MGS class, 0.898¢/kWh for the LGS class, and 0.834¢/kWh for the Lighting class (excluding the regulatory fee). The Commission further

ordered that the EMF increments are to remain in effect for service rendered through November 30, 2023.

In the direct testimony of Public Staff witnesses Zhang and Boswell, they also used the fuel rates approved in Docket No. E-2, Sub 1292 to update revenues and expenses to May 2023 levels. Public Staff Accounting Ex. 1, Schedule 3-1(b)(1), Tr. Ex. vol. 19. In their Supplemental and Stipulation testimony they included an adjustment to fuel costs to reflect the impact of witness Lucas' recommendation to eliminate the equal percentage change in fuel rates. Tr. vol. 19, 91.

The only party that submitted evidence in this proceeding using fuel rates other than those approved in Docket No. E-2, Sub 1292 was the Public Staff. However, as shown on Public Staff Accounting Supplemental and Settlement Exhibit 1, Schedule 3-1(b), they adjusted fuel expense and revenue by the same amount so that there was no impact on the revenue requirement in this proceeding. *Id.* Also, Public Staff witness Lucas recommended that such rates be implemented effective December 1, 2023. No party offered any evidence contesting the testimony of witness Jiggetts that specifically supported the base fuel and fuel-related cost factor proposed by DEP. Accordingly, the Commission concludes for purposes of this proceeding that the total of the approved base fuel and fuel-related costs factors, by customer class — the sum of the respective base fuel and fuel-related costs factors set in the 2019 Rate Case and the annual non-EMF fuel and fuel-related costs riders approved by the Commission in Docket No. E-2, Sub 1292 — are just and reasonable to all parties in light of all the evidence presented.

Fuel Cost Allocations

In DEP's previous general rate case, the parties agreed on production plant as an appropriate allocation factor for purchased power capacity costs. Tr. vol. 11, 107. Under N.C.G.S. § 62-133.2(a2)(2), the Commission shall determine how these costs shall be allocated in a general rate case for the electric public utility. Therefore, this proceeding is the appropriate forum for the Commission to reconsider the appropriate cost allocation methodology for such costs, which are to be requested for cost recovery in DEP's annual fuel proceeding.

Witness Hager testified that DEP is proposing that the Commission use production demand as the more appropriate factor to allocate purchased power capacity costs to North Carolina retail and across North Carolina retail customer classes. Tr. vol. 11, 107. She testified that allocation based on production demand is more appropriate than production plant because purchased power capacity costs that are not recovered through the fuel clause are allocated on production demand. *Id.* She testified that the change towards allocation based on production demand would align all purchased capacity costs under the same allocator. *Id.* Additionally, most production plant is allocated on production demand, except for jurisdiction-specific amounts that are not related to purchase power costs. *Id.*

No party offered testimony opposing DEP's recommendation.

In DEP's previous general rate case, the parties agreed on production plant as an appropriate allocation factor for purchased power capacity costs. Tr. vol. 11, 107. Under N.C.G.S. § 62-133.2(a2)(2), the Commission shall determine how these costs shall be allocated in a general rate case for the electric public utility. Therefore, this proceeding is the appropriate forum for the Commission to reconsider the appropriate cost allocation methodology for such costs, which are to be requested for cost recovery in DEP's annual fuel proceeding. Based upon the evidence presented in this case, the Commission finds and concludes that the same production demand allocation method approved for production demand costs in this case using the 12 CP methodology at NC retail and the Modified A&E methodology for NC retail classes is the most appropriate methodology for allocating purchased power capacity costs in DEP's annual fuel proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 76-77

Residential Decoupling Mechanism and Earnings Sharing Mechanism

The evidence supporting these findings of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Abernathy, Bateman and Stillman, Public Staff witnesses D. Williamson and Thomas, AGO witness Nelson, and the entire record in this proceeding.

Summary of Evidence

DEP's PBR Application seeks approval of performance-based regulation through the proposed three-year MYRP beginning on October 1, 2023 and ending September 30, 2026. DEP witness Bateman testified that in addition to the three-year MYRP, which includes an ESM, DEP's PBR Application also includes PIMs a decoupling mechanism for the residential customer class. Tr. vol. 14, 76. Witness Bateman explained that the PBR approach and DEP's PBR Application better aligns customer and state policy goals with utility revenues and performance than traditional ratemaking. *Id.* at 80.

Residential Decoupling Mechanism

DEP witness Abernathy provided direct testimony on the proposed decoupling mechanism. She testified that the "decoupling rate-making mechanism" is intended to break the link between an electric public utility's revenue and the level of consumption of electricity on a per customer basis. She explained that the following Rate Schedules are affected by the decoupling mechanism: RES, R-TOU, R-TOUD, and R-TOU-CPP, along with any new residential rate schedules approved by the Commission during the Plan Period. She testified that the Residential Energy Conservation Discount Rider is also impacted by decoupling. She testified as to how the annual and monthly target revenue per customer would be calculated for Rate Years 1, 2 and 3. She also testified as to estimated number of residential customers for each year and for each month for each rate year. She also explained that the difference between target residential revenues and actual residential revenues would be deferred, which would be adjusted to account for DSM/EE net lost revenues and incremental EV revenues. She also explained how the

carrying cost on the deferral would be calculated. She explained how the Decoupling Rider will work and DEP's reporting obligations with respect to the deferred balance. Tr. vol. 13, 102-12.

AGO witness Nelson also supported using a lower carrying cost rate on the decoupling deferral amount and placing a hard cap of 3% on surcharges. Tr. vol. 18, 82-83. Witness Nelson explained that a hard cap would limit rate increases and promote cost containment. *Id*. at 84.

The Public Staff expressed only one concern regarding DEP's proposed decoupling mechanism. Public Staff witness Nader testified that N.C.G.S. § 62-133.16 authorizes the Commission to approve a residential decoupling mechanism designed to break the link between revenues and the consumption of electricity. Witness Nader also testified that the statute also the utility with an opportunity to exclude rate schedules or riders associated with EV charging from sales calculations for purposes of the mechanism. Tr. vol. 21, 110-11. Witness Nader objected to how DEP determined the estimate of EV sales for the calculation and recommended that the decoupling mechanism not include DEP's proposed "Incremental EV Revenue Adjustment". *Id.* Witness Nader asserted that the estimate was "highly speculative" and that the decoupling mechanism should only include the adjustment for EV sales when more accurate EV sales data are available. *Id.* He recommended that DEP use a lower kWh per EV estimate than DEP proposed initially.

AGO witness Nelson asserted that DEP's proposal to exclude EV sales from its decoupling mechanism is not in the public interest. Tr. vol. 18, 72-73. Witness Nelson asserted that there is no link between this proposal and the goal of advancing EV adoption. *Id.* at 74. Witness Nelson further stated that the calculation for EV sales is not accurate and recommended that the Commission reject DEP's proposal. *Id.* at 79.

DoD-FEA witness Blank recommended that the Commission deny DEP's proposal to remove EV sales from the ESM. Tr. vol. 21, 34. Witness Blank stated that the PBR Statute explicitly provides what a utility can exclude from the ESM calculation, and the statute does not list EV sales. Tr. vol. 21, 341.

In response to AGO witness Nelson's suggestion to institute a 3% hard cap on the amounts the utility is able to collect from customers, "decoupling cap," witness Abernathy testified that there is no basis for a cap in the statute, that a cap has only been authorized in a few states, and that there is no cap on the recovery of DSM/EE net lost revenues. Tr. vol. 23, 149-50. Witness Bateman's rebuttal testimony offered further support for the exclusion of EV sales from the decoupling mechanism. Tr. vol. 23, 161-62. Witness Bateman testified that adjusting the decoupling mechanism for EV sales allows the utility to retain incremental net revenues driven by EV growth, thereby directly connecting EV growth with net revenues. Witness Bateman explained that if the Commission precluded DEP from including an EV adjustment within the decoupling and ESM calculations, DEP's residential EV sales would be decoupled from the utility's margin, thus eliminating an

important incentive for the utility to encourage EV adoption and grow EV sales in between rate case filings. *Id.*

The PIMs Stipulation provides that the parties thereto agree to allow DEP to exclude all EV sales from the decoupling mechanism subject to the following two conditions: (1) that the parties work together to develop and file EV tariffs and/or programs to estimate and update the revenue associated with residential EV sales in DEP's service territory, within 90 days of the Commission's order in this docket, and (2) that DEP updates the kWh per EV estimate proposed by Public Staff witness Nader with actual, DEP-specific EV usage data in each future decoupling rider proceeding.

Witness Bateman explained that the PIMs Stipulation clarified how DEP will obtain data that will help it to better estimate revenue associated with incremental residential EVs. Tr. vol. 14, 155. Witness Bateman explained that the agreed-upon method entails using DOT data to derive the number of residential EVs in DEP's service territory, using 180 kWh per vehicle as the electric usage (a value DEP measured within the EV Make-Ready Program), and then applying the flat residential tariff rate to the average monthly EV usage amount to derive the amount of residential EV sales to exclude from the decoupling mechanism. Tr. vol. 23, 234. Thereafter, within 90 days of a Commission order in this proceeding, DEP will file tariffs or programs, and using the data from those tariffs and programs, will refine the analytics to update the number of EVs and the usage assigned to each vehicle. *Id.* at 233. Witness Bateman also stated that DEP will also use this agreed-upon method to exclude EV sales from the ESM. *Id*. at 234-35.

Earnings Sharing Mechanism

DEP witnesses Abernathy and Bateman testified in support of the ESM, which is a component of the MYRP. Tr. vol. 13, 112; Tr. vol. 14, 81. Witness Abernathy explained that if DEP's adjusted earnings exceed the authorized ROE established by the Commission in this rate case plus 50 basis points, those excess earnings, including a return calculated at the weighted average cost of capital, must be distributed to customers over a 12-month period via the annual ESM Rider. Tr. vol. 13, 112.

Witness Abernathy testified that, for purposes of the ESM calculation, DEP will adjust earnings for weather, DSM/EE incentives, PIMs, and EV sales. Tr. vol. 13, 113.

Witness Bateman that the ESM allocates risk away from customers and onto DEP, noting how the ESM distributes to customers 100% of earnings in excess of 50 basis points above the authorized ROE on an annual basis, without a corresponding ability for DEP to collect additional revenue from customers if the utility is underearning. Tr. vol. 14, 81.

Also, as noted above, witness Bateman explained that if the Commission precluded DEP from including an EV adjustment within the ESM calculations, DEP's residential EV sales would be decoupled from the utility's margin, thus eliminating an important incentive for the utility to encourage EV adoption and grow EV sales in between rate case filings.

During the expert witness hearing DEP witness Stillman also provided support for DEP's proposal to exclude EV sales from the ESM where he stated that the adjustment would further support the increased adoption of EVs. Tr. vol. 13, 151. Witness Bateman further explained that this is consistent with the policy goals in N.C.G.S. § 62-133, Commission Rules R1-17B(g)(1)(f) and R1-17B(g)(2), and Governor Cooper's Executive Order 246. *Id.* at 162.

In response to Commission questions, DEP witness Jiggetts, noted that the reports DEP currently files to show annualized return on equity for each quarter is a very high level report. Tr. vol. 13, 327. Currently, DEP provides the Commission with a quarterly surveillance report, the ES1, that shows the Commission approximately where DEP's earnings are as compared to what it is allowed to earn. Tr. vol. 13, 324. Witness Jiggetts explained that in preparing that report, DEP makes numerous simplifying assumptions in order to be able to provide the report to the Commission within the required timeframe. *Id.* Witness Jiggetts confirmed that the quarterly surveillance reports provide a "snapshot" at a high level that does not include several ratemaking adjustments that would be necessary to arrive at DEP's actual return on rate base. *Id.* at 327. DEP provides qualifying language in the quarterly reports indicating that the figures do not accurately reflect DEP's earnings. *Id.* at 329.

Commissioner Clodfelter followed up with witness Jiggetts by asking how the Commission and the Public Staff can obtain actual annualized historical returns on equity that DEP has achieved, not for ratemaking purposes. Tr. vol. 14, 35. Witness Jiggetts explained that to reach a figure that represents DEP's true earnings, the Commission would need to ask DEP to do more detailed reporting and make certain adjustments to reflect the expected ongoing earnings, rather than using the high-level assumptions DEP employs for the quarterly ES1 reports. *Id.* at 35-36. Commissioner Clodfelter noted that the Commission, in evaluating the ESM Rider, needs to know a baseline number of what DEP actually earned in order to determine whether DEP over-earned or under-earned, or whether the Commission should increase or decrease the rate of return, or leave it the same. *Id.* at 37.

Discussion and Conclusion

In general, the Commission concludes that the residential decoupling mechanism and the ESM proposed by DEP are consistent with the PBR Statute and with Commission rule. Further, the Commission concludes that DEP's proposal to exclude EV sales from the decoupling mechanism and the ESM, as modified by the PIMs Stipulation, is reasonable and should be approved. The Commission does not find it appropriate, for the reasons advanced by DEP witnesses Bateman and Abernathy, to impose a decoupling cap, or authorize a lower carrying cost on the decoupling deferral amount. The Commission notes that the TCA Stipulation provides that the $20 million adjustment in the revenue requirement agreed to in the stipulation will be included in the ESM for DEP.

The Commission notes that the current ES1 reports were not intended to be used as a method to evaluate the ESM Rider. The Commission further notes that Commission

Rule R1-17B(h)(1) provides for the filing of quarterly earnings reports that require certain enumerated information. The Commission directs DEP to work with the Public Staff to develop a quarterly reporting form for DEP's earnings that will enable the Commission to analyze the information and determine the appropriate application and operation of the ESM Rider. As part of this review, DEP and the Public Staff shall review the requirements of Commission Rule R1-17B(h)(1) and recommend any necessary changes.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 78

Performance Based Regulation

The evidence supporting this finding of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Abernathy, Bateman and Stillman, Public Staff witnesses D. Williamson and Thomas, AGO witness Nelson, and CUCA witness O'Donnell; and the entire record in this proceeding.

Summary of Evidence

DEP's PBR Application seeks approval of performance-based regulation through the proposed three-year MYRP beginning on October 1, 2023, and ending September 30, 2026. DEP witness Bateman testified that in addition to the three-year MYRP, which includes an ESM, DEP's PBR Application includes a residential decoupling mechanism, PIMs, and tracking metrics. Tr. vol. 14, 76. Witness Bateman explained that the PBR approach, in general, and DEP's proposed MYRP better aligns customer and state policy goals with utility revenues and performance than does traditional ratemaking. *Id.* at 80.

The Commission notes, as the Public Staff points out, that the PBR Statute represents a substantial supplement to the existing law related to electric public utilities, such as DEP, and provides DEP with a cost recovery framework that represents fairly significant departure from the traditional cost recovery paradigm that has served North Carolina's electric utilities and their customers well for many decades. Discussed below are four new concepts allowed for the first time in North Carolina under the PBR Statute.

First, electric public utilities in North Carolina are entitled to file a MYRP, which is "a rate-making mechanism under which the Commission sets base rates for a multiyear period that includes authorized periodic changes in base rates without the need for the electric public utility to file a subsequent general rate application …" N.C.G.S. § 62-133.16(a)(5). This approach is a departure from the adjusted historic test year and authorizes certain projections of cost in the setting of rates.

Second, electric public utilities, such as DEP, are now allowed to utilize a decoupling mechanism. Under the PBR Statute's decoupling mechanism, DEP is authorized to "defer to a regulatory asset or liability account the difference between the actual revenue and the target revenue for the residential class" and this variance will result in an annual adjustment to the residential customer classes' bills. N.C.G.S. § 62-133.16(c)(2).

Third, the PBR Statute creates an ESM, which allows the electric public utility to elect to file a new rate case under N.C.G.S. § 62-133 in the event its weather-normalized earnings fall below the authorized rate of return on equity and requires the utility to refund to customers all weather-normalized earnings in excess of the authorized rate of return plus 50 basis points. N.C.G.S. § 62-133.16(c)(1).

Fourth, the PBR Statute requires that the utility implement at least one performance incentive mechanism, which is "a rate-making mechanism that links electric public utility revenue or earnings to utility performance in target areas consistent with policy goals …" N.C.G.S. § 62-133.16(a)(6). PIMs are intended to encourage the types of behavior about which customers care, provide DEP with the opportunity to earn a reward to be collected from customers, and expose DEP to payment of penalties which are refunded to customers (subject to a cap). N.C.G.S. § 62-133.16(c)(4).

While certain of the mechanisms established in the PBR Statute are new to North Carolina, aspects of the law are familiar and well-known to the Commission. For example, the responsibility "[t]o make reasonable and just rates" has been the obligation of the Commission's predecessors since the 19th century. *See, e.g.*, 1899 N.C. Session Laws, Chapter 164, § 2. The requirement that rates be "fair both to the electric public utility and to the customer," set forth in N.C.G.S. § 62-133.16(d)(1)(a) mirrors the charge in N.C.G.S. § 62-133(a) that "the Commission shall fix such rates as shall be fair both to the public utilities and to the consumer." Moreover, N.C.G.S. § 62.133-16 explicitly preserves the Commission's existing rate-making authority, providing: "[n]othing in this section shall be construed to [ ] limit or abrogate the existing rate-making authority of the Commission …" N.C.G.S. § 62-133.16(g) (omission denoted via brackets and ellipses). And, significantly, the Commission has long been required to consider risks both to the electric utility and to its customers, as it is well-established policy in North Carolina "to provide fair regulation of public utilities in the interest of the public" as well as "to promote adequate, reliable and economical utility service to all of the citizens and residents of the State." N.C.G.S. § 62-2(1), (3).

When reviewing a PBR application, the PBR Statute requires the Commission must consider whether a PBR application:

a. Assures that no customer or class of customers is unreasonably harmed and that the rates are fair both to the electric public utility and to the customer.

b. Reasonably assures the continuation of safe and reliable electric service.

c. Will not unreasonably prejudice any class of electric customers and result in sudden substantial rate increases or "rate shock" to customers.

N.C.G.S. § 62-133.16(d)(1).

Elsewhere in this Order the Commission has ruled upon the specific requests of DEP regarding costs to be recovered, as well as the rate of return that DEP has an opportunity to earn. In approving costs for recovery and establishing the rate of return, the Commission has applied well-established law in attempt to put the utility in a position to maintain its system and level of service, in view of the very real challenges that lie ahead for DEP, to earn a fair return, in view of current economic conditions, and to compete in the marketplace for capital on reasonable terms and at times when a capital need arises. The Commission has considered the impact of changing economic conditions on customers, recognizing that certain of the utility's customers will struggle to afford electric utility service, and has endeavored to establish rates that achieve the foregoing objectives most economically. In addition, elsewhere in this Order, the Commission has considered the potential for prejudice to customer classes and accepts the cost allocation methods, as well as certain of the rate designs, proposed by the utility and modified by the various stipulations to be reasonable and not prejudicial to any customer class.

In addition to the requirements for consideration by the Commission set forth in N.C.G.S. § 62-133.16(d)(1), the PBR Statute provides guidance on other considerations the Commission may undertake, including, for example, whether the PBR application "reduces low-income energy burdens;" whether the PBR application "encourages DERs"; whether the PBR application "encourages utility-scale renewable energy and storage"; and whether the PBR application "encourages peak load reduction or efficient use of the system." N.C.G.S. § 62-133.16(d)(2). The Commission notes, for example, that the PIMs Stipulation, discussed in detail elsewhere in this Order, involves PIMs that are intended to increase numbers of customers enrolled in time-differentiated rates, to increase the number of net-metered interconnections, to encourage the interconnection of utility scale generation above DEP's estimated annual limits, and to enable large commercial and industrial customers to achieve clean/carbon free energy objectives. Each of these PIMs aligns with the considerations established in N.C.G.S. § 62-133.16(d)(2). The tracking metrics, agreed upon by the parties to the PIMs Stipulation, pertain to customer service, reliability and "beneficial electrification," all of which should inform the future development of PIMs that align with the guidance set forth in N.C.G.S. § 62-133.16(d)(2). In addition, elsewhere in this Order, the Commission discusses the CAP's proposed by DEP in this proceeding, aimed at proving customers in need of assistance with bill payment, as well as the Affordability Stipulation, which is intended to provide additional relief for customers who will struggle to afford the cost of electricity. These provisions of the PBR Application, as modified by the stipulations, align with the considerations of § 62-133.16(d)(2). Throughout the course of this proceeding, DEP has worked with parties to the proceeding to refine the elements of its PBR Application to better conform to the requirements of N.C.G.S. § 62-133.16(d)(1) and to more closely align with the guidance set forth in N.C.G.S. § 62-133.16(d)(2).

The PBR Statute provides that the Commission is authorized to approve a utility's PBR application "so long as the Commission allocates the electric public utility's total revenue requirement among customer classes based upon the cost causation principle . . . and interclass subsidization of ratepayers is minimized to the greatest extent

practicable by the conclusion of the MYRP period." N.C.G.S. § 62-133.16(b). As previously explained, the PBR Statute also requires that the Commission consider whether a PBR application: 1) assures that no customer or class of customers be unreasonably harmed and that the rates are fair both to the electric public utility and to the customer; 2) reasonably assures the continuation of safe and reliable electric service; and 3) will not unreasonably prejudice any class of electric customers and result in sudden substantial rate increases or "rate shock" to customers. N.C.G.S. § 62-133.16(d). During cross-examination by CIGFUR II, DEP witness Reed acknowledged that the PBR Statute requires DEP to minimize interclass subsidization. Tr. vol. 11, 330. However, witness Reed emphasized that the PBR Statute requires the minimization of interclass subsidization "to the greatest extent practicable," which, the Commission concludes, DEP has achieved. The Commission concludes that DEP's approach of gradually reducing the subsidies between classes by utilizing a variance reduction of 10% is reasonable and that the 10% variance reduction approach moves towards eventual rate parity/minimization of interclass subsidization while, at the same time, balancing the other requirements of the PBR Statute including that no class of customer is unreasonably harmed or faces a sudden and substantial increase in rates resulting in rate shock. The Commission agrees with DEP witness Reed who testified that DEP appropriately considered "competing priorities" such as cost causation, rate shock, and gradualism in proposing the 10% variance reduction. Tr. vol. 11, 320-21. The Commission does not agree with the recommendation of CIGFUR II witness Phillips' argument that a greater variance reduction is warranted in this proceeding, primarily in light of the harm that such a reduction would cause to certain customer classes. Specifically, DEP witness Reed explained that if DEP had employed a 25% subsidy reduction, as recommended by CIGFUR II witness Phillips, the proposed increase to the Residential class would increase from 9.9% to 10.4% and the proposed increase to the Lighting class would increase from 19.9% to 24.9%. Tr. vol. 11, 265. Thus, balancing its obligations under the PBR Statute to ensure allocation of revenue requirement based on cost causation, minimization of interclass subsidization, equitable treatment of customer classes, and avoidance of unreasonable prejudice and rate shock, the Commission concludes that DEP's PBR Application as amended by the stipulations and the various provisions of this Order, is in alignment with cost causation or reasonably headed that way, avoids unreasonable harm to any class of customers, and does not unreasonably prejudice an class of customers or otherwise result in rate shock.

For the foregoing reasons, and as discussed in greater detail throughout this Order, the Commission concludes that DEP's PBR Application, as modified by the stipulations and this Order, results in just and reasonable rates, is in the public interest, and is consistent with the criteria established in N.C.G.S. § 62-133.16.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 79

Revenue Requirement

The evidence supporting this finding of fact is found in DEP's verified Application and Form E-1; the Revenue Requirement Stipulation; the TCA Stipulation; and the

Supplemental Revenue Requirement Stipulation; the testimony and exhibits of the witnesses, including DEP witness Jiggetts and Abernathy and Public Staff witness Zhang and Boswell; and the entire record in this proceeding.

The Revenue Requirement Stipulation, the TCA Stipulation, and the Supplemental Revenue Requirement Stipulation provide for certain accounting adjustments that parties have agreed upon and the Commission has approved in this Order. The stipulation issues that impact the revenue requirement in the Revenue Requirement Stipulation and the TCA Stipulation are detailed in in Jiggetts Partial Settlement Exhibit 2 (Tr. Ex. vol, 14) and the Public Staff Accounting Supplemental and Settlement Exhibit 1 Schedule 1 (Tr. Ex. vol 19), which provide sufficient support for the annual revenue required on the issues agreed to in the Revenue Requirement Stipulation. The stipulation issues that impact the revenue requirement in the Supplemental Revenue Requirement Stipulation are in the Supplemental Revenue Requirement Stipulation Exhibit 1 (Tr. Ex. vol 7).

After giving effect to the approved stipulations and the Commission's decisions on the Unresolved Issues, as discussed herein, the Commission finds that DEP should recalculate the required annual revenue requirement consistent with the Commission's findings herein withing 10 days of the issuance of this Order. DEP is further directed to file with the Commission the final revenue requirements for Rate Years 1, 2, and 3 in the same format as Jiggetts Partial Settlement Exhibit 1. The Commission directs DEP to work with the Public Staff to verify the accuracy of the calculations, and the filing should reflect the corrections identified by DEP and agreed upon by the Public Staff.

The Commission concludes the annual revenue requirement for DEP for Rate Years 1, 2, and 3 which reflect the approved stipulations and the Commission's decisions on the Unresolved Issues will allow DEP a reasonable opportunity to recover its operating costs and earn the overall rate of return on its rate base that the Commission has found just and reasonable upon consideration of the findings in this Order.

IT IS, THEREFORE, ORDERED as follows:

1. That the Revenue Requirement Stipulation, the COSS Stipulation, the TCA Stipulation, the PIMs Stipulation, the Affordability Stipulation, the MGS Partial Rate Design Stipulation, the LGS Partial Rate Design Stipulation, and the Supplemental Revenue Requirement Stipulation are accepted and approved, as detailed in this Order. The Power Quality Stipulation is not approved as detailed in this Order;

2. That the depreciation rates proposed by DEP in this case, which are based on the 2021 Depreciation Study and amended by the Revenue Requirement Stipulation, with such agreed upon amendments proposed by the Public Staff including the amortization periods for General Plant accounts 391 and 397, and the 70-year life of Transmission FERC account 356, shall be, and is hereby approved;

3. That DEP's request for an accounting order for approval to defer to a regulatory asset 75% of the impact of accelerating the retirement of DEP's Mayo and

Roxboro Units 3 and 4, as agreed upon in the Revenue Requirement Stipulation, preserving DEP's ability to recover 50% of the net book value of the subcritical plants through securitization, shall be, and is hereby approved;

4. That the remaining net book value of DEP's Mayo and Roxboro Units 3 and 4 at retirement shall be recovered with a return over the amortization period determined by the Commission in a future rate case;

5. DEP's plant-related capital investments in the base period fossil, renewable, storage, and nuclear fleet assets as adjusted in the Revenue Requirement Stipulation, shall be included in rates for the base period;

6. DEP's transmission and distribution investments made during the test period, as adjusted by the Revenue Requirement Stipulation, shall be included in rates for the base period;

7. That DEP's GIP investments shall be included for recovery in DEP's rates;

8. That in accordance with the Revenue Requirement Stipulation, DEP is permitted to recover the full balance of its GIP deferral over an 18-year amortization period, with a debt-only return during the deferral period and rate base treatment during the 18-year amortization period;

9. That DEP shall recover the balance of the CCR deferral, net of the over amortization, over a five-year amortization period with reduced financing costs during the amortization period calculated based on (1) DEP's cost of debt as approved in this Order adjusted as appropriate to reflect the deductibility of interest expense, (2) an ROE 150 basis points lower than the 9.8% ROE as approved in this Order, and (3) a capital structure of 48% debt and 52% equity as set forth in the CCR Settlement;

10. That in accordance with the Revenue Requirement Stipulation, DEP shall flowback to customers over a three-year period the liability related to the gains on Harris land sales;

11. That in accordance with the Revenue Requirement Stipulation, DEP shall continue to defer any gains on any future Harris land sales to return to customers in a future general rate case;

12. That DEP shall amortize the Roxboro Wastewater Treatment Facility regulatory asset over a period of twelve years and the unamortized balance shall be included in rate base;

13. That DEP shall amortize the regulatory liability for overcollections associated with storm securitization over a three-year period;

14. That the agreed-upon accounting adjustments outlined in the Revenue

Requirement Stipulation shall be, and are hereby, approved;

15. That DEP shall track and report on an annual basis the actual spend and employee head count for each coal generation station over the MYRP period in a manner to be agreed upon by DEP and the Public Staff. DEP shall update the Commission on the manner upon which DEP and the Public Staff have agreed to the tracking and reporting of the actual spend and employee head count for each coal generation station;

16. That DEP shall record any cumulative underspend less than $6 million (North Carolina retail) of annual incremental spend for ongoing O&M for DEP's coal generation fleet for discrete programs and targeted categories to a regulatory liability account accrued through the end of the MYRP period (September 2026) and return the underspend to customers in the next general rate case;

17. That DEP shall perform a lead-lag study before its next general rate proceeding and incorporate the results of that study in its next general rate case filing;

18. That DEP's proposed MYRP, reflecting the projected costs associated with the Transmission, Distribution, Fossil/Hydro, Nuclear, Cybersecurity, Solar, and Storage capital investments, as adjusted by the Revenue Requirement Stipulation, as reflected in Abernathy Partial Settlement Exhibits 1 and 2, is just and reasonable and adopted in its entirety;

19. That DEP has demonstrated a reasonable plan to timely complete the MYRP projects;

20. That DEP shall consult with the Public Staff to develop a report on Rider EC. DEP shall file its first report on Rider EC no later than one year from the date of this Order;

21. That DEP shall report on the issue of CIAC related to IAs in its next rate case application;

22. That DEP shall consult with the Public Staff to develop a report on reliability O&M as the Public Staff proposed. DEP shall file its first report on reliability O&M no later than one year from the date of this Order;

23. That DEP shall consult with the Public Staff to develop its Vegetation Management Program Performance report as provided in this Order;

24. DEP shall, in consultation with the Public Staff, file a report on the Hot Springs Cost Benefit Analysis;

25. That DEP may to recover through base rates DEP's costs associated with its DSDR program;

26. That DEP's request to establish the Payment Navigator program shall be, and is hereby approved;

27. That DEP shall be allowed to recover its costs to implement Customer Connect;

28. That the COSS Stipulation shall be, and is hereby approved;

29. That in its next general rate case, DEP shall provide a comprehensive justification for the use of a NCP demand instead of a coincident peak demand for any cost allocation purpose;

30. That the PIMs Stipulation is consistent with N.C.G.S. § 62-133.16 and Commission Rule R1-17B, achieves a measured balance between encouraging behavior and risk/reward to utility shall be, and is hereby approved;

31. That the Power Quality Stipulation, or the pilot program addressed therein, are not approved, but that DEP may file an application for such a pilot program in a separate proceeding;

32. That, consistent with the Affordability Stipulation, DEP's proposed CAP is hereby approved as a three-year pilot;

33. That DEP's proposed CAP and CAR Riders shall be, and is hereby approved;

34. That the shareholder financial contributions, detailed in the Affordability Stipulation, shall be, and is hereby approved;

35.; That DEP shall convene a stakeholder group to meet at least quarterly to consider data and reporting issues related to the CAP. The stakeholder group is directed to develop an annual report on the CAP as provided in this Order;

36. DEP is directed to file a report on the feasibility and proposed structure of a tiered customer assistance program the later of (i) 18 months after the date of this Order, or (ii) when there is one year of data from the CAP Rider;

37. DEP is directed to report on the Affordability Metrics established in this Order in the same manner as it reports on the tracking metrics agreed to in the PIMS Stipulation;

38. That DEP shall consult with the Public Staff to develop a report on the CAP including the number of CAP recipients, CAP administration costs, and the observed impacts of CAP on arrearage management and disconnections for nonpayment;

39. That the revisions to rate schedules, as proposed by DEP or as otherwise modified herein shall be, and is hereby approved;

40. That the revisions to the service riders, as proposed by DEP or otherwise specifically modified herein, including Rider EC and Rider NSC shall be, and is hereby approved;

41. DEP shall notify all SGS customers that customers may now elect the residential rate schedule for detached garages, barns, and other structures on the same residential premise currently served under a residential rate schedule;

42. That DEP shall inform all Schedule SLR customers that the schedule will not be open to new customers as of October 1, 2023;

43. That DEP shall provide via bill insert or separate mailing amendments to its Outdoor Lighting Service Regulations to all customers subject to those Regulations;

44. That DEP shall, before the next rate case, analyze the impacts of transferring customers receiving service under Riders 7 and 57 to other standby service riders and, if that analysis reveals viable options for transferring these customers, DEP shall propose a transition period in its next general rate case to move these customers to other standby service riders over a reasonable period and in a manner that lessens or avoids rate shock;

45. That DEP's rates during the MYRP Rate Period shall reflect a rate of return on equity of 9.8% and embedded cost of debt of 4.03% based on a capital structure consisting of 53% common equity and 47% long-term, for a rate of return of 7.09%;

46. That DEP's shall be allowed to recover certain COVID-related costs that have been deferred, including customer fees waived, bad debt charge-offs, and costs related to employee safety, netted against the COVID-related savings related to printing, postage, employee travel, and certain measures taken by the federal government that benefitted DEP during the pandemic, over a six-year period with no return on the unamortized balance during the amortization period, which shall begin on the effective date of the rates approved in this proceeding;

47. That DEP's request to continue the deferral of bad debt expenses related to the impact of the COVID-19 pandemic is hereby approved. That any payments associated with bad debt amounts should be credited on a monthly basis through the next general rate case proceeding. That DEP should report on a semiannual basis the actual amounts recorded to the deferral and the payments received;

48. That the inflation adjustment proposed by DEP shall be, and is hereby approved;

49. That DEP's request to recover costs incurred related to the Commission's Order in the 2019 Rate Case in the amount of $5.384 million, which are above and beyond the rate case costs provided for in the 2019 First Partial Settlement is hereby approved. Such costs shall be amortized over a three-year period;

50. That DEP is hereby allowed to recover over a three-year period rate case costs in the amount of $6.551 million related to the present proceeding;

51. That DEP's request to include the unamortized balance of rate case expense in rate base shall be, and is hereby denied;

52. That DEP's request to track actual rate case costs from the March 31, 2023 update cutoff date in this proceeding through the date rates become effective for possible recovery in a future rate case proceeding shall be, and is hereby denied;

53. That the following treatment with respect to over-amortizations of regulatory assets shall be, and hereby is approved for purposes of this proceeding:

a. The over-amortization of rate case expense from Docket No. E-2, Sub 1023 of $1,112,000 should be applied to the balance of rate case expense from the Commission's Order in the 2017 Rate Case of $530,000, which will eliminate that balance. The remaining $582,000 of over-amortization should be applied against rate case costs being requested in this proceeding.

b. The over-amortization of severance costs from the Commisioner's Order in the 2019 Rate Case in the amount of $907,000 should not be applied against the rate case costs being requested in this proceeding but instead should be refunded to customers through a one-year rider with interest.

c. The over-amortization of early retired plant in the amount of $13.8 million should be applied against the outstanding rate base balance for the Asheville early retired coal plant authorized in the 2019 Rate Case.

d. The over-amortization of Hurricane Matthew costs from the Commission's Order in the 2017 Rate Case in the amount of $17 million should be treated as follows: first, to recover 2022 incremental Winter Storm Izzy costs, and second, the remaining $2 million credit should be refunded to customers through a one-year rider with interest.

e. Over-amortization of regulatory fees in the amount of $68 thousand should be refunded to customers through a one-year rider with interest.

54. That if DEP receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, DEP shall continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until DEP's next general rate case for a determination of the appropriate ratemaking treatment of such over-amortizations;

55. That DEP is allowed to collect in rates its North Carolina Retail normalized annual level of storm costs in the amount of approximately $22.2 million;

56. That DEP's request for an accounting order for approval to establish a regulatory asset to defer the incremental costs incurred as a result of Winter Storm Izzy shall be, and hereby is approved;

57. That DEP shall be allowed to recover the 2022 incremental Winter Storm Izzy costs of approximately $15 million applying a portion of the over-amortization of Hurricane Matthew costs in the amount of $17 million from the Commission's Order in the 2017 Rate Case;

58. That the remaining amount of over-amortization of Hurricane Matthew costs of approximately $2.0 million, shall be returned to customers through a levelized rider over a period of one year;

59. That DEP's request for an accounting order for the storm balancing account shall be, and is hereby denied;

60. That DEP's request for an accounting order to defer any incremental revenue requirement impacts, including benefits and costs, associated with the IRA and the IIJA, shall be, and is hereby approved;

61. That DEP's request for an accounting order to defer implementation and administration costs associated with the CAP, Payment Navigator Program, and the Tariffed On-Bill program, and PIMs, shall be, and is hereby denied;

62. That the establishment of a regulatory liability as recommended by the Public Staff to address CIAC collected by DEP related to interconnection agreements is not warranted at this time, however, DEP shall report on the issue of how CIAC is recorded in the context of interconnection agreements in its next general rate case application as required by the Revenue Requirement Stipulation;

63. That the Commission finds DEP's provision of electric service to be adequate;

64. That DEP's proposed revisions to its previously approved North Carolina excess EDIT rider (EDIT-4) to reflect additional amounts due to customers, shall be, and is hereby approved, and that the leveled return rate shall be based on a capital structure consisting of 47% long-term debt and 53% equity, an embedded cost of debt of 4.03% and a rate of return on equity of 9.8%;

65. That DEP shall use the base fuel rates, exclusive of the equal percentage allocation, established above in the current (2023) annual fuel adjustment proceeding;

66. That the approved base fuel and fuel-related cost factors by customer class are as follows: 2.808 cents/kWh for the Residential class, 3.097 cents/kWh for the SGS class, 2.580 cents/kWh for the MGS class, 2.138 cents/kWh for the LGS class, and 3.376 cents/kWh for the Lighting class;

67. The production demand allocation method approved for production demand costs using the 12 CP method at NC retail and the modified A&E method for NC retail classes is the most appropriate method for allocating purchased power capacity costs in DEP's annual fuel proceedings;

68. That DEP's proposed residential decoupling mechanism is consistent with N.C.G.S. § 62-133.16 and Commission Rule R1-17B, and the proposed tariff for the associated rider, shall be, and is hereby approved;

69. That DEP's proposed ESM, as modified by the TCA Stipulation, is consistent with N.C.G.S. § 62-133.16 and Commission Rule R1-17B, and the proposed tariff for the associated rider, shall be, and is hereby approved;

70. That DEP shall file the final annual revenue requirements for Rate Years 1, 2, and 3 consistent with the Commission's findings and rulings herein within 10 days of the issuance of this Order in the same format as Jiggetts Partial Settlement Exhibit 1. DEP shall work with the Public Staff to verify the accuracy of the calculations;

71. DEP shall file schedules (North Carolina Retail Operations – Statement of Rate Base and Rate of Return, Statement of Operating Income, and Statement of Capitalization and Related Costs) with the Commission within 10 days of the issuance of this Order, summarizing the gross revenue and the rate of return that DEP should have the opportunity to achieve based on the Commission's findings and determination in this proceeding;

72. That DEP is authorized to adjust its rates and charges in accordance with the Revenue Requirement Stipulation, the TCA Stipulation, and the Supplemental Revenue Requirement Stipulation and findings in this Order effective for service rendered on and after the following date after the Commission issues an Order accepting the calculations required by Ordering Paragraph No. 70;

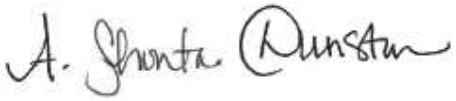
73. That within 30 days of this Order, DEP shall file for Commission approval all rate schedules designed to comply with this Order, accompanied by calculations showing the revenues that will be produced by the rates for each schedule; and

74. That DEP shall submit a proposed customer notice to the Commission for review and approval, and upon approval of the notice by the Commission, shall give appropriate notice of the approved rate increase by mailing the notice to each of its North Carolina retail customers during the billing cycle following the effective date of the new rates.

ISSUED BY ORDER OF THE COMMISSION.

This the 18th day of August, 2023.

NORTH CAROLINA UTILITIES COMMISSION



A. Shonta Dunston, Chief Clerk

Chair Charlotte A. Mitchell dissents in part. Commissioner Kimberly W. Duffley joins in Chair Mitchell's dissent in full. Commissioner Karen M. Kemerait joins in Chair's Mitchell's dissent with respect to the sections on rate of return of equity and the recovery of the deferred COVID-related costs.

Commissioner Daniel G. Clodfelter dissents in part and concurs in part.

DOCKET NO. E-2, SUB 1300

Chair Charlotte A. Mitchell, dissenting in part:

For the reasons set forth below, I dissent from the Order's resolution of the following three issues: rate of return on equity, the recovery of deferred COVID-related costs, and affordability – next steps.

I. Rate of Return on Equity

DEP requested a rate of return on equity (ROE) of 10.4%, and DEP witness Morin testified on cross examination that, due to a tapering in interest rates between the time of filing of his supplemental testimony and the hearing, his recommended rate of return on equity would have been 0.2% lower if recalculated. Tr. vol. 8, 324. The Order concludes that substantial evidence supports the reasonableness of a rate of return on equity ranging from 9.75% to 10.0%, without a downward adjustment due to the MYRP, and ultimately approves 9.8%. I would have approved an ROE of 10.0% for the following reasons.

First, I question whether the Commission regards 10.0% as a Rubicon across which the Commission must not go. I note that in a 2013 general rate case proceeding, DEP and the Public Staff entered into a settlement agreement which, among other things, included agreement on the ROE at 10.2%. Moreover, a historical review of Commission decisions in general rate cases reveals that this Commission has awarded ROEs in excess of 10.0% in many cases in the past. I do not point this out to indicate that an ROE of 10.2% then makes appropriate an ROE of 10.2% now, rather I point this out only to illustrate that the Commission, in the not-too-distant past, has crossed that "symbolic" threshold. *See* Order Granting General Rate Increase, *Application of Progress Energy Carolinas, Inc., for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-2, Sub 1023 (May 30, 2013).

Second, I am concerned that the results of the DCF models are inconsistent with the current capital market environment and bias downward the range of reasonableness presented in the Order. The three models most cited by the expert witnesses in this case – DCF, CAPM, and RPM – involve different approaches to estimating the cost of equity. However, there is a crucial difference between the DCF model and the other two models. While RPM and CAPM involve borrowing costs as a direct input to the model, DCF does not involve borrowing costs as a direct input. Thus, the outcome of the DCF is not directly affected or informed by borrowing costs. Rather, borrowing costs are considered only indirectly in the DCF model. Many of the experts relied on analyst estimates to inform the dividend growth rate, which is a key input to the DCF model, and while some unknown but correlated factor between dividend growth rates and borrowing costs could impact the outcome of the model, there is no input for borrowing costs. Although utility stocks can act somewhat like long-term fixed income securities, causing their prices to fall (and dividend yields to rise) when bond yields rise, that does not necessarily happen in lock-step. Too, the higher betas presently observed indicate that

utility stocks are relatively more correlated to stocks and less so to bonds than they were in the past. The point is that there are structural (i.e., as a result of the model inputs) reasons why the output of the CAPM and RPM will rise due to rising interest rates, when the DCF might not necessarily respond in the same way or to the same extent.

Undisputed in the record of this case is that long-term borrowing costs, both for DEP as well as the U.S. Treasury, have risen significantly and are at multi-year highs. During the pendency of this rate case, DEP's borrowing costs have risen from 3.7% to 4.03%, and since the Commission's decision in the Sub 1219 rate case, 30-year Treasury yields have increased from 2.16% to nearly 3.84% as of May 1, 2023. *See, e.g.,* Tr. vol. 9, 41; tr. vol. 22, 196.

The range of reasonableness identified by the Commission in this case equally weights the DCF, CAPM, and RPM, but of the three, only the DCF model produced results below the range and indicated the cost of equity is lower now than it was in the prior rate case, when the Commission ordered rates to be set using an ROE of 9.6%. Given that the record in this case reflects an increase in borrowing costs and given that the consensus of the DCF models remains below the approved ROE in the last rate case, the results deserve a certain amount of skepticism.

The Commission has at various times in the past placed more or less emphasis on a given model in order to reflect its conclusion as to whether the results of that model accurately reflect the utility's cost of equity. *See, e.g.*, Order Approving Partial Settlement Agreement and Stipulation, Deciding Contested Issues, Granting Partial Rate Increase, Approving Water and Sewer Investment Plan, and Requiring Customer Notice, *Application by Carolina Water Service, Inc. of North Carolina for Authority to Adjust and Increase Rates and Charges for Water and Sewer Utility Service in All Service Areas of North Carolina and Approval of a Three-Year Water and Sewer Investment Plan*, No. W-354, Sub 400, at 44 (Apr. 26, 2023); Order Granting Partial Rate Increase, *Application by Carolina Water Service, Inc. of North Carolina for Authority to Increase Rates for Water and Sewer Utility Service in All Its Service Areas in North Carolina*, No. W-354, Sub 128, at 77-78 (June 10, 1994). Because of the very clear signal sent by the bond market that the cost of capital has risen significantly, an ROE at the top end of the range of reasonableness, implicitly giving the DCF result less weight, is both warranted and necessary at this time.

Third, while the Order gives some acknowledgement to DEP's stressed credit metrics, I am concerned that the decision to approve an ROE of 9.8% will ultimately prolong that stress, leading, potentially, to a downgrade. A downgrade will cost customers. Tr. vol. 22, 186.

DEP witness Newlin explained that credit quality (or creditworthiness) is a term used to describe a company's overall financial health and its willingness and ability to repay all financial obligations in full and on time. Tr. vol. 9, 88. He went on to explain that two major credit rating agencies, Standard & Poor's (S&P) and Moody's Investors Service (Moody's), establish credit ratings for DEP.

Witness Newlin testified that DEP must be in a position to operate and maintain its business without interruption and to refinance maturing debt on time, regardless of financial market conditions. He noted that the financial markets can experience periods of volatility and that DEP must be able to finance its needs throughout such periods. He concluded that strong investment-grade credit ratings provide DEP with greater access to the capital markets on reasonable terms during such periods of volatility. *Id.*

In explaining the qualitative and quantitative factors that rating agencies would consider when assessing DEP's creditworthiness, he testified:

> Quantitative measures are primarily based on operating cash flow and focus on the level at which DEP maintains debt leverage in relation to its generation of cash and its ability to meet its fixed obligations (interest expense in particular) based on internally-generated cash. The percentage of debt to total capital is another example of a quantitative measure. Creditors and credit rating agencies view both qualitative and quantitative factors in the aggregate when assessing the credit quality of a company.

Tr. vol. 9, 90.

He also testified that investors, investment analysts and credit rating agencies, in assessing a utility company's financial strength, consider the allowed rate of return, the cash quality of earnings, the timely recovery of capital investments, the stability of earnings, and the strength of its capital structure. *Id*. at 91. Specifically with respect to ROE, he testified that the allowed return on equity is a key component in the generation of earnings and cash flows and that an adequate return on equity helps ensure equity investors receive fair compensation for their investment while also helping to protect the interests of debt investors. *Id.* at 96. He testified further that a strong capital structure and an adequate return on equity provide balance sheet protection and cash flow generation to support high credit quality. Moreover, he testified that high credit quality creates financial flexibility by providing more readily available access to the capital markets on reasonable terms, and ultimately lower debt financing costs, while a weak capital structure and an inadequate allowed return on equity produces lower earnings and cash flows, lowers credit quality, and may limit financial flexibility. *Id.*

On this record, I am persuaded that ROE is a critical component of creditworthiness. I am also persuaded that high credit quality serves the public interest by putting the utility in a position to compete for capital on the most reasonable terms available and by increasing the potential that the utility will be able to access the capital markets on reasonable terms during all types of market cycles, including periods of high volatility, which, ultimately, lowers borrowing costs passed through to customers.

The Order discusses DEP's stressed credit metrics in the context of capital structure and notes:

> Specifically regarding DEP, Moody's has taken two very recent actions, both of which highlight the immediate credit metric challenges DEP faces. First, in April 2023 Moody's published a "Ratings Action" report (DEP Redirect Newlin Direct Exhibit 1) affirming DEP's A-level rating but at the same time issuing an explicit warning with regard to the principal credit metric utilized by Moody's, the ratio of Funds From Operations (FFO) to debt (FFO/Debt)[1]. In its April 2023 Ratings Action Moody's indicated that it was raising its FFO/Debt downgrade threshold for DEP from 20% to 21% (*Id.* at 4), meaning that while it had in the past forecast a potential downgrade in DEP's credit rating if the FFO/Debt metric stayed below 20% on a sustained basis, it was now forecasting a potential downgrade if the metric stayed below 21% on a sustained basis. This is a particularly worrisome development because, as Company witness Newlin pointed out during his direct testimony, DEP's FFO/Debt ratio has been below 21% for a number of years. Tr. vol. 9, 17-18. In other words, DEP is already operating below the Moody's raised downgrade threshold and has already been doing so on a sustained basis. *Id.* at 18-19.
>
> Between witness Newlin's appearance on direct (May 5) and his appearance on rebuttal (May 16), Moody's issued its May 2023 updated Credit Opinion regarding DEP (DEP Redirect Newlin Rebuttal Exhibit 1), replacing its Credit Opinion issued in March 2022 (introduced into evidence as both Public Staff Cross-Examination Morin Direct and Rebuttal Exhibit No. 15 and DEP Redirect Newlin Direct Exhibit 2). In the updated Credit Opinion, Moody's explicitly referenced as factor that could lead to a downgrade the FFO/Debt ratio "remaining below 21% in 2023." DEP Redirect Newlin Rebuttal Exhibit 1, 2; *see also* Tr. vol. 23, 36-37. Accordingly, Moody's not only alluded to its raised download threshold, but pointedly referenced 2023—this very year.

The Order goes on to note that "the potential for downgrade is not a theoretical issue" and characterizes the Moody's actions as "a series of escalating warnings."

However, I do not agree that an ROE of 9.8%, on this record and at this time, takes those warnings seriously. Even with an equity layer of 53.0%, an ROE of 9.8% does not put the utility in a position to address the challenges it faces.

As was testified to extensively in this proceeding, in November 2022, Moody's placed the entire electric sector on negative outlook as a result of a number of factors including higher fuel costs, higher interest rates, large capital spends, and inflation.

[1] In Moody's parlance FFO/Debt is called "preworking capital cash flow to debt," Tr. vol. 9, 115, or "CFO pre-WC to debt." Both FFO and CFO pre-WC mean the same thing and are a measure of cash flow. *Id.*

Tr. vol. 10, 23. In doing so, Moody's noted that financial metrics for the industry at large are already under pressure with little cushion entering 2023. Subsequent to that action, as mentioned above, Moody's took action with respect to DEP specifically, changing the downgrade threshold from 20% to 21%. *Id.* at 15. The evidence of record demonstrates that DEP is below the downgrade threshold now. Tr. vol. 9, 112.

DEP faces substantial capital needs over the next several years to comply with environmental requirements, to replace and upgrade aging infrastructure, to construct or acquire new generation resources, to upgrade the transmission system, and to satisfy its debt maturities. DEP's capital requirements, including MYRP projects, for the next five years (2022-2026) are projected to be approximately $13.6 billion, which includes $1.3 billion in debt retirements. *Id.* at 98. In the very near term, DEP must retire $300 million of first mortgage bonds, which are due in September 2023. DEP Redirect Newlin Direct Ex. 1, Tr. Ex. vol. 23. DEP witness Newlin testified that DEP's capital requirements, including MYRP projects, are expected to be funded from internal cash generation, the issuance of debt, and equity funding from Duke Energy, as needed. Tr. vol. 9, 98. He explained further that DEP is in a growth cycle, due to the Carbon Plan, and that, while not unusual for utilities in a growth cycle, DEP is a cash flow negative company, which means that its source of funds will not necessarily be limited to debt issuance but must include other sources, such as retained earnings from lowering the dividends paid to the parent or even equity injections from the holding company. *Id.* at 110.

Recognizing some of the challenges ahead for DEP, in a May 2023 credit opinion, Moody's noted that recovery of ongoing coal ash remediation costs and storm costs, along with elevated spending for grid modernization, will maintain pressure on credit metrics. DEP Redirect Newlin Rebuttal Ex. 1, Tr. Ex. vol. 23.

DEP witness Newlin testified that the heightened level of market volatility and uncertainty created by events of recent years have led to an unprecedented number of zero issuance days in the primary debt capital markets. Specifically, he testified that there were 48 zero issuance days in 2022 and already 11 such days to start 2023. Tr. vol. 22, 196. During the hearing, he testified as to a specific recent example, which occurred during the week of the Silicon Valley Bank collapse and sale of Credit Suisse to UBS. He explained that while DEP teed up with two other issuers within the Duke complex to issue that week, the market was very unsettled and they were unable to or decided not to issue into that market. *Id.* at 206. Additionally, evidence in the record, which was not rebutted, shows that borrowing costs increase as credit quality decreases. DEP Redirect Newlin Rebuttal Ex. 2, Tr. Ex. vol. 23. Anticipating the refinancing of low-cost debt the DEP must manage in the coming years – $1.3 billion over the term of the MYRP – potentially impacting DEP's credit quality, such that it might be frozen out of the market or have its borrowing costs significantly increase, is a risk that the Commission should not take. I am concerned that 9.8% takes this risk.

On the record and in light of the very real and complex challenges facing DEP in the coming years – including, to name a few, retirement and/or refinancing of debt in a higher interest rate environment, continued coal ash remediation efforts, construction of

MYRP projects, construction of other transmission and distribution system upgrades necessary to ensure reliability and facilitate the transition, retirement of existing generation, construction of new generation, restoration of system damage caused by extreme weather as a consequence of DEP's being a "storm prone service territory,"[2] fuel price volatility, and labor and materials price volatility – I am not persuaded that an ROE of 9.8%, even with a 53.0% equity layer, particularly given several of the other decisions in this proceeding, will give DEP the cushion it needs to remain consistently above its 21.0% FFO-to-debt downgrade threshold to protect against a downgrade. And, again, I am persuaded that a downgrade will cost customers. As DEP witness Newlin explained in response to cross-examination by the Public Staff, sequential drops in the (Moody's) rating translates to an additional cost to the utility to access capital – each drop can amount to additional incremental borrowing costs of 5-10 basis points but perhaps more given market conditions. Tr. vol 23, 23-24. DEP witness Newlin warns that while allowing DEP to recover less for its cost of equity capital may save customers in the short term, over time as debt matures and must be refinanced, such a measure will impose more cost on customers. *Id.* at 27. Moreover, I note that evidence in the record shows that Georgia Power Company has a credit rating of Baa1, which is two notches below DEP's current credit rating. *Id.* at 24. This lower credit rating results in a higher cost of equity capital of 10.5% for Georgia Power Company and, ultimately, its customers.

DEP witnesses also testified to cost-saving measures, O&M savings, undertaken by DEP since its last rate case. Specifically, DEP witness Abernathy testified:

> We did, you know, implement a series of routine cost-cutting measures to address not only COVID impacts, also mild weather, increased storm costs, things we do in normal course of business when faced with revenue pressures.

Tr. vol. 21, 1332.

While I expect DEP to find every efficiency in the provision of service to its customers and mitigate costs it incurs in providing service to the greatest extent practical, cost-cutting in the face of financial pressure, at a certain point, becomes a concern as it has the potential to impact the reliable operation of the electric system. Given the dynamics of the electric system, including changes in the generating mix, as well as the increasingly extreme summer and winter weather in North Carolina, now is not the time to put DEP in a position to cut to the extent that could impair the reliable operation of the system.

Based on the foregoing, I conclude that the Order's lack of enthusiasm for or lack of consideration of the largely unrebutted testimony of DEP witness Newlin as to credit quality and other evidence of record cited in this dissent is ill-founded. The decision to authorize an ROE of 9.8% has the very real potential to further stress DEP's credit

[2] *See* Moody's Credit Opinion for Duke Energy Progress, LLC, 2 (May 11, 2023); DEP Redirect Newlin Rebuttal Ex. 1, Tr. Ex. vol. 23.

metrics, which will cost customers. Given the real-world challenges that DEP must tackle in the coming years, unlike the majority, I am not willing to take that risk.

Fourth, I note that the Commission recently allowed an ROE of 9.8% for the two largest water and wastewater public utilities in North Carolina. Order Approving Partial Settlement Agreement and Stipulation, Deciding Contested Issues, Granting Partial Rate Increase, Approving Water and Sewer Investment Plan, and Requiring Customer Notice, *Application by Carolina Water Service, Inc. of North Carolina for Authority to Adjust and Increase Rates and Charges for Water and Sewer Utility Service in All Service Areas of North Carolina and Approval of a Three-Year Water and Sewer Investment Plan*, No. W-354, Sub 400 (Apr. 26, 2023); Order Approving Motion on Wastewater Rate Design and Approving Schedules of Rates, Schedules of Connection Fees, and Customer Notices, *Application by Aqua North Carolina, Inc. for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All Its Service Areas in North Carolina and for Approval of a Water and Sewer Investment Plan*, No. W-218, Sub 573 (July 31, 2023). DEP witness Morin testified that when viewing authorized returns on water utilities versus the authorized returns on vertically integrated electric utilities over a long time period, there is a difference typically on the order of 20 to 30 basis points lower for the water utilities. Tr. vol. 9, 32. My review of the record reveals that no party contested or otherwise rebutted this evidence. While I take no issue with and support the Commission's decisions in the recent CWSNC and Aqua cases, I note that at least in recent history, the trend for ROEs for the water/wastewater utilities and electric utilities has more or less mirrored that testified to by DEP witness Morin – until this Order. I must give this evidence some weight in forming my view that 9.8% is not an accurate reflection of DEP's cost of equity capital.

II. COVID Deferral

I dissent as to the Order's treatment of the deferred COVID-related costs. The Order: (1) approves DEP's recovery of the deferred COVID-related costs pertaining to customer fees waived, incremental bad debt expense, and employee safety; (2) reduces these allowed costs by certain COVID-related expense savings for employee travel expenses, printing and postage costs, DEP's filed ERCs, and the carrying cost benefit of the delayed payment of the employer portion of social security tax; (3) does not allow DEP to recover the carrying costs accrued during the deferral period or a return on the unamortized balance during the amortization period; and (4) requires that these costs be amortized over a six-year period.

The Order notes that approximately 90% of the deferred costs incurred are waived customer fees and incremental bad debt expense and concludes that these two costs resulted directly from governmental action, including mandates from the Commission. For this reason, the Order concludes that the costs associated with waived customer fees and incremental bad debt expense are appropriate for recovery from customers. With respect to employee safety costs, the Order concludes that these costs are appropriate for recovery from customers because to provide essential electric service, many of DEP's employees were not allowed the option to work from home and instead had to show up,

in person, at work, at power plants and other facilities, or to repair damage following storms. I agree with these conclusions.

The Order reduces the costs to be recovered by certain COVID-related expenses. I agree that the amount of deferred COVID-related costs should be offset by savings identified by DEP that were directly attributable to the pandemic, which include: (1) reduced employee expense related to reduction in or elimination of travel, and (2) reduced printing and postage costs as a result of the disconnect moratoriums ordered by the Commission. I do not agree with the Order that costs to be recovered should be offset by the carrying cost benefit related to the delayed payment of the employer portion of social security tax, as the benefit received by DEP was simply a temporary deferral from the government and was fully paid by December 31, 2022. Tr. vol. 21, 1291.

I would have allowed recovery of costs associated with remote work, employee stipends and call center costs because I am persuaded that these costs were incurred as a result of the pandemic and facilitated DEP's seamless, uninterrupted and undiminished provision of service to customers during the pandemic. I am persuaded that the call center costs should be recovered, primarily as a result of DEP witness Quick's testimony as to the efforts DEP went to during the pandemic to serve those customers in need who called in seeking assistance. *Id.* at 1276-77. I suspect and anticipate that these efforts are the foundation for a new approach, going forward, to reaching and serving customers in need that will have real, direct impacts on those customers' bills.

In addition, I would have allowed DEP to recover its carrying costs on the deferred balance during the deferral period as well as on the unamortized balance during the amortization period. Evidence in the record indicates that DEP had accrued carrying costs of $12 million on the total incremental deferred costs of $93 million as of March 17, 2023. *Id.* at 1280.

Finally, I would have allowed DEP to recover these costs over a three-year amortization period, coincident with its MYRP.

At the onset of the pandemic, DEP took immediate action to mitigate the hardship to customers and to ensure the continued provision of the essential electric service to all of its customers in North Carolina. Those actions included waiving all disconnections for customers who did not pay their electric bills and waiving customer late payment fees, return check charges, reconnection fees, and residential customers' electronic payment fees. As I see it, DEP took extraordinary action to provide customer support though efforts initiated on its own, ordered by the Commission, and/or resulting from State of Emergency executive orders. Customers were served, even when unable to pay, and DEP carried those balances for customers for many months, now years, in some cases. This provision of service enabled its customers to work from home, attend school from home, and otherwise remain in the home minimizing risk to others. As the AGO pointed out,

> The health and safety of communities are affected by the efforts of all residents to stay home and socially distance to slow the spread of the

coronavirus. Accordingly, entire communities benefit from efforts to keep electric service turned on in households that are struggling.

Reply Comments of the Attorney General's Office, *Joint Petition of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, for Approval of Accounting Order to Defer Incremental Expenses as a Result of COVID-19*, Nos. E-2, Sub 1258, E-7, Sub 1241 (Nov. 30, 2020).

I agree strongly with the AGO that DEP's actions during the pandemic benefitted all customers, not just those who were unable to pay. In addition, DEP's provision of service during the pandemic and disconnect moratorium periods, without the ability to disconnect for non-payment and with the obligation to enter into longer-term payment arrangements, goes to the heart of the regulatory compact.

In my view, the regulatory compact can be framed as follows. In exchange for an exclusive service area sanctioned by the State, the utility accepts an obligation to serve all customers within that service area, subject to regulatory oversight. Additionally, in return for agreeing to commit the necessary capital for the provision of service, the utility must be given the opportunity to earn a fair and reasonable return on that capital. *See generally*, Charles F. Phillips, Jr., The Regulation of Public Utilities, 21, 3d ed. (1993).

I conclude that the record in this proceeding demonstrates that DEP met its obligation under the regulatory compact. It served customers throughout the pandemic-related moratorium period, regardless of whether those customers paid. It had to carry the amounts owed by the customers who could not pay throughout the moratorium, during a period of time when, as the record demonstrates, DEP faced revenue pressures. Tr. vol. 21, 1332. And, DEP was directed by this Commission to enroll automatically customers who had been unable to pay into extended repayment plans. The late fee moratorium, which I view as an incentive for the payment of bills and which was in effect by order of this Commission, was not lifted until September 2022 coincident with the lifting of the State of Emergency declaration related to the pandemic.

Thus, the actions of this Commission obligated DEP: (1) to provide service even to those customers that were not able to pay their bills: (2) to cease to use its approved tools that are incentives for bill payment for a prolonged period of time; and (3) to enter into extended payment plans with customers. The record reflects that DEP complied with the orders of this Commission. No party to this proceeding took issue with DEP's provision of service during this period of time or with the prudency of the costs incurred by DEP to this end. While the Order reflects a balancing of equities to arrive at the final decision, I do not agree with the balance struck. Customers who were unable to pay benefitted during the pandemic and during the extended period of time for repayment of any amounts owed to DEP. All customers benefitted as DEP's actions allowed households in need to continue to have service in their homes during a time when remaining at home was essential to the health and well-being of all. Denying DEP an opportunity to recover all of its costs does not recognize the value that DEP provided to all of its customers. In addition, I note that the denial of the carrying costs is roughly equivalent to 10 basis points, perhaps more. Thus, I am

concerned that this decision compounds the majority's decision to authorize an ROE of 9.8% and that it will erode DEP's financial health, to the detriment of all customers.

The public health situation presented by the pandemic was an unforeseen, unimaginable crisis that impacted the lives of all North Carolinians in many, difficult and, often heart-breaking ways. DEP's efforts to continue the provision of service to all customers during this time and to provide assistance to those who were unable to pay were critical to the health and general well-being of North Carolina. Tr. vol. 21, 1273-74. In my view, aptly captured by the Attorney General's Office, DEP provided service that benefitted all North Carolinians. I do not believe it is appropriate to deny DEP an opportunity to recover all of its costs, including its carrying costs. This Commission ordered DEP to take action, which included carrying costs for customers who could not pay. DEP upheld its obligations under the regulatory compact. This Commission should have done the same.

III. Affordability – Next Steps

As explained in the Order, DEP requested approval of a CAP and two new tariffs, the CAP Rider and the CAR Rider. DEP witness Harris testified that the CAP proposal, initially developed in the LIAC docket, is designed to assist low-income customers who are facing affordability challenges. Under the CAP, eligible customers would automatically receive a $42.00 monthly bill credit for a 12-month period. Customers who are eligible for and receive funds from either the Low Income Energy Assistance Program (LIEAP) or the Crisis Intervention Program (CIP) would qualify for assistance under the CAP. DEP would automatically enroll eligible customers into CAP using a list of customers provided by the North Carolina Department of Health and Human Services (DHHS). The Order also explains that in addition to the $42.00 bill credit on their next 12 monthly bills, DEP will refer CAP customers to other income-qualified weatherization and energy efficiency services that can assist customers with reducing energy usage.

Public Staff witness D. Williamson testified that the concept of the CAP emanated in the LIAC stakeholder meetings, during which a diverse group of stakeholders met over the course of a year to discuss affordability challenges being experienced by low-income customers to propose ways to address those challenges. He testified that one particular proposal (Proposal 24) contained within the LIAC Final Report combined proposals submitted by the NCJC and by Duke and that Proposal 24 received broad support among the LIAC stakeholders. He testified that DEP estimated 60,000 eligible customers would participate and developed its costs associated with the program based on that estimate. Public Staff witness D. Williamson testified regarding the Public Staff's concerns with the cross-subsidization issues created by the CAP, tr. vol. 20, 144, as well as the Public Staff's preference that there be a clear legislative directive for the development and deployment of assistance programs like the CAP. *Id.* at 146. Ultimately, the Public Staff recommend approval of the CAP for a three-year pilot term, running concurrently with the MYRP, on the basis of the uncertainty of CAP-related costs resulting from the unknown number of potential recipients and the potential for the CAP to be more impactful to non-participating customers than anticipated. He also testified as to concern that once an

affordability program is initiated, it would be difficult to end the program regardless of the costs, benefits, or impacts on CAP recipients and non-participating customers. He testified that the three-year pilot period would provide the Commission with an opportunity to evaluate the performance of the CAP. *Id.* at 147.

Sierra Club witness Howat endorsed and advocated for the reporting of certain data at a zip code level primarily to inform program design and targeting of effective energy efficiency and other affordable energy programming. Tr. vol. 18, 201-02. He advocates that the CAP bill credit be tiered based on zip code level data. *Id.* at 219.

As the Order points out, DEP took issue with the recommendation related to the disclosure of zip code level data. Specifically, DEP witness Barnes testified that DEP opposed the sharing of non-public customer information data aggregated at a zip-code level, noting that DEP's Code of Conduct, approved by the Commission in its Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, *Application of Duke Energy Corporation and Piedmont Natural Gas, Inc., to Engage in a Business Combination Transaction and Address Regulatory Conditions and Code of Conduct*, Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682 (Sept. 16, 2016), prohibits the disclosure of aggregated non-public customer data. Tr. vol. 22, 87.

The Order notes that on May 4, 2023, DEP, DEC, Sierra Club, NCJC, et al., and the Public Staff filed the Affordability Stipulation, pursuant to which DEP agreed to withdraw the Low-Income/Affordability PIM it had initially proposed and instead would ensure that a shareholder contribution of $16 million to benefit income-eligible customers would be made as follows: $10 million in support of health and safety repairs that would allow for energy efficiency and weatherization upgrades to homes; and $6 million for the Share the Light Fund, which offers customers bill payment assistance. In addition, DEP agreed to implement the CAP as a three-year pilot, on the Public Staff's recommendation, and to convene a stakeholder engagement process to consider CAP data, metrics, and future CAP program features. The Order also notes that the Affordability Stipulation provides that parties agree to explore "a tiered customer assistance program based on income levels if that feature can be incorporated into the design of the CAP."

The Order approves the Affordability Stipulation but, problematically in my opinion, directs DEP to take action beyond that required by the Affordability Stipulation. Specifically, in a section entitled Affordability – Next Steps, the Order directs DEP to convene a stakeholder group which includes the stipulating parties to the Affordability Stipulation within 90 days of issuance and to invite members of the LIAC to join that stakeholder group. The Order further directs that the group meet quarterly and file a report within six months on the data and information that is to be reported to the Commission annually during each of the three years of the CAP pilot. The Order also directs the stakeholder group to develop a tiered program and directs DEP to file a report relating to the feasibility and proposed structure of a program the later of (i) 18 months after the entry of the order in this proceeding, or (ii) when there is one year of data from the CAP.

As a general matter, I note that the Affordability Stipulation represents the give and take of the parties and that the terms and conditions of the stipulation reflect the compromise each was willing to make, as well as resolution of issues disputed in this proceeding. Among the disputed issues was the term of the CAP, which the Public Staff advocated should be limited, at least initially, to a three-year term in order to provide the Commission with an opportunity to examine the impacts of the program. Whether the CAP should be tiered was also disputed, as the Sierra Club advocated that DEP's proposal for a flat credit be modified to a tiered credit. In addition, the disclosure of zip code level data was a contested issue in this proceeding, with the Sierra Club's advocating that all data be reported at the zip code level and with DEP's opposing that recommendation. Going farther than the settlement of issues between the parties to the Affordability Stipulation upsets the balance the parties struck in the resolution of disputed issues and deprives the Public Staff, and the Commission, of the years of data the Public Staff anticipated would be necessary to make meaningful examination of the CAP before having to design a tiered program.

In addition, well beyond the scope of work envisioned in the Affordability Stipulation, the Order directs that the annual report shall include certain data points at the zip code level and directs that DEP report, on a semi-annual basis, certain data regarding health and safety repairs that are made with shareholder funds, again at the zip code level.

While the Order requires DEP to seek from the Commission any waivers necessary to comply with the Order, it is not clear, based on what the Order requires, whether the Code of Conduct and policies underlying the specific provisions of the Code of Conduct will receive the examination they deserve in any such waiver proceeding. In addition, the Order provides DEP no additional funding for the additional work it directs. The majority directs the collection and reporting of this data, as well as the additional time and effort in a quarterly stakeholder process, without any evidence of record indicating what such effort will cost.

Section III of DEP's Code of Conduct prohibits the disclosure of any "Customer Information" without customer consent, and the Commission has determined in a previous decision that the Code does not even allow for the release of aggregated data except as allowed by the Commission. Order Approving Limited Waiver of Code of Conduct, *Application of Duke Energy Carolinas, LLC, for a Waiver of Code of Conduct Section III A. 2(b) and (f)*, No. E-7, Sub 997 (Feb. 29, 2012). Customer Information is defined, in Section I of the Code, as "Non-public information or data specific to a Customer or a group of Customers, including, but not limited to, electricity consumption, natural gas consumption, load profile, billing history, or credit history that is or has been obtained or compiled by DEC, DEP, or Piedmont in connection with the supplying of Electric Services or Natural Gas Services to that Customer or group of Customers." The fact that a customer has been late, is on a payment plan, or is on a particular rate tariff, including enrollment in CAP and the bills for those CAP customers, seem to fall within the definition of Customer Information.

On this record, which is underdeveloped, I cannot agree with the requirement that DEP disclose to the stakeholder group and report to the Commission the zip code level data required by the Order. There is no evidence in the record as to why the Code of Conduct prohibits the disclosure of this type of information or the policy served by the prohibition. There is no evidence in the record as to why this specific information is necessary for understanding the efficacy and impacts of the CAP pilot. In addition, before directing this type of action, I must be persuaded that customers whose data are being collected and shared, or the communities in which they live, will not be inadvertently harmed by such action. Specifically, I would want to be certain that there is no opportunity, once disclosed to stakeholders or otherwise made public, for such data to be used against a customer in a way that might increase affordability challenges for that customer. I recognize that the data will be anonymous and it may be that collecting and disclosing zip code level data poses no risk in this regard, but the record is not developed on these issues, in particular risks to the customers that the majority is trying to serve. Because I agree that the Code of Conduct adopted by the Commission deserves more respect than that shown by the Order, I would not have imposed additional obligation on DEP.

Finally, I agree with the Public Staff that addressing affordability for the most vulnerable customers is, and must continue to be, a critical focus of the utility and the Commission. However, given the concerns expressed by the Public Staff, as well as by CIGFUR witness Phillips, regarding cross-subsidization, the reduction of customer usage through energy efficiency – actually reducing the amount of electricity that a customer must use and pay for – better serves customers. While I support the give and the take, as well as the outcome, of the Affordability Stipulation, I would not have gone beyond the stipulation, as the majority does, for this reason. In my view, DEP and its stakeholders' resources and efforts are well-spent identifying and developing programs that maximize the deployment of federal funding available for weatherization and energy efficiency, particularly funding that results from recent federal legislation, to the advantage of those customers in need. I see DEP's Residential Income-Qualified Energy Efficiency and Weatherization Program, Order Approving Program, *Application by Duke Energy Progress, Inc. for Approval of Residential Income-Qualified Energy Efficiency and Weatherization Program*, No. E-2, Sub 1299 (Mar. 1, 2023), as the type of program that better addresses energy burden and intensity. I also see the availability of federal dollars available for weatherization as a significant and real opportunity to expand the reach of this program to customers in need and to provide longer term assistance to these customers. My hope is that DEP's resources and attention remain on this program and on the opportunity for its customers created by the availability of the federal funding.

/s/ Charlotte A. Mitchell
Chair Charlotte A. Mitchell

DOCKET NO. E-2, SUB 1300

Commissioner Daniel G. Clodfelter, concurring in part and dissenting in part:

I am in agreement with the Commission's Order in all respects save one, and as to that lone issue I dissent. With respect to all other matters I concur, but I write separately to elaborate two points, one concerning performance incentive measures and the second relating to recovery of rate case expense associated with DEP's prior general rate case, the 2019 Rate Case. I address first the issue as to which I dissent.

I. Revenue Decoupling and Electric Vehicles

It is all very well that DEP's proposal for estimating revenues derived from residential electric vehicle (EV) charging would potentially support and encourage increased adoption of EVs by residential customers.[1] But first, before that worthy objective can be considered, the proposal must fit within the actual language of N.C.G.S. § 62-133.16(c)(2). It does not do so, based on a plain reading of the statute. The statute requires that EV revenues eligible for exclusion from the residential revenue decoupling mechanism are those derived from DEP's EV-specific riders or tariffs, not revenues that are derived from some method of estimation, however reasonable the process of estimation may be. The arguments on this point – and the defects in DEP's methodology for estimation even if estimation were proper in the first place – are well developed in the AGO Post-Hearing Brief at 9-18, and I adopt them here.[2]

II. Performance Incentive Measures

On the matter of performance incentive mechanisms (PIMs), N.C.G.S. § 62-133.16 is not especially demanding, requiring only that "one or more" PIMs be included in a rate application under that section. Even by that modest standard, I find the PIMs offered up pursuant to the PIMs Stipulation underwhelming.[3] Largely if not entirely based on the proposed reliability PIM, however, I am willing to accept that DEP's Application complies with the minimum requirements of the statute.[4] The reliability PIM establishes a target that

[1] AGO witness Nelson challenged whether this claimed linkage actually holds, but for the present I am willing to accept the claim.

[2] I acknowledge that in the PIMs Stipulation DEP agrees to work with the Public Staff and file within 90 days "EV tariffs and/or programs to estimate and update" revenues from EV charging. I do not consider this "and/or" commitment to be sufficient. After DEP has filed and has received approval for specific tariffs for residential EV charging, the decoupling mechanism can be revisited and modified as appropriate.

[3] I will not discuss the PIMs presented in DEP's original rate application since they are no longer before the Commission, except to say that I found the analysis and critique of those proposals by Public Staff witnesses Thomas and D. Williamson, by AGO witness Nelson, by CIGFUR witness Gorman, and by NCJC, et al. witness Posner to be highly persuasive.

[4] I am content to accept, for this first round of ratemaking under the new paradigm, the revised Time Differentiated and Dynamic Rate Enrollment PIM and the Renewables Integration and Encouragement PIM as they are set forth in the PIMs Stipulation, though I do not place much weight on them. I agree with several of the non-stipulating intervenors that those PIMs are not especially well-designed and that they address matters that likely do not require the "push or pull" of a PIM incentive to move the issue forward. Directives and initiatives

responds to the policy goals set forth in N.C.G.S. § 62-133.16(d)(2)(j) and likely also (d)(2)(i); it is well-defined and objectively measurable; and it is primarily, though not solely, under DEP's control. These are all necessary elements for a PIM pursuant to N.C.G.S. § 62-133.16(c)(3).

Though the requirement that it do so is not expressly spelled out in the enabling statute, the reliability PIM is also well-integrated with the other elements of DEP's MYRP application. It will provide some evidence, albeit indirect, of the success of DEP's proposed MYRP investments in transmission and distribution infrastructure over the period of the MYRP. Since these investments lie at the core of the MYRP, it is especially valuable that at least one of the proposed PIMs is linked to that core. Given the new ratemaking environment created by the multi-year ratemaking structure, with the many attendant and new forms of risk and reward for both DEP and ratepayers, I would have preferred to be grappling with PIMs that more directly spoke to the challenges that new ratemaking environment presents. For example, PIMs that would reward DEP for realizing reductions in operating costs and expenses, in order to balance the upward pressure on rates from year-to-year, or PIMs that would incentivize DEP to deliver the capital projects identified and included in the MYRP investment plan on time or under budget, in order to protect against the risk that revenues would have been earned on projects never completed, or delayed, or cancelled due to cost, could have more closely aligned the risks and rewards of the PIMs themselves with the potential risks and rewards of the MYRP.[5]

I do not fault DEP that this did not happen. With no prior history in designing and structuring PIMs and with little specific direction from the statute or from the Commission's rule about how to do so, DEP understandably defaulted to measures that were readily at hand and could be set up and proposed without great effort. Nor do I fault the Commission for not providing, in Rule R1-17B, more explicit guidance for DEP with respect to such things as the preferred or desired policy goals for PIMs and the methods for structuring PIMs to best achieve those goals. The Commission was given the task of implementing the new ratemaking paradigm established by the PBR Statute on a short timetable that simply did not permit an extended process of analysis, review, and stakeholder involvement on such matters. One thing that has been apparent from conversations with commissioners in other jurisdictions, from academic literature on the topic, from presentations on the topic of performance-based ratemaking at conferences, and from the work of the NERP task forces in North Carolina is that successful implementation of a robust system of performance-based incentives requires considerably more time and more stakeholder involvement than was available in the present circumstance. Put

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stemming from the Carbon Plan, the recently approved revised residential NEM tariff, and the revised non-residential NEM tariff approved in this case are likely to provide more than sufficient incentives for interconnection of new renewable resources, for expanded adoption of net metering, and for migration to time-differentiated rate structures. As several intervenors also note, the financial rewards proposed for these PIMs are modest, far less individually and collectively than the statutory cap, and are therefore unlikely to drive any significantly different behavior by the utility than what would otherwise occur without the PIMs.

[5] The reporting requirements set forth in Rule R1-17B(h)(2) and (3) do permit tracking of performance relative to capital projects included in the MYRP, including such matters as project substitutions, delays, and costs relative to projections, but they lack the incentive element that would have been provided by a PIM.

another way, the development of a sound policy and regulatory basis for PIMs – most especially the process for prioritizing and selecting goals for PIMS that are supportive of and integrate well into the larger framework of regulatory policy initiatives – is just not something that could be done in a hurry. In the present instance DEP, the various intervenors and interested parties, and the Commission have done the best that could be done in the time that has been available.

First time attempts to tackle any new challenge – or to take up an old challenge in a new way – may prove rocky and will most likely produce surprises and disappointments. This first MYRP rate case effort has not proved otherwise. What is most important now is that we build upon this experience and spend the time we collectively have between now and when DEP's next MYRP rate case is expected to be filed working to build out a more robust structure for selecting, developing, evaluating, and implementing PIMs. In particular, I believe it would be valuable for DEP and interested stakeholders to engage in a deeper discussion concerning the priority among the various optional policy goals set forth in N.C.G.S. § 62-133.16(d)(2) in order to ensure that the PIMs incorporated into an MYRP reinforce and build upon the policies embodied in the Carbon Plan and in related regulatory initiatives. To this end, I believe the Commission should revisit the recommendations made by the Public Staff and by a number of other intervenors in the original rulemaking docket that the Commission initiate a more extended and in-depth proceeding to put more "flesh on the bones" of the statute and of existing Rule R1-17B.[6] As we noted in our Order adopting Rule R1-17B, "the Commission may choose to initiate dockets to set policy goals for PBRs if it determined in the future that such dockets would be useful."[7] This is our opportunity to build out a more meaningful platform to enable DEP and its ratepayers to benefit from the potential contained in the performance-based ratemaking elements in the PBR Statute. We need to take that opportunity while we have time to do so and before the next MYRP is upon us.

III. Recovery of Additional Rate Case Expense Associated with 2019 Rate Case

The Commission has allowed recovery through the rates established in this case of certain additional rate case expenses associated with and arising out of DEP's prior

[6] E.g., Initial Comments and Proposed Rule of the Public Staff, Rulemaking Proceeding to Implement Performance-Based Regulation of Electric Utilities, No. E-100, Sub 178 (Nov. 9, 2021); AGO Reply Comments, Rulemaking Proceeding to Implement Performance-Based Regulation of Electric Utilities, No. E-100, Sub 178 (Dec. 17, 2021); Comments and Partial Proposed Rules Submitted on Behalf of North Carolina Justice Center et al., Rulemaking Proceeding to Implement Performance-Based Regulation of Electric Utilities, No. E-100, Sub 178 (Nov. 21, 2021); Reply Comments of CIGFUR I, II and III, Rulemaking Proceeding to Implement Performance-Based Regulation of Electric Utilities, No. E-100, Sub 178 (Dec. 17, 2021). The position taken by these parties is also supported by the PBR Regulatory Guidance document issued by the NERP working group, which noted the process of developing, monitoring, and evaluating PIMs is best considered an "iterative" process. See PBR Regulatory Guidance - Implementation Suggestions for the NCUC from the North Carolina Regulatory Process at 19 (Dec. 22, 2020).

[7] Order Adopting Rule, Rulemaking Proceeding to Implement Performance-Based Regulation of Electric Utilities, No. E-100, Sub 178, at 14 (Feb. 10, 2023).

general rate case, (2019 Rate Case).[8] It has done so over the strong objection of the Public Staff, and it has acknowledged the justice of the Public Staff's position. But for one overriding factor, I would be inclined to deny recovery of the additional 2019 Rate Case expense for the reasons well stated by the Public Staff.

At the time of the Second Agreement and Partial Stipulation of Settlement between DEP and the Public Staff on July 31, 2020, DEP already knew that due to the Covid-19 pandemic the hearing of its 2019 Rate Case would be conducted under considerably different circumstances than were customary – that the hearing would be conducted remotely, that portions of the hearing would be consolidated with the hearing of common issues in the then-pending general rate case involving DEC, and that there would likely be delay in hearing those portions of the case that were specific only to DEP. In addition, DEP knew at that time that the Commission's Order in the 2017 Rate Case was on appeal and that there was a risk that order would be reversed in whole or in part and remanded for further proceedings. In its negotiations with the Public Staff, DEP could have taken steps to protect itself from these "known unknowns" affecting rate case expenses, but it did not do so.

The Supreme Court's action to remand to the Commission for further proceedings the order in the 2017 Rate Case came after the close of evidence in the 2019 Rate Case and after the parties had submitted their post-hearing briefs and proposed orders. One possible result of that remand could have been extended re-litigation of issues from the 2017 Rate Case and, even quite possibly, re-opening of the record in the 2019 Rate Case to permit the parties to offer additional evidence or argument concerning the effect of the Supreme Court's ruling on coal ash cost recovery issues in the 2019 Rate Case. In the end, DEP, the Public Staff, the AGO, and others were able to resolve the issues arising from the remand of the 2017 Rate Case in a settlement agreement that was comprehensive in nature and eliminated the risk of prolonged and expense continuing litigation. I consider the result obtained by this resolution to be far less costly for ratepayers in both the short term and in the long run than that alternative. For that reason, and that reason alone, I concur in the Commission's disposition of the issue of supplemental rate case expense associated with the 2019 Rate Case. As does the Commission in its Order, I find the circumstances to be unusual and wish to emphasize that I do not consider this disposition to be precedential for future cases.

/s/ Daniel G. Clodfelter
Commissioner Daniel G. Clodfelter

[8] Strictly, a good portion of these additional expenses can also be said to relate to DEP's next previous general rate case, the 2017 Rate Case, since they were incurred as a result of the Supreme Court's partial reversal and remand of the Commission's Order in the 2017 Rate Case.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 20-G-0101 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Corning Natural Gas Corporation for Gas Service.

Case 16-G-0204 - Petition of Corning Natural Gas Corporation to Defer Leak Survey and Repair Costs Over and Above the Level Last Established in Rates.

ORDER ESTABLISHING RATES AND RATE PLAN

Issued and Effective: May 19, 2021

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on May 19, 2021

COMMISSIONERS PRESENT:

John B. Howard, Interim Chair
Diane X. Burman, concurring
James S. Alesi
Tracey A. Edwards

CASE 20-G-0101 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Corning Natural Gas Corporation for Gas Service.

Case 16-G-0204 - Petition of Corning Natural Gas Corporation to Defer Leak Survey and Repair Costs Over and Above the Level Last Established in Rates.

ORDER ESTABLISHING RATES AND RATE PLAN

(Issued and Effective May 19, 2021)

BY THE COMMISSION:

I. INTRODUCTION

In this Order we establish rates and a rate plan for Corning Natural Gas Corporation ("Corning" or "the Company"). In lieu of the one-year revenue increase of $6,256,000 requested by the Company, we determine that a base rate reduction of $766,000 is required. The revenue requirement supporting the $766,000 decrease is detailed in Appendix 2. In addition to the base rate decrease, a $1.3 million tax surcredit is expiring and the Delivery Rate Adjustment ("DRA") surcharge is forecast to be reduced by $30,000. Including the impact of the expiration of the surcredit and change to the DRA, the total net revenue

impact on ratepayers will be an annual increase of $505,000. The overall revenue increase is 1.77% over the twelve-month period ending January 31, 2022 (“Rate Year”). The average annual bill impact on residential customers during the Rate Year will be an increase of approximately 2.43%. We are also improving the Company’s low-income program. Due to these improvements qualifying low income customers will see an annual bill decrease of approximately 6.14%.

In this Order we also continue a number of positive and negative incentive mechanisms and direct a number of measures to ensure that the Company continues its leak-prone pipe replacement program at its current level, increases its efforts to reduce its leak backlog, minimizes excavation damage to its facilities, maintains its current targets for fast response times in emergencies, fully complies with pipeline safety regulations, increases its work to repair minor leaks in a flood-prone area, improves its coordination with and training of other emergency responders, and establishes a pilot program for residential methane detectors. We also continue and improve the Company’s customer service metrics and programs to minimize complaints, achieve good results on customer satisfaction surveys, and minimize missed appointments, uncollectibles and terminations. We also direct an improvement to the Company’s outreach and education plan, approve a proposal by Staff (accepted by the Company) to eliminate fees for credit and debit card payments, and approve a proposal by Staff (also accepted by the Company) to file a plan for electronic Deferred Payment Agreements.

II. PROCEDURAL BACKGROUND

On February 27, 2020, Corning filed with the New York Public Service Commission (the “Commission”) revised tariff

leaves with an effective date of April 1, 2020 (the "Rate Filing"). Using as a base period the 12 months ended September 30, 2019 (the "Historic Test Year"), the revised tariff leaves would result in an increase in revenues from the Company's gas operations of $6,255,926 in the Rate Year. The Company proposed a three-year rate plan encompassing the initial Rate Year and the two succeeding rate years (the 12-month periods ending January 31, 2023, and 2024), with rate increases of $845,142 and $680,913, respectively. The Company asserted that three years of stand-alone rate increases would impact customers' total bills by 23.4%, 2.56% and 2.01%, respectively. Corning proposed that these increases be levelized over three years, which it asserts would result in an increase of $3,523,167 in each Rate Year, with a total bill impact of 10.93% in each Rate Year.

In the Rate Filing, Corning indicated its openness to developing a staged increase proposal for the 12 month periods ending January 31, 2025, and January 31, 2026. Under the staged increase approach, the Company would recover the carrying costs on incremental plant additions over the previous year. As an alternative to the staged increase, Corning suggested a construction surcharge mechanism ("CSM") that would permit the Company to establish a surcharge factor to be applied to all delivery customers, except those with contractually determined prices, that would permit the Company to cover the carrying costs on projected infrastructure investments.

The Rate Filing included prepared testimony and exhibits constituting Corning's direct case. In Attachment B to the transmittal letter for the Rate Filing, Corning summarized the major drivers behind the proposed rate increases. Of the $6,255,926 Rate Year increase, the costs of mandated initiatives comprise $4,535,731. Of that total, $3,122,469 was in response to legislation enacted by the State of New York, including in

particular the Climate Leadership and Community Protection Act (the "CLCPA"). Corning's filing asserted that such accelerated depreciation is necessary because the CLCPA will shorten the effective life of the Company's existing and future investment in infrastructure. The $3,122,469 increase in revenue requirement from the proposed accelerated depreciation is the largest single issue in this case, amounting to nearly half of the proposed one-year rate increase.

This proceeding was commenced upon the Commission's receipt of the Rate Filing and two Administrative Law Judges (ALJs) were appointed to preside over this case. Procedural and technical conferences were held remotely on April 14, 2020. On April 24, 2020, the ALJs issued a Ruling on Procedure and Schedule, establishing dates for the filing of Company updates, direct testimony of Department of Public Service trial Staff ("Staff") and intervenor parties, rebuttal testimony, and the commencement of evidentiary hearings.

On April 16, 2020, the Company filed Supplemental Direct Testimony, and an exhibit, providing an update on financial market conditions and the effect of those conditions on risk perceived by equity investors. On May 12, 2020, Corning filed updates and corrections to the Rate Filing, consisting of additional direct testimony and revisions to certain exhibits.

On June 26, 2020, Staff and Multiple Intervenors ("MI") filed direct testimony and exhibits, and an individual intervenor-party, Bob Wyman, filed direct testimony. On July 14, 2020, the New York Geothermal Energy Organization ("NY-GEO") filed comments opposing Staff's rejection of Corning's proposal to shorten depreciation service lives. On July 24, 2020, the Natural Resources Defense Council ("NRDC") and the Sierra Club filed joint comments voicing similar opposition to Staff's position. On July 24, 2020, Corning filed

rebuttal testimony and exhibits and Mr. Wyman filed rebuttal testimony. Corning filed supplemental rebuttal testimony on July 30, 2020.

By letter dated August 4, 2020, Corning provided notice of impending settlement negotiations to the Secretary, the ALJs, and the parties in this case. By separate correspondence dated August 7, 2020, Corning set August 21, 2020, as the date for the commencement of settlement negotiations.

On August 10, 2020, the ALJs held a prehearing procedural conference. On August 12, 2020, the Examiners issued a Ruling on Schedule and Procedure, which, among other things, cancelled the evidentiary hearings previously scheduled to commence on August 17, 2020, and required biweekly reports on the status of the settlement negotiations.

The Commission next scheduled information sessions and public statement hearings, which were subsequently held remotely on September 22, 2020. Corning presented its settlement offer at the August 21, 2020 settlement conference. It was anticipated that a Staff counter-offer would be presented at a subsequent settlement conference. Corning provided the ALJs with biweekly reports from September until early March 2021. To accommodate the potential for a settlement, Corning, by letter dated November 20, 2020, agreed to an extension of the statutory suspension period from January 29, 2021, to June 1, 2021 conditioned upon a “make-whole” provision to keep customers and the Company in the same position as they would have been absent the extension. On January 22, 2021, the Commission granted the extension through May 31, 2021.

The ALJs required Corning to provide notice, by March 17, 2021, whether it would request a further extension of the suspension period to continue pursuing settlement. Corning

decided not to request a further extension of the suspension period and notified the ALJs of its decision on March 18, 2021. The ALJs held a prehearing conference on March 19, 2021, and presided over an evidentiary hearing on March 23, 2021. The resulting record consists of 1,259 pages of stenographic minutes and 55 exhibits. At the conclusion of the evidentiary hearing, the ALJs established a briefing schedule, with initial briefs due on April 16, 2021, and reply briefs due on April 23, 2021.

Initial briefs were filed by Corning, Staff, MI, Public Utility Law Project ("PULP"), Utility Intervention Unit ("UIU") and Mr. Wyman. Reply briefs were filed by Corning, Staff, and Mr. Wyman.

On April 29, 2021, Corning filed a letter purporting to address certain aspects of Staff's Reply brief. In response, DPS Staff, PULP, and UIU filed letters asking that Corning's letter be wholly disregarded because the ALJs had not authorized sur-replies and any consideration of the substantive arguments advanced by Corning in its filing would prejudice the other parties. We agree that Corning's letter failed to comply with the Commission's procedural regulations regarding sur-replies and thus will not consider it in this Order.

On May 5, 2021, Corning filed another letter, asking the Commission to take administrative notice of the Governor's recent announcement regarding the accelerated reopening of the New York State economy. We will disregard the request for administrative notice in the May 5 letter as an additional unauthorized sur-reply. In that letter, Corning also provided additional information regarding the status of the collective bargaining agreement between the Company and its employees, and the Company's position on wage increases.

On May 6, 2021, Corning filed a letter stating that the union membership voted on May 5, 2021, to ratify the terms

of the collective bargaining agreement. We have routinely recognized the completion of collective bargaining agreements prior to our decision in a rate case, and as discussed below we will do so here.

III. PUBLIC NOTICE

A notice pursuant to the State Administrative Procedure Act was published in State Register on October 14, 2020.[1] Four comments were filed on the page maintained for this case in the Document and Matter Management System. Three of those comments were filed by residential customers of Corning, while one comment was filed by a developer that undertakes business in Corning's service area.

All four comments expressed opposition to the proposed rate increase. One commenter described the Company's proposed rate increase as clever but bad for customers because it is too large. Commenters also asserted the Commission should not allow accelerated depreciation because the costs of climate change should not be borne entirely by ratepayers. They argued the rate impacts are too great, especially for customers on fixed incomes. Commenters argued it is an especially bad time for an increase in rates because of the adverse economic impacts of the COVID-19 pandemic. They argued that even in good times residents and businesses have trouble paying increased gas rates and pointed out that half the population of Corning's service territory is below the poverty line. Commenters also noted the fact that Corning laid-off or furloughed 700 workers due to the pandemic and that those families are still struggling. Commenters argued that the Company's requested return on equity of 10.2 percent is too high, especially since customers cannot

[1] SAPA No. 41-20-00011-P.

afford a significant rate increase at this time. Commenters pointed out that, while the Company cannot at present terminate service for non-payment, customer arrearages are up because of the pandemic and the full extent of the pandemic's impacts will only be realized when the Company can again begin terminating service for nonpayment. Commenters also claim that Corning can take other measures to cut its costs without raising rates so much. Finally, the developer-commenter stated that natural gas is quickly becoming an energy source of the past and that any additional investments in gas infrastructure will lead to stranded assets.

On September 4, 2020, the Secretary issued a notice of public statement hearings to be held, virtually, on September 22, 2020. Two public statement hearings were held on September 22, 2020, at 1 p.m. and 6 p.m. Four speakers made statements. The Town of Bath opposed the rate increase, describing the Company's proposals for return on equity and depreciation as aggressive and insensitive. The Town expressed concerns about meter accuracy and non-redundant plant serving the Town. The three remaining speakers supported the Company's proposal to depreciate all of the Company's assets within 30 years, both to avoid stranded investments and to promote the transition to the use of renewable energy. One speaker categorically objected to any new gas infrastructure investments by the Company.

IV. RATEMAKING ISSUES

A. COVID-Related Austerity Adjustments

Corning filed its rate case on February 27, 2020, prior to any understanding of the extent, if any, that the COVID-19 epidemic would result in financial impacts to Company's customers. Corning initially sought a Rate Year revenue requirement increase of more than 23%, or over $6.25 million.

In its May 12, 2020 update, Corning still sought a revenue requirement increase of over $6.22 million.

Corning claims that its proposed Rate Year revenue requirement reflects the Company's costs of implementing the Commission's policies and goals related to the CLCPA and its efforts to reduce greenhouse gasses, particularly with regards to the accelerated depreciation of its plant. Staff challenges the increase sought by Corning, arguing that such significant revenue requirement increases are almost unheard of, even during periods of economic prosperity.[2] Staff further argues that the Company's filings were ill-conceived in light of the tremendous revenue and rate impacts during the COVID-19 pandemic. Staff asserts that the impacts of the COVID-19 pandemic are unprecedented both in our lifetimes and in the history of the Public Service Commission.

In testimony Staff recommended a Rate Year revenue requirement increase of $270,773.[3] In its brief, however, Staff recommended four additional adjustments, totaling $47,218, and recommended a Rate Year revenue requirement of $223,555.[4] In recognition that Corning's rate plan was filed prior to any understanding of the economic ramifications of the COVID-19 pandemic, Staff also noted that the Commission may make additional discretionary reductions to the increase in the revenue requirement, if the Commission decides the economic climate faced by Corning's customers warrants further reductions. Staff identified four policy-based austerity adjustments that could be made: 1) modifying the amortization periods for regulatory assets and liabilities; 2) removing the

[2] Staff Initial Brief at 3.

[3] Staff Initial Brief at 1-2.

[4] Staff Initial Brief at 1-2.

allowance for management wage increases in the Rate Year; 3) removing the allowance for certain proposed new employees; and 4) removing the accelerated amortization of leak prone pipe ("LPP"). Staff noted that, although these adjustments were not specifically addressed during the evidentiary hearing, the Commission may nevertheless address them in this Order given that they are based on underlying Commission policies.

Corning charges that Staff's suggested methods for further austerity adjustments lack any record basis. Corning urges the Commission not to make any such adjustments because they would be antithetical to the Commission's ratemaking process.[5] This would be illegal, Corning also argues, because they are unsupported by any clearly established nexus between the customer impacts of the COVID-19 pandemic and the issues raised in this rate case.[6]

We discuss these austerity adjustments in greater detail below.

1) Amortization of Regulatory Assets and Liabilities

As of the end of the Historic Test Year, Corning is expected to have $2.864 million of regulatory assets, i.e., moneys owed to the Company, and $0.916 million of regulatory

[5] Company Reply Brief at 2.

[6] Company Reply Brief at 4 and note 13.

liabilities, i.e., moneys owed to ratepayers.[7] To further mitigate the revenue requirement increase, Staff notes that the Commission could accelerate the return of regulatory liabilities to customers and/or defer the Company's collection through rates of regulatory assets. In choosing an approach, Staff recommends weighing the benefits of mitigating the increase in revenue requirement against the costs, to customers, of delaying the Company's collection of regulatory assets.[8] Staff notes that amortizing all new deferrals over ten years would reduce the revenue requirement by approximately $269,972.[9] Alternatively, Staff notes, the Commission could choose to not amortize any regulatory assets in the Rate Year but pass regulatory liabilities back to customers over five or three years. These two options would reduce revenue requirement by approximately $631,884 or $728,348, respectively.

2) Removing the Allowance for Management Wage Increases in the Rate Year

In testimony and its initial brief, Staff recommended allowing union and management wage increases at the general rate

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[7] Staff Initial Brief at 6. For each new deferred asset or liability, including deferred Pension and OPEB costs, the Company proposes to amortize the forecast balances as of January 31, 2021 over a three-year period. Tr. 86, Ln. 1-2, Tr. 87, Ln. 5-6; Staff Initial Brief at 22. Staff disagrees and recommends that, for all new deferrals, except rate case expenses, the actual deferral balances as of the end of the Historic Test Year be amortized over five years, to mitigate the potential rate increase. Tr. 766, Ln. 10-13. For rate case expense, Staff argues a three-year amortization period is appropriate because the Company has historically entered into three-year rate plan agreements. Staff Initial Brief at 22-23. Staff's initial brief incorrectly stated that these balances were as of the beginning of the Rate Year, however we have been advised that the correct time period of these amounts is as of the end of the Historic Test Period.

[8] Staff Initial Brief at 7.

[9] Staff Initial Brief at 7.

of inflation, or 1.34%.[10] However, based on current economic conditions due to COVID-19, Staff suggested that the Commission could consider reducing management wage increases to 0% in the Rate Year and thereby reduce the revenue requirement by $5,139.

Corning contests Staff's proposed 1.34% limit on wage increases based on the general rate of inflation. Corning argues that a 3% increase in wages is necessary to retain its employees. Corning also challenges Staff's assertion that the Commission is authorized to freeze management wage increases based on general concerns about the adverse economic impacts of the COVID-19 pandemic.

3) Removing the Allowance for Certain Proposed New Employees

Staff suggests the Commission could deny cost recovery for four new employees and a contractor that Corning has proposed.[11] This approach, Staff argues, would reflect the fact that many businesses have imposed hiring freezes, and/or terminated or furloughed employees due to financial constraints associated with the COVID-19 pandemic. Imposing temporary limits on Corning's ability to hire new staff, Staff reasons, may be appropriate given these circumstances. Disallowing all four employees and the contractor would reduce the revenue requirement by approximately $344,513. Alternatively, Staff suggests, the Commission could limit the adjustment to only reflect new employees not yet hired by Corning.

Corning opposes this adjustment, arguing that its testimony demonstrates that these new employees will pursue significant tax and operating cost savings that are expected to

[10] Tr. 689, Ln. 3-9; Staff Initial Brief at 17-18.

[11] The Company has asked for cost recovery relating to retaining an information technology (IT) contractor or hiring four new employees: one IT employee, two gas specialists and one laborer. Staff Initial Brief at 8.

offset their salaries and the Company is prepared to reduce future rates to reflect savings that might be achieved.[12]

4) Removing the Accelerated Amortization of Leak-Prone Pipe

Corning's proposed depreciation expense included the amortization of the remaining plant balance associated with LPP over a seven-year period. In testimony, Staff agreed with amortizing the remaining LPP plant balance over the time period of expected removal, to limit intergenerational inequity and reduce rate base for assets no longer used and useful. However, Staff suggests that, to reduce rate impacts on customers, amortization of the remaining LPP plant balance could be pushed outside of the Rate Year and addressed in a future rate proceeding. This would decrease revenue requirement by approximately $439,206.

Corning argues this proposed adjustment has no record basis and, if adopted, will cause intergenerational inequity and lead to significantly increased rates in the future. Corning asserts that, for these reasons, this proposed adjustment must be rejected by the Commission.[13]

DISCUSSION

Over the past fifteen months, because of the COVID-19 pandemic, all State residents have been forced to make hard sacrifices and to bear up under extraordinary and unforeseen circumstances. The Commission cannot ignore the pandemic-related economic hardships caused by the COVID-19 pandemic. When setting rates, we must make adjustments that account, in some degree, for the economic fallout from the pandemic. Failing to do so would, in effect, impose additional hardships

[12] Company Reply Brief at 10-11.

[13] Company Reply Brief at 11.

on ratepayers at a time of unusual and unexpected need. The austerity adjustments offered by Staff are warranted due to the current extraordinary circumstances. While Corning argues recent events have suggested that things are getting better, that is not a rational basis for ignoring what actually happened in the recent past. On the other hand, it is reasonable to require the Company to bear part of the economic burden of recent events.

Accordingly, we adopt Staff's suggested austerity adjustments relating to removing the allowance for management wage increases in the Rate Year; removing the allowance for certain proposed new employees; and, removing the accelerated amortization of LPP. To further mitigate the revenue requirement increase, we will also accelerate the return of regulatory liabilities to customers and/or defer the Company's collection through rates of regulatory assets. In deciding which approach to take, we have weighed the benefits of mitigating the revenue requirement increase against the costs, to customers, of delaying the Company's collection of regulatory assets. We find that an appropriate balance between these competing concerns can be struck by amortizing all deferred regulatory assets, including both pension and Other Post-Employment Benefits ("OPEB") amounts, over a ten year period, and amortizing all deferred regulatory liabilities, other than the OPEB deferral, over a three year period.[14] This will reduce the increase in the Company's revenue requirement by approximately $466,905. These measures, along with the other austerity measures described above, will mitigate the increase in the Company's revenue requirement, and thereby protect the

[14] See Appendix X for a full list of regulatory deferrals and amortization periods.

interests of ratepayers in the context of the still-ongoing COVID-19 pandemic.

Most of the adjustments identified in the prior paragraph fall squarely within the discretion of the Commission in that they are based on underlying Commission policies and thus need not be grounded in any evidentiary record colloquy. It is sufficient that these matters have been raised and countered in the overall case record in the parties' briefs. Although Corning's request for management wage increases and to hire employees for newly created positions are not associated with any underlying Commission policies, we find that Corning has not met its burden with respect to these matters. Specifically, we find that the need to employ austerity measures far outweighs the Company's need to increase management salaries and add these new positions. We also note that the rates at issue in this case will have a one-year duration and, should the economy recover in the interim, such austerity measures would likely not need to be employed in future rate cases.

B. Estimated Sales and Revenues

1. Sales Forecast

Staff made a number of adjustments to the Company's sales forecasts. The Company accepted all of Staff's adjustments and there are no remaining areas of disagreement on this topic.[15] The calculations in Appendix 2 reflect these agreements.

2. Local Production Revenues

The Company accepts Staff's adjustments to delivery revenues, local production revenues, and other transportation

[15] Staff Initial Brief at 10; Company Initial Brief at 10; Company Reply Brief at 15.

revenues.[16] The calculations in Appendix 2 reflect this agreement.

3. Other Revenue Issues

Staff and the Company also agree to continue the mechanism established in the 2017 Rate Order in Case 16-G-0369[17] estabishing annual revenue targets and sharing the difference between the actuals and the targets between customers (85%) and shareholders (15%). Staff and the Company agreed to revenue imputation targets of $1,650,029 for contract revenues and $263,201 for local production revenues, with no changes to the sharing mechanism.[18] While we accept this agreed-upon mechanism, certain contract revenues are dependant on firm delivery rates, and therefore, the contract revenue imputation target needs to be updated to reflect the base delivery rates adopted in this Order. As such, the imputed contract revenue target is set at $1,472,455.

Staff and the Company also agree to Staff's adjustments to the Revenue Decoupling Mechanism ("RDM") to use a revenue per class RDM target rather than a revenue per customer RDM target,[19] Merchant Function Charge target revenue of $40,813 for credit and collections and $82,884 for gas supply

16 Staff Initial Brief at 10-11; Company Initial Brief at 11; Company Reply Brief at 15-16.

17 Case 16-G-0369, Corning – Gas Rates, Order Adopting Terms of Joint Proposal and Establishing Gas Rate Plan (issued June 15, 2017).

18 Staff Initial Brief at 12-13; Company Initial Brief at 12; Company Reply Brief at 16.

19 Staff Initial Brief at 14; Company Reply Brief at 14.

procurements[20], and an uncollectible rate of 0.464% rather than 0.565%.[21] We accept these agreements.

C. Operation and Maintenance Expenses

1. Direct Labor

Staff and the Company agree on Staff's adjustments to set overtime expenses at a three-year average and to correct the vacation accrual.[22] Three of Staff's other direct labor adjustments are disputed: (1) disllowance of the costs of one proposed new IT employee; (2) disallowance of the costs of the Company's incentive compensation plan; and (3) a wage increase of 1.34% based on the general inflation rate rather than the Company's proposed 3% increase. As discussed below, we agree with the first two of Staff's adjustments. In addition, as discussed above in the section on Austerity Adjustments, we are making additional adjustments regarding new employees and management wage and salary increases. The discussion immediately below relates to the specific adjustments proposed in Staff's testimony.

a. Additional IT Employee.

Staff proposed to disallow the costs of two proposed new IT employees. The Company agreed to the removal of the costs of one of the two.[23] Staff argued that the Company's justification was inadequate because the work of the disputed employee is already being handled by other Company employees, and because the tax savings alleged by the Company to be provided by the work of the new employees were not reflected in

[20] Staff Initial Brief at 14; Company Reply Brief at 16-17.

[21] Id.

[22] Staff Initial Brief at 16; Company Initial Brief at 13; Company Reply Brief at 17.

[23] Staff Initial Brief at 18-19; Company Initial Brief at 13; Company Reply Brief at 17-19.

the Company's case. The Company argues that the tax savings will primarily be reflected in future years (and therefore future rate cases), but agrees to notify the Commission of any savings achieved during the Rate Year. We agree with Staff's adjustment. Given the Company's claim that the savings achieved by the employee will more than cover the salary costs[24] and the Company's failure to offset any of the salary costs by expected savings in its case, we disallow the costs of the disputed employee position.

b. Incentive Compensation Plan

Staff proposed to disallow recovery of the costs of the Company's management incentive compensation plan. As Staff testified, the Commission requires a company to make one of two showings for the costs of such a plan to be allowed: (1) that the Company's total level of employee compensation inclusive of incentive pay is reasonable relative to peer companies and that the incentive pay does not contain performance targets that adversely affect customer interests or are inconsistent with Commission policies; or (2) that the incentive pay plan provides quantifiable or demonstrable benefits to customers, in a financial sense, or in terms of reliability, environmental impact or customer service.[25] Staff argues that the Company failed to make either of these showings with respect to its incentive compensation plan. Staff notes that the Company did not provide a compensation study, and that the majority of incentives focus on goals that benefit shareholders, especially in light of the provision of the plan that no incentive is paid if the earnings target is not achieved.[26] The Company argues

[24] Company Reply Brief at 17.

[25] Tr. 923-926.

[26] Hearing Exh. 36 (DSG-1, p. 1); Tr. 927-928.

that all of its business and the work of all of its employees are dedicated to achieving safety, reliability and customer service and that disallowing the costs of the incentive program would send the wrong signal to the Company's employees.[27] The Company also argues that the plan's financial performance goals benefit customers by maintaining the financial strength and solvency of the Company.[28]

We are not persuaded by the Company's arguments. They are broad, general and would justify virtually any incentive compensation plan. We find that the Company has not made the specific showings required by Commission policy, and we adopt Staff's adjustment.

c. Wage Increase.

Staff proposed in testimony to limit the allowed wage increases in the Rate Year to the general inflation rate. The Company proposes a 3% increase. The Company's union contract expired on April 5, 2021,[29] thus requiring a forecasted amount for the Rate Year. Staff's position was that the Company's forecast of 3% was not appropriate in light of the uncertainties of the COVID pandemic, and that the inflation rate should be used to forecast Rate Year wage increases.[30] Staff agreed that the Company could update the record during the course of this proceeding in the event of material changes in union negotiations,[31] but there were no such updates as of the date briefs were due.[32] The Company in its Initial Brief reported a tentative agreement with the union "consistent with the level

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27 Company Reply Brief at 19.

28 Company Initial Brief at 13-14.

29 Tr. 83.

30 Tr. 687-688.

31 Tr. 688.

32 Staff Initial Brief at 17.

projected by the Company for the rate year".[33] In its Reply Brief the Company stated that it expected a contract to be finalized "within a few days."[34] In its May 5 and May 6, 2021 letters the Company informed the Commission that a collective bargaining agreement has been reached and ratified by union membership vote. In the May 5 letter, the Company stated that, although the agreement provides for wage increases of 3.5%, 3.5% and 3.0% for years 1-3 of the agreement, the Company would adhere to its 3.0% Rate Year request in this case. The Company also argues that its forecast is reasonable and consistent with past history and that it may lose employees if its wages are non-competitive.[35]

We will allow a 3% wage increase applicable to the Rate Year as requested by the Company. It is standard Commission practice to recognize completed collective bargaining agreements during the pendency of the case and, as noted above, Staff agreed that the Company could update the record during the course of the proceeding.[36]

2. Insurance

Staff and the Company agree on the use of the latest-known Gross Domestic Product ("GDP") Deflator as the general inflation rate applied to property insurance, injury and damages, other insurance, life insurance and plan administrative costs.[37] The parties disagree on the Rate Year forecast of health care costs. The Company proposes a 10% increase, and Staff applies the general inflation rate. The Company testified

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33 Company Initial Brief at 16.

34 Company Reply Brief at 19.

35 Tr. 83, 114-115; Company Initial Brief at 15-16.

36 However, we make an additional adjustment to management wages and salaries in the section above on Austerity Adjustments.

37 Tr. 700, 724-725; Company Reply Brief at 21.

that health care costs increase at a higher rate than average cost increases.[38] Staff testified that the general pool of costs subject to the general inflation rate includes some costs that are higher and some costs that are lower than the the general inflation rate, and that the inclusion of health care cots in the general pool of costs is consistent with long-standing Commission practice.[39] Staff cites the June 26, 2014 Order Establishing Rates in Case 13-W-0235[40] as the most recent statement by the Commission of its policy, followed since 1986, that:

> ". . . in the generic inflation pool, by its nature, some costs are fully expected to increase faster than general inflation rates while others are not. If medical expense falls into the former category … that does not alter the fact that the generic inflation rate is an average of inflationary and deflationary changes in the prices of all the various goods and services in the pool. Thus, a deviation between the increase in a single pooled cost item such as medical expense, relative to the average increase, does not justify removing that item from the pool in an attempt to predict it separately."

The Company has not convinced us that we should change this policy, and we adopt Staff's adjustment.

3. Regulatory Expenses and Amortizations

Staff and the Company agree on the amounts of regulatory and rate case expenses, on the assumption that the rate case expense amount will be amortized over three years based on the actual amount as of the time of the Commission decision.[41] However, as previously discussed, we are delaying

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38 Tr. 65-67; Company Initial Brief at 18-19.

39 Tr. 803, 931-933; Staff Initial Brief at 15-16.

40 Case 13-W-0235, United Water New York Inc. – Rates, Order Establishing Rates (issued June 26, 2014).

41 Staff Initial Brief at 21-22; Company Initial Brief at 20-22; Company Reply Brief at 23-24.

the Company's collection of its regulatory assets as a means of mitigating the revenue requirement increase. Accordingly, rate case expenses will be amortized over ten years, consistent with other deferrals assets.[42]

Regarding regulatory expense deferrals, the Company objects to Staff's calculation of the balances as of the end of the Historic Test Year as opposed to forecasting them for the Rate Year. The Company argues that forecasting is "normal Commission practice"[43] but fails to cite any Commission precedent. Staff's position is that the Historic Test Year balances have been audited but that forecasted balances cannot be audited.[44] We accept Staff's position for the reason stated by Staff.

Staff and the Company also disagree on the time period for amortization of deferrals other than rate case expenses. The Company's position is that a period longer than three years risks overlapping with the next rate plan, that prior rate plans have used a three-year period and that the period should be consistent with the period of amortization of rate case expenses.[45] Staff proposes a five-year period given the potential for large rate increases in this case and the uncertainties facing ratepayers during the COVID epidemic.[46] We reject both the Company's and Staff's amortization periods. As discussed, we are modifying the Company's amortization of its regulatory assets and liabilities as a means of mitigating the

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42 A listing of Corning's deferred debits and credits for the rate year ending January 31, 2022 is contained in Appendix 3.

43 Company Reply Brief at 24.

44 Tr. 765-766; Staff Initial Brief at 22.

45 Tr. 117-118; Company Initial Brief at 22; Company Reply Brief at 24.

46 Staff Initial Brief at 23.

revenue requirement increase. Accordingly, all regulatory assets will be collected from customers over ten years and all regulatory liabilities, with the exception of the OPEB deferral, will be passed back to customers over three years.

Staff and the Company also disagree on recovery of $349,547 of survey and repair costs related to cold weather that were incurred in 2015. This issue was first raised in a deferral petition that the Company filed on April 13, 2016[47] and remains pending. The Company proposes a three-year amortization of the amount in question. Staff's position is that the Company's request fails to meet the second prong of the Commission's three-prong test for eligibility for deferral treatment and that the Company's deferral petition should be rejected. The parties agree that the request meets the first prong (the expenses are incremental to the amount allowed in rates) and third prong (the Company cannot earn above its authorized rate of return). The dispute is over the second prong: that the incremental amount must be material and extraordinary in nature. The parties agree that the amount is material, and the dispute is therefore over whether the expenses were extraordinary.

The Staff Accounting Panel testified that the expenses were not extraordinary in nature. Staff's analysis is based on the overall heating degree days during the winter of 2015, noting that the winter was only 1.7% colder than the previous winter.[48] Staff also noted that no other gas utility undertook a similar survey of its entire system in 2015.[49] The Company's

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47 Case 16-G-0204, Corning – Petition to Defer Leak Survey and Repair Costs Over and Above the Level Established in Rates.

48 Tr. 752; Hearing Exh. 37 (SAP-2); Staff Initial Brief at 25-27.

49 Tr. 752-753.

position is that the January to February period of that winter was extremely harsh and that frost was deeper than had been experienced in a long time.[50]

We accept Staff's position and deny the Company's deferral petition. Every winter has periods of time that are significantly colder than average. The appropriate period of time for determining whether cold weather is extraordinary is the entire winter, not the period of a particular cold temperature event. As a whole, the winter of 2015 was not materially colder than the previous winter, and it is a common occurrence for heating degree days in January and February to be significantly colder than average in any winter.[51] We also find it noteworthy that other gas utilities did not undertake a similar systemwide survey and repair program during the winter in question.

4. Pensions and Other Post-Employment Benefits

The Company agreed to Staff's adjustments to pensions and OPEBs except for the appropriate period of amortization of new deferrals. As with regulatory expenses, Staff proposes a five-year period and the Company proposes a three-year period. For the reasons discussed above for regulatory expenses,[52] we reject both the Company's and Staff's recommended amortization periods. The pension and OPEB deferrals will be amortized over ten years.

5. Other Expense Items

Staff and the Company agree on many of the remaining expense items, including the costs of pension and OPEB

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50 Tr. 118-119; Company Initial Brief at 23-24.

51 See data for 2013, 2014 and 2015 in Hearing Exh. 37 (SAP-2, page 321).

52 Staff Initial Brief at 22-23; Company Initial Brief at 25; Company Reply Brief at 27.

management, uncollectibles,[53] the low income program, building services, transportation, outside services, inventory and Other O&M.[54] We accept these agreements.

We also note the parties' agreement to eliminate credit and debit card payment fees charged to customers, with an allowance in rates for the relevant costs. The Commission welcomes this agreement and notes that it will save customers approximately $8,000 per year.[55]

6. Productivity

Staff proposes a 1% productivity improvement imputation in the Rate Year forecast of direct labor expense, employee fringe benefits expense and payroll taxes, asserting that this adjustment reflects a long-standing Commission policy to capture unidentified and/or unquantifiable productivity gains, efficiencies and cost savings that could be realized in a Rate Year.[56] The Company opposes such an adjustment, stating that it has already increased productivity by reducing costs, and that the application of the general inflation rate to health care expenses is effectively a productivity adjustment.[57]

We have explained above why the use of the general inflation rate is appropriate for health care expenses as part of a large pool of expenses that are subject to cost increases.

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53 Staff and the Company agree that the Company may file a petition to defer the difference between actual and rate year forecast uncollectibles. Company Initial Brief at 27. Staff clarifies that such a petition must meet the Commission's standard three-prong test for eligibility. Staff Reply Brief at 7. We concur with Staff's clarification.

54 Company Reply Brief at 28-33 reflects these agreements.

55 Company Initial Brief at 29-30; Staff Initial Brief at 103-104; Company Reply Brief at 29.

56 Tr. 824, 827-828; Staff Initial Brief at 21-22.

57 Tr. 63-67; Company Initial Brief at 35-37.

We are not persuaded that the Company's forecasted Rate Year savings capture the level of productivity improvements that the Company can and should achieve. We are also not persuaded that we should abandon our normal practice of imputing a productivity adjustment, and we therefore adopt Staff's proposed productivity adjustment.

7. Taxes

For the most part, the parties are in agreement on tax issues, including property taxes, payroll taxes, revenue taxes, and state and federal income taxes.[58] Staff and the Company also agree to remove from this case and to address in a future rate case the appropriate deferred federal income tax refund balance associated with the federal income tax savings due to customers for the Tax Cuts and Jobs Act of 2017 corporate federal income tax rate reduction.[59] We accept these agreements. An in depth analysis is required to reconcile and determine the tax savings amount that should have accrued to customers as compared to the amount that has been provided to customers by the tax savings sur-credit implemented October 1, 2018. The amount that is determined to be an over or under passback of savings, will be accounted for in the deferred federal income tax refund account. The only area of disagreement related to taxes is Staff's proposed amortizaton of accumulated deferred income taxes over an average depreciable life of 42 years for long-lived assets as opposed to the Company's proposed 30-year amortization for such assets in accordance with its proposal to depreciate all long-lived assets over a 30 year period.[60] Because we are rejecting the Company's 30-year depreciation proposal, we accept Staff's

[58] Company Reply Brief at 42-47; Tr. 123-124.

[59] Staff Initial Brief at 33; Company Reply Brief at 43.

[60] Company Reply Brief at 46-47.

proposal for amortization of accumulated deferred income taxes.

8. Depreciation Expense

By far the largest issue in this case, amounting to nearly half of the requested rate increase,[61] is the Company's proposal to depreciate its long-lived assets by 2050, a 30-year period, as opposed to the depreciation lives that would result from the Company's depreciation study. The Company argues that, because the CLCPA mandates the reduction of statewide greenhouse gas emissions by 85% of 1990 levels by 2050, the statute "effectively shortens the effective life of the Company's existing and future investments in infrastructure."[62] The Company further argues that the CLCPA will reduce customer demand and increase the cost of capital. The Company asserts that the proposed shortened lives "will allow the Company to continue its systematic replacement program with more internally generated funds."[63] The Company also asserts that delay in adjusting its depreciation rates in this case "effectively kicks the can down the road" and would only lead to higher rates in the future.[64]

Intervenor Bob Wyman supports the Company's proposed useful lives for the same reasons stated by the Company.[65] Mr. Wyman agrees that the Company's proposal involves some degree of speculation, but argues that all ratemaking necessarily involes forecasting and some degree of speculation. In this case, Wyman argues, the Company's proposal is reasonable and well-grounded.[66]

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61 Tr. 53.

62 Tr. 52-53.

63 Id; Company Initial Brief at 38-39,

64 Tr. 123.

65 Bob Wyman Initial Brief at 3-6.

66 Bob Wyman Reply Brief at 5-11.

Staff responds that any change in depreciable lives at this time is premature, because it is unknown how the CLCPA will be implemented.[67] Staff also raises concerns about the bill impact of the change, particularly in light of the COVID epidemic.[68] UIU also opposes the shortening of useful lives proposed by the Company. UIU argues that the CLCPA does not explicity state that all gas assets will be retired by 2050, nor has it been determined what role, if any, pipeline infrastructure will play in reaching the CLCPA's goals.[69] UIU also notes that when the Rochester Gas & Electric ("RG&E") steam system in Rochester was retired as no longer profitable, shareholders took on a significant portion of the costs of retirement and assets were transferred to a newly-formed municipal corporation to create a district loop.[70]

We reject the Company's proposal for shortened asset lives and adopt Staff's adjustment.[71] Logically, the shortening of depreciable lives to a 2050 end-point amounts to a forecast that the Company will cease utility operations by 2050 and that none of its assets at that time will have any value. Because the Company has not met its burden of proof that such a result is probable, we find the Company's position to be speculative. It simply does not follow that a target of 85% statewide greenhouse gas reductions by 2050 means that the Company will close up shop by 2050 and that none of its assets will remain in

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67 Tr. 419-420; Staff Initial Brief at 27-29.

68 Staff Initial Brief at 5-6.

69 UIU Initial Brief at 6.

70 UIU Initial Brief at 7; see Case 28612, Op. No. 84-19, Rochester Gas & Electric Corporation – Steam Rates, Opinion and Order concerning Steam Service and Determining Revenue Requirements (issued July 11, 1984).

71 A schedule showing the Rate Year Depreciation Expense is attached as Appendix 4.

service. It is impossible to make a precise forecast at this time of what the Company's business will look like in 2050, but it is clear that the assumption that the Company will be out of business at that time is at the extreme end of many possibilities. These possibilities include business as usual if the State's climate goals can be met through other means, the total or partial use by the Company of renewable natural gas supplies, and the total or partial conversion of the Company's system to renewable hydrogen gas. All of these alternatives are consistent with a financially healthy gas utility using its existing assets long after 2050. UIU is also correct that in an arguably similar situation when RG&E retired its steam system in Rochester, some of the utility assets still had a useful function, and RG&E's shareholders bore much of the cost of early retirement.

Further, several of the Company's rationales – that the CLCPA will lead in the future to lower revenues and a higher cost of capital and that the adjustment will provide more internally generated funds for the Company's capital program – have little to do with the depreciation expense allowance in this case. If revenues decline and the cost of capital increases in the future, those matters will no doubt be raised by the Company in future rate cases, and the Commission will address them at that time. The fact that the shortened lives would give the Company more internally generated funds for its line repleacement program is not a justification for the depreciation proposal. Such an argument could be made for any ratemaking adjustment that gives the Company more cash at the expense of its customers. The argument does not establish that the proposal is appropriate.

It also appears that the Company itself may not believe in its forecast. If the Company truly believes that its

assets will be valueless in 2050, the financial statements that the Company's parent holding company provides on a quarterly and annual basis to the investment community and to the Securities and Exchange Commission should fully reflect these dire circumstances. However, as admitted by the Company's Chief Financial Officer, although the Company's operations are fully reflected in the parent company's financials, the shortened depreciable lives proposed in this case are not reflected in its recent SEC 10-Q and 10-K financial statement filings.[72] It appears to the Commission that the Company is claiming materially worsened financial circumstances to justify a large rate increase, while at the same time it presents financial statements to the investment community on a business-as-usual basis that is at odds with the greatly reduced asset lives claimed in this case.[73]

For these reasons we reject the Company's proposal to depreciate all of its assets by 2050. We are not just "kicking the can down the road." We find that the Company has not demonstrated that its proposed useful lives are anything more than speculation. The dire circumstances raised by the Company are far from the only potential outcomes from the CLCPA. If in the future we were to take the drastic step of directing a regulated gas utility to cease operations, the mechanism to do so would not be what the Company proposes in this case – a large transfer of cash from ratepayers to shareholders. We note also that the Company proposes no plan for its customers to transition away from gas by 2050 and proposes no limitations on

[72] Tr. 166-167.

[73] We note that shortening the asset lives and increasing depreciation expense in the relevant 10-K and 10-Q financial statements would have negatively impacted the reported net income of the Company's parent.

its use of the proposed incremental ratepayer funding. The implementation of the CLCPA by the Commission will be difficult, complicated and potentially expensive, but however it is implemented the plan will not look like what the Company has proposed here.

9. Inflation

The parties agree on the use of the GDP deflator at the time of the Commission decision as the general inflation rate.[74] We accept this agreement.

D. Rate Base

1. Plant in Service and Capital Spending

Staff and the Company disagree on three plant in service and capital spending issues: (1) an increase by Staff in the capital budget to maintain the replacement of bare steel mains at 10 miles per year, rather than the 8.6 mile figure proposed by the Company; (2) Staff's deletion of two projects that were funded in the Company's preceding rate case but not accomplished; and (3) Staff's proposal to continue the downward-only reconciliation mechanism for net plant investment targets in the Rate Year.

We accept Staff's adjustment to the bare steel main replacement program. The Company proposes to decrease the replacement program from 10 miles to 8.6 miles per year "as a COVID mitigation measure."[75] While we appreciate the concern of the Company in this respect, the public safety concerns related to bare steel pipe outweigh the relatively minor decrease in

[74] Company Initial Brief at 17; Staff Initial Brief at 21; Company Reply Brief at 21, 31.

[75] Company Reply Brief at 39.

capital spending that the Company proposes.[76] We therefore direct the Company to maintain its current program of 10 years of pipe replacement per year, and we make allowance for that capital spending in the revenue requirement calculation in this case.

We also accept Staff's proposed disallowance of capital spending for two projects, totalling $230,000, because the Company's last rate case already included funding for these projects.[77] The Company responds that although it did not perform these projects, it expended the allowed capital budget funds on other projects, and that the Commission's capital budget allowance allows for flexible allocations of funding among projects as long as the total allowed budget is spent.[78] Although we agree with the Company that funding these projects a second time would not amount to double recovery of the allowed capital spending in the last rate case, the Company clearly has placed low priority on these projects. We are not convinced that the Company would complete them if we included their costs a second time in this rate case. In other words, the Company has not met its burden to establish that it would actually complete these projects if given a second bite at the apple, and we are concerned that the Company would again use the allowed funds for other projects of its choosing that it did not reflect in this case. A schedule listing our allowances for Corning's Capital Expense Budget is contained in Appendix 5.

We also accept Staff's proposed continuance from the Company's last rate case of the downward-only reconciliation

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[76] The parties agree on the size of the Company's replacement program for unprotected service lines. Staff Brief at 34.

[77] Tr. 411-414; Staff Initial Brief at 35-36.

[78] Company Reply Brief at 40.

mechanism of net plant targets for the Rate Year.[79] This mechanism protects ratepayers against paying for capital expenditures in an amount greater than the Company incurs. The Company argues that although this mechanism has been used in the Company's last three rate cases, it is unnecessary in a single-year rate case because ratepayers are fully protected by the penalties applicable if the Company misses its leak-prone pipe replacement targets.[80] We agree with Staff and will continue the downward-only reconciliation mechanism. The pipe replacement program penalties cover only a portion of the Company's net plant investments, and we see no reason to remove the protection that the ratepayers have had for the last three rate cases against underspending by the Company. Appendix 6 shows the net plant true-up targets, as well as an example for how the true-up calculation is performed.

2. Reporting Requirements

Staff recommends that the Commission require capital expense and variance reporting. These reports should include: (1) a final variance summary of capital expenditures for all capital projects and programs including all on-going and active construction projects and programs; (2) a narrative explaining any cost or timeline differences from estimated costs in the project's white paper; (3) a narrative on project design, permitting and/or construction status, including a detailed construction schedule for each project, for any ongoing projects; and (4) a description of any new projects or programs with, at minimum, information that is provided in a white paper.[81] Staff asserts that it is important for Staff and the

[79] Tr. 422-423; Staff Initial Brief at 37.

[80] Company Reply Brief at 41.

[81] Tr. 423-424; Staff Initial Brief at 38.

Commission to monitor the Company's capital work, and that the reports should be filed with the Commission Secretary within 45 days after the end of each calendar year.[82]

The Company objects to the proposed reporting on the ground that no allowance is made for the costs of staff to prepare the reports. The Company also objects to a filing date 45 days after each calendar year because the applicable data will not be available until approximately 30 days after the end of the year, leaving only 15 days to compile and file the reports. The Company suggests a minimum of 90 days to file the reports.[83]

We adopt Staff's position on the need for the reports. We are not convinced that the additional reporting costs would be so material that they require an adjustment to the revenue requirement in this case. However, the Company makes a reasonable argument about the due date of the reports. To minimize the incremental costs and difficulty of reporting we accept the Company's proposal that the reports shall be due 90 days after the end of the calendar year.

E. Cost of Money

1. Capital Structure

Staff and the Company dispute certain elements that make up the Company's overall after-tax rate of return. After accounting for these differences, Staff recommends that the Commission provide Corning with a return of 6.07% compared to Corning's request of 7.28%. The difference is attributed to disputes over the cost of equity, the common equity ratio, and the cost of long-term debt. In summary, Staff urges the

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82 Id.

83 Company Reply Brief at 44-45.

Commission to reduce Corning's requested cost of equity from 10.20% to 8.45%, common equity ratio from 50.77% to 48.00%, and cost of long-term debt from 4.45% to 3.91%.[84]

Underlying the dispute are the parties' positions on whether using a stand-alone capital structure is appropriate in this matter. Corning proposes the use of such a structure for setting its rates, while Staff, despite providing an analysis of and corrections to the Company's stand-alone capital structure, proposes the use of a hypothetical capital structure to set rates. Staff's recommendation is based on the assertion that it is not clear if the Company and its parent are employing rational financing policies because of the use of preferred equity in the parent company's capital structure. In this respect, Staff notes that it is difficult to determine the extent to which the parent company is effectively leveraged relative to Corning. Staff posits that it would not be appropriate to authorize rates predicated on either Corning's stand-alone capital structure or the consolidated capital structure of the parent because of this difficulty.[85]

Corning counters that a stand-alone structure is appropriate because the Commission has already determined that its ring-fencing measures are appropriate in its 2013 order approving of a Joint Proposal that established the use of a

[84] Staff Initial Brief 39-40. Staff notes that in terms of revenue requirement, a 1% change in the common equity ratio is worth approximately $51,693 and a 10 basis-points change in return on equity (ROE) is worth approximately $44,612.

[85] Staff Initial Brief 41-43.

holding company between Corning and its parent.[86] Corning also notes that Staff's approach ignores the fact that Corning's relatively small size negatively impacts its ability to access capital markets on reasonable terms.

Staff counters that, although the Commission has sometimes allowed the use of a stand-alone capital structure in setting rates where sufficient ring-fencing exists, Corning's Affiliate Standards do not rise to that level. Staff notes that, while Corning's measures were determined to be adequate for establishing the Holding Company, the Commission has not determined that they are sufficient for rate-setting and observes that there are deficiencies from what Staff determined would be suitable in its testimony in Case 16-G-0257.[87] By way of example, Staff observes that Corning has neither implemented a "golden share" provision to prevent the bankruptcy of the parent company or affiliates from affecting the Company, nor issued a non-consolidation letter to demonstrate the implementation of ring-fencing and the creation of the separate legal and credit entity for the utility subsidiary. Staff states that, in the absence of sufficiently strong ring-fencing provisions, the Commission typically compares the stand-alone capital structure of the utility to the consolidated capital structure of the utility's parent in order to ascertain whether they reflect rational financing policies. Staff concludes that because of its concern the Commission should instead use its

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86 Corning Reply Brief 57-58 (citing Case 12-G-0141, Petition of Corning Natural Gas Corporation for Authority to Form a Holding Company and for Approval of Certain Related Transactions, Order Adopting Terms of a Joint Proposal and Approving Formation of a Holding Company, with Modifications and Conditions (issued May 17, 2013)).

87 Staff Initial Brief 44. Case 16-G-0257, National Fuel Gas – Rates.

proposed hypothetical capital structure.[88]

We agree with Staff. In particular, Corning's reliance on recent Commission-authorized weighted equity cost rates in New York is misplaced. Those rates were set in the context of multi-year plans. Given that Corning is making no commitment to delay any new rate filing, there is no additional risk to its investors. As for the other issues raised by Corning to support its request that we set rates using the Company's proposed equity ratio of 50.77%, we have reviewed the record and do not find it convincing. In particular, the Company's concerns about its cash flow do not convince this Commission that adjustments in favor of higher utility rates are warranted, particularly where the higher equity ratio would be borne by the utility's customer base through higher rates. While the record is devoid of evidence that Corning's requested 50.77% equity ratio is actually achievable, we also do not see it as a viable figure on which to set the Company's rates. As Staff notes, at best, Corning could be expected to maintain a stand-alone equity ratio of only 48.05% during the Rate Year.[89] To set rates based on an equity ratio higher than the actual rate borne by the Company would unreasonably shift additional costs on customers. Thus, we find that it is appropriate in this instance to employ a hypothetical capital structure and set the Company's rates using a common equity ratio of 48.00% as recommended by Staff.

2. Cost Rates

As for cost rates, Staff and the Company agree on the rates we should use for customer deposits and short-term debt.[90]

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88 Staff Initial Brief 44-45.

89 Staff Initial Brief 47.

90 Corning Initial Brief 68.

The Commission annually sets the customer deposits rate which is currently at 0.05% and is appropriate here. For the cost of short-term debt, Corning forecast a rate of 3.78% and it was not disputed by Staff. We adopt this rate.

3. Long-Term Debt

Corning's requested long-term debt cost of 4.45% is based on the actual or estimated cost of each debt issuance reflecting the effective interest to Corning.[91] There is no real dispute as to the embedded costs used to calculate the Company's long-term debt cost. Instead, Staff takes issue with Corning's projections regarding anticipated new debt issuances that Staff disputes and makes an ultimate recommendation for the Commission to employ a long-term debt cost of 3.91%. Staff attributes the difference to a largely resolved correction related to three outstanding loans, as well as to disputes regarding the amounts and timing of the Company's future borrowing and the cost rate estimates for those anticipated new issuances.[92]

The two parties contest the significance of representations from an M&T Bank communication to Corning indicating that the applicable interest rate for new debt securities would be fixed at 4.75%. The Company claims that this figure is reliable and offers in brief another letter from M&T Bank received post-hearing that ostensibly indicates that, at present, Corning would be charged a rate of 4.57%, which the Company says favorably compares to its requested 4.45%.[93] Staff observes that the M&T Bank letter related to the 4.75% interest rate does not communicate any reliable estimate of the interest rate the bank would require on a loan to Corning during the Rate

91 Corning Initial Brief 68.

92 Staff Initial Brief 48.

93 Corning Initial Brief 68.

Year.[94]

Staff proposes that the Commission look instead to other evidence in the case that demonstrates how M&T Bank determines interest rates when it lends to Corning and apply that formula. Staff notes that M&T Bank calculates the interest rate of 10-year loans at 1.80 percentage points above the yield on the 10-year Treasury and it fixes the interest rate on three-year debt at 3.00 percentage points above the three-year Treasury plus the ask side of the three-year London Interbank Offered Rate ("LIBOR") swap spread. At the time of Staff's testimony, the 10-year Treasury was trading at 0.66% and there was no change forecasted, indicating that Corning's 10-year debt issuances during the Rate Year would be issued at a cost of 2.46%. Also, the three-year Treasury was trading at 0.20% with the three-year LIBOR swap spread equal to 0.06%. With the addition of a spread of 3.00%, the resulting estimate for a cost of 3.26% for Corning's three-year debt issuances during the Rate Year.[95]

We agree with Staff that its formula serves as a reasonable proxy for a litigated result. We adopt that approach noting that we are updating the forecasts for the formula's components to reflect the actual Treasury and LIBOR rates as of the issuance of this decision. Given that we are adopting Staff's formula approach as reasonable, we do not need to rely on Staff's alternative grounds which were based on its observation that Corning has failed to comply with the Commission's Order Authorizing the Issuance of Securities in Case 17-G-0346. However, we do agree with Staff that the Company's failures to promptly disclose the terms of the long-

94 Staff Initial Brief 49.

95 Staff Initial Brief 49-50.

term debts that it issued and to demonstrate the reasonableness of those terms is unacceptable. We expect that the Company will comply going forward and so not require a prudence review.

4. Return on Equity

The largest point of contention surrounds the dispute on the authorized ROE. Corning's requested 10.20% is contrasted with Staff's recommended 8.45%, a difference of approximately $8 million in revenue requirement.[96] Disputed issues involve the composition of appropriate proxy groups, appropriate growth rates for the discounted cash flow ("DCF") analyses, key inputs employed in the capital asset pricing model ("CAPM") analyses, the relative weighting of the CAPM and DCF results, and appropriateness of imputing a size premium. Before we discuss the specific disputes, we note that the Commission's concern is in arriving at a just and reasonable result that balances the needs of the Company to access investment capital with those of the customer that must pay the rates we set.

a. Proxy Groups

A proxy group analysis is used as a guide to reduce the potential for bias and inaccuracy in equity analyst estimates. Selected members of a proxy group should be reasonably comparable to the utility seeking new rates as determined by a set of selection criteria. The elements of such criteria can significantly influence the constituents of a proxy group affecting the final ROE recommendations. Thus, it is important to analyze what criteria has been applied to determine whether those constituent members represent similarly situated utilities.

The Company proposed the use of two proxy groups: a group consisting of a combination of gas and electric utilities;

[96] See Staff Initial Brief 39-40.

and a group consisting of gas only utilities all the members of which were included in the combined group. Staff analyzed only a single group consisting of 33 electric utilities and five natural gas utilities. The two parties agreed on certain criteria for proxy utilities such as each utility maintaining investment-grade credit ratings, not being a party to mergers or acquisitions, and having paid regular dividends. While both parties also evaluated prospective companies to determine how much is earned from regulated operations, Staff measured the amount relative to the companies' revenues while Corning measured their earnings relative to net operating income. Lastly, Corning also included a criterion by which a member could not own generation exceeding 60% of its megawatt-hour ("MWh") sales.[97]

Staff challenged both these differences, noting that the MWh criterion was unreasonably restrictive, and that net operating income created a proxy group that was ultimately much riskier in profile than Corning. On this second point, Staff asserted that inclusion of a riskier, non-utility subsidiary would make it more likely that a subsidiary with poor operating income would be included in the Company's proxy group.[98] Corning defended its exclusion of companies owning significant generation resources as not reflecting a similar risk profile to the Company.[99] Similarly, although Staff contested Corning's use of a gas-only proxy group as being too small, the Company countered that Staff's proxy group consisting of 85% electric utilities does not appropriately reflect the risks associated

97 Staff Initial Brief 51-53.

98 Staff Initial Brief 54.

99 Corning Reply Brief 48-49.

with Corning's gas-only distribution operations.[100] Having reviewed the points raised by both parties, we opt to rely on Staff's proxy group as reasonable.

b. Discounted Cash Flow

As Staff notes, the primary challenge in applying the DCF is determining the rate of growth in future dividends that investors expect. Although Staff contested As Staff contends, the Company's DCF models contain inputs that are problematic and some of which the Commission has rejected in past rate matters.

Staff reasonably demonstrates that Corning's use of earnings growth forecasts rather than dividend growth forecasts for the short-term growth rates is not supported by the record and is of questionable validity at best.[101] The Commission has never endorsed a DCF formula that substitutes earnings growth for dividend growth and we do not see anything in the Company's submittals that would make us inclined to endorse it now. We agree with Staff that the assumption is problematic in that it does not serve to measures the present value of future dividends as intended by the DCF.

Additionally, we agree that Corning's long-term growth rate GDP growth rate derived from forecasted inflation rates and historic real economic growth rates is excessive. Staff demonstrates that the use of historic growth rates creates issues where, as here, there is no demonstration that circumstances for the historic period are adequately similar to current economic conditions and likely to provide an accurate forecast for future growth. In particular, we find compelling Staff's illustration that the Company's historically derived long-term growth rate of 5.52% exceeds the forward-looking GDP

[100] Corning Initial Brief 62.

[101] See Staff Initial Brief 57-58.

estimate of 4.00%, published by Blue Chip Economic Indicators, by 152 basis points, while Staff's long-term growth rate of 4.70% exceeds this forward-looking GDP growth forecast by 70 basis points.[102] From this observation, it is clear that the Company's projection is very likely an outlier and of questionable reliability. Lastly, the Commission has already rejected the arguments raised by Corning regarding the timing of future dividend payments and the effect of the time value of money in Case 08-E-0539.[103] On the record before us, we see no reason to revisit that determination as nothing new has been raised in this case. The Commission's observation there that any additional allowance in the Company's ROE based on adjustments for the timing of dividends would be duplicative for those who actually reinvest dividends and unnecessarily generous to those who do not still applies. Thus, consistent with the Commission's 2008 Con Edison Rate Order, we decline to apply an upward adjustment to Staff's DCF results on which our ROE decision here is based.

c. Capital Asset Pricing Model

Both Corning and Staff calculated CAPM results for their respective proxy groups using a traditional and a zero-beta methodology. The parties differ, however, on the inputs used. Specifically, Staff takes issue with three facets of the Company's analysis arguing that Corning used an excessive market-return estimate of 14.27%, used a flawed source for its beta input, and used inappropriate risk-free rates.[104]

Regarding the Company's 14.27% market rate of return

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[102] Staff Initial Brief 59-60.

[103] See Case 08-E-0539, Consolidated Edison Company of New York, Inc. – Electric Rates, Order Setting Electric Rates 125-126 (issued April 24, 2009) (2008 Con Edison Rate Order).

[104] Staff Initial Brief 63-66.

estimate, relying on language from a Federal Energy Regulatory Commission order, Corning omits the use of a long-term component in its methodology relying wholly on a constant growth analysis of the S&P 500 index derived from short-term earnings. Staff challenges the Company's methodology stating that it is unreasonable to assume that near-term earnings growth forecasts formulated for the next three to six years will last into perpetuity. Additionally, Staff dismisses Corning's use of a beta from Bloomberg noting that the Commission has consistently used Value Line betas based on research that demonstrates the superiority of those betas. Nothing was presented in this case to make us reconsider that use in favor of other beta sources, or even as additional beta sources. We also agree with Staff that a five-year measurement period for beta balances the interests of having a long enough timeframe to produce reliable estimates but using recent enough data to reflect current market conditions. Lastly, we agree with Staff that the best forecast of future interest rates is a no-change forecast. There is no credible evidence that forecasts of changes in interest rates are reliable not just in terms of the amount of a predicted change, but even in the direction of any such change. Accordingly, we affirm the Commission's practice of not relying on any published analysts' interest rate forecasts to determine the risk-free rate, but rather to assume a no-change forecast.

Corning challenges Staff's CAPM result as being too low attributing such result to Staff's exclusive use of Value-Line betas,[105] but a review of the record demonstrates that the Staff methodology used follows Commission precedent as reflected in the rate case decisions that have been issued since the

[105] Corning Initial Brief 62.

Generic Finance Recommended Decision.[106] We agree with Staff and will employ its CAPM as updated.

As the Commission did in Case 16-G-0257 when it considered the litigated record to establish rates for National Fuel Gas, we rely on certain longstanding elements of the Commission's finance methodology: the application of both DCF and CAPM analyses to a representative proxy group of utility companies; the use of a two-stage DCF computation with inputs derived from Value Line; the basing of CAPM results on an average of the outcome from standard and zero-beta models with a risk-free rate based on Treasury bonds, market risk premium provided by Merrill Lynch's Quantitative Profiles, and betas taken from Value Line.

d. DCF/CAPM Weighting

The Commission has expressed its preference for a two-thirds weight of the DCF and a one-third weight to the CAPM results on numerous occasions. Relying on more observable and less subjective inputs, the DCF is superior to the CAPM and our preferred weighting for determining an ultimate ROE recognizes that superiority of the DCF. As Staff discusses in its brief, Corning's issues with the differences between the Company's own CAPM and DCF results are products of questionable inputs that we have rejected in this Order. Were the Company to run their respective calculations using our adopted inputs, it is more than likely that the two results would be more closely aligned. In any event, we see nothing new raised that has not been considered and rejected in past Commission orders on the question of weighting the two methodologies and affirm its use herein.

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[106] Case 91-M-0509, Proceeding on Motion of the Commission to Consider Financial and Regulatory Policies for New York State Utilities, Recommended Decision (issued July 19, 1994).

e. Size Premium

As a final issue, Corning urges the Commission to employ a 50-basis point upward adjustment to our final ROE to account for Corning's small size relative to some other New York investor-owned gas utilities.[107] The Company claims that such an adjustment is warranted because its smaller size makes it less able to weather events that adversely impact its revenues and expenses creating additional risk that should be compensated. In the universe of regulated utilities, difficulties faced by other smaller-sized companies are not present for precisely the reasons cited by Staff, e.g., they are heavily regulated and follow similar accounting procedures to each other, they are required to seek regulatory approval for security issuances, and they are provided just and reasonable rates that can be changed upon a demonstration of inadequacy. Thus, we see no reason based on size-alone to provide a premium to the Company's allowed ROE.

Here, we have already declined to apply numerous inputs used by Corning underlying its requested 10.20% ROE. In doing so, we have affirmed past Commission precedent and decided to apply Staff's application of the Commission's generic finance methodology. In so doing, we are allowing the Company to set rates based on an 8.80% ROE which has been updated from the time of Staff's testimony to reflect the most current financial information available. This result is the product of a rational methodology that creates predictability and certainty and balances all interests involved. As such, our allowed ROE and the other cost of money issues resolved in this section contribute significantly to the rate plan included in this Order and our finding that the rates we are setting are, as a whole,

[107] Corning Initial Brief 65-66.

just and reasonable.

F. Overall Revenue Requirement

All the changes discussed above result in a base rate decrease of $0.766 million. As previously stated, a $1.3 million tax surcredit is expiring and the DRA surcharge is forecast to be reduced by $30,000. These changes result in a total net revenue impact of $505,000, which is an overall revenue increase of 1.77% over the Rate Year. The average annual bill impact on residential customers will be an increase of approximately 2.43% and the average annual bill impact on low income customers will be a decrease of approximately 6.14%. However, as new rates will not go into effect until June 1, 2021, these impacts will need to be compressed into the remaining eight months of the Rate Year. To effectuate this compression, the Company must institute a surcharge, allocated to all service classes based on revenues excluding contract customers, that will collect $311,501 from June 1, 2021, through the end of the Rate Year. The amount is comprised of: 1) the tax sur-credit passed back between February 1, 2021, and May 31, 2021; 2) the residential base revenue decrease that the Company should have implemented beginning February 1, 2021, through May 31, 2021; and 3) the non-residential base revenue decrease that the Company should have implemented beginning February 1, 2021, through May 31, 2021. This surcharge shall expire on January 31, 2022. The Company shall reconcile the amounts collected through the compression surcharge to the amounts that should have been collected if rates had gone into effect on February 1, 2021. The residential base revenue collected through the compression surcharge shall not be included in this reconciliation as it will be reflected in the RDM reconciliation. The reconciliation amount shall be booked

to a regulatory asset or liability account, dependent upon the result of the calculation, for the Commission's future determination.

G. Gas Safety

Staff and the Company are mostly in agreement with the revenue adjustment programs applicable to its gas safety initiatives. These initiatives establish safety performance targets in the areas of Leak Management, Infrastructure Enhancement, Emergency Response, Damage Prevention, and Non-compliance with the Commission's Gas Safety Regulations.[108]

Consistent with other gas utilities, Corning's performance is subject to a maximum negative revenue adjustment of 150 basis points for unsatisfactory performance.[109] The parties agree both to the total amount of revenue exposure and as to how the allocation of those points should be made. Corning also has some metrics by which it can earn positive revenue adjustments. There are some minor differences between the parties as to how to measure performance in certain targets and as to the amount and eligibility for positive adjustments.

As of the end of 2019, Corning's system included approximately 70 miles of leak prone pipe remaining to be replaced. The parties have agreed on requiring the Company to replace ten miles per year, which puts Corning on track to conclude its replacement program in approximately seven years. The parties also agree to a target of replacing a minimum of 250 leak prone services per year, concurrently with the main replacement program, and that all gas meters and service regulators be placed outside a customer's building or structure

[108] See Appendix 7 for a full description of all metrics and programs.

[109] Staff Initial Brief 81-82.

on all new and replacement service installations. The parties also agree that any leaks that Corning need repair in a flood control area may be included as part of the leak prone pipe replacement program. This allowance is for the period addressed in this rate proceeding and may not be extended, explaining that to remove and avoid conflicts with the flood control levees that currently contain leak prone pipe with active leaks, if the length of the pipe required to be replaced or relocated is longer than the actual length of the pipe in the ditch, Corning will be allowed to count the entire length of the pipe installed towards its annual 10 mile replacement target.[110] There is additional agreement on the treatment of incremental costs over the $33.96 cost per foot for systematic replacement of distribution main in calendar year 2021 utilized by the Staff Infrastructure and Operations Panel to calculate the average unit cost and on the maintaining of records of the number of miles and feet of main replaced, specifically in the flood control area.[111] Finally, the parties also agree that Corning be subject to a maximum negative revenue adjustment of 15 basis points[112] for not meeting its targets.[113]

There is one area of dispute as to whether Corning should be provided with a positive revenue adjustment for exceeding its annual leak prone pipe replacement targets.[114] The Company raised this possibility for the first time in rebuttal preventing Staff from addressing it in testimony. In brief, however, Staff does not recommend we adopt any positive

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110 Staff Initial Brief 82-83.

111 Staff Initial Brief 83.

112 All basis points applicable to negative revenue adjustments in this section are assessed on a pre-tax basis.

113 Staff Initial Brief 83.

114 Corning Initial Brief 70-71.

adjustment mechanism for leak prone pipe replacement. Staff relies mostly on its agreement with Corning that allows it to count additional pipe replacement in flood control areas towards its annual replacement goal. Staff notes that this allowance already provides an incentive to the Company and allow it to easily achieve its annual target.[115] We agree and decline to adopt a positive rate adjustment in this particular instance.

For leaks on the Company's system, Corning and Staff agree to total leak backlog targets of 45 at the end of 2021 and 40 at the end of 2022. The Company and Staff also agree for Corning to meet a repairable leak backlog of four leaks or fewer until changed by the Commission. As for an assessed revenue adjustment, Corning agrees to Staff's recommendation of five basis points for the total leak backlog target and ten basis points for the repairable leak backlog target.[116] Again, the two parties disagree on the application of positive revenue adjustments, although in this case they agree that some program of positive adjustments should be included in the rate order.

Staff proposes a tiered approach such that two basis points would be awarded for total year-end leaks between 34 and 26, four basis points for total year-end leaks between 25 and 16, and six basis points for fewer than 16. Corning contests the fairness of increasing the risk attached to potential negative revenue adjustments while reducing the additional earnings attached to superior performance.[117] Corning proposes that the respective tiers be valued at four, six and eight basis points, respectively.[118] Staff notes that its recommended

[115] Staff Initial Brief 83-84.

[116] Staff Initial Brief 84.

[117] Staff Initial Brief 84-85.

[118] Corning Initial Brief 70.

positive revenue adjustment amounts are commensurate to other New York gas utilities.[119] Corning's fairness argument is tied to the fact that Staff's recommendation has reduced the revenues available to it under its previous rate plan. However, the Company does not dispute Staff's representation regarding similarly situated gas utilities. Accordingly, we adopt Staff's recommendation.

For Damage Prevention, Staff and Corning agree that its existing categorized program be converted into one metric applicable to total damages assessed on a tiered basis.[120] However, the parties disagree on the maximum exposure to which the Company should be subject. Under Staff's recommended program, for the maximum exposure tier, the target is set at a rate in excess of 2.50 damage incidents per 1000 one call tickets with an associated negative revenue adjustment of 20 basis points. For the second tier, the applicable target is between 2.26 and 2.50 incidents per 1000 one call tickets with an associated negative revenue adjustment of ten basis points. For the third tier, the applicable target is between 2.01 and 2.25 incidents per 1000 one call tickets with an associated negative revenue adjustment of five basis points. After a neutral tier whereby no revenue adjustment is made for performance within 1.51 and 2.00 incidents per 1000 one call tickets, the Company would begin to realize a positive revenue adjustment of five basis points for performance within 1.26 and 1.50 incidents, and ten basis points for a rate below 1.26 incidents.[121]

Corning argues that 20 basis points is too high and

[119] Staff Initial Brief 85.

[120] Corning Initial Brief 73.

[121] Staff Initial Brief 85-86.

proposes a maximum exposure of fifteen basis points. The Company relies on its small size asserting that any change in the number of total damages results in a large impact on its overall damage performance.[122] Staff does not specifically respond to Corning's assertion, but instead observes that when measured against the 2019 statewide average, Corning's performance for overall damages was at a rate of 2.10 per 1000 one-call tickets, worse than the average statewide performance level of 1.84 per 1000 one-call tickets of other gas utilities. Citing to the Company's historic performance, Staff asserts that its recommendation is designed to bring Corning closer to the statewide average.[123] We share Staff's concern regarding the Company's standing vis-à-vis its peer utilities. Accordingly, we adopt Staff's recommended exposure levels, as well as its positive incentive levels to which Corning did not object.

For Corning's emergency response program, Staff and the Company agree to maintain the current targets which require Corning to respond within 30 minutes to 75% of all gas leak, odor, and emergency calls; respond within 45 minutes to 90% of all gas leak, odor, and emergency calls, and respond within 60 minutes to 95% of all gas leak, odor, and emergency calls.[124] Staff has recommended an increase in the maximum exposure applicable to these tiers to twelve, eight, and five from the Company's last rate plan which applied six, four and two, respectively. Staff posits that such an increase will provide an incentive for Corning not to backslide from its current performance which was compliant.[125] Corning counters that there

[122] Corning Initial Brief 73.

[123] Staff Initial Brief 86.

[124] Staff Initial Brief 86-87.

[125] Staff Initial Brief 87.

is no reason to believe that the Company's performance will decrease.[126] Although we agree with Staff's recommended increase in exposure, we think the more compelling reason to do so than Staff's backsliding prevention concern is because such an increase better reflects the Commission's elevated concern with the importance of responding to an emergency situation, particularly in the context of retaining a 150 basis point total maximum exposure, but reallocating that exposure among the complete profile of Corning's gas safety programs.

Finally, for the outcomes of field audits performed by the Department's Gas Pipeline Safety Staff to determine compliance with the Commission's pipeline safety rules and regulations contained in 16 NYCRR Parts 255, 261 and 753, Corning and Staff are in agreement across the program. As an initial matter, for violations that occurred in previous years, Corning owes to customers $153,000 of which the parties to propose to invest $75,000 in the implementation of a Residential Methane Detector Program.[127] We agree.

As to the specifics of violations of the Commission's rules and regulations, the parties agree on a negative revenue adjustment maximum exposure of 75 basis points per year, which is consistent with the pipeline safety performance measure metrics for other New York gas utilities.[128] The 75 basis points would be assessed as follows: for record audits, the first five high risk violations would not subject the Company to any adjustment; from the sixth to the 20th high-risk violations, the Company would incur one-half basis point per violation; and for each high-risk violation greater than 20, the Company would

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[126] Corning Initial Brief 73.

[127] Staff Initial Brief 88, 94-95; Corning Initial Brief 75-76.

[128] Corning Initial Brief 73.

incur one basis point per violation. For the first 15 other risk violations, the Company would not be subject to an adjustment; and for each other risk violation greater than 15, the Company would incur a negative revenue adjustment of one-fourth of a basis point per violation. For field audits and investigations, the Company would incur a negative revenue adjustment of one-half a basis point for each of the first 20 high-risk violations; for each high-risk violation in excess of 20, the Company would incur a negative revenue adjustment of one basis point per violation; and for all other risk violations, the Company would incur a negative revenue adjustment of one-fourth basis point. In addition, for each audit year, a cap on the total record audit violation count of ten basis points will apply to each of the code sections identified in Hearing Exhibit 44 which lists several discrete code sections, with any additional noncompliance of those sections subject to further review and action. As explained by Staff, in any case where the Company has more than ten violations of a single code section, the Company is to develop a corrective action plan to ensure that violations do not continue and should the Company fail to comply with its corrective action plan, the number of violations of a given code section that are in excess of ten would be included with the remainder of the violations being considered for the compliance measure, thereby increasing the basis points at risk in a potential negative revenue adjustment. While the corrective action plan is intended to avoid the need for formal, intensive penalty actions against the Company for each noncompliance, it does not replace the Commission’s ability to pursue a penalty action should the need for such action become apparent so as to compel compliance.[129]

[129] Staff Initial Brief 88-90.

H. Customer Service and Low Income

Since 2017, the Commission has been working with Office of Consumer Services to bring consistency across the State's utilities to their Customer Service Performance Indicator (CSPI) programs, including consolidating the names of the different metrics as well as the timing of annual reporting. We continue that trend and adopt Staff's general recommendations, to which the Company agrees, as to the names and applicability of the various metrics, the requirement that Corning's annual performance review be done on a calendar year basis, and to apply negative revenue adjustments for each metric that are measured in terms of pre-tax basis points rather than specific dollar amounts.[130]

The Company and Staff agree to maintain the current target level of three or fewer customer complaints to avoid a negative revenue adjustment.[131] Additionally, the Company and Staff agree to a Customer Satisfaction Survey minimum score of 87.7% to avoid a negative revenue adjustment. Should its score fall between 86.7% and less than or equal to 87.7%, Corning would be subject to a five-basis point adjustment, ten basis points for a score between 85.7% and less than 86.7%, and fifteen basis points for a score less than 85.7%.[132]

For Appointments Kept, Corning agrees to Staff's recommendation at this time to develop written policies and procedures for scheduling, logging, tracking and verification of service appointments and missed appointment information. Corning also will inform customers that they will receive a $25 credit for a missed appointment either at the time the

130 Corning Initial Brief 78.

131 Staff Initial Brief 98.

132 Staff Initial Brief 98-99.

appointment is made or when confirming the scheduled appointment.[133] Corning should file its proposed policies and procedures with the Secretary within 30 days after issuance of this Order.

While the parties have agreed that Corning will add an Arrearage component to its existing Residential Service Terminations and Uncollectibles metric, Staff and the Company disagree on the targets that would be applied and the associated positive and negative revenue adjustments that would be applied against performance.[134] We, however, will pause this mechanism because, on May 11, 2021, Governor Cuomo signed into law an extension to the moratorium on utility terminations for residential and small businesses for a period of 180 days after the COVID-19 state of emergency is lifted or 180 days after December 31, 2021, whichever is earlier. The moratorium may be in effect much of the Company's rate year, which will impact company operations. Corning's actual termination, arrearage and uncollectible performances will be impacted by the legislation and its performance will not be comparable to either Staff or the Company's proposed performance targets. Staff, the Company and parties can explore reinstating this mechanism in the Company's next rate filing.[135]

The parties are also in agreement that the Company will file a feasibility proposal for an Electronic Deferred Payment Agreements (e-DPA) program.[136] We take no further action on this item, noting that only a proposal is required here. Thus, issues raised by Coring as to its Customer Information

[133] Corning Initial Brief 79.

[134] Corning Initial Brief 79.

[135] See Appendix 8 for the CSPI metrics.

[136] Corning Initial Brief 82.

System not being connected to the Company web page for a secure portal for signatures and any alternatives may be raised in the filed proposal. The parties also agree as to securing support for its Customer Information System. Corning's proposal should be included in the Company's next rate filing, unless such filing is not made within 60 days after issuance of this Order, in which case the proposal should be filed within the same 60 days as a stand-alone compliance item.

Lastly, Corning agrees with Staff's recommendations to increase the existing low-income discount from $8.00 to $16.00 per month and its overall Low-Income Program budget to $250,000.[137]

I. Rate Design Issues

1. Embedded Cost of Service Study

The Company provided an embedded cost of service studay ("ECOS Study") allocating the Company's revenues and expenses to each service class. The ECOS study calculated a rate of return by class for guidance in revenue allocation and rate design, and allocated costs between customer-related (exclusive of demand) and demand-related costs. The ECOS Study classified gas distribution main costs as customer-related on the basis of a minimum system study, a 2-inch main system that would be required without consideration of any demand.[138]

Staff criticized the minimum system study on the basis that the five years of data on 2-inch mains were limited and not reflective of the Company's entire system cost. Staff recommends that the Company use in future cases the average installation cost for 2-inch mains based on the Company's entire

[137] Corning Initial Brief 83.

[138] Tr. 279-289.

plant in service, not just the last five years of costs. Staff further proposes that if the relevant data are unavailable, the Company usea state-wide average customer componenet of the minimum system study to allocate distribution main costs.[139] The Company responded in rebuttal testimony that only a few years of data are necessary for this calculation and that a state-wide average would be meaningless.[140]

Because we are not using the ECOS study to design rates in this case, we do not need to resolve this issue here. We urge the Company to work with Staff prior to filing its next rate case to reach a mutual agreement on the data to use for the minimum system study. If agreement is not reached, we expect to see testimony on this matter in the next case, and we will address the issue at that time.

Multiple Intervenors objects to the Company's use of an "adjusted customer allocation factor" to allocate the costs of mains larger than two inches as this underallocates costs to small customers by attempting to combine the number of customers with the aggregation of larger loads. Multiple Intervenors witness Baudino testified that the Company's adjusted customer allocation factor was highly unusual.[141] The Company took issue with Mr. Baudino's illustrative alternative calculation but did not directly address Mr. Baudino's objections to the adjusted customer allocation factor.[142]

We see merit in Multiple Intervenors' objections to the adjusted customer allocation factor, but because we are not using the ECOS study for rate design in this case, this issue

[139] Tr. 1018-1020.

[140] Tr. 311-313.

[141] Tr. 882-885.

[142] Tr. 314.

can be addressed if necessary in the Company's next rate case.

2. Revenue Allocation

Because of the unresolved disputes about the details of the ECOS study and because the revenue requirement increase we are authorizing in this case is relatively small, we will allocate the revenue requirement increase to each class of service on a uniform basis as proposed by the Company[143] with one exception: we will allocate a slightly larger increase to SC 8 Hamondsport Transportation to move it closer to SC 6 Commercial Transportation, which has similar characteristics. This adjustment was recommended by Staff[144] and not contested by the Company.[145] UIU also concurs with a uniform increase as adjusted by Staff.[146] Multiple Intervenors objects to a uniform rate increase and proposes adjustments to rate design based on the ECOS study,[147] but given the multiple criticisms of the ECOS study and the small revenue increase allowed in this case, we will adopt Staff's position.

3. Rate Design

The Company proposed increases in minimum charges of appproximately 25%.[148] Staff proposed proportional increases across the board to minimum customer charges and all other volumetric charges based on the revenue requirement authorized in this case.[149] The Company accepted Staff's proposal in its Reply Brief.[150] We accept the agreement of the parties. The

[143] Company Reply Brief at 75.
[144] Staff Initial Brief at 78.
[145] Company Reply Brief at 75.
[146] UIU Initial Brief at 10-11.
[147] Multiple Intervenors Initial Brief at 7-9.
[148] Hearing Exh. 11 (CNG-10, PMN-5, p. 1)
[149] Hearing Exh. 46 (SRP-4); Staff Initial Brief at 79.
[150] Company Reply Brief at 76.

final revenue allocation is contained in Appendix 9.

4. Lost and Unaccounted for Gas

For the last two rate proceedings, the Company has operated under an incentive mechanism for Lost and Unaccounted for ("LAUF") gas, which is calculated by subtracting metered deliveries from metered supplies. The mechanism is based on a LAUF Factor of Adjustment, which contains a deadband above which the Company incurs a penalty, and below which the Company achieves an incentive. Within the deadband the Company recovers its actual commodity costs. The current Factor of Adjustment is 1.0037, and the deadband is from 1.0 to 1.0160. The Company recommended no change in these amounts. Staff proposed to reset the Factor of Adjustment to 1.0027 based on the most recent five year period as the Commission did in the last two rate cases, and to reset the deadband at 1.0 to 1.0192.[151] The Company accepted these adjustments in its Reply Brief,[152] and we accept the agreement of the parties.

V. CONCLUSION

We find that the rates and rate plan adopted herein provide just and reasonable rates, terms and conditions, and, consistent with the discussion herein, are in the public interest.

The Commission orders:

1. Corning Natural Gas Corporation is directed to file cancellation supplements, effective on not less than one day's notice, on or before May 26, 2021, cancelling the tariff amendments and supplements listed in Appendix 1 to this Order.

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[151] Tr. 1031-1032.

[152] Company Reply Brief at 76.

2. Corning Natural Gas Corporation is directed to file, on not less than five days' notice, such further tariff revisions as are necessary to effectuate the provisions adopted by this Order, including a total net revenue increase of $505,000 to take effect June 1, 2021, as detailed in Appendix 2 to this Order. Corning Natural Gas Corporation shall serve copies of its filing on all active parties in these cases. Any comments on the compliance filing must be received at the Commission's offices within 14 days of service. The amendments specified in the compliance filing shall not become effective on a permanent basis until approved by the Commission.

3. The requirement of Section 66(12)(b) of the Public Service Law that newspaper publication be completed prior to the effective date of the proposed amendments directed in Clause 2 above is waived and Corning Natural Gas Corporation is directed to file with the Commission, not later than six weeks following the amendments' effective date, proof that a notice to the public of the changes made by the amendments has been published once a week for four successive weeks in newspapers having general circulation in the areas affected by the amendments.

4. Corning Natural Gas Corporation is directed to file within 90 days after the end of each calendar year, beginning with 2021, capital expense and variance reports as described in the body of this Order.

5. The Petition of Corning Natural Gas Corporation to Defer Leak Survey and Repair Costs Over and Above the Level Last Established in Rates in Case 16-G-0204 is denied.

6. Corning Natural Gas Corporation shall, within 30 days of the date of issuance of this Order, file proposed policies and procedures with respect to missed appointments and a customer credit of $25 for missed appointments.

7. Corning Natural Gas Corporation shall, either in its next rate case filing or within 60 days of the issuance of this Order, whichever first occurs, file a proposal for an electronic deferred payment agreements program.

8. These proceedings are continued.

By the Commission,

(SIGNED) MICHELLE L. PHILLIPS
Secretary

CASE 20-G-0101 APPENDIX 1

SUBJECT: Filing by CORNING NATURAL GAS CORPORATION

Amendments to Schedule P.S.C. No. 7 – Gas

Seventh Revised Leaves Nos. 153, 157, 160, 162, 165, 197
Ninth Revised Leaf No. 155

Suspension Supplement Nos. 7,8,9

Corning Natural Gas Corporation
Case 20-G-0101
Statement of Operating Income
For the Rate Year Ending January 31, 2022

	Rate Year As Adjusted Per Staff	Adj No.	Commission Adjustments	Rate Year As Adjusted By the Commission	Revenue Requirement Adjustment	Rate Year with Revenue Increase
Operating Revenues	$ 26,827,587		$ -	$ 26,827,587	$ (765,664)	$ 26,061,923
Purchased Gas	7,227,396		-	7,227,396	-	7,227,396
Operating & Maintenance Expense	9,270,709	1	(697,204)	8,573,505	(3,555)	8,569,950
Depreciation Expense	2,525,056	2	(534,058)	1,990,998	-	1,990,998
Accelerated Recovery of Plant	177,222		-	177,222		177,222
Taxes Other Than FIT	3,153,509	3	(15,303)	3,138,206	(9,687)	3,128,519
Total Operating Expense	22,353,891		(1,246,565)	21,107,326	(13,242)	21,094,084
Operating Income Before Income Taxes	4,473,696		1,246,565	5,720,261	(752,422)	4,967,839
State Income Taxes						
Current	261,981		52,202	314,183	(48,907)	265,275
Deferred	(59,086)	4	26,370	(32,716)	-	(32,716)
Total State Income Taxes	202,895		78,572	281,467	(48,907)	232,560
Federal Income Taxes						
Current	1,062,564		188,849	1,251,413	(147,738)	1,103,675
Deferred	(762,190)	5	54,037	(708,152)	-	(708,152)
Total Federal Income Taxes	300,375		242,887	543,261	(147,738)	395,523
Operating Income	**3,970,427**		**925,106**	**4,895,533**	**(555,776)**	**4,339,757**
Rate Base	$ 68,650,777	6	$ 466,132	$ 69,116,909		$ 69,116,909
Rate of Return	**5.78%**			**7.08%**		**6.28%**

Corning Natural Gas Corporation
Case 20-G-0101
Schedule of Revenues and Operating and Maintenance Expenses
For the Rate Year Ending January 31, 2022

	Rate Year As Adjusted Per Staff	Adj No.	Commission Adjustments	Rate Year As Adjusted By the Commission
Operating Revenues				
Total Delivery Revenues	$ 18,062,487			$ 18,062,487
Merchant Function Charge	246,869			246,869
Total Base Revenues	18,309,356		-	18,309,356
Gas Costs	7,227,396			7,227,396
Revenue Taxes	322,803			322,803
NYSE&G	421,657			421,657
Gas Operating Revenues	26,281,212		-	26,281,212
Other Gas Revenues				
Customer Discounts Forfeited	101,031			101,031
Reconnect Fees	1,992			1,992
Misc. Revenues	2,929			2,929
Local Production Shortfall	213,114			213,114
Local Production - Transportation Short Fall	50,088			50,088
Accelerated Recovery Plant	177,222			177,222
Total Other Gas Revenues	546,375		-	546,375
Operating Revenues	**$ 26,827,587**		**$ -**	**$ 26,827,587**

	Rate Year As Adjusted Per Staff	Adj No.	Commission Adjustments	Rate Year As Adjusted By the Commission
Operating Expenses				
Purchased Gas Other	$ (21,142)		$ -	$ (21,142)
Direct Labor	3,302,952	1A	(150,181)	3,152,771
Supervisory & Indirect Labor	552,394			552,394
Insurance Costs	1,389,575	1B	(82,931)	1,306,644
Regulatory Costs	493,775	1C	(405,698)	88,077
Pensions and OPEBS	1			1
Pension Current	1,072,432			1,072,432
Pension Amortization	222,637	1D	(111,318)	111,319
OPEB Current	64,968			64,968
OPEB Amortization	(72,626)	1E	36,313	(36,313)
Uncollectible Accounts	118,564			118,564
Low Income Program	250,000			250,000
Debit Card & Credit Card fees	44,000	1F	8,242	52,242
Building Services	112,305			112,305
Transportation	195,546			195,546
Outside Services	476,425	1G	(72,000)	404,425
Inventory	166,307			166,307
Other O&M Costs	970,566	1H	80,369	1,050,935
Productivity Adjustment	(67,970)			(67,970)
Total Operating Expense	**$ 9,270,709**		**$ (697,204)**	**$ 8,573,505**

Corning Natural Gas Corporation
Case 20-G-0101
Depreciation Summary
For the Rate Year Ending January 31, 2022

	Rate Year As Adjusted Per Staff	Adj No.	Commission Adjustments	Rate Year As Adjusted By the Commission
Depreciation Expense	2,525,056	2	(534,058)	$ 1,990,998
Depreciation (Bath Line Project 11-G-0280 rate case)	177,222			177,222
Total Depreciation	**$ 2,702,278**		**$ (534,058)**	**$ 2,168,220**

Appendix 2
Schedule 4 of 9

Corning Natural Gas Corporation
Case 20-G-0101
Taxes Other than Income Taxes
For the Rate Year Ending January 31, 2022

	Rate Year As Adjusted Per Staff	Adj No.	Commission Adjustments	Rate Year As Adjusted By the Commission
Property Tax	$ 2,618,171			$ 2,618,171
Payroll Taxes	212,535	3A	(15,303)	197,232
Revenue Taxes	322,803			322,803
Taxes Other Than Income Taxes	**$ 3,153,509**		**$ (15,303)**	**$ 3,138,206**

Corning Natural Gas Corporation
Case 20-G-0101
Rate Base Summary
For the Rate Year Ending January 31, 2022

	Rate Year As Adjusted Per Staff	Adj No.	Commission Adjustments	Rate Year As Adjusted By the Commission
Net Utility Plant				
Plant in Service	$ 98,562,604	6A	104,242	$ 98,666,846
CWIP-Non Interest Bearing	3,182,055			3,182,055
Plant Allocated to Subsidiaries Operations	(817,715)			(817,715)
Plant Reserves				
Normal Depreciation	(26,268,942)	6B	253,197	(26,015,745)
Accelerated Recovery-Root Well/ Upgrades	(2,689,522)			(2,689,522)
Accelerated Recovery-Virgil	(1,000,000)			(1,000,000)
Accelerated Recovery-Bath	(1,569,704)			(1,569,704)
Accelerated Recovery-Other	(52,724)			(52,724)
Total Net Plant	69,346,052		357,439	69,703,491
Working Capital				
Material and Supplies	1,754,033			1,754,033
Prepayments	1,588,832			1,588,832
Cash Working Capital	926,215	6C	(27,063)	899,152
Total Working Capital	4,269,079		(27,063)	4,242,017
Deferred Debits	1,498,815	6D	164,637	1,663,452
Deferred Credits	(382,449)	6E	(78,677)	(461,126)
Unamortized Debt Discount & Expense	94,284			94,284
Accumulated Deferred Income Taxes	(9,946,487)	6F	49,796	(9,896,692)
Total Rate Base	64,879,295		466,132	65,345,427
Earnings Based Capitalization Adjustment	3,771,482			3,771,482
Rate Base as Adjusted	**$ 68,650,777**		**$ 466,132**	**$ 69,116,909**

Corning Natural Gas Corporation
Case 20-G-0101
Calculation of State Income Taxes
For the Rate Year Ending January 31, 2022

	Rate Year As Adjusted Per Staff	Adj No.	Commission Adjustments	Rate Year As Adjusted By the Commission
Operating Income Before Income Taxes	$ 4,473,696		$ 1,246,565	$ 5,720,261
Interest Expense	(1,382,499)		(37,760)	(1,420,259)
Amort of Excess Book Depreciation Reserve	(151,619)			(151,619)
ADR Normalized	18,100			18,100
Book Depreciation Expense	5,158,266			5,158,266
Deduct Tax Depreciation (less accelerated)	(4,659,039)			(4,659,039)
Rate Case Cost 2016	95,000		(82,333)	12,667
Amortization of Gas Specialist	(3,997)		2,221	(1,776)
Other Surcharges Applied to Plant	177,222			177,222
Deferred Net Plant Due	(24,624)		13,674	(10,950)
Rate Case 2020	211,967		(148,377)	63,590
Safety & Reliability Shortfall	29,372		(14,686)	14,686
Customer Affiliate Allocation Shortfall	17,557		(8,778)	8,779
Customer Make Whole Increase	18,397		(9,198)	9,199
Leak Repair/Survey	(0)			(0)
Pass Back of Interest on Over Collection	(57,912)			(57,912)
Fixed Interest	119,561		(59,781)	59,780
Customer Incentive	12,800		(6,400)	6,400
2019 mismarks	-		(2,011)	(2,011)
Leak backlog, total damages and mismarks for 2016, 2017 and 2018	-		(29,372)	(29,372)
Updated NRA balance	-		(14,520)	(14,520)
PP OPEB	-		(38,608)	(38,608)
Deferred Credits - 2016 Regulatory Liability	(4,704)		(3,137)	(7,841)
Deferred Credits - 2017 Regulatory Liability	(3,671)		(2,447)	(6,118)
Deferred Credits - 2018 Regulatory Liability	(3,397)		(11,945)	(15,342)
Deferred Credits - 2019 Regulatory Liability	(10,000)		10,000	0
Total Adjustments for Taxable Income	(443,221)		(443,458)	(886,679)
	939,278			533,580
Tax Income	$ 4,030,475		$ 803,107	$ 4,833,582
Rate	6.50%			6.50%
Current SIT	261,981		52,202	314,183
Total Current State Income Tax	**$ 261,981**		**$ 52,202**	**$ 314,183**

	Rate Year As Adjusted Per Staff	Adj No.	Commission Adjustments	Rate Year As Adjusted By the Commission
ADR Normalized	(1,176)			(1,176)
ACRS Normalized	(32,450)			(32,450)
Other Surcharges applied to plant	(11,519)			(11,519)
Deferred Net Plant Due	1,601		(889)	712
Rate Case 2016	(6,175)		5,352	(823)
Safety & Reliability Shortfall	(1,909)		955	(955)
Customer Affiliate Allocation Shortfall	(1,141)		571	(571)
Customer Make Whole Increase	(1,196)		598	(598)
Gas Specialist	260		(144)	115
Leak Repair/Survey	0		-	0
Pass Back of Interest on Over Collection	3,764		-	3,764
Fixed Interest	(7,771)		3,886	(3,886)
Customer Incentive	(832)		416	(416)
Def Debit-FIT Refund	(0)		-	(0)
2019 mismarks	-		131	131
Leak backlog, total damages and mismarks for 2016, 2017 and 2018	-		1,909	1,909
Updated NRA balance	-		944	944
PP OPEB	-		2,510	2,510
Def Debit-Rate Case 2020	(13,778)		9,645	(4,133)
Deferred Credits - 2016 Regulatory Liability	306		204	510
Deferred Credits - 2017 Regulatory Liability	239		159	398
Deferred Credits - 2018 Regulatory Liability	221		776	997
Deferred Credits - 2019 Regulatory Liability	650		(650)	(0)
Amortization of Accelerated Recovery Deferred Tax	11,822			11,822
Total Deferred State Income Tax	**$ (59,086)**	4A	**$ 26,370**	**$ (32,716)**

Corning Natural Gas Corporation
Case 20-G-0101
Calculation of Federal Income Taxes
For the Rate Year Ending January 31, 2022

	Rate Year As Adjusted Per Staff	Adj No.	Commission Adjustments	Rate Year As Adjusted By the Commission
Operating Income Before Income Taxes	$ 4,473,696		$ 1,246,565	$ 5,720,261
SIT Current	(261,981)		(52,202)	(314,183)
Interest Expense	(1,382,499)		(37,760)	(1,420,259)
Amort of Excess Book Depreciation Reserve	(151,619)			(151,619)
ADR Normalized	18,100			18,100
Deduct Tax Depreciation (less accelerated)	(3,367,705)			(3,367,705)
Rate Case 2016	95,000		(82,333)	12,667
Other Surcharges applied to Plant	177,222			177,222
Safety & Reliability Shortfall	29,372		(14,686)	14,686
Customer Affiliate Allocation Shortfall	17,557		(8,778)	8,779
Customer Make Whole Increase	18,397		(9,198)	9,199
Amortization of Specialist Wage Diff	(3,997)		2,221	(1,776)
Leak Repair/Survey	(0)			(0)
Pass Back of Interest on Over Collection	(57,912)			(57,912)
Fixed Interest	119,561		(59,781)	59,780
Customer Incentive	12,800		(6,400)	6,400
Def Debit-Rate Case 2020	211,967			211,967
2019 mismarks	-		(1,207)	(1,207)
Leak backlog, total damages and mismarks for 2016, 2017 and 2018	-		(29,372)	(29,372)
PP OPEB	-		(38,608)	(38,608)
Updated NRA balance	-		(15,324)	(15,324)
Deferred Credits - 2015 Regulatory Liability	0			0
Deferred Credits - 2016 Regulatory Liability	(4,704)		(3,137)	(7,841)
Deferred Credits - 2017 Regulatory Liability	(3,671)		(2,447)	(6,118)
Deferred Credits - 2018 Regulatory Liability	(3,397)		(11,945)	(15,342)
Deferred Credits - 2019 Regulatory Liability	(10,000)		10,000	0
Deferred Net Plant Due	(24,624)		13,674	(10,950)
Book Depreciation -includes clearing accounts	5,158,266			5,158,266
Total Adjustments for Taxable Income	586,133		(347,283)	238,850
Tax Income	5,059,829		899,282	5,959,111
Rate	21.00%		21.00%	21.00%
Current Federal Income Tax	**$ 1,062,564**		**$ 188,849**	**$ 1,251,413**

	Rate Year As Adjusted Per Staff	Adj No.	Commission Adjustments	Rate Year As Adjusted By the Commission
ADR Normalized	(3,801)			(3,801)
ACRS Normalized	(376,018)			(376,018)
Other Surcharges Applied to Plant	(37,217)			(37,217)
Deferred Net Plant Due	5,171		(2,872)	2,300
Rate Case 2016	(19,950)		17,290	(2,660)
Safety & Reliability Shortfall	(6,168)		3,084	(3,084)
Customer Affiliate Allocation Shortfall	(3,687)		1,843	(1,844)
Customer Make Whole Increase	(3,863)		1,932	(1,932)
Gas Specialist	839		(466)	373
Leak Repair/Survey	-			-
Prior Year Pension Recoverable Costs	(0)		-	(0)
Amortization of Prior Period OPEB Over-Collection	(0)		-	(0)
Pass Back of Interest on Over Collection	12,162		-	12,162
Fixed Interest	(25,108)		12,554	(12,554)
Customer Incentive	(2,688)		1,344	(1,344)
Def Debit-Rate Case 2020	(44,513)		-	(44,513)
2019 mismarks	-		253	253
Leak backlog, total damages and mismarks for 2016, 2017 and 2018	-		6,168	6,168
Updated NRA balance	-		3,218	3,218
Deferred Credits - 2016 Regulatory Liability	988		659	1,647
Deferred Credits - 2017 Regulatory Liability	771		514	1,285
Deferred Credits - 2018 Regulatory Liability	713		2,508	3,222
Deferred Credits - 2019 Regulatory Liability	2,100		(2,100)	(0)
PP OPEB	-		8,108	8,108
Amortization of Accelerated Recovery Deferred Tax	38,194			38,194
Regulatory Tax Asset Protected Rates	119,231			119,231
Regulatory Tax Asset Unprotected Rates	(38,611)			(38,611)
Regulatory Incremental Tax Asset Unprotected	(260,835)			(260,835)
Regulatory Incremental Tax Asset Protected	1,859			1,859
Deferred Regulatory Liability Current FIT Due	(139,313)			(139,313)
Deferred Regulatory Liability Depreciation FIT	(295,045)			(295,045)
Deferred Regulatory Liability FIT Other	752,350			752,350
Adjust amortization of excess ADFIT protected	66,952			66,952
Adjust amortization of excess ADFIT unprotected	(506,703)			(506,703)
Adjust amortization of excess ADFIT unprotected - CIAC	-		-	-
Total Deferred FIT	**$ (762,190)**	5A	**$ 54,037**	**$ (708,152)**

Corning Natural Gas Corporation
Case 20-G-0101
Capital Structure
For the Rate Year Ending January 31, 2022

Corning Natural Gas Corporation
Case 20-G-0101
Summary of Adjustments
For the Rate Year Ending January 31, 2022

Adj No.	Description of Adjustment	Commission Adjustments	Total Amount
Adj. 1	**Operations and Maintenance**		
A.	**Direct Labor**		
(1)	To eliminate management wage increases	(5,139)	
(2)	To update overtime pay for union contract	3,258	
(3)	To update vacation pay for union contract	2,557	
(4)	To reflect union wage increases of 3%	18,923	
(5)	To remove allowance for four new hires	(169,780)	(150,181)
B.	**Insurance**		
(1)	To reduce health insurance related to removal of four hires	(77,680)	
(2)	To reduce dental insurance related to removal of four hires	(5,251)	(82,931)
C.	**Regulatory**		
(1)	To reflect amortization of Prior Period OPEB deferral over 3 years	(38,608)	
(2)	To reflect amortization of 2016, 2017, 2018 NRAs deferral over 3 years	(11,749)	
(3)	To reflect amortization of new 2019 NRA deferral over 3 years	(804)	
(4)	To reflect amortization of 2016 NRA deferral over 3 years	(3,137)	
(5)	To reflect amortization of 2017 NRA deferral over 3 years	(2,447)	
(6)	To reflect amortization of 2018 NRA deferral over 3 years	(11,945)	
(7)	To reflect amortization of Gas Supply Specialist deferral over 3 years	2,221	
(8)	To reflect amortization of Net Plant deferral over 3 years	13,674	
(9)	To reflect amortization of 2016 Rate Case deferral over 10 years	(82,333)	
(10)	To reflect amortization of Fixed Interest deferral over 10 years	(59,781)	
(11)	To reflect amortization of Customer Incentive deferral over 10 years	(6,400)	
(12)	years	(14,686)	
(13)	To reflect amortization of Customer Affiliate Allocation Shortfall deferral over 10 years	(8,778)	
(14)	To reflect amortization of Customer Make Whole Increase deferral over 10 years	(9,198)	
(15)	To reflect amortization of Rate Case 2020 deferral over 10 years	(148,377)	
(16)	To include leak backlog, total damages and mismarks NRA deferrals for 2016, 2017 and 2018	(17,623)	
(17)	To include updated NRA balance	(14,520)	
(18)	To include removal of Company's 2019 NRA deferral estimate	10,000	
(19)	To include 2019 mismark NRA deferral	(1,207)	(405,698)
D.	**Pension-Amortization**		
(1)	To reflect amortization of pension deferral over 10 years		(111,318)
E.	**OPEB-Amortization**		
(1)	To reflect amortization of OPEB deferral over 10 years		36,313
F.	**Debit Card & Credit Card Fees**		
(1)	To update estimated vendor costs		8,242
G.	**Outside Services**		
(1)	To remove allowance for the IT consultant		(72,000)
H.	**Other O&M**		
(1)	To update for the latest construction overhead rate		80,369
	Total O&M Expense Adjustments		(697,204)
Adj. 2	**Depreciation Expense**		
(1)	To reflect correction to depreciation expense	(119,845)	
(2)	To remove the allowance for accelerated depreciation of leak prone pipe	(414,213)	(534,058)
Adj. 3	**Taxes Other Income Taxes**		
A.	**Payroll Tax**		
(1)	To track labor adjustments		(15,303)
	Total Taxes other than Income Tax Adjustments		(15,303)

Adj. 4	**New York State Income Tax**		
A.	**Deferred Taxes**		
(1)	To track deferral adjustments		26,370
Adj. 5	**FED Income Tax**		
A.	**Deferred Taxes**		
(1)	To track deferral adjustments		31,511
Adj. 6	**Rate Base**		
A.	**Net Utility Plant**		
(1)	To correct for errors in Company's plant model		104,242
B.	**Plant Reserves**		
(1)	To reflect correction to accumulated depreciation	46,091	
(2)	To remove the allowance for accelerated depreciation of leak prone pipe	207,106	253,197
C.	**Cash Working Capital**		
(1)	To track adjustment to working capital		(27,063)
D.	**Deferred Debits**		
(1)	To reflect amortization of 2016 Rate Case deferral over 10 years	41,027	
(2)	To reflect amortization of Fixed Interest deferral over 10 years	29,890	
(3)	To reflect amortization of Customer Incentive deferral over 10 years	3,200	
(4)	years	7,343	
(5)	To reflect amortization of Customer Affiliate Allocation Shortfall deferral over 10 years	4,389	
(6)	To reflect amortization of Customer Make Whole Increase deferral over 10 years	4,600	
(7)	To reflect amortization of Rate Case 2020 deferral over 10 years	74,188	164,637
E.	**Deferred Credits**		
(1)	To reflect amortization of Prior Period OPEB deferral over 3 years	19,304	
(2)	To reflect amortization of 2016, 2017, 2018 NRAs deferral over 3 years	5,875	
(3)	To reflect amortization of new 2019 NRA deferral over 3 years	403	
(4)	To reflect amortization of 2016 NRA deferral over 3 years	1,568	
(5)	To reflect amortization of 2017 NRA deferral over 3 years	1,224	
(6)	To reflect amortization of 2018 NRA deferral over 3 years	5,972	
(7)	To reflect amortization of Gas Supply Specialist deferral over 3 years	(1,110)	
(8)	To reflect amortization of Net Plant deferral over 3 years	(6,837)	
(9)	To include leak backlog, total damages and mismarks NRA deferrals for 2016, 2017 and 2018	(79,304)	
(10)	To include updated NRA balance	(65,341)	
(11)	To include removal of Company's 2019 NRA deferral estimate	45,000	
(12)	To include 2019 mismark NRA deferral	(5,431)	(78,677)
F.	**Deferred Taxes Amount**		
(1)	To reflect the ADSIT impact related to the depreciation adjustments	17,357	
(2)	To reflect the ADFIT impact related to the depreciation adjustments	56,076	
(3)	To reflect amortization of Prior Period OPEB deferral over 3 years	(5,309)	
(4)	To reflect amortization of 2016, 2017, 2018 NRAs deferral over 3 years	(1,615)	
(5)	To reflect amortization of new 2019 NRA deferral over 3 years	(110)	
(6)	To reflect amortization of 2016 NRA deferral over 3 years	(431)	
(7)	To reflect amortization of 2017 NRA deferral over 3 years	(336)	
(8)	To reflect amortization of 2018 NRA deferral over 3 years	(1,642)	
(9)	To reflect amortization of Gas Supply Specialist deferral over 3 years	305	
(10)	To reflect amortization of Net Plant deferral over 3 years	1,880	
(11)	To reflect amortization of 2016 Rate Case deferral over 10 years	(11,282)	
(12)	To reflect amortization of Fixed Interest deferral over 10 years	(8,220)	
(13)	To reflect amortization of Customer Incentive deferral over 10 years	(880)	
(14)	years	(2,019)	
(15)	To reflect amortization of Customer Affiliate Allocation Shortfall deferral over 10 years	(1,207)	
(16)	To reflect amortization of Customer Make Whole Increase deferral over 10 years	(1,265)	
(17)	To reflect amortization of Rate Case 2020 deferral over 10 years	(20,401)	
(18)	To include leak backlog, total damages and mismarks NRA deferrals for 2016, 2017 and 2018	21,808	
(19)	To include updated NRA balance	17,969	
(20)	To include removal of Company's 2019 NRA deferral estimate	(12,375)	
(21)	To include 2019 mismark NRA deferral	1,493	49,796

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Appendix 3
Schedule 1
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Corning Natural Gas Corporation
Deferred Debits and Credits
For the Rate Year Ending January 31, 2022

Deferred Debits

	Balance as of 9/30/19	Number of Years of Amortization	Amortization Expense
Fixed Interest	$ 597,803	10	$ (59,780)
Customer Incentive	64,000	10	(6,400)
Safety & Reliability Shortfall	146,859	10	(14,686)
Customer Affiliate Allocation Shortfall	87,785	10	(8,779)
Customer Make Whole Increase	91,987	10	(9,199)
Rate Case 2020	635,900	10	(63,590)
Rate Case 2016	126,667	10	(12,667)
Total Deferred Debits	**$ 1,751,002**		**$ (175,099)**
Pension Deferral	**$ 1,113,185**		**$ (111,319)**
Total Amortization Expense			***$ (286,418)***

Deferred Credits

	Balance as of 9/30/19	Number of Years of Amortization	Amortization Expense
Prior Period OPEB Interest Due Customers	$ (289,558)	3	$ 96,519
Amortization of Gas Specialist Wage Differential	(5,329)	3	1,776
Deferred Net Plant Due	(32,850)	3	10,950
Deferred Credits-2016 Regulatory Liability	(23,522)	3	7,841
Deferred Credits-2017 Regulatory Liability	(18,355)	3	6,118
Deferred Credits-2018. Regulatory Liability	(89,587)	3	29,862
Deferred Credits-2019 Regulatory Liability	(6,034)	3	2,011
Additional 2016 - 2018 NRAs	(88,115)	3	29,372
Total Deferred Credits	**$ (553,350)**		**$ 184,450**
OPEB Deferral	**$ (363,130)**	10	**$ 36,313**
Total Amortization Expense			***$ 220,763***

CORNING NATURAL GAS CORPORATION
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RATE YEAR DEPRECIATION EXPENSE

Account	Measuring and Regulating Station Structures	Staff Monthly Depreciation Rates	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22
	INTANGIBLE PLANT:													
301	Organization	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
302	Franchise and Consents	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-	-	-	-	-
	TRANSMISSION PLANT:													
	Land	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
365	Rights of Way	0.128%	69	69	69	69	69	69	69	69	69	69	69	69
366	Structures and Improvements	0.167%	86	86	86	86	86	86	86	86	86	86	86	86
367	Mains	0.119%	4,616	4,616	4,616	4,616	4,616	4,616	4,616	4,616	4,616	4,616	4,616	4,616
369	Measuring and Regulating Station Equipment	0.185%	785	785	785	785	786	786	787	788	789	790	790	791
371	Other Equipment	0.208%	490	490	490	490	490	490	490	490	490	490	490	490
			6,046	6,046	6,047	6,047	6,047	6,048	6,049	6,050	6,050	6,051	6,052	6,052
	DISTRIBUTION PLANT:													
	Land	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
374	Land Rights	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
375	Structures and Improvements	0.167%	330	330	330	330	330	330	330	330	330	330	330	330
376	Mains	0.128%	64,848	64,916	64,983	65,153	65,492	65,967	66,510	67,053	67,528	67,972	68,260	68,356
378	Measuring and Regulating Station Equipment	0.208%	8,494	8,525	8,556	8,633	8,788	9,004	9,251	9,498	9,715	9,876	9,959	9,986
380	Services	0.152%	28,675	28,697	28,719	28,775	28,885	29,040	29,217	29,394	29,549	29,672	29,739	29,762
381	excl. ERTS	0.278%	5,547	5,553	5,558	5,572	5,598	5,636	5,679	5,721	5,759	5,788	5,805	5,810
381.1	ERTS (Encoder, Receiver, Transmitter)	0.417%	1,225	1,231	1,237	1,252	1,282	1,324	1,372	1,420	1,462	1,495	1,513	1,520
382	Meter Installations	0.167%	4,656	4,656	4,656	4,656	4,656	4,656	4,656	4,656	4,656	4,656	4,656	4,656
383	House Regulators	0.185%	816	817	817	819	823	829	835	842	847	852	854	855
384	House Regulator Installations	0.185%	684	684	684	684	684	684	684	684	684	684	684	684
385	Industrial Meas and Reg Station Equipment	0.208%	311	311	311	311	311	311	311	311	311	311	311	311
			115,587	115,720	115,853	116,186	116,851	117,782	118,846	119,910	120,841	121,636	122,112	122,270
	GENERAL PLANT:													
389	Land and Land Rights		-	-	-	-	-	-	-	-	-	-	-	-
390	Structures and Improvements	0.177%	8,723	8,725	8,728	8,735	8,748	8,766	8,787	8,808	8,827	8,842	8,851	8,854
391	Office Furniture and Equipment	0.641%	20,451	20,493	20,534	20,637	20,844	21,133	21,463	21,794	22,083	22,236	22,272	22,283
392	Transportation Equipment	0.926%	12,168	12,226	12,283	12,427	12,714	13,117	13,577	14,037	14,439	14,792	15,008	15,081
393	Stores Equipment	0.333%	214	214	214	214	214	214	214	214	214	214	214	214
394	Tools, Shop and Garage Equipment	0.417%	5,079	5,090	5,100	5,128	5,182	5,257	5,344	5,430	5,506	5,564	5,594	5,604
395	Laboratory Equipment	0.333%	122	122	122	122	122	122	122	122	122	122	122	122
396	Power Operated Equipment	0.595%	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932
397	Communications Equipment	0.556%	813	813	813	813	813	813	813	813	813	813	813	813
			49,502	49,614	49,726	50,007	50,568	51,353	52,251	53,149	53,935	54,514	54,806	54,903
	Total		171,135	171,380	171,626	172,239	173,466	175,183	177,146	179,109	180,826	182,202	182,969	183,225
	Depreciation Expense Balance		(12,635)	(12,635)	(12,635)	(12,635)	(12,635)	(12,635)	(12,635)	(12,635)	(12,635)	(12,635)	(12,635)	(12,635)
	Depreciation of LPP at Applicable Rates		1,843	1,843	1,843	1,843	1,843	1,843	1,843	1,843	1,843	1,843	1,843	1,843
			160,343	160,588	160,834	161,447	162,673	164,391	166,354	168,316	170,034	171,409	172,177	172,433
	Annual Depreciation Expense	$ 1,990,998												

CORNING NATURAL GAS CORPORATION
CASE 20-G-0101

CAPITAL BUDGET BY PROJECT

Acct. No.	Project	Description	CY 2020	CY 2021	CY 2022	CY 2023	CY 2024
	1	**Services**					
380	1.1	New installations	$ 140,550	$ 143,361	$ 146,228	$ 149,153	$ 152,136
380	1.2	Systematic replacement	$ 612,848	$ 625,105	$ 637,607	$ 650,359	$ 663,366
380	1.3	Other replacement	$ -	$ -	$ -	$ -	$ -
		Project Total	**$ 753,398**	**$ 768,466**	**$ 783,835**	**$ 799,512**	**$ 815,502**
	2	**Meters & Regulators**					
383	2.1	Residential regulators	$ 22,176	$ 22,620	$ 23,072	$ 24,004	$ 24,004
378	2.2	Non-residential regulators	$ 4,490	$ 4,580	$ 3,870	$ 4,765	$ 4,860
381	2.3	Residential meters	$ 61,500	$ 62,730	$ 63,985	$ 65,264	$ 66,570
381	2.4	Non-residential meters	$ 37,875	$ 38,633	$ 39,405	$ 40,193	$ 40,997
378	2.5	Rotary / turbine meters	$ 43,400	$ 37,944	$ 38,703	$ 39,477	$ 40,266
378	2.6	Volume correctors	$ 15,600	$ 15,912	$ 16,230	$ 16,555	$ 16,886
378	2.7	Pressure recorders	$ 3,720	$ 3,794	$ 3,870	$ 3,948	$ 4,027
378	2.8	AMR	$ 74,160	$ 75,643	$ 77,156	$ 78,699	$ 80,273
		Project Total	**$ 262,921**	**$ 261,856**	**$ 266,292**	**$ 272,905**	**$ 277,883**
	3	**Main - Distribution**					
376	3.1	New installations	$ -	$ 285,532	$ 291,242	$ 297,067	$ 303,008
376	3.2	Systematic Replacement	$ 1,546,787	$ 1,523,937	$ 1,097,234	$ 1,492,239	$ 1,617,214
376	3.3	Other replacement (Cross Town Line repair)	$ -	$ -	$ -	$ -	$ -
376	3.4	Other replacement (Leak Repair, system upgrades)	$ -	$ -	$ -	$ -	$ -
376	3.5	Blank	$ -	$ -	$ -	$ -	$ -
376	3.6	Blank	$ -	$ -	$ -	$ -	$ -
376	3.7	Blank	$ -	$ -	$ -	$ -	$ -
		Project Total	**$ 1,546,787**	**$ 1,809,469**	**$ 1,388,476**	**$ 1,789,306**	**$ 1,920,222**
	4	**Main - HP Distribution**					
376	4.1	New installations	$ -	$ -	$ -	$ -	$ -
376	4.2	Line 11	$ -	$ -	$ -	$ -	$ -
376	4.3	Bath Reliability - Second Supply	$ 480,000	$ 306,000	$ 312,120	$ 318,363	$ 324,730
376	4.31	Line 15 Systematic Replacement	$ 600,000	$ 612,000	$ 2,184,840	$ 955,088	$ 649,459
376	4.4	Blank	$ -	$ -	$ -	$ -	$ -
376	4.5	Blank	$ -	$ -	$ -	$ -	$ -
		Project Total	**$ 1,080,000**	**$ 918,000**	**$ 2,496,960**	**$ 1,273,450**	**$ 974,189**
	5	**Main - Distribution extension**					
376	5.1	Blank	$ -	$ -	$ -	$ -	$ -
		Project Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	6	**Cathodic Protection**					
376	6.1	System Cathodic Protection	$ 57,222	$ 58,366	$ 59,534	$ 60,724	$ 61,938
369	6.2	Blank	$ -	$ -	$ -	$ -	$ -
376	6.3	Blank	$ -	$ -	$ -	$ -	$ -
		Project Total	**$ 57,222**	**$ 58,366**	**$ 59,534**	**$ 60,724**	**$ 61,938**
	7	**SCADA**					
391	7.1	Hardware / Software upgrade	$ -	$ -	$ -	$ -	$ -
378	7.2	RTU /other equipment (current installation improvements)	$ 46,818	$ 47,754	$ 48,709	$ 49,684	$ 50,677
		Project Total	**$ 46,818**	**$ 47,754**	**$ 48,709**	**$ 49,684**	**$ 50,677**
	8	**M&R Stations**					
378	8.1	M&R Station replacement	$ -	$ 94,889	$ 96,787	$ 98,724	$ 100,698
378	8.2	Herrington Station (odorizer install)	$ -	$ 500,000	$ 408,000	$ -	$ -
378	8.3	Orr Hill Station (odorizer install)	$ -	$ -	$ -	$ -	$ -
378	8.4	Blank	$ -	$ -	$ -	$ -	$ -
378	8.5	Blank	$ -	$ -	$ -	$ -	$ -
		Project Total	**$ -**	**$ 594,889**	**$ 504,787**	**$ 98,724**	**$ 100,698**

CORNING NATURAL GAS CORPORATION
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CAPITAL BUDGET BY PROJECT

Acct. No.	Project	Description	CY 2020	CY 2021	CY 2022	CY 2023	CY 2024
	9	**Transportation Equipment**					
392	9.1	Replace small vehicle	$ -	$ 206,000	$ 210,120	$ 214,323	$ 163,957
392	9.2	Replace1987 Line Truck	$ 190,000	$ -	$ 200,000	$ -	$ -
392	9.3	Heavy Equip Trailer	$ -	$ -	$ -	$ -	$ -
392	9.4	Replace Backhoe	$ -	$ -	$ -	$ -	$ -
392	9.5	Purchase Mini Excav	$ -	$ 80,000	$ -	$ -	$ -
392	9.6	Replace small vehicle	$ -	$ -	$ -	$ -	$ -
392	9.7	Replace line tech truck	$ -	$ 40,800	$ -	$ -	$ -
392	9.8	Replace dump truck	$ -	$ -	$ -	$ -	$ -
392	9.9	Replace backhoe	$ -	$ -	$ -	$ -	$ -
392	9.10	Replace 1987 line truck	$ -	$ -	$ -	$ -	$ -
392	9.11	Heavy Equipment Trailer	$ -	$ -	$ -	$ -	$ -
392	9.12	Replace line truck	$ -	$ -	$ -	$ -	$ -
392	9.13	Replace 1996 line truck	$ -	$ -	$ -	$ -	$ -
		Project Total	**$ 190,000**	**$ 326,800**	**$ 410,120**	**$ 214,323**	**$ 163,957**
	10	**Tools and Equipment**					
394	10.1	Pipeline Locator	$ 4,412	$ 4,500	$ 4,590	$ 4,682	$ 4,776
394	10.2	HFI	$ 12,000	$ -	$ -	$ -	$ -
394	10.3	CGI	$ 5,400	$ 5,508	$ 5,618	$ 5,731	$ 5,845
394	10.4	Portable Shoring	$ -	$ 10,200	$ -	$ -	$ 10,400
394	10.5	CP Data Logger	$ -	$ -	$ -	$ -	$ -
394	10.6	Blank	$ -	$ -	$ -	$ -	$ -
394	10.7	Electro fusion Controller	$ -	$ -	$ -	$ -	$ -
394	10.8	Mueller (8" to 12") machine	$ -	$ -	$ -	$ -	$ -
394	10.9	Health HFI	$ -	$ -	$ -	$ -	$ -
394	10.10	Engineering survey equipment	$ -	$ -	$ -	$ -	$ -
394	10.11	Blank	$ -	$ -	$ -	$ -	$ -
394	10.12	GPS Survey Equipment	$ -	$ -	$ -	$ -	$ -
394	10.13	Welding Machine	$ -	$ -	$ -	$ -	$ -
394	10.14	Blank	$ -	$ -	$ -	$ -	$ -
394	10.15	Blank	$ -	$ -	$ -	$ -	$ -
394	10.16	Lighting	$ -	$ -	$ -	$ -	$ -
394	10.17	Stopper Replacement Equipment	$ -	$ -	$ -	$ -	$ -
394	10.18	Misc.Tools and Equipment	$ 3,184	$ 3,247	$ 3,312	$ 3,378	$ 3,446
		Project Total	**$ 24,996**	**$ 23,455**	**$ 13,521**	**$ 13,791**	**$ 24,467**
	11	**Safety Equipment**					
394	11.1	PPE	$ 70,000	$ 71,400	$ 72,828	$ 74,285	$ 75,770
394	11.2	Flash fire coveralls / hood / gloves	$ 40,800	$ 41,616	$ 42,448	$ 43,297	$ 44,163
394	11.3	Supplied Air Respirator	$ -	$ -	$ -	$ -	$ -
394	11.4	Confined space gas monitor	$ 7,500	$ -	$ -	$ 7,950	$ -
		Project Total	**$ 118,300**	**$ 113,016**	**$ 115,276**	**$ 125,532**	**$ 119,933**
	12	**General Office**					
390	12.1	HVAC	$ -	$ -	$ -	$ -	$ -
390	12.2	Parking Lot Refurbishment	$ -	$ -	$ -	$ -	$ -
390	12.3	Office Furniture and Equipment	$ -	$ -	$ -	$ -	$ -
390	12.4	Building Upgrades	$ -	$ -	$ -	$ -	$ -
390	12.5	Work Stations	$ -	$ -	$ -	$ -	$ -
390	12.6	Roof	$ -	$ -	$ 90,000	$ -	$ -
390	12.7	Training Center	$ -	$ 78,000	$ -	$ -	$ -
		Project Total	**$ -**	**$ 78,000**	**$ 90,000**	**$ -**	**$ -**
	13	**IT equipment**					
391	13.1	Computers / software	$ 28,830	$ 29,402	$ 29,990	$ 30,590	$ 31,200
391	13.2	Field Laptops	$ 8,268	$ 4,216	$ 4,301	$ 4,386	$ 4,476
391	13.3	Field GPS equipment	$ 300,000	$ 100,000	$ -	$ -	$ -
391	13.4	CADD Software replacement	$ -	$ 100,000	$ -	$ -	$ -
391	13.5	Blank	$ 90,000	$ 5,000	$ 5,000	$ -	$ -
391	13.6	Printer and Computer Replacement	$ -	$ 3,000	$ -	$ -	$ -
391	13.7	Accounting and Billing System Upgrade	$ -	$ 15,000	$ -	$ -	$ -
391	13.8	Enterprise Software (Microsoft and Norton Updates)	$ -	$ 75,000	$ 50,000	$ -	$ -
391	13.9	AS400 Equipment/Software/Licensing Costs	$ -	$ 7,500	$ 7,500	$ -	$ -
		Project Total	**$ 427,098**	**$ 339,118**	**$ 96,791**	**$ 34,976**	**$ 35,676**
	14	**Major Projects**					
369	14.1	Virgil expansion - Main & Services	$ 10,000	$ 3,300	$ 3,366	$ 3,433	$ 3,502
380	14.2	Blank	$ -	$ -	$ -	$ -	$ -
383	14.3	Blank	$ -	$ -	$ -	$ -	$ -
378	14.4	Blank	$ -	$ -	$ -	$ -	$ -
369	14.6	Cross Town-E Pultney repair 2010	$ -	$ -	$ -	$ -	$ -
		Project Total	**$ 10,000**	**$ 3,300**	**$ 3,366**	**$ 3,433**	**$ 3,502**
						$ -	$ -
						$ -	**$ -**
		Total Budget	**$ 4,517,539**	**$ 5,342,489**	**$ 6,277,667**	**$ 4,736,359**	**$ 4,548,643**

CORNING NATURAL GAS CORPORATION
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RATE YEAR NET PLANT

	Rate Year Gross Plant Balance	CWIP Balance	Depreciation Reserve Balance
Jan-21 (1/2)	$ 48,151,334	$ 1,394,082	$ (15,129,567)
Feb-21	$ 96,405,610	$ 2,788,164	$ (30,434,244)
Mar-21	$ 96,508,551	$ 2,788,164	$ (30,609,601)
Apr-21	$ 96,611,492	$ 2,788,164	$ (30,785,203)
May-21	$ 97,023,257	$ 2,788,164	$ (30,961,418)
Jun-21	$ 97,640,904	$ 3,113,252	$ (31,138,860)
Jul-21	$ 98,464,434	$ 3,329,977	$ (31,318,019)
Aug-21	$ 99,287,963	$ 3,546,702	$ (31,499,141)
Sep-21	$ 100,111,493	$ 3,546,702	$ (31,682,226)
Oct-21	$ 100,729,140	$ 3,546,702	$ (31,867,029)
Nov-21	$ 101,332,908	$ 3,329,977	$ (32,053,206)
Dec-21	$ 101,453,661	$ 3,315,363	$ (32,240,152)
Jan-22 (1/2)	$ 50,787,207	$ 1,403,457	$ (16,213,677)
AVG OF THE MONTHLY AVG	$ 98,708,996	$ 3,139,906	$ (31,327,695)
NET PLANT	$ 70,521,206		

CORNING NATURAL GAS CORPORATION
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NET PLANT TRUE UP TEST

		RATE YEAR GROSS PLANT BALANCE *A*	NIB CWIP BALANCE *B*	DEPRECIATION RESERVE BALANCE *C*	AVERAGE DEFERRED TAXES *D*
Jan-21	(1/2)	47,167,434	1,602,443	(15,129,567)	
Feb-21		94,421,920	3,204,885	(30,434,244)	
Mar-21		94,508,972	3,204,885	(30,609,601)	
Apr-21		92,086,342	3,204,885	(30,785,203)	
May-21		92,434,551	3,204,885	(30,961,418)	
Jun-21		92,956,865	3,204,885	(31,138,860)	
Jul-21		93,653,283	3,479,787	(31,318,019)	
Aug-21		94,349,701	3,663,055	(31,499,141)	
Sep-21		95,046,120	3,846,323	(31,682,226)	
Oct-21		95,582,080	3,846,323	(31,867,029)	
Nov-21		96,096,786	3,846,323	(32,053,206)	
Dec-21		96,199,727	3,677,455	(32,240,152)	
Jan-22	(1/2)	48,151,334	1,827,532	(16,213,677)	
AVG OF THE MONTHLY AVG		$ 94,387,926	$ 3,484,473	$ (31,327,695)	$ 5,135,789

NET PLANT TARGET PER ORDER	$ 124,064,305	*E = A + B - C - D*
EXAMPLE ACTUAL NET PLANT	$ 91,000,000	*F*
OVER/(UNDER)	$ (33,064,305)	*G = F - E*
Pre Tax Rate of Return	10.61%	*H*
Carrying Costs	$ (3,508,123)	*I = G * H*
Average Plant Balance	$ 94,387,926	*A*
Actual Depreciaton Expense	$ 986,284	*J*
Composite Depreciation Rate	1.045%	*K= J/A*
Delta Depreciation Expense	$ (345,497)	*L = G *K*
Total Carrying Costs	$ (3,853,620)	*M = I + L*

NOTE:
The Net Plant In Service includes all writedowns (e.g. Virgil Surcharge, Rootwell Surcharge, Service Adjustment), however these writedowns are not specifically identified in this Appendix.

Corning Natural Gas Corporation (Corning) Case 20-G-101 Gas Safety Metrics Appendix

Gas Safety Metric	Staff recommendation	CNG Counteroffer
Leak Management	- Reducing the number from five to four leaks at year end. - An NRA of ten basis points for failure to meet the repairable leak target, and five basis points for failure to meet the total leak backlog targets. - If the Company maintains less than 35 total leaks, but not less than 26 total leaks at calendar years-end, it would earn a PRA of two BPs. If the Company maintains less than 25 total leaks, but not less than 16 total leaks at calendar year's end, it would earn a PRA of four BPs. If the Company maintains 15 or less total leaks at calendar year's-end, it would earn a PRA of six BPs. If the Company maintains 15 or less total leaks at calendar year's-end, it would earn a PRA of eight BPs - The Commission should not provide a PRA for Type 3 leaks in its determination of the rate case.	- Corning proposes and Staff agrees to a more stringent target for total leak backlog, by reducing them from 50 to 45 leaks at year-end 2021.
Leak Prone Pipe Replacement	- Corning replace or eliminate a minimum of 10 miles of leak prone pipe (LPP) annually. - Corning replace a minimum of 250 leak prone services per year, concurrently with the main replacement program.	- Corning agrees with Staff's recommended target of ten miles of LPP per year but proposes that LPP include Lines 11 and 15.

Gas Safety Metric	Staff recommendation	CNG Counteroffer
	- All gas meters and service regulators be located outside on all new and replacement service installations. - Corning agrees that it will maintain records of the number of miles and feet of mains replaced, more specifically of the pipe replaced in the flood control area, and any incremental cost over the $33.96 cost per foot for systematic replacement of distribution main in calendar year 2021 utilized by the Staff Infrastructure and Operations Panel to calculate the average unit cost, but no more than 1.5 times cost per unit, be deferred. - The maximum NRA exposure increases to 15 BPs. Corning agrees with Staff's recommendation	- Corning agrees with Staff's recommendation that Corning replace 250 leak prone services per year in conjunction with main replacement. - Corning agrees with Staff's recommendation. Fourth, Staff recommends and Corning supports Staff's recommendation to allow Corning to address the leaks found in the flood control area through the leak prone pipe replacement program.
Damage Prevention	- The total damage target be set at a rate of 2.50 damage incidents per 1000 one call tickets; failure to achieve this target would result in an NRA of 20 BPs; for a rate between 2.26 and 2.50, the Company would incur an NRA of ten basis points; for a rate between 2.01 and 2.25, the Company would incur an NRA of five basis points; for a rate between 1.51 and 2.00, the Company would not incur or earn any revenue adjustments; for a rate between 1.26 and 1.50, the	- Corning proposes and Staff agrees that damages due to mismarks and damages due to Company or Corning Contractor targets be eliminated, and instead Corning should be allowed to maintain an overall damage target. - Corning counter-offered to Staff's

Gas Safety Metric	Staff recommendation	CNG Counteroffer
	Company would earn a PRA of five basis points; for a rate below 1.26 the Company would earn a PRA of ten basis points.	proposed maximum NRA exposure of twenty BPs by proposing a maximum NRA exposure of fifteen BPs, asserting that given the size of the company, a small change in the number of total damages would have a large impact on its overall damage performance.
Violations	- Recommends that of the $153,000 resulting from the negative revenue adjustments, $75,000 be used to fund the implementation of a Residential Methane Detector Program. - Modifying the current NRA BPs allocation by reducing the NRA BPs maximum exposure by 25 BPs, from 100 to 75 BPs per year for this measure. - Violation measure targets and associated NRAs be modified as follows: for record audits, the first five high risk violations would not subject the Company to NRAs; from the sixth to the 20th high-risk violations, the Company would incur one-half BP per violation; and for each high-risk violation greater than 20, the Company would incur one BP per violation. For the first 15 other risk violations, the Company would not	- Corning agrees and accepts Staff's recommendations regarding the violation measure targets and associated NRAs as stated in its testimony.

Gas Safety Metric	Staff recommendation	CNG Counteroffer
	be subject to a NRA; and for each other risk violation greater than 15, the Company would incur a NRA of one-fourth BP per violation. For field audits and investigations, the Company would incur a NRA of one-half BP for each of the first 20 high-risk violations; for each high-risk violation in excess of 20, the Company would incur a NRA of one BP per violation; and for all other risk violations, the Company would incur a NRA of one-fourth BP per violation. - For each audit year, capping the total record audit violation count at ten basis points for each of the code sections identified in Exhibit 44. - If the Company fails to comply with its implementation plan, the number of violations of a given code section that are in excess of ten would be included with the remainder of the violations being considered for the compliance measure. - The performance measure provide a financial disincentive for non-compliance with the pipeline safety regulations, but it addresses only the first ten record audit violations of a specific requirement. If the financial disincentive is insufficient to induce compliance, then additional measures are necessary to change the	

Gas Safety Metric	Staff recommendation	CNG Counteroffer
	performance. It is critical for the Commission to be able to address all violations of its pipeline safety regulations given the potential for serious harm.	
New York State Department of Environmental Conservation requirements and gas leaks found in Flood control area	- Corning be directed by the Commission to seek approval from DEC to perform the necessary work to repair or eliminate these leaks in the flood control area, and file quarterly updates with the Chief of Pipeline Safety and Reliability Section on the status of its work to eliminate or repair the leaks, along with copies of all DEC communications with the Company until all the leaks are eliminated.	- Corning agrees and states that leaks will be addressed through the leak prone pipe replacement program and they will continue to work with the DEC to complete the repairs. - Corning proposes to provide Staff a list of project(s) completed the prior year and those slated to be completed that year, the report will be submitted by January 10th of each year. Staff accepts.
The 1.1 miles of Pipe Located at Sullivan Park Science Center	- Corning perform the necessary operating and maintenance (O&M) work, such as: leak surveys, mark-outs, CP readings, corrosion control/monitoring, identification and inspection of below grade valves, etc. - Within 60 days from the date of Staff filing its direct testimony, the Company files with the Chief of Safety	- Corning states that Staff's recommendation to expect Corning to be able to assure the integrity of the 1.1 miles of pipe within matters of weeks is unrealistic, and that the Company proposes

Gas Safety Metric	Staff recommendation	CNG Counteroffer
	and Reliability Section a report outlining the O&M performed and the records obtained with an explanation of how the integrity of this pipe is guaranteed.	to file the requested report outlining the O&M performed and the records obtained by December 31, 2020.
Residential Methane Detector Program	- Commission direct Corning to develop and file a proposal, within 90 days from the issuance of its rate order, for a Residential Methane Detector pilot program. This proposal will include details on Corning's deployment strategies, the number of customers involved, the number of methane detector units, and the associated cost per unit.	
Training with First Responders and New York Pipeline Emergency Responders Initiative, or NYPERI	- Corning improves its existing training with fire departments and first responders by conducting emergency drills, hands-on activities, and workshops with a review of the processes and procedures that would be used during an emergency. To accommodate this training, we recommend that $78,000 be included in Corning's capital budget for the purpose of establishing a training center so that Corning can conduct fire drills, or for the acquisition of a trailer type vehicle equipped with the necessary equipment to conduct drills and simulate real-life or life like environmental conditions that	- Corning agrees with the necessity of this training and believes that it has an advantage in that its Training Technician is a Chief with a local volunteer department and is a Training Technician with the New York State Fire Training Academy.

Gas Safety Metric	Staff recommendation	CNG Counteroffer
	change similar to situations experienced in the field. - An incentive, a PRA of one BP for each drill conducted up to six BP per year, with the assumption that Department Gas Safety Staff will be invited to attend each drill and that documentation is provided following each drill including a video recording of each drill and a list of all persons taking part. - Implementing emergency drills which will help educate and train those individuals on how to respond prior to an incident. - Corning participates in the collaborative effort with the stakeholders (Natural Gas Local Distribution Companies, Fire Departments, State Fire Marshal, Department of Public Service, etc.) of the NYPERI.	
Monthly Leak Report	- Staff did not address this request in its direct testimony, however, it would not be opposed to the Company's request.	- Corning proposed in its direct and rebuttal testimony that it be allowed to discontinue submitting reports on a monthly basis regarding leak repair status, leak survey status, quantity of leaks discovered, quantity

Gas Safety Metric	Staff recommendation	CNG Counteroffer
		of leaks repaired, and quantity of main, pursuant to Commission order issued in case 05-G-1539.

Customer Service Performan Indicator (CSPI)		
Indicator Metric	**Calendar Year Metric Targets**	**NRA - Pre-Tax Basis Points**
Escalated Customer Complaints	3 or less	0
	4	5
	5	10
	6	15
Customer Satisfaction Survey	≥87.7%	0
	≥86.7% to <87.7%	5
	≥85.7% to <86.7%	10
	<85.7%	15
Appointments Kept	$25 Credit for Each Missed Appointment	

Customer complaints are not a rate, rather the acutal aggregate number of escalated complaints received in the calendar year.

Revenue Allocation
Rate Year Ending January 31, 2022

Incremental Revenue Adjustment	$ (765,664)
Contract Adjustment	$ 20,559
Revenue Tax Adjustment	$ 9,671
Merchant Function Charge	$ (92,274)
Adjustment Revenue Requirement	$ (827,708)
Percent On Base Rate	-5.00%

		Unitized ROR	Allocation Factor	Revenue at Current Rates	Based Revenue Increase	Adjustment	Total	% Increase	Revenue Target
	7.00%								
S.C. 1 & SC 14 Residential	5.84%	0.835	1.00	$ 11,918,904	$ (595,393)	$ (1,187)	$ (596,581)	-5%	$ 11,322,323
S.C. 3 & SC 14 Commercial	14.72%	2.103	1.00	$ 2,252,461	$ (112,519)	$ (224)	$ (112,743)	-5%	$ 2,139,718
S.C. 6 Commercial Transportation	4.51%	0.645	1.00	$ 678,674	$ (33,902)	$ (68)	$ (33,970)	-5%	$ 644,704
SC-7 Bath S.C. 1, 2 & 3 Transportation	11.57%	1.653	1.00	$ 1,554,565	$ (77,656)	$ (155)	$ (77,811)	-5%	$ 1,476,754
S.C. 8 Hamondsport Transportation	0.86%	0.123	0.80	$ 164,899	$ (6,590)	$ (13)	$ (6,603)	-4%	$ 158,296
Total				**$ 16,569,503**	**$ (826,061)**	**$ (1,647)**	**$ (827,708)**		**$ 15,741,795**

Delivery Revenue by Service Classification
Rate Year Ending January 31, 2022

			Rate Year Usage Ccf	Current Rates	Revenue @ Current Rates	Recommended Rat	Recommended Impact	Revenue @ Proposed Rates	% Increase	Revenue Impact	Revenue Targets
S.C. 1 & S.C. 14 Residential											
Customers			167,634	$ 19.75	$ 3,310,772	$ 19.75	$ -	$ 3,310,772	0%	$ -	
	First 3 Ccf		475,891								
	Next 47 Ccf	38.78%	5,359,007	$ 0.8274	$ 4,434,042	$ 0.7701	$ (0.0573)	$ 4,126,744	-7%	$ (307,298)	
	Over 50 Ccf	57.78%	7,984,105	$ 0.5228	$ 4,174,090	$ 0.4866	$ (0.0362)	$ 3,884,808	-7%	$ (289,283)	
			13,819,003		**$ 11,918,904**			**$ 11,322,323**		**$ (596,581)**	**$ 11,322,323**
S.C. 3 & S.C. 14 Commercial											
Customers			13,090	$ 30.25	$ 395,973	$ 30.25	$ -	$ 395,973	0%	$ -	
	First 3 Ccf		30,040						\		
	Next 47 Ccf	9.49%	385,525	$ 0.6902	$ 266,089	$ 0.6483	$ (0.0419)	$ 249,930	-6%	$ (16,159)	
	Over 50 Ccf	89.77%	3,646,867	$ 0.4361	$ 1,590,399	$ 0.4096	$ (0.0265)	$ 1,493,815	-6%	$ (96,584)	
			4,062,433		**$ 2,252,461**			**$ 2,139,718**		**$ (112,743)**	**$ 2,139,718**
S.C. 6 Commercial Transportation											
Customers			276	$ 120.00	$ 33,120	$ 120.00	$ -	$ 33,120	0%	$ -	
	First 3 Ccf		771								
	Over 3 Ccf	99.96%	2,168,471	$ 0.2977	$ 645,554	$ 0.2820	$ (0.0157)	$ 611,584	-5%	$ (33,970)	
			2,169,241		**$ 678,674**			**$ 644,704**		**$ (33,970)**	**$ 644,704**
S.C. 7 & Bath S.C. 1 2 & 3 Transportation											
Customers			122	$ 1,220.00	$ 148,840	$ 1,220.00	$ -	$ 148,840	0%	$ -	
	First 2500 Ccf		339,870								
	Over 2500 Ccf	97.00%	11,456,601	$ 0.1227	$ 1,405,725	$ 0.1159	$ (0.0068)	$ 1,327,914	-6%	$ (77,811)	
			11,811,471		**$ 1,554,565**			**$ 1,476,754**		**$ (77,811)**	**$ 1,476,754**
S.C. 8 Hammondsport Transportation											
Customers			91	$ 100.00	$ 9,100	$ 100.00	$ -	$ 9,100	0%	$ -	
	First 3 Ccf		267								
	Over 3 Ccf	99.96%	713,694	$ 0.2183	$ 155,799	$ 0.2090	$ (0.0093)	$ 149,196	-4%	$ (6,603)	
			713,961		**$ 164,899**			**$ 158,296**		**$ (6,603)**	**$ 158,296**
Total Firm Sales					**$ 16,569,503**			**$ 15,741,795**			
Corning Contracts											
	1		0		0			$ -			
	2		20,488,434		$ 633,868			$ 633,868			
	3		0		0		**Rate Increase Adjustment**	$ -			
	4		3,594,290		$ 446,178		$ 20,559.00	$ 425,619			
	5		281,136		$ 120,303			$ 120,303			
	6		1,574,280		$ 45,526			$ 45,526			
	7		3,906,244		$ 247,140			$ 247,140			
	8		0		0			$ -			
Total Contracts			29,844,384		**$ 1,493,014**			**$ 1,472,455**			
		12,949,755	44,396,226								
Total Sales		85,179,902	17,758,490		**$ 18,062,517**			**$ 17,214,250**			

Delivery Rates
Rate Year Ending January 31, 2022

	Current Rates		Rate Year Rates	
SC. 1 & 14 Residential				
Minimum Charge	$ 19.75	$	18.76	per month
First 3				
Next 47 CCF	$ 0.8274	$	0.7860	per Ccf
All Over 50 CCF	$ 0.5228	$	0.4966	per Ccf
S.C. 3 & 14 Commercial				
Minimum Charge	$ 30.25	$	28.74	per month
First 3 CCF				
Next 47 CCF	$ 0.6902	$	0.6557	per Ccf
All Over 50 CCF	$ 0.4361	$	0.4143	per Ccf
S.C. 6 Commercial Transportation				
Minimum	$ 120.00	$	113.99	per month
First 3 CCF				
All Over 3 CCF	$ 0.2977	$	0.2828	per Ccf
S.C. 7 & Bath S.C. 1, 2 & 3				
Minimum	$ 1,220.00	$	1,158.93	per month
First 2500 CCF				
All Over 2500 CCF	$ 0.1227	$	0.1166	per Ccf
S.C.8 Hammondsport Transportation				
Minimum	$ 100.00	$	96.00	per month
First 3 CCF				
All Over 3 CCF	$ 0.2183	$	0.2096	per Ccf

Note: Bath S.C. 2 and 3 is billed as one customer and assessed one minimum charge.

Appendix 9

Corning Natural Gas Corporation
Rate Year Ending January 31, 2022

ANNUAL BILL IMPACTS

S.C. 1 Residential

Month	Sales Ccf	Bills at Presents Rates	Bills at Rate Year Rate	Difference Amount	Difference Percent
January	188	$ 196.92	$ 204.28	$ 7.36	3.7%
February	165	$ 176.59	$ 182.84	$ 6.25	3.5%
March	144	$ 158.60	$ 163.86	$ 5.26	3.3%
April	107	$ 125.76	$ 129.23	$ 3.47	2.8%
May	60	$ 84.76	$ 85.99	$ 1.23	1.4%
June	27	$ 48.65	$ 48.65	$ 0.00	0.0%
July	18	$ 38.97	$ 38.71	$ (0.27)	-0.7%
August	15	$ 35.05	$ 34.68	$ (0.37)	-1.1%
September	16	$ 36.28	$ 35.94	$ (0.34)	-0.9%
October	32	$ 54.86	$ 55.03	$ 0.17	0.3%
November	66	$ 90.32	$ 91.86	$ 1.53	1.7%
December	125	$ 141.95	$ 146.31	$ 4.35	3.1%
Annual Totals	**964**	**$ 1,188.72**	**$ 1,217.37**	**$ 28.65**	**2.4%**

	Present Rates	Rate Year Rates
First 3 Ccf	$ 19.75	$ 18.76
Next 47 Ccf	$ 0.82740	$ 0.78599
Over 50 Ccf	$ 0.52280	$ 0.49663
DRA	$ 0.00596	$ 0.00596
Federal Tax Act	$ (0.07260)	$ -
Merchant Function Charge	$ 0.01747	$ 0.01876
Gas Supply Charge	$ 0.39971	$ 0.39971

The Average Annual Usage is 964 Ccf.

S.C. 14 Residential Aggregation

Month	Sales Ccf	Bills at Present Rates	Bills at Rate Year Rates	Difference Amount	Difference Percent
January	265	$ 155.01	$ 164.01	$ 9.00	5.8%
February	214	$ 131.43	$ 138.38	$ 6.96	5.3%
March	195	$ 122.68	$ 128.88	$ 6.20	5.1%
April	146	$ 99.89	$ 104.11	$ 4.22	4.2%
May	83	$ 70.73	$ 72.42	$ 1.69	2.4%
June	41	$ 48.35	$ 48.49	$ 0.14	0.3%
July	29	$ 39.45	$ 39.30	$ (0.14)	-0.4%
August	23	$ 34.79	$ 34.49	$ (0.30)	-0.9%
September	25	$ 36.31	$ 36.07	$ (0.25)	-0.7%
October	46	$ 52.65	$ 52.94	$ 0.28	0.5%
November	97	$ 77.37	$ 79.63	$ 2.27	2.9%
December	177	$ 114.21	$ 119.67	$ 5.46	4.8%
Annual Totals	**1,339**	**$ 982.86**	**$ 1,018.41**	**$ 35.55**	**3.6%**

	Present Rates	Rate Year Rates
First 3 Ccf	$ 19.75	$ 18.76
Next 47 Ccf	$ 0.82740	$ 0.78599
Over 50 Ccf	$ 0.52280	$ 0.49663
DRA	$ 0.00596	$ 0.00596
Federal Tax Act	$ (0.06630)	$ -
Merchant Function Charge	$ -	$ -

The Average Annual Usage is 1,339 Ccf.

S.C. 3 Commercial

Month	Sales Ccf	Bills at Present Rates	Bills at Rate Year Rates	Difference Amount	Difference Percent
January	558	$ 492.38	$ 507.12	$ 14.74	3.0%
February	479	$ 428.50	$ 440.86	$ 12.36	2.9%
March	414	$ 375.26	$ 385.65	$ 10.38	2.8%
April	293	$ 277.59	$ 284.34	$ 6.75	2.4%
May	151	$ 163.09	$ 165.59	$ 2.50	1.5%
June	84	$ 109.00	$ 109.48	$ 0.49	0.4%
July	71	$ 98.21	$ 98.30	$ 0.08	0.1%
August	62	$ 91.34	$ 91.17	$ (0.17)	-0.2%
September	67	$ 94.83	$ 94.78	$ (0.04)	0.0%
October	96	$ 118.83	$ 119.68	$ 0.85	0.7%
November	184	$ 189.96	$ 193.46	$ 3.50	1.8%
December	**354**	**$ 327.47**	**$ 336.08**	**$ 8.61**	**2.6%**
Annual Totals	**2,814**	**$ 2,766.46**	**$ 2,826.50**	**$ 60.04**	**2.2%**

	Present Rates	Rate Year Rates
First 3 Ccf	$ 30.25	$ 28.74
Next 47 Ccf	$ 0.69020	$ 0.65565
Over 50 Ccf	$ 0.43610	$ 0.41427
DRA	$ 0.00596	$ 0.00596
Federal Tax Act	$ (0.05060)	$ -
Merchant Function Charge	$ 0.01747	$ 0.01876
Gas Supply Charge	0.39971	0.39971

The Average Annual Usage is 2,814 Ccf.

Corning Natural Gas Corporation
Rate Year Ending January 31, 2022

ANNUAL BILL IMPACTS

S.C. 6 Commercial Transportation

Month	Sales Ccf	Bills at Present Rates	Bills at Rate Year Rate	Difference Amount	Difference Percent
January	15,523	$ 10,688.29	$ 10,806.30	$ 118.01	1.1%
February	14,023	$ 9,666.61	$ 9,773.21	$ 106.60	1.1%
March	12,663	$ 8,741.09	$ 8,837.37	$ 96.27	1.1%
April	8,409	$ 5,844.44	$ 5,908.38	$ 63.94	1.1%
May	5,365	$ 3,772.28	$ 3,813.10	$ 40.82	1.1%
June	3,662	$ 2,612.38	$ 2,640.25	$ 27.87	1.1%
July	3,246	$ 2,329.00	$ 2,353.71	$ 24.71	1.1%
August	3,091	$ 2,223.74	$ 2,247.27	$ 23.53	1.1%
September	3,645	$ 2,600.69	$ 2,628.43	$ 27.74	1.1%
October	6,341	$ 4,436.31	$ 4,484.54	$ 48.23	1.1%
November	9,874	$ 6,842.16	$ 6,917.24	$ 75.08	1.1%
December	14,022	$ 9,666.47	$ 9,773.07	$ 106.60	1.1%
Annual Totals	**99,864**	**$ 69,423.45**	**$ 70,182.87**	**$ 759.42**	**1.1%**

	Present Rates	Rate Year Rates
First 3 Ccf	$ 120.00	$ 113.99
Over 3 Ccf	$ 0.29770	$ 0.28280
DRA	$ 0.00596	$ 0.00596
Federal Tax Act	$ (0.02250)	$ -
Merchant Function Charge	$ -	$ -
Gas Supply Charge	$ 0.39971	$ 0.39971

The Average Annual Usage is 99,864 Ccf.

S.C. 7 Industrial Transportation

Month	Sales Mcf	Bills at Present Rates	Bills at Rate Year Rates	Difference Amount	Difference Percent
January	13,256	$ 68,838.80	$ 69,384.11	$ 545.31	0.8%
February	11,193	$ 58,267.32	$ 58,720.64	$ 453.33	0.8%
March	11,200	$ 58,304.80	$ 58,758.45	$ 453.65	0.8%
April	7,846	$ 41,119.09	$ 41,423.21	$ 304.12	0.7%
May	7,664	$ 40,184.16	$ 40,480.15	$ 295.98	0.7%
June	7,477	$ 39,223.40	$ 39,511.02	$ 287.63	0.7%
July	7,470	$ 39,188.77	$ 39,476.10	$ 287.32	0.7%
August	7,838	$ 41,075.09	$ 41,378.83	$ 303.74	0.7%
September	7,302	$ 38,329.21	$ 38,609.06	$ 279.84	0.7%
October	7,247	$ 38,046.68	$ 38,324.07	$ 277.39	0.7%
November	10,551	$ 54,979.49	$ 55,404.21	$ 424.72	0.8%
December	11,166	$ 58,126.26	$ 58,578.36	$ 452.10	0.8%
Annual Totals	**110,210**	**$ 575,683.08**	**$ 580,048.20**	**$ 4,365.13**	**0.8%**

	Present Rates	Rate Year Rates
First 250 Mcf	$ 1,220.00	$ 1,158.93
Over 250 Mcf	$ 1.22700	$ 1.16558
DRA	$ 0.00596	$ 0.00596
Federal Tax Act	$ (0.10600)	$ -
Merchant Function Charge	$ -	$ -
Gas Supply Charge	$ 3.99712	$ 3.99712

The Average Annual Usage is 110,210 Mcf.

S.C. 8 Hammondsport Transportation

Month	Sales Ccf	Bills at Present Rates	Bills at Rate Year Rates	Difference Amount	Difference Percent
January	13,588	$ 8,317.12	$ 8,459.27	$ 142.14	1.7%
February	13,900	$ 8,505.58	$ 8,650.98	$ 145.40	1.7%
March	11,683	$ 7,164.59	$ 7,286.80	$ 122.21	1.7%
April	7,473	$ 4,618.91	$ 4,697.09	$ 78.19	1.7%
May	4,345	$ 2,726.96	$ 2,772.43	$ 45.47	1.7%
June	3,402	$ 2,156.50	$ 2,192.10	$ 35.60	1.7%
July	3,304	$ 2,097.66	$ 2,132.25	$ 34.58	1.6%
August	3,448	$ 2,184.75	$ 2,220.84	$ 36.09	1.7%
September	4,511	$ 2,827.61	$ 2,874.82	$ 47.21	1.7%
October	5,171	$ 3,226.74	$ 3,280.85	$ 54.11	1.7%
November	7,973	$ 4,920.91	$ 5,004.32	$ 83.41	1.7%
December	12,823	$ 7,854.25	$ 7,988.39	$ 134.14	1.7%
Annual Totals	**91,621**	**$ 56,601.59**	**$ 57,560.14**	**$ 958.55**	**1.7%**

	Present Rates	Rate Year Rates
First 3 Ccf	$ 100.00	$ 96.00
Over 3 Ccf	$ 0.21830	$ 0.20956
DRA	$ 0.00596	$ 0.00596
Federal Tax Act	$ (0.01920)	$ -
Merchant Function Charge	$ -	$ -
Gas Supply Charge	$ 0.39971	$ 0.39971

The Average Annual Usage is 91,621 Ccf.

Corning Natural Gas Corporation
Rate Year Ending January 31, 2022

ANNUAL BILL IMPACTS

S.C 14 Commercial Aggregation

Month	Sales Ccf	Bills at Present Rates	Bills at Rate Year Rates	Difference Amount	Difference Percent
January	1,800	$ 765.64	$ 795.41	$ 29.77	3.9%
February	1,639	$ 700.56	$ 727.48	$ 26.91	3.8%
March	1,500	$ 644.63	$ 669.09	$ 24.46	3.8%
April	977	$ 434.24	$ 449.47	$ 15.22	3.5%
May	638	$ 297.68	$ 306.91	$ 9.23	3.1%
June	376	$ 192.20	$ 196.79	$ 4.60	2.4%
July	298	$ 160.92	$ 164.14	$ 3.22	2.0%
August	279	$ 153.22	$ 156.11	$ 2.89	1.9%
September	310	$ 165.58	$ 169.01	$ 3.43	2.1%
October	387	$ 196.79	$ 201.58	$ 4.80	2.4%
November	679	$ 314.25	$ 324.21	$ 9.95	3.2%
December	1,246	$ 542.32	$ 562.29	$ 19.97	3.7%
Annual Totals	**10,129**	**$ 4,568.05**	**$ 4,722.49**	**$ 154.44**	**3.4%**

	Present Rates	Rate Year Rates
First 3 Ccf	$ 30.25	$ 28.74
Next 47 Ccf	$ 0.69020	$ 0.65565
Over 50 Ccf	$ 0.43610	$ 0.41427
DRA	$ 0.00596	$ 0.00596
Federal Tax Act	$ (0.03950)	$ -
Merchant Function Charge	$ -	$ -

The Average Annual Usage is 10,129 Ccf.

Compression Surcharge Calculation

TCJA Surcredit Component

Service Classes	Four Months Sales *CCF	Total Annual Sales CCF	TCJA Rate (Per CCF)	TCJA Surcredits
S.C. 1 Residential	6,459,891	13,088,273	$ (0.0726)	$ (468,988)
S.C. 3 Commercial	1,117,822	2,345,495	$ (0.0506)	$ (56,562)
S.C. 6 Commercial Transportation	860,925	2,061,961	$ (0.0225)	$ (19,371)
S.C. 7 Industrial Transportation	2,653,272	7,859,634	$ (0.0106)	$ (28,125)
S.C. 8 Hammondsport Transportation	294,861	713,961	$ (0.0192)	$ (5,661)
S.C. 14 Residential Aggregate	349,916	730,730	$ (0.0663)	$ (23,199)
S.C. 14 Commercial Aggregate	835,072	1,716,938	$ (0.0395)	$ (32,985)
S.C. 1 Bath Firm	1,143,036	2,702,968	$ (0.0105)	$ (12,002)
S.C. 2 & 3 Bath Transportation	507,967	1,248,869	$ (0.0109)	$ (5,537)
Total	**14,222,762**	**32,468,829**		**$ (652,430)**

***CCF (January 31, 2021 through May 31, 2021)**

Base Rates Component

Base Rate Compression Surcharge %		**44.5%**
Revenue Requirement Decrease	$	(765,664)
Base Rate Compression Surcharge	**$**	**(340,929)**

	Percent	Amount
Residential Allocation	72%	$ (245,469)
Non Residential Allocation	28%	$ (95,460)
TCJA Surcredit		$ 652,430
Total Compression Surcharge		**$ 311,501**

Revenue Decoupling Mechanism Target

RDM Residential Service Classes		
S.C. 1 & 14 Residential	$	11,322,323

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

REBUTTAL TESTIMONY

OF

JESSICA R. BYROM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Q. Please state your name and business address.

A. My name is Jessica R. Byrom, and my business address is One Energy Plaza, Jackson, MI 49201.

Q. Are you the same Jessica R. Byrom who previously submitted testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut the direct testimony of Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witness Brittany Klocke on the topics of the Company's Low and Medium Income ("LMI") Customer Support Enhancement project and its Customer IT and IT Enhancements; Attorney General witness Sebastian Coppola's testimony regarding operating and maintenance ("O&M") for Customer Digital Customer Operations ("DCO") and Analytics and Outreach work, Michigan Environmental Council ("MEC") and Sierra Club ("SC") (collectively "MEC") witness Alice Napolean's testimony that discusses the Company's energy waste reduction ("EWR") programs, and Citizen's Utility Board of Michigan ("CUB") witness Joshua W. Denzler's testimony regarding the Company's Customer Order Service Tracker ("COST") project and associated O&M.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-129 (JRB-4) LMI Mindset Map.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Staff Witness Klocke Regarding LMI

Q. Starting on page 13, line 20 of her testimony, Staff witness Klocke has recommended disallowance of $1.9 million in capital for the Company's Customer-based LMI Customer Support Enhancement project. How does the Company respond?

A. The Company disagrees with Ms. Klocke's assertion that the expenses related to this LMI project are unjustified. 36% of all Consumers Energy customers assume they are not eligible for utility payment assistance, 33% lack awareness of available assistance, and 18% do not know where to start the application process. The project will allow the Company provide assistance to customers in a thoughtful, prescribed manner. Additionally, as an active participant in the MPSC's Low-Income Energy Policy Board, Energy Affordability and Accessibility Collaborative ("EAAC") and EWR Low-Income Workgroup, the Company has planned and executed this project to align with the priorities for assisting LMI customers, responding directly to the EAAC's key area of focus including "strategies for streamlining the energy assistance process; and recommendations on tying energy waste reduction to energy assistance.[1]"

Q. Why is the LMI project's alignment with the MPSC's EAAC and EWR Low-Income Workgroup important?

A. Alignment with the EAAC and EWR Low-Income Workgroup is important because it ensures that this project reflects the needs of the most vulnerable customers and is grounded in best practices developed through statewide collaboration. Parties within these groups represent a broad cross-section of stakeholders, including residents, non-profits, utilities, and state agencies, all holistically working toward assessing energy affordability and

[1] https://www.michigan.gov/mpsc/commission/workgroups/energy-affordability-and-accessibility-collaborative

accessibility, particularly through linking EWR services and energy assistance programs. Their work has produced clear, data-informed recommendations and guiding principles that define what effective, just, and sustainable energy assistance should look like in Michigan. The Company's LMI project responds directly to these recommendations to deliver a solution that reduces duplication of customer efforts while seeking assistance, aligns with State programs, and is grounded in the needs and best practices identified by these collaborative groups.

Q. Beginning at page 14, line 14, of her direct testimony, Staff witness Klocke states "through numerous rounds of audit questions, to ascertain exactly what the LMI Customer Support Enhancement will do or will offer customers and still does not have a clear answer." Has the LMI project implementation produced a more dependable project scope for what it offers customers?

A. Although the LMI Customer Support Enhancement project was in development and early implementation at the time of the Company's initial filing, it has now been operational for four months. In that short time, the project has clearly demonstrated its value in improving access to assistance for all Consumers Energy customers.

The project has already seen a measurable increase in customer engagement and uptake—indicators that the tool is well-designed to meet the needs of the population it is intended to serve. Since its launch on December 12, 2024, over 55,000 customers have interacted with the tool, and 12,000 customers have enrolled in an offering, with 22% of interested customers enrolling in programs (compared to .05% of customers who enroll after being reached via email), ensuring that the efforts put into developing and promoting the tool are yielding tangible benefits. Given its strong foundation, evidence-based design,

immediate positive outcomes, and clear trajectory for ongoing improvement, this LMI project is a reasonable and prudent investment. Funding it now ensures that the Company can continue delivering meaningful support to customers who need it most.

Q. Can the Company provide results that demonstrate effectiveness and progress toward the stated goals of the LMI project?

A. Yes. Since its launch, the LMI project has delivered several measurable outcomes that demonstrate its early effectiveness and validate the Company's approach. Within the first four months of deployment:

- Over 55,000 customers have engaged with the tool since launch, and nearly 30,000 (55%) of those users have self-identified as LMI, indicating high visibility within and interest from the intended user base.
- Of the 55,000 customers who have interacted with the tool roughly 40% completed the full eligibility assessment, successfully identifying one or more programs for which they may qualify.
- Of the 12,000 users completing the flow, nearly 20% have enrolled in more than one offering, demonstrating the effectiveness of the simplified digital enrollment flow in making it easier for customers to access the programs they need.
    - By streamlining the process, customers can quickly and efficiently determine their eligibility and enroll in multiple beneficial programs, leading to better support and improved outcomes for those in need.
- On April 20, 2025, Green Giving was added to the simplified digital enrollment experience. In just the first hour, six customers enrolled—matching the total enrollments agencies achieved in the previous six weeks.
    - Since then, the Company has enrolled 515 low-income customers digitally, while agencies have enrolled 10.

      This contrast highlights the urgent need to streamline enrollment and eliminate administrative barriers. Modernizing the Company's approach is essential to better serve its customers and maximize program impact.

- 87% of users that completed the survey reported that it was extremely easy[2], or easy to complete the experience.

- 56% of users that completed the survey reported that they felt the offerings provided to them were extremely personalized or very personalized to them.

- By implementing the tool, the Company has reduced the need to send approximately 300,000 emails to promote individual products to reach enrollment goals, streamlining the Company's outreach efforts and maximizing efficiency.

- The tool has captured over 3,000 leads for EWR programs[3]. The tool's ability to capture leads organically indicates a user-friendly and effective design, making it easier for customers to navigate and enroll in programs.

These results affirm that the tool is immediately delivering on its intended purpose: reducing enrollment barriers, increasing program visibility, and helping LMI customers more easily access the support they need. Continued monitoring and feedback collection will allow the Company to further refine the tool and expand its impact in the months ahead.

Q. On page 19, lines 5 through 10, Staff witness Klocke states "A main reason Staff does not support this project is because Staff does not believe this project will do anything to fix or prevent the root causes of customers either in or on the brink of crisis. The LMI project will not reduce customers' energy burden, even if they are able to utilize a payment plan, select their due date, or anything else – these solutions are mere band aids to the larger root problem of energy unaffordability." Does the Company agree with this assessment?

[2] Based on a rating scale the rating scale includes:
Extremely Easy
Very Easy
Moderately Easy
Slightly Easy
Not Easy at all

[3] The tool captures leads to send to CLEAR, to then contact customers to schedule Home Energy Analysis appointments.

A. No. While Staff witness Klocke says that the LMI project does not address the root causes of energy unaffordability and merely offers band-aid solutions, it is important to recognize the immediate and tangible benefits this project provides to LMI customers. The LMI project is designed to provide crucial immediate relief and support to those who are currently facing significant energy affordability challenges.

By simplifying enrollment processes, proactively communicating with customers, and integrating and improving existing assistance programs, the project ensures that customers can access the support they need without unnecessary hurdles. This immediate support can help prevent service disconnections, reduce energy burdens, and improve household stability, which are essential outcomes given the current economic realities. This project serves as a necessary step in building a more comprehensive support system for LMI customers. The Company's broader strategy encompasses several key initiatives aimed at addressing both immediate needs and long-term challenges.

Q. On page 15, and page 16, lines 1 through 16, Staff witness Klocke references the LMI project's Simplified Enrollment goal, stating "Staff frankly does not understand why this information regarding enrollment is not already available to customers and is unclear why the Company needs so much money to allow customers to enroll in applicable programs." How does the Company respond?

A. While enrollment information is available on the website and accessible to all customers (and non-customers), it is not presented in a way that is easily navigable or actionable for a specific subset of customers: those in need of assistance. Staff have stated that the tool should be available to all customers, and it is indeed accessible to all customers who are authenticated on the Company's website. Data shows that 8% of customers who have self-

identified within this LMI enrollment flow are market rate customers, falling outside of the LMI eligibility parameters. This demonstrates that these customers are still able to access the flow and enroll in offerings for which they are eligible. The flow does not limit access; it streamlines enrollment, making it easier for customers to understand what programs they are eligible for based on their customer profile.

Staff witness Klocke points out that links to assistance programs exist on the Company's website on page 19, lines 13–14, but that information shared via a static website versus interactive web tool significantly limits its effectiveness and often adds to the burden of figuring out what to do with that information.

For example, recommendations from State collaborative workgroups supported by primary customer research, including surveys and usability testing, show that the current assistance enrollment experience is burdensome, fragmented, and often overwhelming. Research findings include:

- "It takes about 30 minutes, filling out nine forms to begin to sign up for State benefits, assuming steady internet access, device compatibility, and printing/scanning ability"[4];
- "25% of LMI customers indicated say they are not interested in learning about EE (Energy Efficiency) programs because they do not have time to participate[5]"; and
- 51% of LMI customers agree with the statement "I never seem to have enough time to get things done[6]."

Making information available on the website does nothing to address the root cause of some of these difficulties.

[4] From a Consumers Energy customer interview
[5] From third party research conducted by Bellomy
[6] From third party research conducted by Bellomy

The project's simplified enrollment goal is not to duplicate content—it is to deliver a centralized, web and mobile-friendly tool that provides step-by-step guidance based on a customer's individual circumstances. It matches customers only with programs for which they are eligible, explains what is required for enrollment, and allows them to share their information once, rather than repeatedly. The Company has supported and acted on simplifying assistance enrollment in direct response to the complexity of government bill assistance approval flows. With various levels of assistance, programming options, and requirements/eligibility, customers can find themselves lost in the details. Within the LMI project, the focus is on individual opportunity and not a one-size-fits-all information download. This level of customization, guided by real customer insights, goes far beyond a standard web feature or program list. The tool ensures that customers are not just informed—but effectively guided—through the enrollment process with clarity and ease.

The LMI project goes beyond making information available to customers. The funding request reflects the work required to design, build, test, and deploy a digital tool with a personalized, human-centered interface that addresses complex processes and long-standing barriers for LMI customers. Therefore, while the Company agrees that the information should be accessible on the website, the development and deployment of this tool is a distinct, necessary investment that fills a critical gap in the Company's current service model that goes beyond simply making the information available. It is a reasonable and prudent initiative that directly supports equity and ease of access for the customers who need it most.

Q. On page 16, beginning at line 21 through page 17, line 4, Staff witness Klocke stresses that assistance information should be accessible to all customers, and in doing so states (page 17, lines 2 through 6) that "Staff is not convinced that the Company's definition of customers in crisis adequately captures all those customers who could end up in crisis..." How does the Company respond?

A. As noted by Ms. Klocke on page 16, lines 17 through 19, "In an uncertain economic climate, virtually anyone could be in crisis with the loss of a job, unexpected bill, medical emergency, etc." Under the LMI project, the Company has identified low-income customers as "being in crisis" –and moderate-income customers as "one crisis away" from being in crisis. Examples of "one crisis away" include situations such as a missed paycheck or job loss. The scope of the LMI Customer Support Enhancement Project includes exploring ways to support customers who do not currently qualify for low-income assistance but still face significant financial challenges including emergency or unexpected challenges as noted by Staff witness Klocke. In alignment with Ms. Klocke's comments, the intent of this project is to expand support for customers beyond the traditional low-income definition to also include moderate income customers at risk of financial hardship and all customers that may be seeking opportunities to lower their energy bills.

Q. On page 16, lines 6-12, Staff witness Klocke states another core function of the LMI project--Proactive Communications and Program Awareness is unneeded because the Company already conducts outreach. Does the Company agree?

A. No. On page 16, lines 11 through 12, Staff witness Klocke states that the $400,000 cost of this targeted LMI outreach is unnecessary given that "Residential customers, regardless of income, are given outreach via direct mail and email for information about EWR, demand

response, and Renewable Energy Programs." Additionally, Ms. Klocke states on page 17, line 4 "believes all customer classes – not just those identified as low-to-moderate income – should have access to the information the LMI project provides"

The Company disagrees with the notion that targeted outreach is unnecessary. All customers will continue to receive information about available programs and have access to the LMI tool, as discussed above. However, the LMI project's Proactive Communications and Program Awareness initiatives are designed to complement broad marketing efforts by applying focused awareness tactics specifically tailored to the unique needs of LMI customers who face unique and well-documented barriers to engagement.

This is a "yes, and" approach—not an either/or. It ensures the Company continues to engage the full customer base while also delivering more effective, personalized communication to those who are most in need. The foundation of the communications targeted to the LMI customer population is based on identified risk and an assessment thereof based on (1) account and behavior data and (2) information gathered through the self-attestation a customer provides when accessing the larger LMI project flow--that may indicate or serve as evidence that a customer may be struggling now or will be in the near future. This data paired with LMI Mindset Map included as Exhibit A-129 (JRB-4) insights inform proactive communication strategies. There is a planned methodology behind the targeted communications. Consequently, the Company is enabled to anticipate needs, align with customer motivations and preferences, and drive stronger engagement with better outcomes.

Q. On page 17, starting at line 12, Staff witness Klocke discusses another stated goal of the LMI project, New and Improved LMI Offerings, by which the "Staff is perplexed why a new program such as this one would need such expensive 'improvements' already." How does the Company respond?

A. The Company believes it will take a significant, upfront investment to create an infrastructure, both programming and technological, to support the goals of new and responsive LMI offerings, as well as the LMI project as a whole. Part of the infrastructure required is assessing how current programs fit together, what gaps exist between current and potential services, and how to tie everything together for the most efficiency for the overall customer experience.

Q. On page 18, starting at line 9, Staff witness Klocke discusses the final stated goal of the LMI project—Continuous Improvement—where she states, "Again, it appears the cost requests and the overall LMI project itself is too premature to be deemed reasonable and prudent." Why is the proposed LMI project a reasonable and prudent investment for the Company and its customers?

A. This project's goal of Continuous Improvement speaks to the fact that it is not a one-time deployment; it is an evolving solution, especially in this startup phase. The Company is actively monitoring usage patterns and collecting feedback to enhance the tool's performance and expand its capabilities. The lessons being captured today will further strengthen the tool's effectiveness and enable it to reach a broader segment of the customer population over time.

The proposed LMI project is a reasonable and prudent investment because it is directly informed by robust, customer-centered research and is designed to address

well-documented barriers that prevent LMI customers from accessing the assistance they need. The Company initiated primary and secondary research with over 2,000 low-income customers to better understand LMI customers and to identify barriers to awareness about assistance options and participation in utility programs. This research included surveys, interviews, customer panels, and usability tests, and uncovered two primary barriers: a general lack of awareness about available programs and a perception that the enrollment process is overly complex.

In response to these findings, the LMI project is tailored to reduce these specific barriers by improving communication, simplifying enrollment processes, and streamlining customer experience. By doing so, the project aims to improve access to critical assistance programs and ensure more equitable outcomes for vulnerable customer groups. The design of the project is evidence-based, targeted, and aligned with the Company's obligation to serve all customers effectively, particularly those most in need. For these reasons, the investment is both reasonable and prudent, as it addresses a demonstrated customer need with appropriately scoped and strategic solutions.

Q. Please explain why the overall, upfront investment in the LMI project is justified, and how that investment ultimately provides long-term benefits, including utility bill reductions, for customers?

A. The upfront investment in the LMI Customer Support Enhancement Project is both necessary and justified because it lays the foundation for long-term, sustainable benefits that directly improve customer outcomes and reduce energy burdens over time. This investment supports the development, deployment, and refinement of a digital tool that

helps customers more easily identify and enroll in assistance programs for which they are eligible—many of which provide direct utility bill savings.

Historically, LMI customers face multiple barriers to accessing support: limited awareness, confusion about eligibility, and difficulty navigating enrollment processes. By removing these barriers through a streamlined, automated solution, the program increases uptake in bill assistance and energy efficiency offerings—leading to tangible, recurring reductions in monthly utility bills for eligible customers.

For example, customers who successfully enroll in assistance programs may receive monthly credits, arrearage forgiveness, or energy efficiency upgrades that lower usage, which translates to lower bills. By making it easier to access these benefits, the program not only delivers immediate relief but also supports long-term household stability and improved payment behavior, which benefits the broader customer base by reducing uncollectible expenses. Thus, while the initial costs are concentrated at the front end, the return on investment is realized over time. This is an informed, customer-centric investment that aligns with the Company's and goals of affordability, equity, and service quality.

Q. What would be the impact of disallowing the LMI Customer Support Enhancement Project?

A. Disallowing this project would have significant and immediate negative consequences, particularly for the Company's most vulnerable customers. The LMI digital tool was developed to address persistent challenges—such as lack of awareness, confusion about eligibility, and difficulty navigating the application process. These challenges disproportionately affect low-income households, who are often already struggling with

affordability and energy insecurity. A disallowance of this project means effectively deferring meaningful relief and continuing to rely on fragmented systems that are not meeting the needs of these customers. Moreover, this project benefits all ratepayers by promoting broader enrollment in assistance and energy efficiency programs, which in turn can reduce bills, improve payment behavior, and ultimately lower the level of uncollectibles carried by the utility. In sum, this is a proven, customer-informed solution ready for deployment. Disallowing the project unnecessarily extends hardship for low-income customers and undermines the Company's commitment to equitable access and affordability.

Staff Witness Klocke Regarding Click To Chat, Web Chat AI, And Self-Service Mobile App

Q. Staff witness Klocke also recommends historical, bridge, and test year disallowances for several Customer-related IT Enhancement projects. Please discuss.

A. Staff witness Klocke's proposed disallowances include $45,683 in capital for the historic year ended December 31, 2023, as well as $2,958 in capital expenditures for the bridge year period ended December 31, 2024 for Click to Chat (Staff witness Klocke Direct Testimony, page 5, lines 20 through 23, through page 6, lines 1 and 2); proposed disallowances for Web Chat AI include $180,565 in capital expenditures, and $14,929 in O&M for the test year ending October 31, 2026 (Staff witness Klock Direct Testimony, page 8, lines 16 through 18); and finally, proposed disallowances for Enhancements to the Company's Mobile App include a decrease of $61,562 in historical capital, $274,116 in capital costs for the year ended December 31, 2024, $598,472 in capital costs for the year ending December 31, 2025, and $550,025 in capital costs and $6,510 in O&M costs for the

projected test year ending October 31, 2026 (Staff witness Klocke Direct Testimony, page 10, lines 11 through 14).

Q. Does the Company, in general, agree with Staff witness Klocke's reasoning?

A. No. All three digital tools that Staff witness Klocke puts forth for disallowance are: (1) based on industry research that supported customer desire for chat-based applications; (2) currently in existence and in use by customers; and (3) consequently require updating and maintenance. For those projects previously supported in rate cases Staff have not pointed to any circumstances that have emerged since the Commission issued these orders that should cause them to revisit.

The Company has previously cited JD Powers findings regarding chat tools, including one that found that live chat has become the leading digital contact method for online customers with 42% of customers preferring live chat compared to just 23% for email. The development and maintenance of these tools are not driven by utility preference but are a direct response to the expressed needs and expectations of the customers the Company serves. Furthermore, peer institutions have both similar tools and similar restrictions to customer assistance hours (see Help Center | DTE Energy[7] and Contact Us | AEP Energy[8]), setting Consumers Energy on equal footing with its peers, implementing best practices by providing customers with channels of choice.

In providing different channels of communication, it becomes a necessary obligation for the Company to update and maintain the tools customers prefer to use. From the emerging Web Chat AI tool to the Click to Chat tool available to business customers and the established and popular Mobile App, investments into these enhancements ensure

[7] https://www.dteenergy.com/us/en/quicklinks/help-center.html
[8] https://www.aepenergy.com/contact-us/#:~:text=Chat,am%20%E2%80%93%207%3A00%20pm.

these tools work as requested or expected. To that end the associated investment should be considered reasonable and prudent.

Q. Does the Company agree with Staff witness Klocke's reasoning for recommending the disallowances for Click to Chat.

A. No. Starting on page 5, line 20, Staff witness Klocke states Staff's points against the Click to Chat project—including finding "the project does not offer any new technology or features that are innovative, nor does it represent any cost savings" (page 6, lines 7 to 8).

She further restates on page 7 lines 6 through 12 that "Staff also has concerns that just 314 uses of Click to Chat have been reported by the Company's agents. (Staff Exhibit S-11.1.) For a project that has now been available for over three years, usage is very low. In that same audit response, the Company stated that it currently has 'no tracking regarding how many of their [customers'] problems/issues were fully resolved using this feature.' (Staff Exhibit S-11.1.) Staff finds it troubling that the Company is not tracking the results of this project in an effort to measure its success."

The goal of Click to Chat was not to only reduce call center costs, but to offer customers another channel through which to reach the Company and potentially self-serve.

Additionally, Staff continues to support only the implementation of IT applications that are considered valuable because of associated cost savings. This fails to consider that both customer preference and accessibility have value of their own. On page 7, lines 13 to 14, Staff witness Klocke states that "any major problems will still require CSR intervention" but fails to recognize: (1) Click to Chat was never envisioned or intended to solve urgent customer inquiries, and (2) that both time and costs savings might be realized

in the disposition of common or simple issues that customers may solve via chat without any involvement from the Customer Service personnel.

The administrative law judge ("ALJ"), and ultimately the Commission, recommended recovery of historical costs for Click to Chat in Case No. U-21585 (See MPSC Case NO. U-21585, March 21, 2025 Order, page 185 "The ALJ agreed with Consumers that, although the Click to Chat function does not save money, it contributes to the provision of utility service").

Q. Does the Company agree Staff witness Klocke that usage of the Click to Chat tool is low?

A. No. On page 7, line 6, Staff witness Klocke cites the number of completed Click to Chat interactions as 314 and then states that "For a project that has now been available for over three years, usage is very low." However, the Click to Chat project implementation had been delayed until late October 2023. Consequently, the project has been available for approximately 18 months, not three years, effectively doubling the usage statistics. When added to the fact that Click to Chat was initially available as a non-market soft launch to business customers, Staff witness Klocke has understated the number of customer interactions with the tool and underestimated the potential of a relatively new channel.

Q. Does the Company agree with Staff witness Klocke's reasoning for recommending the disallowances for Web Chat AI Enhancements. Please discuss.

A. No. Staff witness Klocke states on page 9, line 5that Staff finds Web Chat AI "redundant and not worth the cost." And "In essence, the Web Chat will simply be aggregating information that is already available to customers on the Company's website." (page 9, lines 11-12). The Company maintains that chat functionality is a customer channel of

choice, and as such should be supported, maintained, and updated as necessary. Additionally, Web Chat AI is in the early stages of enhancement and consequently cost savings are unquantified at this time. The Company remains committed to the tool as an alternative channel of interaction with the Company. Not every customer has an issue or question that rises to the level of calling a service center and the Web Chat AI tool will provide relevant information in an instant and the customer may interact according to their situation.

Q. Please discuss Staff witness Klocke's reasoning for recommending the disallowances for Mobile App Enhancements.

A. Starting at page 11, line 6, Ms. Klocke states that Staff is against the Company's Mobile Application funding—and in this case that includes the funding for enhancements—recommending a decrease of $61,562 in historical capital costs for the year ended December 31, 2023, $274,116 in capital costs for the year ended December 31, 2024, $598,472 in capital costs for the year ending December 31, 2025, and $550,025 in capital costs and $6,510 in O&M costs for the projected test year ending October 31, 2026 (page 11 , lines 11 through 14).

She states on page 11, lines 21 through 23, and page 12, lines 1 through 4 that "Staff's position regarding the Mobile App has remained the same in every case it has been presented in, starting with Case Nos. U-20697, U-20963, U-21224, U 21389, electric cases, and Case Nos. U-21148, U-21308, and U-21490, gas cases. In each of those cases, Staff's position is that the Mobile App represents functionality that is duplicative of the Company's website and is therefore unnecessary and its over $10 million total costs should

not be passed on to ratepayers." Further, page 12, lines 7 and 8, "the Company has never conclusively proven a need for such an application or customers' interest in it."

Q. Does the Company agree with this assessment?

A. No. The Company has consistently supported the development and launch of its Mobile Application for several reasons, including those outlined below. It is for these reasons that the Mobile App enhancement dollars should be allowed.

1. The Commission took no position on the Mobile App in Case No. U-21224, which was settled. However, the Commission expressly approved the Mobile App project on its merits in Case No. U-21389 finding "The Commission agrees with the company's arguments that, while there may be some redundancy in the functions of the app and the website, there is value in offering varying communication channels to meet customer needs. As pointed out by Consumers in its exceptions, it could be argued that there is redundancy between the functions of call centers and the company's website as both are avenues to receive customer payment. As technologies and customer preferences evolve, the Commission finds that duly supported, reasonable, and prudent expenditures to meet those preferences are appropriate for recovery."(MPSC Case No U-21389, March 1, 2024 Order, page 83.);

2. Since the app's launch, there have been almost 1.5 million downloads and the Company has seen the popularity of the app continually increase, with a current share of digital traffic at over 28%, and now exceeding Desktop Web use (App use of 5.3 million sessions vs Desktop use of 4.6 million sessions for 2025 YTD);

3. The Mobile App is not a carbon copy of website functionality, nor was it conceived in this way. As the Company has stated several times, the Mobile App has separate functionality and has the added benefit of not needing a web interface to interact with the Company. The Mobile App was developed to provide a streamlined experience for customers, allowing them to complete common interactions quickly and efficiently on their phones, with features like simple login and direct access.

4. The Mobile App continues to serve as a reliable platform during potential website downtimes, ensuring that customers can still complete routine transactions like bill payments.

5. As shown by adoption and use statistics above, customers prefer to perform more complex interactions in the mobile app and additional functionality should be expanded in response.

These points highlight the recognized functionality and growing popularity of the Mobile App amongst Consumers Energy's customers for an array of their interaction needs. The related enhancement dollars should be allowed to support and enrich the Mobile App experience.

Website Redesign

Q. Staff witness Klocke often mentions disallowances in conjunction with a desire to see the Company's website update realized saying regarding Web Chat AI on page 9, Lines 12-15 "Staff has and does support the Company's planned website redesign and feels it would be a much better use of Company resources – and ratepayer money – to update the website to make any general, frequently asked questions easily found."). and includes this language in relation to the LMI project, the Mobile App, and Enhancements to Company chat functionality. Please respond to the suggestion that the website is the central technology vehicle for the Company.

A. The Company agrees with Staff witness Klocke that a current and robust website is beneficial to an organization that provides a large volume and wide variety of information and resources to their customer base. The Company has requested and received support for its website redesign (Case No. U-21308, Case No. U-21224, and Case No. U-21490) and has been delayed in fully realizing its stated plans (please see Company witness Stacy H. Baker's rebuttal testimony for information on overall website redesign progress). However, in relation to the Mobile App and chat functions, the Company has stated and reiterates here that these tools are not intended to have all the functionality of the website, nor are they intended to replace the website or other customer channels. The customer IT projects

referenced by Staff witness Klocke provide support for specific yet complex interactions that are not necessary in all channels of communication.

The Company remains committed to updating its website to provide accurate and up-to-date information for all of its customers. As the Company works through the IT solutions in progress to achieve this goal, it also remains committed to growing channels utilized by customers.

Attorney General O&M Disallowance for DCO and Analytics and Outreach

Q. Does the Company agree with Attorney General witness Coppola's recommendation, starting at page 174, line 12, to page 175, line 15, to disallow $2,325,000 from Analytics and Outreach related O&M.

A. No. The Company disagrees with Attorney General witness Coppola's recommendation to disallow $2,325,000 in Analytics and Outreach related O&M. While Attorney General witness Coppola notes (page 174, lines 19 to 20) that the Company responded to a discovery request including historical and forecasted staffing, work activities, and associated outcomes he then dismisses the information provided to be of insufficient clarity.

Starting at line 3 on page 175, Attorney General witness Coppola shares the Company's personnel numbers, but continues to state that when it came to accurate responses regarding customer interactions, "From the response, it is not clear what customer interactions entail, why there are so few, and why they decline from 2022 and stay the same between 2024 and the projected test year when the number of employees and contractors in this function increases." The Company provided overviews of the Analytics

and Outreach department's responsibilities and activities as seen in Exhibit AG-60, page 1, as well as work units, headcounts, and budgets.

The Analytics and Outreach group serves a vital function for incorporating customer feedback and data into the Company's operations, which directly contributes to improving customer experience. This allows the company to use its resources more efficiently, target communications to precise customer segments, and select programs that are most likely to provide customer value.

Program priorities include:

- All MPSC reporting – providing reporting metrics and data as required or requested by internal stakeholders
- Estimated Time of Restoration ("ETR" – utilizing Machine Learning in real time, to provide an ETR when a customer loses power, on blue sky days through catastrophic storms)
- Customer Experience Index – supporting the Company's top level goal of consolidation of all live and automated phone calls, app and web traffic, and customer experience surveys across all channels
- Data Automation – centralizing all data outputs from the dozens of source systems and properly storing and maintaining in a centralized resource
- Data Quality – ensuring accurate Customer information for address, email, phone numbers, etc. - improving communication accuracy
- Data Visualization – the execution of all metrics tracked by both Customer Operations and Customer Experience
- Problem Solving – deep dive analysis into the most granular data to support the improvement of customer impacting metrics

Q. Does the Company agree with Attorney General witness Coppola's recommendation to disallow $536,000 or half of the original $1,072,000 request from O&M related to DCO.

A. No. Starting on page 176, lines 5 through 17, Mr. Coppola argues there is a lack of information about who and what comprise the DCO organization.

Mr. Coppola states "it is not clear why most of the system functions already developed would require repeat work using the same number of employees and contractors every year. The general description of accomplishments does not make a compelling case that significant value is being generated. There is insufficient support to justify the number of resources assigned to this function. The evidence is inadequate, and the expense level remains unsupported." See Direct testimony of Mr. Coppola at page 176, line 19, through page 177, lines 1 through 5.

The DCO manages a channel that gets more than 45 million customer interactions annually and provides customers with a valuable self-service tool when managing their energy consumption. The teams' services are particularly valuable when viewing 2024 statistics for the Company's website and mobile application, including 15.7 million views related to checking billing status, 13.8 million related to payments via web or app, and 4.5 million views to view outage status. The DCO team keeps the website and mobile app running, accessible for and responsive to Consumers Energy customers as a well-used channel of choice. The DCO team is critical to the success of the company's objective to digitize more transactions to better serve customers on the website, which is a more cost-effective means of serving customers than other channels.

Additionally, as evidenced in Exhibit AG-60, page 2, overall costs for DCO O&M have been relatively decreasing as the group finds efficiencies and constancy in the technologies it supports.

Attorney General on Affordability

Q. On pages 16 and 17, lines 4 through 9 and 2 through 10, respectively, of his direct testimony, witness Coppola states that capital spending will pose a significant burden on residential customers and business bills. What options does the Company have available to assist customers?

A. Company witness Neal P. Dreisig's rebuttal testimony discusses the economic effect of capital spending on both residential and business bills, including the Company's efforts to balance the cost of reliability and safety with rates. In his testimony, witness Dreisig references both the Company's energy-efficiency programs and its LMI assistance Consumers Affordable Resource of Energy ("CARE") Program as examples of the Company's commitment to providing customers with energy assistance.

Q. Please provide details about how the Company's energy efficiency and CARE program provide assistance to ratepayers.

A. The Company's CARE program is designed to assist income-qualified customers in managing their energy use and bills more effectively. CARE provides customers with bill assistance via a 24-month program that includes a fixed monthly bill—offering a consistent, reduced monthly payment plan that makes budgeting for energy expenses more manageable. As customers make regular, on-time payments, existing past due balance will be forgiven. Customers may also be provided with no-cost, in-home energy efficiency upgrades to help reduce energy costs

Q. Does Consumers Energy offer other assistance programs for qualifying customers?

A. Yes. Consumers Energy offers assistance via several additional programs, including State and Local programs. Details may be found at Payment Plans & Assistance | Consumers Energy.[9] Additionally, investment in the LMI project will allow the Company to better assist customers enroll in programs.

CUB Witness Bunch's Affordability and Uncollectable Discussion

Q. Starting on page 4 of his testimony, CUB witness Bunch also voices concern about the Company's proposed rate increase, citing its effect on affordability for low-income and senior customers. Starting on page 7, lines 3 through 4, CUB witness Bunch provides the source for calculations that follow. What is that source?

A. Mr. Bunch is referencing data from the Company's quarterly reports filed in the docket for Case No. U-18120 the Rule 51 report), a snapshot of which is in Figure 1 below.

Figure 1

Rule 51 Trending	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22
Customer Service											
Total customer contacts (Res and Non-Res)	716,767	704,762	847,519	764,817	741,068	842,070	836,679	1,102,010	779,668	764,582	881,079
Total customer complaints	6,902	6,773	8,241	7,120	6,601	7,092	6,798	7,635	7,706	6,865	6,173
a. Billing	1,909	1,766	2,025	1,702	1,624	1,633	1,759	1,814	1,851	2,011	1,585
b. Service	701	665	918	853	814	966	930	1,209	995	903	928
c. Credit and Collection	3,831	3,887	4,773	4,173	3,791	4,114	3,733	4,157	4,478	3,583	3,287
d. Other	443	445	504	392	372	379	364	438	364	354	362
Freeform area	18	10	21	19	12	15	12	17	18	14	11
Customer Payment Performance											
Number of customers paid by the due date	2,763,645	2,725,736	2,739,286	2,756,938	2,715,413	2,731,921	2,744,007	2,736,725	2,745,207	2,748,898	2,764,311
Number of customers delinquent 31-60 days or more	83,193	82,080	82,371	86,369	94,906	84,652	95,991	78,187	91,310	92,197	87,698
Number of customers delinquent 61-90 days or more	42,392	40,093	31,935	37,120	42,730	46,023	51,012	50,595	39,214	48,793	48,138
Number of customers delinquent 91 days or more	70,694	68,233	63,849	54,117	59,186	62,876	69,453	80,876	80,730	78,122	79,799
Payment Plans and Settlements											

Q. Does the Company dispute CUB witness Bunch's findings using this data?

A. Yes.

[9] https://www.consumersenergy.com/residential/account-and-billing/billing-and-payment/payment-assistance

Q. Please explain.

A. For example, on page 7, lines 4 through 5, CUB witness Bunch uses this data to support his assertion that delinquent accounts are growing significantly.

Q. Is this an accurate statement?

A. CUB witness Bunch is correct when he states, "The number of accounts that are 90+ days in arrears has been growing" (when referring to years 2022-2024). However, the significance of this growth is open to interpretation due to the potential exaggeration from the chart's scaling. For example, if the same dataset referenced on page 7, lines 3 and 4, can be expanded to show the period of 2020-2024, customer accounts in arrears did increase (Figure 2), but also saw several decreases. Additionally, over the same 2020-2024 timeframe, correlated dollar amounts arrearage decreased (Figure 3).

Q. Why does this matter?

A. By selecting a specific timeframe on which to focus, CUB witness Bunch provides only the context of the data and no social, political, or economic context for which there might logically be a drop or a surge in arrears. He also fails to offer policy implications, either macro or micro (e.g. the way arrears were reported or accounted for), context.

Figure 2

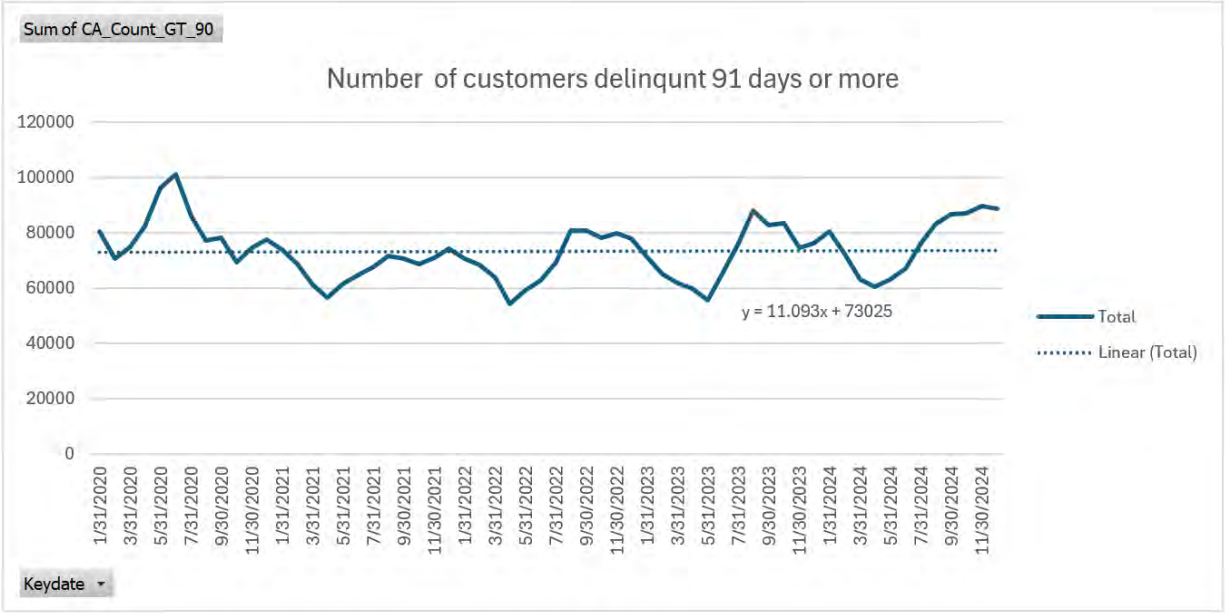
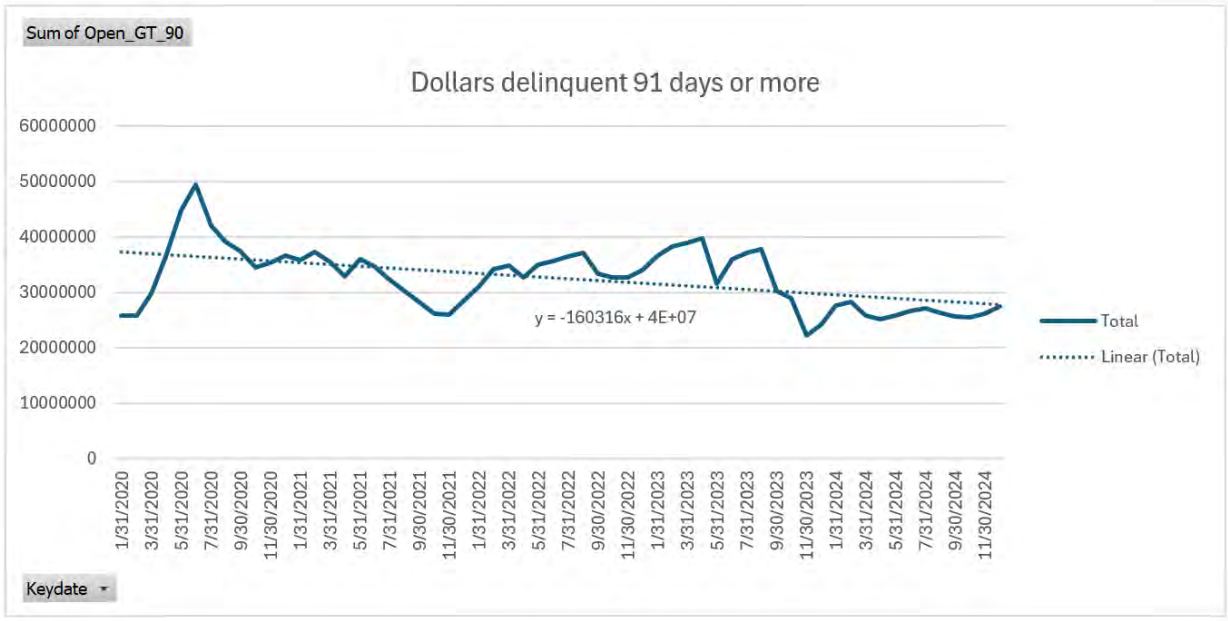


Figure 3



Q. On page 7, lines 9 through 10, CUB witness Bunch indicates "Long-term delinquencies have grown by about 25% over the past three years." Is this accurate?

A. Mr. Bunch may be referring to the percent change in customer count in the Over 90 bucket, from Jan 2022 to Dec 2024: (88,577 – 70,694) / 70,694 = +25%. in Figure 1. Though this is the accurate percent change in customer count, a comparison of a data point from one month (January) to the data point from a different month (December), may not be comparable since arrears is cyclical. Also, it's worth noting that while customer count did trend up, dollars in the 91+ days-past-due bucket trended down over the time period highlighted by CUB witness Bunch.

Q. On page 8, line 5, Mr. Bunch states "From 2021 to 2023, residential uncollectible expenses increased 53.7%." Is this accurate?

A. The date on page 8, line 6, and on which CUB witness Bunch bases his statement is accurate and was cited from Company-provided data.

Q. Starting on page 8, line 10, and continuing through page 10, line 6, CUB witness Bunch discusses the Company's rate impact in conjunction with inflation and spend. Does the Company agree with his testimony?

A. Company witness Dreisig discusses the Company's position on spending and rates and the rate of inflation in his rebuttal testimony.

Q. On page 10, starting at line 7 and continuing through page 8, after noting the assistance levels the Company provides, CUB witness Bunch concludes "I find that Consumers' customers received almost $24 million (or 57%) more in various forms of assistance in 2023 than in 2022. Yet the number of customers who are more than three months behind, and the dollar value of residential uncollectibles, are both surging." How does the Company respond?

A. The Company recognizes that many of its customers either cannot pay or cannot pay the totality of an energy bill. As previously noted, Company witness Dreisig discusses the efforts the Company has taken to keep rates in line with inflation and the Company's efforts to balance the cost of reliability and safety with rates. In addition to these efforts, the Company has provided increased assistance available to numerous customers but there are other factors that may contribute to arrears or uncollectables. CUB witness Bunch's statements provide one factor but the issues are multi-factored.

Q. CUB witness Bunch questions (page 11, lines 9 and 10) why increased assistance has not affected and not offset the observed increase in delinquent accounts and uncollectibles and reasons that it is because the Company is not reaching, or reaching only a subset, of those who are in most need. How does the Company respond?

A. The Company is actively trying to reach both those who are currently delinquent or in arrears and those who might be approaching that status through the LMI Customer Support Enhancement Project.

MEC Witness Napolean Regarding the EWR Programs

Q. MEC witness Napolean states (page 18, lines 6-11) that the Company's EWR program savings and design are relevant in the present case, since they inform Consumers Energy's investment plan. Further, she states that the focus of the gas efficiency program should be on electrification measures as well as weatherization and building envelope measures. Does the Company agree?

A. No. Please reference Company witness Neal P. Dreisig's rebuttal testimony for a discussion on gas efficiency as related to electrification and declining gas consumption. The Company's next EWR plan (MPSC Case No. U-21680) will be filed in August 2025 and its reconciliation MPSC Case No. U-21671 Is currently pending before the Commission and by statute, these programs are designed and reconciled outside of general rate proceedings, and the proper venue to make suggestions on EWR program design would be in a reconciliation or plan filing.

CUB Witness Denzler's Disallowance of COST Projected O&M Savings

Q. Starting on page 27, line 3, of his testimony, CUB witness Denzler supports the COST project, including supporting the project's objective of tracking customer orders in real time and saving costs associated with incoming calls for information and outgoing truck rolls based on erroneous or out-of-date information. However, he recommends the Company's projected O&M savings be disallowed in the present case, and as a counter to the Company's discovery response that these savings are estimated and not included in present Company projects. Mr. Denzler states that all projected costs are estimated and therefore able to be reduced accordingly. How does the Company respond?

A. The Company agrees the COST project will result in significant savings, but it is important to note that the project is in the early stages, and that the savings are in fact estimated as part of the related cost/benefit analysis, and subsequently have not been accounted for in Operations other than IT implementation, and consequently should not be pulled from the present case.

The Company's test year forecast for the COST project should be approved, excluding O&M savings that cannot be realized within the test year. During this period, the Company will complete the project, without yet benefiting from the anticipated savings. It is unreasonable for CUB witness Denzler to assume immediate realization of savings upon project completion. Approval of the project's spending should be based on the understanding that O&M savings will be evident in the Company's subsequent rate case.

While Mr. Denzler's focus is on the financial aspects, the benefits of the project extend beyond mere cost savings. The project aims to enhance customer interaction and streamline Company processes, which are not fully captured in a traditional cost/benefit analysis. The reduction in contact center calls and improved scheduling efficiency are expected to lead to better resource utilization and customer satisfaction.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

EXHIBIT

OF

JESSICA R. BYROM

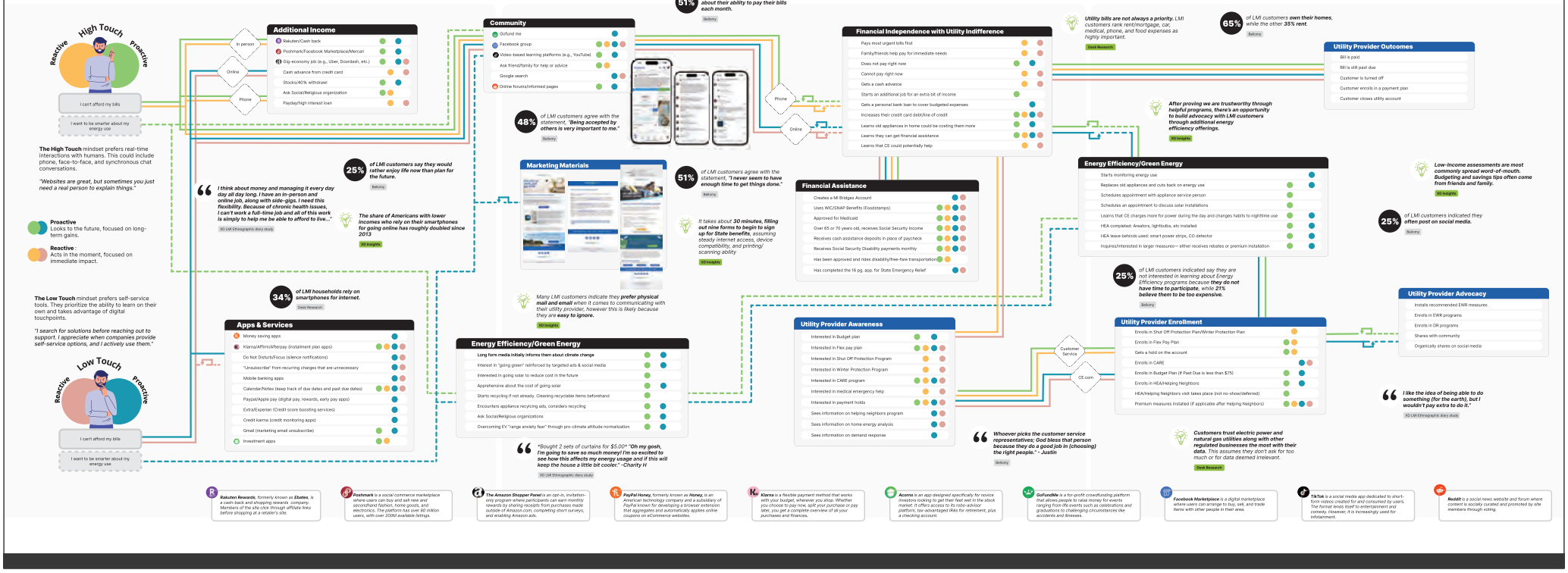
ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

LOW & MODERATE INCOME CUSTOMERS MINDSET MAP

CONSUMERS ENERGY EXPERIENCE DESIGN XD



STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

REBUTTAL TESTIMONY

OF

AMY M. CONRAD

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Q. Please state your name and business address.

A. My name is Amy M. Conrad, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Amy M. Conrad who previously submitted testimony in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut the direct testimony and exhibits presented by witnesses for the Attorney General and the Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") regarding Consumers Energy Company's ("Consumers Energy" or the "Company") incentive compensation plan and the recommendations to exclude incentive compensation costs from the revenue requirement in this case. For the reasons discussed in my direct testimony and in this rebuttal testimony, the Commission should find that the incentive compensation costs linked to operational measures that Consumers Energy is seeking to recover in this case are a reasonable cost of doing business and should be included in rates. Consumers Energy has acted reasonably in paying its employees at market levels. It would be unreasonable not to allow the Company to have that reasonable and appropriate business expense recovered in rates.

Q. How is your rebuttal testimony organized?

A. In Section I of my rebuttal testimony, I address the direct testimony and exhibits presented by Attorney General witness Sebastian Coppola. In Section II, I address the direct testimony and exhibits presented by Staff witness Theresa McMillan-Sepkoski.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes. I'm sponsoring Exhibit A-132 (AMC-4), which shows the data that was attached to audit response U21806-SA-CE-028, but which was excluded from Staff witness McMillan-Sepkoski's Exhibit S-8.2 reproducing that response.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

I. REBUTTAL TO ATTORNEY GENERAL WITNESS COPPOLA

Q. At page 187, lines 12 through 13, of his direct testimony, Mr. Coppola states: "Generally, the Company's short-term incentive plans are too heavily weighted toward financial measures that mostly benefit shareholders and not customers." Do you agree?

A. No, the Company is not requesting recovery of any Employee Incentive Compensation Plan ("EICP") dollars in this case related to the financial metrics**.** The Company in this case is seeking recovery only for the incentive costs at target level associated with the operational goals portion of the short-term incentive (EICP) for both non-officers and all officers. Consumers Energy has adopted incentives that are designed to emphasize operational performance criteria in areas that are critical to the Company's utility business and customers. Focusing employees on these goals provides both qualitative and quantitative benefits for Consumers Energy's utility customers.

Q. At page 188, lines 10 through 13, Mr. Coppola states: "Even mediocre performance will be rewarded if only a single metric is achieved. This is a very generous incentive plan that is not directly connected with achieving superior customer benefits before making threshold incentive payouts." Do you agree?

A. No. Employees, as a whole, must re-earn the incentive/at-risk portion of compensation each year. Moving to a banded goals payouts for each operational measure sets minimum (thresholds), targets, and maximum payout. The Company is only seeking recovery of target level payout. It is common market practice to use individual goals that set minimums (thresholds), targets, and maximum goals (banded goals) with payout percentages based on level of achievement. Structuring the payout to consider performance of each goal individually also ensures that employees have an independent motivation to achieve each goal regardless of whether another goal may be off target to meet payout levels during the year. This removes any potential mis-incentive to "give up" on one goal just because another may have become unlikely to be achieved. Each goal has the ability to earn an EICP payout on its own achievement, so every goal remains important and employee motivation to attain each goal individually remains high.

Rewarding employees for the level of achievement aligns pay for performance. Employees know what the minimum level of achievement is to receive a payout and have visibility to what above-target rewards they can receive for over achievement. This structure motivates employees to attain the target or goal but still allows for recognition for some below-target performance and additional reward for above-target performance.

If the threshold to achieve a payout was set at a level viewed as unachievable, it would be difficult to maintain employee motivation and would result in less customer

benefits. Overall compensation levels including the EICP are established at a target (100%) level that is not excessive. The incentive compensation portion of the Company's total compensation ensures that employees are provided a reasonable incentive to achieve exceptional performance levels. The Company's proposal to include incentive compensation costs at target levels will result in the Company absorbing the incentive compensation costs in those years when the actual payouts are greater than target level. Thus, shareholders will absorb any resulting increase in costs arising from above-target performance.

Q. At page 188, lines 13 through 14, of his direct testimony, Mr. Coppola states: "[T]he fact that the performance measures use CMS Energy financial information and comingle electric and gas business measures is a concern." Do you agree?

A. No. The incentive structure incorporates continuous improvement, safety, quality, cost, delivery, morale, and financial performance measures. Performance in these areas is critical for the Company's success in its electric public utility business. For purposes of efficiency and improved service, the Company has combined operations as one organization. For that reason, the plan contains both gas and electric measures. The related incentive expense is then allocated between electric and gas businesses based on multiple factors determined by the Accounting Department based on the type of activities the departments or business units perform. These factors include but are not limited to: (i) percentage of time; (ii) property, plant, and investments; (iii) operating revenue; (iv) headcount; and (v) labor. Only the gas portion of the EICP expense is being requested in this case. The Company has used this same approach for many rate cases with Commission approval of the recovery of the costs associated with the operational goals.

Q. At page 188, of his direct testimony, Mr. Coppola states: "the Company has stated that it continues to pay salary increases each year of approximately 3.5%." Do you agree?

A. No. For rate making purpose, the Company follows the direction of the Commission's Order in Case No. U-20963 and uses the same inflation factor to adjust both labor and non-labor expenses for determining projected labor costs. Consumers Energy's compensation is designed to be competitive with what is seen in the labor market including rewarding and motivating talent rather than trying to keep up with inflation.

Q. At pages 186 through 187 of his direct testimony, Mr. Coppola discusses various reasons that he disagrees with the Company's request to recover incentive compensation costs in rates. Do the concerns and issues he has identified in his direct testimony provide a valid basis to not allow any recovery of incentive compensation costs in rates?

A. No. I disagree with his analysis and his conclusions. Mr. Coppola's conclusion that Consumers Energy's incentive compensation plans do not benefit customers is not correct. A wide body of research supports the view that, when properly selected and implemented, as has been done with the Consumers Energy plans, incentives motivate employees, focus employees on a company's goals, and increase both individual work performance and team performance. The overall compensation levels are reasonable. The incentive compensation is part of the overall reasonable compensation level, not an addition to it.

Q. At pages 186 through 187 of his direct testimony, Mr. Coppola states that "the average achievement rate for the past five years was 66%". Do you agree?

A. No. I disagree with his analysis and his conclusions. The EICP operational payouts averaged 105% as shown in the table below:

Performance Year	Operational Goal Payout %
2020	125%
2021	75%
2022	109%
2023	94%
2024	124%
5 Year Average	105%

The Company is requesting recovery of target level payout for operational measures only. When setting payout levels, threshold is set at a level of achievement that can typically be reached 80% to 90% of the time in a 10-year period. Maximum payout is for exceptional performance (10% to 20% of the time in a ten-year period). These levels are to engage the employees in meeting the goals. Employees must re-earn the incentive at-risk portion of compensation each year. If the threshold to achieve a payout were set at a level viewed as not achievable, it would be difficult to maintain employee motivation and would result in fewer customer benefits. When goals are challenging yet achievable, employees are motivated to increase productivity and performance to achieve the goal.

II. REBUTTAL TO STAFF WITNESS MCMILLAN-SEPKOSKI

Q. What is the pay process for officer incentive targets?

A. As stated on page 21 of my direct testimony, Consumers Energy creates a compensation package for officers that delivers base salary, annual incentives, and long-term incentives (excluded from the Company's request in this rate case) targeted at the 50th percentile of the market, as defined by a Compensation Peer Group approved by the Compensation

Committees of the Board of Directors. Annually, the Compensation Committees engage an independent third-party consultant to provide advice and information regarding compensation practices of a Compensation Peer Group.

Q. Is survey data information for the third-party consultant proprietary information?

A. Yes. Consumers Energy's Compensation Committees engage an independent third-party consultant to provide information regarding officer compensation practices of the Compensation Peer Group as well as additional information from Willis Towers Watson published surveys of compensation in the public utility sector and general industry.

The Willis Towers Watson survey sources used by Pay Governance are produced solely for use by database participants and are maintained by Willis Towers Watson in connection with the participant's own internal human resources management department. The surveys are the confidential and proprietary work product of Willis Towers Watson, which owns all related intellectual property rights. Pay Governance has written consent from both Willis Towers Watson and CMS Energy to use the surveys on CMS Energy's behalf. Pay Governance is prohibited from using or reproducing the database and survey reports prepared by Willis Towers Watson.

Q. Is the proprietary nature of officer compensation the reason the Company did not provide Staff with the compensation level of the top five officers compared to market median referenced in Staff Exhibit S-8.2?

A. Yes. As illustrated in the Company's response shown in Staff Exhibit S-8.2, the market median information requested is confidential, proprietary, and commercially sensitive data belonging to third parties. Consumers Energy is contractually prohibited from sharing this information.

Although the Company is prohibited from sharing the market data used in setting compensation for its top five officers, the Company recognizes that it could be helpful for Staff to have access to some market data to evaluate the reasonableness of the compensation included in rates for the Company's top five officers. Therefore, the Company compiled and provided non-confidential market data using the following compensation elements from the Compensation Peer Group's publicly filed proxy statements: salary, stock awards, and non-equity incentive.

Because this market data uses only publicly available non-proprietary information, it does not perfectly represent the information that the Company used to benchmark and assist the Compensation Committee to determine compensation for Consumers Energy's top five officers. But, that does not support the conclusion that it is inadequate to support the level of compensation for the Company's top give officers. First, the proprietary benchmarking information alone does not mechanically decide how compensation will be set. When making pay adjustments, the Compensation Committee considers the CEO's recommendations, along with proprietary Compensation Peer Group data, internal equity, tenure, and other proprietary market data from surveys provided by the independent compensation consultant. Actual compensation decisions are based on the following as described on page 21 through page 24 in my testimony. Second, the data provided in Exhibit A-132 (AMC-4) is sufficiently consistent with the proprietary data that it does allow Staff to see a valid comparison of the compensation of the highest paid through the 2nd, 3rd, 4th and 5th highest paid named officers compared to the Company's compensation peer group. As Staff indicated, it was able to review the proprietary Pay Governance report under the following conditions set forth by the proprietary owners, Pay Governance:

> That it will review these materials in the presence of an appropriate representative of CMS and shall keep these extracts strictly confidential and shall not copy or distribute these extracts to any other party, shall use them solely for the purpose of this inquiry and shall exempt Pay Governance from public disclosure under any other inquiry or applicable freedom of information or open records acts.

As the owner of the reports, these were the conditions Pay Governance required. These were not limitations imposed by Consumers Energy. The report that Staff viewed contained the same data shared with the Compensation Committee of the Board for their decision making on officer compensation. In other words, Staff saw the exact data used in making the compensation decision for the top five officers.

Q. At page 8 of her direct testimony, Ms. McMillan-Sepkoski states that, "There was no financial presentation of the compensation data that Staff needed to examine to make a valid comparison?" Do you agree?

A. No. The presentation contained individual charts for all the officers that report to the Chief Executive Officer with the officer names redacted. These charts contain the percentages of base salary, total cash compensation and total direct compensation compared to market. The market data position titles were also contained on the charts. These charts allowed for a visual comparison of the position relative to the market of the top officers. There was also a summary table that illustrated the three market data references (Peer, Investor-Owned Utility, and General Industry) with "x" marking the position compared to the market each officer fell into (i.e. Below 15% of the market range, within +/- 15% of market, or Above 15% of the market range) for all officer positions. The information that Staff claims was missing was there.

Q. Do you agree with Staff's recommendation to exclude the top five officer operational goal annual incentive expense?

A. No. As stated above, having the officers hold specific operational measures provides a stronger linkage to Company operational incentive priorities that support customer benefits. This is a result of the addition of 30% of officer pay directly linked to operational measures. Starting in 2022, the officer operational goal modifier was removed, and the operating cash flow measure was replaced with the same operational measures as non-officers with a weighting of 30%.

In previous cases, the Company regarded the work performed by the top five officers as focused broadly across the entire CMS Energy enterprise; however, in light of the move to a 30% weighting on Consumers Energy-specific operational measures for EICP, we now have a measurable component of their compensation linked directly to work on behalf of the utility and to operational outcomes that benefit customers. Under the Company's current proposal in this case, shareholders continue to bear 100% of the cost of incentive compensation for financial measures and above-target operational measure performance.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

EXHIBIT

OF

AMY M. CONRAD

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Highest-Paid Officer Total Compensation Summary

			Total Compensation Opportunity					
Company	**Executive**	**Position**	**Base Salary**	**Target Annual Incentive ($)**	**Target Annual Incentive (%)**	**Target Total Cash Compensation [1]**	**Total Long-Term Incentive**	**Target Total Direct Compensation [2]**
Alliant Energy Corporation	John O. Larsen	Chair, President & CEO	$1,025,000	$1,178,750	115%	$2,203,750	$3,776,810	$5,980,560
Ameren Corporation	Martin J. Lyons	President & CEO	$1,100,000	$1,210,000	110%	$2,310,000	$4,125,000	$6,435,000
Atmos Energy Corporation	John K. Akers	President & CEO	$920,000	$920,000	100%	$1,840,000	$2,957,744	$4,797,744
CenterPoint Energy, Inc.	David J. Lesar	Pres. & CEO	$1,475,000	$2,065,000	140%	$3,540,000	$8,481,250	$12,021,250
Consolidated Edison, Inc.	Timothy P. Cawley	COB, Pres., & CEO	$1,250,000	$1,562,500	125%	$2,812,500	$5,551,295	$8,363,795
DTE Energy Company	Gerardo Norcia	COB, Pres. & CEO	$1,276,923	$1,560,000	122%	$2,836,923	$6,524,979	$9,361,902
Edison International	Pedro J. Pizarro	Pres. & CEO, EIX	$1,330,000	$1,729,000	130%	$3,059,000	$7,647,587	$10,706,587
Entergy Corporation	Leo P. Denault	COB & CEO	$1,300,000	$1,820,000	140%	$3,120,000	$8,986,053	$12,106,053
Eversource Energy	Joseph R. Nolan, Jr.	Pres. & CEO	$1,200,000	$1,320,000	110%	$2,520,000	$5,624,000	$8,144,000
Hawaiian Electric Industries, Inc.	Constance H. Lau	Former HEI President & CEO	$955,000	$955,000	100%	$1,910,000	$3,204,098	$5,114,098
NiSource Inc.	Lloyd Yates	President & CEO	$1,000,000	$1,150,000	115%	$2,150,000	$4,500,000	$6,650,000
OGE Energy Corp.	S. Trauschke	Chair, President & CEO	$1,071,005	$1,178,114	110%	$2,249,119	$3,981,998	$6,231,117
Pinnacle West Capital	Jeffrey B. Guldner	COB, Pres. & CEO, PNW & APS	$1,100,000	$1,210,000	110%	$2,310,000	$4,079,762	$6,389,762
PPL Corporation	Vincent Sorgi	President & CEO	$1,133,000	$1,416,250	125%	$2,549,250	$5,111,866	$7,661,116
Public Service Enterprise Group	Ralph Izzo	President, Chair & CEO	$1,421,400	$1,989,960	140%	$3,411,360	$9,100,065	$12,511,425
Sempra Energy	Jeffrey W. Martin	Chair, CEO & President	$1,350,000	$2,025,000	150%	$3,375,000	$8,916,873	$12,291,873
WEC Energy Group, Inc.	Gale E. Klappa	COB	$1,083,600	$1,462,860	135%	$2,546,460	$3,204,333	$5,750,793
Xcel Energy Inc.	Bob Frenzel	COB, Pres. & CEO	$1,200,000	$1,500,000	125%	$2,700,000	$6,300,028	$9,000,028
n=18								
		Summary Statistics[3]						
		25th Percentile	$1,074,154	$1,186,563	110%	$2,264,339	$4,006,439	$6,270,778
		50th Percentile	$1,166,500	$1,439,555	124%	$2,547,855	$5,331,581	$7,902,558
		Average	$1,177,274	$1,458,469	122%	$2,635,742	$5,670,763	$8,306,506
		75th Percentile	$1,294,231	$1,687,375	134%	$3,003,481	$7,366,935	$10,370,416
CMS Energy	**Garrick Rochow**	**President & CEO**	**$1,150,000**	**$1,380,000**	**120%**	**$2,530,000**	**$5,200,000**	**$7,730,000**

Notes:

1. Target TCC (total cash compensation) includes base salary and target annual incentive.
2. Target TDC (total direct compensation) = base salary + target annual incentive + long-term incentive.
3. Data are independently arrayed and thus will not sum to total cash/total direct compensation.

Second Highest-Paid Officer Total Compensation Summary

			Total Compensation Opportunity					
Company	**Executive**	**Position**	**Base Salary**	**Target Annual Incentive ($)**	**Target Annual Incentive (%)**	**Target Total Cash Compensation [1]**	**Total Long-Term Incentive**	**Target Total Direct Compensation [2]**
Alliant Energy Corporation	Robert J. Durian	EVP & CFO	$565,000	$423,750	75%	$988,750	$1,027,048	$2,015,798
Ameren Corporation	W.L. Baxter	Executive Chairman	$1,000,000	$1,000,000	100%	$2,000,000	$3,000,000	$5,000,000
Atmos Energy Corporation	Christopher T. Forsythe	SVP & CFO	$496,500	$322,725	65%	$819,225	$910,712	$1,729,937
CenterPoint Energy, Inc.	Jason P. Wells	EVP & CFO	$695,000	$521,250	75%	$1,216,250	$1,675,003	$2,891,253
Consolidated Edison, Inc.	Robert N. Hoglund	SVP & CFO	$838,400	$628,800	75%	$1,467,200	$1,608,575	$3,075,775
DTE Energy Company	David E. Meador	Former Vice Chairman & Chief Admin Officer	$789,231	$625,600	79%	$1,414,831	$1,895,147	$3,309,978
Edison International	Maria Rigatti	EVP & CFO, EIX	$710,000	$568,000	80%	$1,278,000	$1,775,086	$3,053,086
Entergy Corporation	Andrew S. Marsh	EVP & CFO	$710,700	$604,095	85%	$1,314,795	$2,008,880	$3,323,675
Eversource Energy	Werner J. Schweiger	EVP & COO	$770,001	$616,000	80%	$1,386,001	$1,748,151	$3,134,152
Hawaiian Electric Industries, Inc.	Ann C. Teranishi	ASB President & CEO	$790,617	$553,432	70%	$1,344,049	$766,898	$2,110,947
NiSource Inc.	Pablo A. Vegas	EVP, COO & President, NiSource Utilities	$618,000	$494,400	80%	$1,112,400	$1,235,000	$2,347,400
OGE Energy Corp.	B. Buckler	CFO	$440,000	$308,000	70%	$748,000	$755,200	$1,503,200
Pinnacle West Capital	James R. Hatfield	Former Advisor to CEO, PNW	$700,000	$525,000	75%	$1,225,000	$1,258,562	$2,483,562
PPL Corporation	Gregory N. Dudkin	EVP & COO	$740,000	$592,000	80%	$1,332,000	$1,595,363	$2,927,363
Public Service Enterprise Group	Ralph A. LaRossa	COO	$810,700	$729,630	90%	$1,540,330	$2,400,087	$3,940,417
Sempra Energy	Trevor I. Mihalik	EVP & CFO	$780,000	$702,000	90%	$1,482,000	$2,431,809	$3,913,809
WEC Energy Group, Inc.	J. Kevin Fletcher	Pres. & CEO	$1,087,934	$1,414,314	130%	$2,502,248	$3,241,666	$5,743,914
Xcel Energy Inc.	Timothy O'Connor	EVP & COO	$750,000	$637,500	85%	$1,387,500	$1,550,079	$2,937,579
n=18								
		Summary Statistics[3]						
		25th Percentile	$696,250	$522,188	75%	$1,218,438	$1,240,891	$2,381,441
		50th Percentile	$745,000	$598,048	80%	$1,338,024	$1,641,789	$2,995,333
		Average	$738,449	$625,916	82%	$1,364,366	$1,715,737	$3,080,103
		75th Percentile	$790,270	$635,325	85%	$1,454,108	$1,980,447	$3,320,251
CMS Energy	**Rejji Hayes**	**EVP & CFO**	**$775,000**	**$620,000**	**80%**	**$1,395,000**	**$1,700,000**	**$3,095,000**

Notes:

1. Target TCC (total cash compensation) includes base salary and target annual incentive.
2. Target TDC (total direct compensation) = base salary + target annual incentive + long-term incentive.
3. Data are independently arrayed and thus will not sum to total cash/total direct compensation.

Third Highest-Paid Officer Total Compensation Summary

			Total Compensation Opportunity					
Company	Executive	Position	Base Salary	Target Annual Incentive ($)	Target Annual Incentive (%)	Target Total Cash Compensation [1]	Total Long-Term Incentive	Target Total Direct Compensation [2]
Alliant Energy Corporation	James H. Gallegos	EVP, GC & Corporate Secretary	$554,000	$360,100	65%	$914,100	$789,331	$1,703,431
Ameren Corporation	Michael L. Moehn	EVP & CFO	$715,000	$536,250	75%	$1,251,250	$2,298,567	$3,549,817
Atmos Energy Corporation	David J. Park	SVP, Utility Operations	$468,650	$281,190	60%	$749,840	$665,440	$1,415,280
CenterPoint Energy, Inc.	Scott E. Doyle	EVP, Utility Operations	$600,000	$450,000	75%	$1,050,000	$1,500,000	$2,550,000
Consolidated Edison, Inc.	Matthew Ketschke	Pres., Con Edison of New York	$646,000	$516,800	80%	$1,162,800	$1,608,575	$2,771,375
DTE Energy Company	Trevor F. Lauer	Pres. & COO - DTE Electric Company	$616,846	$496,800	81%	$1,113,646	$1,351,952	$2,465,598
Edison International	Steven D. Powell	Pres. & CEO, SCE	$650,000	$487,500	75%	$1,137,500	$1,527,600	$2,665,100
Entergy Corporation	Roderick K. West	Group Pres., Utility Operations	$753,819	$603,055	80%	$1,356,874	$1,840,794	$3,197,668
Eversource Energy	Philip J. Lembo	EVP & CFO	$720,001	$576,000	80%	$1,296,001	$1,634,650	$2,930,651
Hawaiian Electric Industries, Inc.	Gregory C. Hazelton	HEI EVP & CFO	$546,400	$355,160	65%	$901,560	$950,731	$1,852,291
NiSource Inc.	Donald E. Brown	EVP, CFO & President, Corporate Services	$618,000	$463,500	75%	$1,081,500	$1,200,000	$2,281,500
OGE Energy Corp.	W. Sultemeier	GC & Chief Compliance Officer	$460,000	$298,995	65%	$758,995	$694,817	$1,453,812
Pinnacle West Capital	Maria L. Lacal	EVP, Chief Nuclear Officer	$600,000	$450,000	75%	$1,050,000	$839,352	$1,889,352
PPL Corporation	Joseph P. Bergstein	EVP & CFO	$632,500	$506,000	80%	$1,138,500	$1,477,272	$2,615,772
Public Service Enterprise Group	Daniel J. Cregg	EVP & CFO	$714,300	$535,725	75%	$1,250,025	$1,750,045	$3,000,070
Sempra Energy	Kevin C. Sagara	EVP & Group President	$780,000	$702,000	90%	$1,482,000	$2,012,345	$3,494,345
WEC Energy Group, Inc.	Scott J. Lauber	Senior EVP & COO	$950,000	$807,500	85%	$1,757,500	$2,192,990	$3,950,490
Xcel Energy Inc.	Brian Van Abel	EVP & CFO	$650,000	$487,500	75%	$1,137,500	$1,550,036	$2,687,536
n=18								
		Summary Statistics[3]						
		25th Percentile	$600,000	$450,000	75%	$1,050,000	$1,013,048	$1,987,389
		50th Percentile	$639,250	$492,150	75%	$1,137,500	$1,513,800	$2,640,436
		Average	$648,640	$495,226	75%	$1,143,866	$1,438,028	$2,581,894
		75th Percentile	$714,825	$536,119	80%	$1,250,944	$1,721,196	$2,982,715
CMS Energy	**Shaun Johnson**	**SVP & General Counsel**	**$540,000**	**$405,000**	**75%**	**$945,000**	**$800,000**	**$1,745,000**

Notes:

1. Target TCC (total cash compensation) includes base salary and target annual incentive.
2. Target TDC (total direct compensation) = base salary + target annual incentive + long-term incentive.
3. Data are independently arrayed and thus will not sum to total cash/total direct compensation.

Fourth Highest-Paid Officer Total Compensation Summary

			Total Compensation Opportunity					
Company	**Executive**	**Position**	**Base Salary**	**Target Annual Incentive ($)**	**Target Annual Incentive (%)**	**Target Total Cash Compensation [1]**	**Total Long-Term Incentive**	**Target Total Direct Compensation [2]**
Alliant Energy Corporation	David A. de Leon	SVP & President of WPL	$390,000	$195,000	50%	$585,000	$325,744	$910,744
Ameren Corporation	Richard J. Mark	Chairman & Pres., Ameren Illinois	$566,000	$396,200	70%	$962,200	$1,031,102	$1,993,302
Atmos Energy Corporation	Karen E. Hartsfield	SVP, GC & Corporate Secretary	$440,000	$264,000	60%	$704,000	$665,440	$1,369,440
CenterPoint Energy, Inc.	Monica Karuturi	EVP & GC; Former SVP	$580,000	$406,000	70%	$986,000	$1,102,000	$2,088,000
Consolidated Edison, Inc.	Deneen L. Donnley	SVP & GC	$630,400	$441,280	70%	$1,071,680	$903,540	$1,975,220
DTE Energy Company	David Ruud	SVP & CFO	$623,077	$441,000	71%	$1,064,077	$1,279,526	$2,343,603
Edison International	Adam S. Umanoff	EVP & GC, EIX	$605,000	$453,750	75%	$1,058,750	$1,331,021	$2,389,771
Entergy Corporation	Paul D. Hinnenkamp	EVP & COO	$649,877	$487,408	75%	$1,137,285	$1,923,508	$3,060,793
Eversource Energy	Gregory B. Butler	EVP & GC	$670,002	$469,000	70%	$1,139,002	$1,244,544	$2,383,546
Hawaiian Electric Industries, Inc.	Scott W. H. Seu	HE President & CEO	$506,667	$405,334	80%	$912,001	$821,385	$1,733,386
NiSource Inc.	Violet G. Sistovaris	EVP & Chief Experience Officer	$515,000	$386,250	75%	$901,250	$1,000,000	$1,901,250
OGE Energy Corp.	D.O. Jones	VP, Utility Operations	$355,000	$230,750	65%	$585,750	$412,809	$998,559
Pinnacle West Capital	Robert E. Smith	EVP, GC & Chief Development Officer	$610,000	$457,500	75%	$1,067,500	$762,436	$1,829,936
PPL Corporation	Paul W. Thompson	EVP, LG&E & KU Energy LLC (LKE)	$682,800	$580,380	85%	$1,263,180	$1,087,296	$2,350,476
Public Service Enterprise Group	Tamara L. Linde	EVP & GC	$657,800	$493,350	75%	$1,151,150	$1,300,019	$2,451,169
Sempra Energy	Karen L. Sedgwick	Chief Administrative Officer & Chief HR Officer	$460,000	$276,000	60%	$736,000	$736,000	$1,472,000
WEC Energy Group, Inc.	Xia Liu	EVP & CFO	$739,450	$591,560	80%	$1,331,010	$1,778,476	$3,109,486
Xcel Energy Inc.	Brett Carter	EVP, Group Pres., Utilities & CCO	$580,000	$464,000	80%	$1,044,000	$1,125,019	$2,169,019
n=18								
		Summary Statistics[3]						
		25th Percentile	$508,750	$388,738	70%	$903,938	$777,173	$1,757,523
		50th Percentile	$592,500	$441,140	73%	$1,051,375	$1,059,199	$2,040,651
		Average	$570,060	$413,265	71%	$983,324	$1,046,104	$2,029,428
		75th Percentile	$645,008	$467,750	75%	$1,120,884	$1,270,780	$2,375,278
CMS Energy	**Brian Rich**	**SVP & Chief Customer Officer**	**$495,000**	**$321,750**	**65%**	**$816,750**	**$850,000**	**$1,666,750**

Notes:

1. Target TCC (total cash compensation) includes base salary and target annual incentive.
2. Target TDC (total direct compensation) = base salary + target annual incentive + long-term incentive.
3. Data are independently arrayed and thus will not sum to total cash/total direct compensation.

Fifth Highest-Paid Officer Total Compensation Summary

			Total Compensation Opportunity					
Company	**Executive**	**Position**	**Base Salary**	**Target Annual Incentive ($)**	**Target Annual Incentive (%)**	**Target Total Cash Compensation [1]**	**Total Long-Term Incentive**	**Target Total Direct Compensation [2]**
Alliant Energy Corporation	Terry L. Kouba	SVP & President of IPL	$390,000	$195,000	50%	$585,000	$325,744	$910,744
Ameren Corporation	Fadi M. Diya	SVP & Chief Nuclear Officer, Ameren Missouri	$555,000	$360,750	65%	$915,750	$1,011,064	$1,926,814
Atmos Energy Corporation	J. Matt Robbins	SVP, HR	$332,072	$199,243	60%	$531,315	$665,440	$1,196,755
CenterPoint Energy, Inc.	Kenneth M. Mercado	Former EVP, Electric Utility	$525,000	$367,500	70%	$892,500	$997,500	$1,890,000
Consolidated Edison, Inc.	Robert Sanchez	Pres. & CEO, Orange & Rockland	$530,500	$424,400	80%	$954,900	$1,013,060	$1,967,960
DTE Energy Company	Mark W. Stiers	Pres. & COO - DTE Vantage and Energy Trading	$573,077	$403,900	70%	$976,977	$965,680	$1,942,657
Edison International	J. Andrew Murphy	SVP, Strategy & Corp Development, EIX	$475,000	$332,500	70%	$807,500	$712,515	$1,520,015
Entergy Corporation	Marcus V. Brown	EVP & GC	$710,700	$568,560	80%	$1,279,260	$1,507,328	$2,786,588
Eversource Energy	Christine M. Carmody	EVP HR & Info Technology	$541,001	$379,000	70%	$920,001	$1,005,122	$1,925,123
Hawaiian Electric Industries, Inc.	Kurt K. Murao	HEI EVP, GC Chief Admin Officer & Corporate Secretary	$402,000	$241,200	60%	$643,200	$499,262	$1,142,462
NiSource Inc.	Charles E. Shafer	SVP & Chief Safety Officer	$360,500	$216,300	60%	$576,800	$360,000	$936,800
OGE Energy Corp.	C. McQuistion	VP, Corporate Responsibility & Stewardship	$325,000	$146,250	45%	$471,250	$283,240	$754,490
Pinnacle West Capital	Theodore N. Geisler	SVP & CFO, PNW & APS	$450,000	$315,000	70%	$765,000	$1,051,582	$1,816,582
PPL Corporation	Wendy E. Stark	SVP, GC, Corporate Secretary & CLO	$525,000	$393,750	75%	$918,750	$647,968	$1,566,718
Public Service Enterprise Group	David M. Daly	Former Executive Advisor	$600,000	$450,000	75%	$1,050,000	$1,360,046	$2,410,046
Sempra Energy	Peter R. Wall	SVP, Controller & Chief Accounting Officer	$390,000	$195,000	50%	$585,000	$540,519	$1,125,519
WEC Energy Group, Inc.	Margaret C. Kelsey	EVP, GC & Corporate Secretary	$579,232	$434,424	75%	$1,013,656	$990,694	$2,004,350
Xcel Energy Inc.	Amanda Rome	EVP, Chief Legal & Compliance Officer	$570,000	$427,500	75%	$997,500	$1,050,034	$2,047,534
n=18								
		Summary Statistics[3]						
		25th Percentile	$393,000	$222,525	60%	$599,550	$567,381	$1,156,035
		50th Percentile	$525,000	$364,125	70%	$904,125	$978,187	$1,853,291
		Average	$490,782	$336,127	67%	$826,909	$832,600	$1,659,509
		75th Percentile	$566,250	$419,275	75%	$971,458	$1,012,561	$1,961,634
CMS Energy	**Brandon Hofmeister**	**SVP, Governmental, Regulatory & Public Affairs**	**$525,000**	**$341,250**	**65%**	**$866,250**	**$800,000**	**$1,666,250**

Notes:

1. Target TCC (total cash compensation) includes base salary and target annual incentive.
2. Target TDC (total direct compensation) = base salary + target annual incentive + long-term incentive.
3. Data are independently arrayed and thus will not sum to total cash/total direct compensation.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

REBUTTAL TESTIMONY

OF

NEAL P. DREISIG

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Q. Please state your name and business address.

A. My name is Neal P. Dreisig, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. Are you the same Neal P. Dreisig who previously submitted testimony in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut testimony associated with concerns on the Natural Gas Delivery Plan ("NGDP") by Attorney General witness Sebastian Coppola, Michigan Environmental Council ("MEC") and Sierra Club ("SC") (collectively, MEC) witnesses Alice Napoleon and Dr. Sol deLeon, Citizens Utility Board of Michigan ("CUB") witnesses Richard J. Bunch and Joshua W. Denzler.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes, the following exhibit is sponsored with my rebuttal testimony:

Exhibit A-133 (NPD-2) Confidential	Discovery Responses U21806-MNSC-CE-0039, 0066, 0573, and 0771 with Attachments.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

I. ATTORNEY GENERAL WITNESS COPOLLA

Q. On page 14, lines 18 through 20, of his direct testimony, Attorney General witness Coppola states that the Company is investing in the gas system as an opportunity to accelerate rate base growth to increase earnings growth. Is this accurate?

A. No, it is not. The Company's investments and the focus of the NGDP, Exhibit A-42 (NPD-1), are founded on the Company's commitment to providing a safe, reliable, affordable, and clean natural gas system for the people of Michigan. The capital

investments are made by the Company to ensure safety and reliability for its natural gas customers and to prevent incidents like those experienced by other operators in recent years. The NGDP, and the Company's investments, were developed by the Company's engineers. Planned work undertaken in gas distribution, transmission, compression, and storage are discussed in my direct testimony and in the direct testimony of Company witnesses Timothy K. Joyce, Kristine A. Pascarello, Lincoln D. Warriner, James P. Pnacek, and Michael P. Griffin. The comprehensive NGDP discusses the investments the Company is making, the reasons for the investments, the benefits of these investments, and considers the cost of these investments to customers.

Q. On page 15, lines 14 through 18, of his direct testimony, Attorney General witness Coppola states that the gas utility forecasts to spend $20 billion in capital over the next five years. Is this accurate?

A. No. As shown in Exhibit A-42 (NPD-1), the proposed five-year plan shows approximately $5.5 billion in proposed capital spending, not $20 billion.

Q. On pages 16 and 17, lines 4 through 9 and 2 through 10, respectively, of his direct testimony, Attorney General witness Coppola states that capital spending will pose a significant burden on residential customers and business bills. Is this accurate?

A. No. As discussed in Exhibit A-42 (NPD-1), the Company is committed to a bill growth rate at or below inflation and below the average rate of other gas utilities in the Midwest. Despite a historical 12% increase in rate base over the past 10 years, as described by Mr. Coppola, customer bills have shown a continuous annual growth rate ("CAGR") of -0.60%, which shows bills have actually decreased over the same period. Note, this is well

below Consumer Price Index of 2.80%[1] over the same period. When adjusted for inflation, customer bills decreased in real terms by approximately 4% per year compared to other goods and services making it a smaller component of a household's overall spend. In fact, data shows the average residential gas bill is approximately 1% of Michigan household income, considerably below other necessities such as transportation and cellular communication, 15% and 2%, respectively.[2] It is important to note that an increase in rate base does not necessarily correlate to an increase in bills as demonstrated above. Furthermore, the Company is committed to helping customers use less natural gas through energy efficient solutions and helping low-income customers through the Consumers Affordable Resource of Energy ("CARE") Program. These programs are discussed by Company witness Byrom.

Q. How does the Company's residential bill affordability compare to gas utility peers in the Midwest?

A. The Company benchmarks residential bills against Midwest gas utilities who experience similar climate conditions. Over the past five years, the Company has maintained a monthly residential bill below the Midwest average by approximately 24%. Additionally, the rate of bill growth is also below the Midwest average. Specifically, over the past five years, the Company's residential bills grew 1.4% less than the Midwest average. This is due in part to the Company's storage capabilities where natural gas can be purchased in

[1] U.S. Bureau of Labor Statistics. (2024). Consumer Price Index Summary. Retrieved from https://www.bls.gov/regions/midwest/data/consumerpriceindexhistorical_detroit_table.pdf.
[2] US Wages & Salaries and Expenditures. (2023). Retrieved from https://www.bls.gov/cex/tables/calendar-year/mean-item-share-average-standard-error.htm
Michigan Income Fred St. Louis. (2023). Retrieved from https://fred.stlouisfed.org/series/MEHOINUSMIA672N

the summer at a lower rate, stored, and then sold to customers in the winter at the same price.

II. CUB WITNESS BUNCH

Q. On page 6 of his direct testimony, CUB witness Bunch asserts that the proposed 12% rate increase is much higher than expected inflation. Is this accurate?

A. No. The proper comparison to inflation is the actual rate per mcf customers pay on their bill. Over the past 10 years, the Company's residential rate per mcf shows a CAGR of 1.38%, well below the rate of inflation over the same period at 2.80%.[3] As described above, when adjusted for inflation, residential customers saved on their natural gas bill compared to other goods and services included in the Consumers Price Index.

Q. On page 9, lines 6 through 10, of his direct testimony, CUB witness Bunch asserts that the proposed spending plan would severely impact residential rates, driving them by 158%. Is this accurate?

A. No. As shown in the Natural Gas Delivery Plan over the next 10 years, the Company expects an approximate 4.7% CAGR in residential bills, which is approximately the rate of inflation over the past five years. This projected increase equates to a cumulative 67% increase, not 158%. Additionally, increases assume relatively flat natural gas load over the next 10 years. Given the projected energy increases in the future, increased natural gas use in power generation and industrial development will potentially offset bill increases to a certain extent.

[3] U.S. Bureau of Labor Statistics. (2024). Consumer Price Index Summary. Retrieved from https://www.bls.gov/regions/midwest/data/consumerpriceindexhistorical_detroit_table.pdf.

III. MEC WITNESS DENZLER

Q. On pages 4 and 5, lines 6 through 13 and 11 through 18, respectively, of his direct testimony, MEC witness Denzler asserts that the proposed spending plan would severely impact residential rates, driving them by 158% and will be "super-inflationary." Is this accurate?

A. No, it is not. See my response to CUB witness Bunch on in Section II.

Q. On page 6, lines 3 through 14, of his direct testimony, MEC witness Denzler asserts that natural gas demand is not certain, leading to stranded costs in the future. Is this accurate?

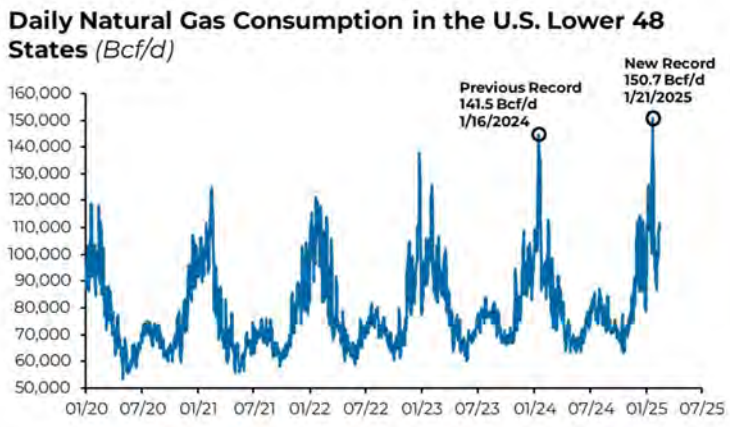
A. No, it is not. Data shows that the natural gas system is critical to Michigan's energy future from a low cost, customer, and energy capacity perspective. Regarding low-cost, natural gas is by far the least cost energy source for Michigan. The table below demonstrates this by comparing various energy costs on a $/MMbtu basis using the recent Company gas residential rates, Michigan average electric residential rates, and Michigan propane rates. For example, using the recent Michigan average electric rate of $0.1921/KWh, the conversion to MMbtu would equate to $56.30/MMbtu, showing over a 5x increase in commodity cost versus natural gas. It is clear all other fuels are considerably more expensive than natural gas.

	$/Mmbtu
CE Natural gas	$10.30
Propane	$25.36
MI Electric rate	$56.30

From a customer perspective, when asking gas customers "how do you feel Consumers Energy should prioritize each of the following as they plan for the future?"

with the ability to rank the options of "reliability," "affordability," and "sustainability," 48.9% rated reliability as a first priority for the Company. 41.2% of gas customers ranked affordability as a second priority, with 35% ranking affordability as the first priority. This tells us that natural gas is preferred as an exceptionally reliable and affordable energy source that will not only remain stable in the future but enable quality of life supported by low cost natural gas.

Lastly, the natural gas infrastructure provides significant energy capacity for Michigan. Recent climate trends, shown below, continue to set natural gas daily consumption records when cold snaps occur. During these peak conditions, the combination of space heating demand with lower output from renewables during winter months allow natural gas generators to fill demand. These spikes in demand highlight the critical importance of gas system capacity in delivering heat on the coldest days and fuel for potential future gas generation.



IV. MEC WITNESS DELEON

Q. On pages 10 and 11, lines 19 through 23 and 1 through 4, respectively, of her direct testimony, MEC witness deLeon asserts that natural gas assets will become stranded due to the energy transition. Is this accurate?

A. No. In addition to the responses above to CUB witness Bunch, analysis shows the gas system infrastructure will become more critical from the perspective of the energy transition. As described in Exhibit A-133 (NPD-2) Confidential, which is a packet of discovery response that the Company provided to MEC which includes discovery response U21806-MNSC-CE-0066, the retirement of coal generation and high cost of nuclear indicates natural gas will likely serve as a reliable, low-cost, baseload fuel for the significant growth in future energy demand through gas generation. Additionally, the gas distribution system enables cost effective heating that mitigates an otherwise 40% additional electric load for winter heating if end uses were electrified. Accordingly, gas distribution reduces the need for investment in electric generation and infrastructure by ~$20-25 billion.

Q. On page 14 of her direct testimony, MEC witness deLeon questions the effectiveness of the Renewable Natural Gas ("RNG") Program to contribute to the Company's greenhouse gas emission reduction goal. Is this a concern?

A. No. Customers have shown significant interest in the Company's RNG product, concentrated in the large industrial space. With most customer voluntary goals around the 2030 timeframe, customers have indicated they do not want a natural gas decarbonization solution until they need it, further emphasizing customer's priority around cost. Total expressed interest well exceeds the Company's available production emphasizing the need

to potentially expand the Program in the future. Customers show high interest in RNG because it is the least cost clean fuel alternative to natural gas, it is considered "drop-in" meaning no infrastructure modifications are required, the feedstock is readily available in Michigan, and it strongly supports the agricultural industry. Customer data aligns with the MI Healthy Climate Plan presumption that clean fuel alternatives like RNG are critical in decarbonizing high heat end uses.

Q. On page 17 of her direct testimony, MEC witness deLeon indicates the NGDP shows no evidence that the Company is pursuing non-pipe alternatives to meet its customer emission reduction goal. Is this true?

A. No. As described in the NGDP, the Company is actively investigating all potential carbon reduction pathways to meet the needs of customers in the future with an established framework. As demonstrated in Exhibit A-133 (NPD-2) Confidential, which is a packet of discovery response that the Company provided to MEC which includes discovery response U21806-MNSC-CE-0063 and U21806-MNSC-CE-0771, this framework includes maintaining a marginal cost abatement curve and long term modeling for a decarbonized future. The Company extensively collaborates with stakeholders around the industry to inform and validate modeling and analysis assumptions. Collaborations include other domestic and global peer utilities, the Low Carbon Resources Initiative, the H2EDGE Program, the MI Hydrogen Initiative, and the Midwest Alliance for Clean Hydrogen ("MachH2") hydrogen hub as an energy provider These collaborations are evident in the Company's work in network geothermal technology supported by the associated grant received from the Michigan Public Service Commission ("MPSC" or the "Commission"), along with the industry grant received to study synthetic gas production in Michigan using

green hydrogen. It is well understood through these collaborations that non-pipe alternatives that involve introducing new technologies raise cost for customers, and in some cases jeopardize the safety of the gas system. For these reasons, meeting customers' current and future needs is core to the NGDP. As described above, customers are most interested in reliable, low-cost energy, not more expensive non-pipe alternatives.

V. MEC WITNESS NAPOLEON

Q. On page 10, lines 10 through 13, MEC witness Napoleon indicates the decarbonization study by the Company is inconsistent with other studies performed. Is this true?

A. No. The Low Carbon Resource Initiative net-zero 2050 study, performed by the Electric Power Research Institute ("EPRI"), was used to test outputs of the Company led study, showing similar findings. Specifically, EPRI found that "Optionality enables affordability. Achieving economy-wide net-zero CO2 emissions while maintaining reliable delivery of energy and energy services across the economy will require a broad set of low-carbon technologies. An economy-wide, net-zero target with the flexibility to allocate positive and negative CO2 emissions allows each sector and region to follow their own decarbonization path while minimizing overall costs. Imposing greater limitations on resource and technology options could significantly increase the overall cost to achieve net zero emissions." This finding aligns with the Company's own study concluding that the balanced combination of multiple technologies such as energy waste reduction ("EWR"), RNG, carbon capture, hydrogen, and electrification will all be needed to cost effectively meet the State's 2050 net zero goal. The MI Healthy Climate Plan also supports the findings of the Company's decarbonization study demonstrating that no one pathway is viable to achieving the State's 2050 net zero ambitions. Additionally, the Company

performed the decarbonization study from an energy agnostic standpoint to truly understand the most effective way Michigan can decarbonize energy use. It was not in any way bias towards natural gas.

Q. On page 15 and 16, MEC witness Napoleon claims electrification can save costs by avoiding traditional infrastructure investments. Is this true?

A. No. The economics of electrification are based on the combination of technology capital costs, costs of energy, and technology efficiencies specific to geographic regions. The components are not mutually exclusive. As described above, if all customers electrified space heating, they would not only be impacted by an energy source 5x more costly than natural gas but also impacted by the cost of electric infrastructure buildout, estimated between $20-$25 billion. While forms of electrification can be highly energy efficient, they also have high upfront costs. Efficiency gains from electrification cannot make up for the up-front cost and disparity in energy cost. Regarding efficiency, electrified space heating efficiency drops considerably and consumes more energy in colder climates like Michigan, requiring supplemental heating. The Company agrees with Ms. Napoleon that energy efficiency and electrification go hand in hand. It is not practical to assume a heat pump can provide sufficient space heating without proper insulation. In fact, according to the American Community Survey, the median residential home in Michigan is 51 years old, up 4 years since 2014, indicating that homes are getting older. Older homes often do not carry sufficient insulation to take advantage of heat pump efficiencies. Additionally, as shown in Exhibit A-133 (NPD-2) Confidential, which is a packet of discovery response that the Company provided to MEC which includes discovery response U21806-MNSC-CE-0039 and U21806-MNSC-CE-0573, independent third party studies that conclude

reality for electrification in Michigan citing it is likely not cost effective due to climate and building retrofits required to realize benefits.

Q. On page 17, MEC witness Napoleon claims the Company is not assessing non-pipe alternatives. Is this true?

A. No. See my response above to MEC witness deLeon.

Q. On page 17, MEC witness Napoleon claims all non-pipe alternatives reduce emissions. Is this true?

A. No. It is industry standard to quantify emissions using lifecycle assessment measured in grams of carbon dioxide equivalent per megajoule ("gCO2e/MJ"). This measurement is called carbon intensity ("CI"). Natural gas shows an approximate CI of 80. Any fuel source below 80 is considered low carbon and contributes to emission reduction. On the contrary, any fuel above 80 increases emissions. Electrification and hydrogen technologies powered by the electric grid carry the emissions profile of the electric grid. According to real-time electricity maps at the time of this writing[4], the Midwest Independent System Operator, Inc. ("MISO") has a CI of 110, nearly 40% higher than conventional natural gas. This indicates that technologies powered by the electric grid like heat pumps and hydrogen electrolyzers actually emit more carbon than heating with natural gas today.

Q. On pages 25 and 26 of her direct testimony, MEC witness Napoleon claims gas consumption will decline in the future due to trends in electrification. Is this true?

A. No. As described by Company witness Warriner in his rebuttal testimony, trends in gas growth exceed electrification. Additionally, as described above, the cost of electrification

[4] Electricity Maps. (2025). Retrieved from Live 24/7 CO_2 emissions of electricity consumption | App | Electricity Maps.

in many cases for customers is considerably higher than natural gas. For this reason, the practicality of electrification in Michigan is limited.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

REDACTED

EXHIBIT

OF

NEAL P. DREISIG

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Question:

34. Refer to page 82 of the NGDP where it states, "Consumers Energy is assessing where hybrid heating and heat pump technology can best serve customers."
a. Please provide details about any assessment the Company has conducted to-date.
b. Please provide all analysis, resources, and references behind this statement, including any supporting data and workpapers with formulas intact and all sources, assumptions, and units clearly identified.
c. Please describe the Company's plans for deploying or supporting residential and commercial hybrid heating through 2030 and through 2050.
d. Is the Company analyzing any full electrification technologies (heat pump technology without natural gas back-up)?
i. If so, please provide this analysis. In answering this question, please also provide data on:
1. The switchover temperature at or below which a hybrid heating system (combining a heat pump with a backup gas heating system) would rely on the backup gas heating.
2. The associated efficiency value, expressed as the coefficient of performance (COP), for the hybrid heat pump at that switchover temperature.
e. If the Company is not analyzing full electrification technologies, please explain how the Company can assess the benefits of hybrid heating and heat pump technologies relative to full electrification technologies.

Response:

a. The Company has not yet assessed where hybrid heating and heat pump technology can best serve customers but has evaluated the impact of heat pump technology with Michigan residents served by non-regulated fuels. Please reference U21806-MNSC-CE-0039_Dreisig_ATT_1 for completed impact evaluation on heat pump pilot study.
b. Attachments U21806-MNSC-CE-0039_Dreisig_ATT_1, U21806-MNSC-CE-0039_Dreisig_ATT_2, U21806-MNSC-CE-0039_Dreisig_ATT_3 and Appendix C – Decarbonization Modeling of the Natural Gas Delivery Plan are the analyses performed to date on heat pump technology.
c. The Company does not have current plans to deploy or support hybrid heating through 2030 and 2050. Customer research will continuously monitor behavior and preferences to assess the future need to support hybrid heating and heat pump technology.
d. The Company is currently evaluating geothermal technology through thermal energy networks in local communities. Please reference attachment U21806-MNSC-CE-0039_Dreisig_ATT_4 showing the Company's network geothermal proposal to the MPSC.
    i. The Company has not determined the optimum switchover temperature yet for network geothermal technology.
    ii. A coefficient of performance (COP) value is not evaluated at this switchover temperature; however, industry research suggests that network geothermal technology provides the highest COP of any electrification technology. Attachment U21806-MNSC-CE-0039_Dreisig_ATT_5 compares network geothermal against other heat pump pathways clearly showing the highest COP amongst alternatives. This is important because it may provide the most mitigation to incremental peak electric load during winter months in a highly electrified future.

e. As noted, the Company's gas business at this time is investigating full electrification through network geothermal technology.

Witness: NEAL P. DREISIG
Date: February 3, 2025

U21806-MNSC-CE-0066
Page **1** of **1**

Question:

61. Refer to the following statement on page 82 of the Natural Gas Delivery Plan: "Modeling shows the most cost-effective means of electrifying residential end uses is with hybrid heating. Hybrid heating combines the heat content of natural gas with the efficiency of a heat pump. In this context, heat pumps would be used as much as possible; however, during the coldest winter months, natural gas furnaces would still be used to mitigate winter peak electric load. Consumers Energy is assessing where hybrid heating and heat pump technology can best serve customers."

a. Please provide the Company's analysis for this modeling in MS Excel workbook.

b. Please provide a detailed plan for the assessment of hybrid heating.

Response:

a. The Company does not have modeling completed for hybrid heating in Excel format. Analysis for electrifying residential end uses with hybrid heating is based on third party consultant modeling that sought to achieve the combination of technologies that provided the lowest societal cost.

   Confidential Attachment U21148-MNSC-CE-0066_CONF_ATT_1 shows the analysis that demonstrates the balanced combination of multiple technologies will all be needed to meet the State's 2050 net zero goal at the lowest cost. This attachment will be provided to parties that have executed a non-disclosure agreement under the protective order. This analysis is a State level analysis using proprietary data modeling through third party expert consultants. The Company does not own, have a copy of, nor have access to the modeling program used.

b. Hybrid heating is anticipated to have high carbon abatement costs compared to other technologies but can help mitigate the shift of electric peak demand to winter. This approach could reduce the need for $20-25B in capital investment for electric generation and transmission infrastructure making it an overall affordable solution without impacting the existing system. Customer research will continuously monitor behavior and preferences to assess future need for hybrid heating technology.

Witness: NEAL P. DREISIG
Date: January 30, 2025

U21806-MNSC-CE-0573
Page **1** of **1**

Question:

8. Refer to U21806-MNSC-CE-0039 Attachment 2, slides 11 through 13.

a. Please provide all sources and assumptions behind the Company's estimate for the cost of "New gas furnace + installation" and "New ASHP + installation".

b. Please explain what the figures "Preferred technology based on trends assumptions" show.

i. What do the numbers on these figures indicate?

ii. What are the assumptions behind the 'current trends' and 'accelerated trends' scenarios?

Response:

a. Heat pump analysis details on U21806-MNSC-CE-0039 Attachment 2, slides 11 through 13, are based on proprietary data modeling through third party expert consultants. The Company does not own, have a copy of, nor have access to the modeling program used. The Company used U21806-MNSC-CE-0573_ATT 1 and U21806-MNSC-CE-0573_ATT 2 to verify cost estimates and conclusions shown on U21806-MNSC-CE-0039 Attachment 2.

b.

i. Numbers on the figures reflect the most likely electrification technology to be adopted given a "business as usual" environment vs. an environment where accelerated decarbonization trends exist. Natural gas is overlaid to better understand directionally when specific electrification technologies make sense for customers. In all cases, the "business as usual" trend shows natural gas as the most affordable option for customers. U21806-MNSC-CE-0573_ATT 1 and U21806-MNSC-CE-0573_ATT 2 studies confirm this.

ii. Assumptions behind "current trends" include the current state of federal and state policy along with current cost estimates and efficiency factors for various electrification technologies. In this scenario, natural gas is the most affordable option for customers. Assumptions behind "accelerated trends" include scenarios where climate policy is pulled forward requiring the accelerated adoption of various technologies.

Witness: NEAL P. DREISIG
Date: March 18, 2025

U21806-MNSC-CE-0771
Page **1** of **1**

Question:

5. Refer to MNSC-CE-0571 where it states, "Cost of carbon abatement is assessed through a marginal cost of carbon abatement framework. This assessment is performed annually by primary pathway to understand cost effectiveness of reducing carbon as standalone technologies. External cost impacts are excluded from assessment. This analysis provides directional cost effectiveness by pathway to help prioritize decision-making."

a. Please provide all workpapers and analysis used to assess the marginal cost of carbon abatement for each standalone technology and pathway, in excel format with formulas intact and all units and assumptions clearly identified.

b. Please provide the workpapers and results of the latest "directional cost effectiveness" analysis including all calculations used in the analysis in excel format with formulas intact and all units and assumptions clearly identified.

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request on the grounds that said request is not relevant to this proceeding. Consumers Energy is not requesting rate relief in this case related to carbon abatement in this proceeding. This request is outside the scope of the proceeding and does not appear to be reasonably calculated or necessary to gather any information that is important to the issues at stake in the case; thus, the request is not proportional to the needs of the case. S**ubject to the Company's objection and without waiving its objection, Consumers Energy responds as follows:**

a. Please find attached U21806-MNSC-CE-0771_ATT1, U21806-MNSC-CE-0771_ATT2, U21806-MNSC-CE-0771_ATT3, U21806-MNSC-CE-0771_ATT4.

b. Please find attached U21806-MNSC-CE-0771_ATT1.

Witness: NEAL P. DREISIG
Date: April 7, 2025

U21806-MNSC-CE-0039_ATT 1

Consumers Energy Count on Us®

CADMUS

2021 Cold-Climate Heat Pump Initiatives Evaluation Report

August 26, 2022

Presented to:

Consumers Energy

Joseph Forcillo

Director of Evaluation, Measurement & Verification

One Energy Plaza

Jackson, MI 49201

Presented by:

Cadmus

2490 Junction Place, Suite 400

Boulder, CO 80301

TRC

807 Roy Street, Suite 301

Seattle, WA 98102

U21806-MNSC-CE-0039_ATT 1

Prepared by:

Cadmus Team

Steve Cofer
Cheryl Winch
Matai Perussi
Andrew Mielcarek
Noah Lieb

TRC Companies

Donna Whitsett
Hannah Justus
Sagar Deo

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Acronyms and Abbreviations

Acronym	Definition
AC	Air conditioner
AMI	Advanced metering infrastructure
ASHP	Air-source heat pump
CCHP	Cold-climate heat pump
CDH	Cooling degree hour
COP	Coefficient of performance
HDH	Heating degree hour
HSPF	Heating seasonal performance factors
MEMD	*Michigan Energy Measures Database*
NPS	Net promoter score
PMOs	Property owners and managers
SEER	Seasonal energy efficiency ratio
TMY3	Typical meteorological year version 3

Executive Summary

In its March 5, 2020 Order Approving Settlement Agreement in Consumers Energy's *2020-2023 Energy Waste Reduction (EWR) Plan*, the Michigan Public Service Commission (MPSC) authorized the Company to invest in cold-climate heat pump (CCHP) initiatives for both income-qualified and non-income-qualified residential customers and business customers to test the efficacy, performance, and customer experience, among other factors. The Settlement Agreement[1] required the Company to submit an interim and final report delineating cold-climate heat pump (CCHP) initiative findings with the Company's 2020 and 2021 EWR Reconciliation filings, respectively. This report supplements the CCHP final report submitted as required by the March 5 Order and documents 2021 evaluation activities.[2]

The approved Settlement Agreement included both increased investment to support the income-qualified program performance metric associated with CCHP installations and a CCHP retrofit pilot initiative targeted to residential homes and businesses heated with electricity or heating fuels not regulated by the Michigan Public Service Commission, such as delivered propane or fuel oils. Given the challenges with implementing the CCHP initiatives, as well as unanticipated delays due to COVID-19, participation for income-qualified single-family and small commercial customers in 2021 occurred late in the year. This late participation has delayed the evaluation impact analysis for these two initiatives. All impact evaluation efforts will be completed in 2022 and the report will be filed in the case docket.

The main objective of these CCHP Initiatives was to demonstrate the potential for energy savings by replacing inefficient heating and cooling equipment with CCHPs. Consumers Energy targeted four distinct customer groups:

- Residential customers with electric or delivered fuel heating
- Income-qualified single-family customers with electric or delivered fuel heating
- Income-qualified multifamily customers with electric heating
- Small commercial customers with electric or delivered fuel heating

Consumers Energy designed its CCHP Initiatives to address both the supply and demand for CCHPs. The initiatives were implemented through Consumers Energy's existing residential, income qualified and small business product offerings. They aimed to strengthen trade allies' capabilities to install and service advanced heat pumps while increasing customers' awareness of and confidence in heat pumps as a viable, affordable, and environmentally friendly home heating source.

The CCHP Initiatives' incentives varied by customer type and ranged from $1,000 for market-rate customers to the full cost of installation for income-qualified and small business customers.

[1] Original settlement agreement: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000009hu1HAAQ at page 2
Settlement agreement amendment: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000CGUIcAAP

[2] Cadmus. 2020-2021 Cold-Climate Heat Pump Initiatives Final Report. May 18, 2022.

Consumers Energy marketed the initiatives through participating contractors, who were familiar with heat pump technology and had been educated about the offering, as well as through mass marketing campaigns and other Consumers Energy network partners like Habitat for Humanity. Table 1 through Table 3 shows participation and investments through December 31, 2021, by customer group and year.

Table 1. 2020 and 2021 Cold-Climate Heat Pump Participation and Investment

	Residential Market Rate	Income Qualified		Small Commercial	Total
		Single-Family	Multifamily		
2020 - 2021 Target	50 [a, b]	160	558	25 [b]	**793**
2020 - 2021 Installations	53	179	663	26 [c]	**921**
Percentage of Target	106%	112%	119%	88%	**116%**
Total Investment	$579,297	$3,184,143	$3,664,670	$999,000	**$8,427,110**

[a] The original Settlement Agreement targeted 100 heat pumps. Per the end of July 2020 reforecast; this was adjusted to 50 heat pumps.

[b] While the income qualified targets are specific to each year and summed in this table, the residential market rate and small commercial targets represent the total adjusted targets for the two-year period.

[c] This is updated from the 2020–2021 Cold Climate Heat Pump Initiatives Final Report.

Table 2. 2020 Cold-Climate Heat Pump Participation and Investment

	Residential Market Rate	Income Qualified		Small Commercial [a]	Total
		Single-Family	Multifamily		
2020 Target	100 [b]	100	225	25	**450**
2020 Installations	5	78 [c]	276	0	**359**
Percentage of Target	5%	78%	123%	0%	**80%**
2020 Investment	$258,771	$1,447,290	$1,523,558	$225,204	**$3,454,823**

[a] The small commercial initiative had eight commitments with three customers at the end of 2020, but no completed installations.

[b] The original Settlement Agreement targeted 100 heat pumps. Per the end of July reforecast, this was adjusted to 50 heat pumps.

[c] Of the 78 heat pumps, 74 were installed for a large group of duplexes owned by one landlord. Duplexes are classified as single-family homes.

Table 3. 2021 Cold-Climate Heat Pump Participation and Investment

	Residential Market Rate	Income Qualified		Small Commercial	Total
		Single-Family	Multifamily		
2021 Target	50	60	333	25	**468**
2021 Installations	48	101	387	26 [a]	**562**
Percentage of Target	96%	168%	116%	112%	**120%**
2021 Investment	$320,526	$1,736,853	$2,141,112	$773,796	**$4,972,287**

[a] This is updated from the 2020-2021 Cold-Climate Heat Pump Initiatives Final Report.

In addition to persistent market barriers to the adoption of CCHPs documented in the first-year summary of pilots, the Settlement Agreement imposed eligibility restrictions for Consumers Energy CCHP initiatives, requiring heat pump systems to displace at least 50% of a customer's heating load from delivered fuels or electric resistance heating systems and limiting residential eligibility to primary residences only (i.e. secondary or vacation homes were ineligible).

Consumers Energy continued to encounter several challenges with encouraging heat pump adoption across all income levels and all residential and multifamily building types. These challenges resulted in lower participation than expected and are attributed to a lack of consumer awareness, difficulty identifying eligible customers, lack of contractor participation, and, in some cases, high incremental costs. Consumers Energy encountered fewer challenges with small business owners given that the Initiative covered the full installation cost of the CCHP, but Consumers Energy recognizes this is not a sustainable program option and expects to encounter similar challenges as the residential market when the incentive no longer covers the full equipment and installation cost for customers.

Despite these challenges, participants were generally satisfied with their experience and gave high satisfaction ratings for the overall performance of their new heat pump. Participants also reported better working equipment and increased comfort compared to their previous equipment. In addition, the Evaluation team's impact analysis for market rate and income-qualified multifamily customers show most participants will save energy, and in turn, money on their heating and cooling bills; however, the ranges of savings vary based on the heating fuel type of the replaced equipment. An engineering analysis for income-qualified single-family customers and metering analysis for small commercial customers is currently underway and will be completed by end of 2022.

Consumers Energy contracted with independent teams led by Cadmus and TRC to evaluate its respective residential and commercial program portfolios (referred to jointly as the Evaluation team throughout this report). The Evaluation team focused on providing Consumers Energy with the necessary details to inform later phases of the CCHP Initiatives and on monitoring early performance in 2021 to comply with the evaluation and reporting requirements in its Settlement Agreement.

Research Objectives

The Cadmus team focused our evaluation on providing Consumers Energy with the necessary details to inform later phases of promoting CCHPs. Following discussions with Consumers Energy's program management staff, the Cadmus team identified several research objectives regarding the evaluation.

Cadmus assessed four research objectives:

Assess the CCHP Initiatives' performance according to energy savings, customer satisfaction, impacts to customer bills, operational issues, and customer comfort.

Understand market readiness to adopt heat pump technology on a large scale and learn about the challenges of installing CCHPs.

Determine current limitations in the CCHP supply chain and their potential implications for the CCHP Initiatives.

Understand how CCHPs impact low-income customers and property managers who own income-qualified housing on non-energy factors such as changes in energy bills, heating and cooling equipment operation, and comfort levels.

Research Approach

Starting in 2021, the Evaluation team conducted several research and evaluation activities:

- Interviews with Consumers Energy CCHP Initiatives managers and implementation contractors (n=7)
- Interviews with HVAC contractors, distributors, and CCHP manufacturers (n=18)
- Billing analysis, engineering reviews, site visits, and metering for commercial participants (n=9)
- Surveys or interviews with Initiative participants and property owners (n=51)
- Residential Market Rate Participant Engineering Analysis (n=51)
- Multifamily and Income Qualified Billing Analysis (n=77 participants and 112 comparison buildings)

Participation was limited across all initiatives. This meant there were small populations to survey, interview, and perform billing analysis activities even using the census of participants. Therefore, the generated results, in most cases, are not statistically significant and while the evaluation team has made some conclusions and recommendations in this report, there is remaining uncertainty about the technology performance and market potential of CCHPs in Michigan. In addition, participation for small business customers occurred later in 2021, which delayed the metering of small business CCHPs.[3] Results from this activity will be prepared for Consumers Energy in Q4 2022.

Report Organization

We organized this report as follows:

- Summary of Key Findings, Conclusions, and Recommendations
- Contractor, Distributor, and Manufacturer Findings
- Residential Market Rate Initiative Findings
- Income Qualified Multifamily Initiative Findings
- Commercial and Industrial Cold-Climate Heat Pump Pilot Findings
- Appendices
  - Appendix A: Survey and Interview Methodology and Details
  - Appendix B: Impact Analysis Methodology and Details
  - Appendix C: Consumers Energy Heat Pump Market Rate Customer Survey
  - Appendix D: Consumers Energy Heat Pump Property Owner and Manager Interview Guide
  - Appendix E: Consumers Energy Heat Pump Multifamily Tenant Survey Guide
  - Appendix F: Consumers Energy Heat Pump Commercial Interview Guide
  - Appendix G: Consumers Energy Heat Pump Contractor Interview Guide
  - Appendix H: Consumers Energy Heat Pump Manufacturer and Distributor Interview Guide

[3] Initial impact analysis for commercial customers is reported in " 2021 Cold Climate Heat Pump Pilot Impact Evaluation Results Memo submitted to Consumers Energy by TRC. Updated cooling savings will be provided at the conclusion of additional metering in November 2022.

Summary of Key Findings, Conclusions, and Recommendations

This section presents the Evaluation team's key research findings, conclusions, and recommendations associated with the four cold-climate heat pump (CCHP) research objectives, which informed our evaluation tasks. The remaining chapters of this report provide further explanation of these findings and support for our conclusions and recommendations.

Key Findings and Recommendations

CONCLUSION 1. There is low and varied awareness of cold-climate heat pumps by homeowners, property owners and their tenants, and commercial businesses and even lower awareness that Consumers Energy offers cold-climate heat pump rebates.

Participants' awareness of CCHPs and Consumers Energy rebates was largely driven by HVAC contractors and Consumers Energy. However, awareness varied among contractors and within the territories they served. Where contractors were aware of CCHPs, they were a driving force of information dissemination about heat pumps and Consumers Energy rebates for both residential and commercial customers.

TRADE ALLIES: Contractors' overall awareness of heat pump technologies was largely correlated with the heating fuels used by their customer base. Contractors serving rural populations (where delivered fuels are more common) were more familiar with ducted heat pump systems, while contractors serving urban populations (where electric resistance heating is more prevalent) were more familiar with ductless heat pump systems. Contractors indicated that Consumers Energy could be instrumental in driving awareness of heat pump technologies, citing the success of the campaigns used to promote smart thermostats.

MARKET RATE: Most Residential Market Rate pilot participants reported being familiar with CCHPs before deciding to purchase one for their home (eight of nine), but few (three of nine) were aware that Consumers Energy provided heat pump rebates. While CCHP rebates were new in 2020, respondents' awareness of heat pumps came primarily from contractors, with about half (five of nine) indicating that a contractor had recommended a heat pump before they learned about and applied for the Consumers Energy heat pump rebate. A small number of participants (two of nine) heard about the rebate through Consumers Energy email communications.

INCOME QUALIFIED MULTIFAMILY: Multifamily property owners and managers were generally aware (31%, or n=10 of 32) of CCHPs prior to being approached by Consumers Energy, though they were not aware of Consumers Energy incentives until their involvement. However, the property owners and managers' tenants reported a lack of knowledge regarding heat pumps, with 66% of tenant respondents (n=21 of 32) saying they did not know about CCHPs, and half saying they were not aware that there was a CCHP installed in their apartment at the time of the survey. Of the half that were aware of the heat pump installation, 56% (n=9 of 16) did not know that Consumers Energy was involved in the project.

COMMERCIAL: Only two out of seven interviewed commercial respondents were familiar with cold-climate heat pump technology prior to participation. Those who had heard of cold-climate heat

pumps were unaware of the advancements in technology that made heat pumps more feasible for regions, like Michigan, with very cold winters. After learning about the new cold-climate heat pumps and Consumers Energy's pilot, most respondents were motivated to participate, but still held reservations about performance during the winter, prompting some to ask to keep their old heating system as a back-up.

RECOMMENDATIONS

High Priority: Identify opportunities for Consumers Energy to promote the cold-climate heat pump technology and incentives. Consider providing materials, such as one-page initiative summaries, for distributors to leave with contractors during their interactions. Continue to promote cold-climate heat pumps through events like the Annual Trade Ally Kickoff or identify larger distribution events or trainings where Consumers Energy can interact with trade allies.

High Priority: Increase contractor and customer education of cold-climate heat pump benefits and technology. Consider increasing the promotion of cold-climate heat pumps through planned marketing campaigns (such as bill inserts and online advertising) and through cross-program promotions.

CONCLUSION 2. Because natural gas is the predominate heating fuel in Michigan, and current Michigan Public Service Commission policy limits fuel-switching, there are limited cost-effective cold-climate heat pump installation opportunities. This contrasts with other states such as Maine and Vermont where a higher percentage of homes use more costly heating fuels such as propane and oil and where state policies incentivize fuel-switching.

TRADE ALLIES: While demand is increasing, trade allies reported that multiple barriers have limited demand for CCHPs in Michigan compared to other states. Manufacturers and distributors noted that awareness of and affinity for CCHPs among contractors varied and some maintain the belief that heat pumps are not effective in cold climates. Contractors and distributors also reported that increased customer awareness would help increase adoption; however, the cost of new CCHPs remains prohibitive. A homeowner likely needs to financially benefit from switching to a CCHP to be interested, but the lifecycle cost of a new CCHP compared to alternative heating technologies supplied by natural gas (the predominate heating fuel in Michigan) likely does not financially benefit the homeowner at a time when natural gas rates are low. Contractors acknowledged this fuel-switching challenge and said that even when they identify a potential cold-climate heat pump customer, there are few tools available for the contractor or customer to make accurate projections of the total system lifetime cost savings.

MARKET RATE AND COMMERCIAL CUSTOMERS: During 2021 and 2022, the Michigan Public Service Commission allowed Consumers Energy to target market rate and commercial customers who receive non-regulated fuels and those with electric heating systems. Consumers Energy's *2018 Residential Appliance Saturation and Home Characteristics Study* found that approximately 82% of customers in single-family homes across Consumers Energy's natural gas, electric and combination fuel

service territory heat their homes with natural gas, while 4% use electric heat and 14% use another source such as propane, fuel oil, or wood. This heating fuel distribution creates a significant challenge with identifying homeowners and businesses that may be eligible for a CCHP under the current regulatory rules (i.e., heat their homes or buildings with electric or distributed fuels), and limits market potential. Of the residential market rate participants for which baseline analysis was conducted (n=51), the majority (59%) used propane or oil, while 31 % used electric heat and 10% used natural gas heat prior to installing their heat pump[4].

Four of the seven commercial respondents interviewed discussed wanting to move away from using propane, and two of the respondents were motivated to participate in the pilot specifically so they could stop using propane. While respondents appreciated the opportunity to move from propane to electric heating, it is unclear whether Consumers Energy can continue with this targeted approach beyond the pilot phase. Future negotiations between the Michigan Public Service Commission and Consumers Energy and its stakeholders will determine whether Consumers Energy can continue to rely on this targeted approach in future initiative cycles.

RECOMMENDATIONS

High Priority: Because contractors reported that it is not always simple to determine when cold-climate heat pumps are economically more beneficial than traditional equipment, provide them with sales tools, such as a cost-effectiveness calculator, that can assist them in identifying when a cold-climate heat pump makes financial sense for their customers.

Low Priority: Promote the space cooling benefits associated with a cold-climate heat pump. Cold-climate heat pumps are a good option to add cooling where there was not previously a whole-home space cooling system or where the cold-climate heat pump can replace inefficient central air conditioners and room air conditioners.

CONCLUSION 3. Participants were generally satisfied with their experience and gave very high ratings for the CCHP Initiatives offering. However, multifamily tenants' satisfaction was split, largely based on whether the tenant received education on how to operate the new equipment.

MARKET RATE: Market rate customers gave high satisfaction ratings, with all nine respondents giving a rating of 8 or higher for their overall experience with the heat pump. In addition, market rate customers were highly likely to recommend the heat pump to a friend (with a net promoter[5] score of +89).

[4] Consumers Energy excluded most customers that used natural gas for space heating from the CCHP initiative, but a small number of participants recruited by contractors used natural gas prior to installation of the CCHP.

[5] The net promoter score is expressed as an absolute number between -100 and +100 that represents the difference between the percentage of promoters (respondents giving a rating of 9 or 10) and the percentage of detractors (respondents giving a rating of 1 to 6).

INCOME QUALIFIED MULTIFAMILY: The three interviewed income qualified multifamily property owners and managers provided an average rating of 9.5 (on a 10-point scale) for their satisfaction with the CCHP Initiatives and their likelihood to recommend heat pumps to a colleague. The property owners and managers also rated their likelihood to adopt similar CCHP equipment in their other properties as a 9.0 on a 10-point scale.

Income-qualified multifamily tenants (n=23 of 32) were *very satisfied* with their CCHP experience, and generally felt that the heat pumps provided improved winter heating and summer cooling comfort. Multifamily tenant participants gave an average rating of 8.7 for their overall experience with the heat pump, though some may not have been aware of their heat pump until they were contacted for the survey. Respondents also gave an average rating of 8.8 regarding summer comfort and 7.9 regarding winter comfort. However, tenants' willingness to recommend Consumers Energy was dependent on the level of communication and instruction provided to them regarding equipment operation. Tenants who provided verbatim feedback around lack of instruction were more likely to provide a lower overall net promoter score (averaging +13) than those who received instructions (averaging +50). Similarly, tenants who reported that the installer did not set up their heating and cooling schedule were also more likely to provide a lower overall net promoter score (averaging +10) than those who had the installer set up a schedule (averaging +67).

COMMERCIAL: Commercial participants rated their overall satisfaction with the CCHP Initiatives as an average of 9.9 out of 10, and 86% (six out of seven interviewees) strongly agreed that Consumers Energy made it easy to participate in the initiative.[6] In follow up interviews with participants, four out of five interviewees reported being satisfied with their heat pump's performance during the winter.[7]

CONCLUSION 4. Some participants received a new thermostat with their CCHP. Participants who received a new thermostat had varied knowledge about how to use it to optimize operation of their heat pump and some could have benefitted from additional instructions and training.

MARKET RATE: Seven of the nine residential market rate participants had a programmable or smart thermostat, while two reported having a non-programmable thermostat. Of those who had a programmable thermostat, only two programmed temperature setbacks. Despite most having thermostat programming capability, four of nine tended to adjust the temperature manually.

INCOME QUALIFIED MULTIFAMILY: Only three income qualified multifamily respondents could confirm with certainty that the contractor set up a heating and cooling schedule for their heat pump. These three participants also confirmed that the heating and cooling schedule set up by the

[6] Commercial participants were interviewed prior to experiencing a full heating season and some respondents listed this uncertainty about how the equipment would perform during the heating season as a reason for not giving a higher satisfaction rating for their heat pump, though the average rating was still 9.3 out of 10.

[7] The one respondent who was displeased, noted that the heat pump took a while to turn on, they often felt a cool breeze that was discharged directly onto an employee, and they had to adjust their thermostat higher than usual in order to achieve their preferred temperature.

contractor was still in operation. Only 25% (n=8) reported receiving instructions or documentation about the heat pump or use of their thermostat with the heat pump.

COMMERCIAL: Most respondents needed additional time to learn how to use their new thermostats and a few had minor issues operating their heat pumps. While most respondents did not have any problems with their new heat pumps, some (43%; n=3) reported that learning how to use their new thermostat was the most challenging aspect of their new equipment. Two respondents (29%) also reported needing a contractor's assistance with minor issues related to operating their heat pump. These minor issues included resolving an installation error and adjusting the cooling so that the air temperature was reaching the thermostat's temperature setpoint. Another finding from the follow up interviews was that some customers needed additional support understanding the controls and settings of the heat pumps to maximize the value, especially when sites have overlapping building controls with multiple heating units.

RECOMMENDATION

High Priority: Consider increasing follow up communications and support after the installation to ensure participants understand their new technology. Sending follow-up emails with resources and providing high-touch support after the installation engenders a positive equipment experience, which is critical for word-of-mouth testimonial marketing. Encourage contractors to provide set up and programming instructions and provide contractor training to ensure they are familiar with different types of thermostats and systems.

CONCLUSION 5. Participants reported better working equipment and increased home and business comfort levels after the installation of their CCHP.

MARKET RATE: Most market rate participants surveyed (seven of nine) said their home was more comfortable after installing the heat pump. The nine respondents rated their comfort level as 9.1 on average during the summer, with a slightly lower rating of 8.6 (n=5) during the winter. None of the respondents indicated any concerns with the heat pump's ability to heat to a preferred comfort level. Five respondents also mentioned improved heating and cooling distribution across sections of the home.

INCOME QUALIFIED MULTIFAMILY: Income-qualified multifamily tenants said their homes were as comfortable with the CCHPs as before (43%), with one-quarter reporting increased comfort levels. A few tenants said their home was too hot or too cold after the heat pump installation. Property owners and managers indicated that tenant comfort was a key decision factor to install CCHPs.

COMMERCIAL: Customers were very satisfied with heat pump performance overall , though three interviewees (43%) reported some minor initial issues with their heat pumps, including one who said it did not cool down to the expected temperature and two who had issues with the installation that required a contractor to fix.

RECOMMENDATION

Medium Priority: Promote the increased home and business comfort that cold-climate heat pumps can provide during both the heating and cooling seasons. Developing and using home and business testimonials could be an effective way Consumers Energy can promote the benefits of cold-climate heat pumps such as increased comfort, lower energy bills, and for some, the addition of space cooling.

CONCLUSION 6: Distributors generally had heat pump inventory on hand, so delivery times were either not impacted or were only impacted temporarily by manufacturing delays.

While manufacturers and distributors reported manufacturing delays as a result of COVID-19, as well as on-going transportation delays, distributors generally reported having sufficient stock on hand to meet current demand. Only one distributor reported a delay (6 to 8 weeks) in getting equipment to the customer. Note that custom equipment was generally not discussed in the interviews with manufacturers and distributors, and it is possible that timelines for custom equipment could be different. It is also worth noting that the manufacturer and distributor interviews were conducted in April of 2021, and the factors influencing supply chains may have changed since this time.

CONCLUSION 7: Most residential market rate and income-qualified Multifamily participants realized heating and cooling utility bill savings after the installation of their CCHP. However, bill savings largely depends on heating fuel prior to the heat pump installation, as well as how the homeowner used their new equipment.

MARKET RATE: The majority of market rate participants replaced propane heating systems (51%), followed by electric heating (31%), natural gas heating (10%), and fuel oil heating (8%).[8] Based on engineering estimates, market rate participants who replaced propane or electric heating systems will realize approximately $910 to $1,680 in heating and cooling savings per year[9]. The five homes that previously heated with natural gas will likely see an increase in their utility bill of $450 per year on average due to the higher cost of electricity compared to natural gas; also, four of the five homes did not have existing central air conditioning, which means they will add electrical load in the summer.

INCOME QUALIFIED MULTIFAMILY: Income-qualified multifamily tenants, even though retaining their original baseboard heating systems, experienced annual savings of 896 kWh, which translates to approximately $147 in annual bill savings. Most of the savings (93%) were realized during the heating season (largely October-April). These savings during the heating season were equivalent to approximately 23% of baseline weather-sensitive electric heating use. Income qualified multifamily tenants experienced lower than anticipated savings attributable to the heat pumps because they continued use of their baseboard heating systems, consistent with other recent evaluation findings.

[8] At the time of conducting the engineering analysis the evaluation team had a sample of 51 CCHP installations.

[9] Based on fuel costs at the time of the analysis in January 2022.

INCOME QUALIFIED SINGLE FAMILY: Due to low participation and delays due to COVID, the Income Qualified Single-Family Impact analysis will be completed in 2022. The Evaluation team is currently conducting an engineering analysis of the impacts for the income-qualified single-family installations, relying on MEMD parameters and assumptions collected from customers such as home vintage, presence of central cooling, equipment efficiencies, tonnage, and other data. The analysis will be completed later in 2022 and filed in the case docket.

COMMERCIAL: Because participation in the small business pilot occurred later in 2021, the impact evaluation was delayed. The impact evaluation is based on metered data, and TRC is keeping the meters in place to collect data for at least one complete heating season and one complete cooling season for each site.[10] The results of the heating season impact analysis are presented in a separate memo that is included in the filing of 2021 studies made on August 31, 2022.[11] Metering for the 2022 cooling season is still in progress as of the writing of the report, and analysis will take place in later in 2022.

RECOMMENDATIONS

High Priority: Provide multifamily property owners who had cold-climate heat pumps installed with information for how continued use of baseboard heating systems will minimize the tenant's ability to achieve the highest potential heating, and cost savings.

High Priority: Provide multifamily property owners with handouts they can distribute to tenants with simple operational instructions to ensure all new tenants understand how to operate their heat pump systems. Additional follow up and coordination with maintenance staff to review proper operations would ensure persistence of heat pump savings.

High Priority: If the Michigan policy on fuel switching should change, natural gas heating customers should be screened prior to approval to ensure the heat pump has potential to reduce energy bills.

Table 4 shows the Evaluation team's conclusion for each research objective outlined above.

[10] Metering analysis was performed for 22 CCHP installations.

[11] TRC. 2022. C&I 2021 Cold Climate Heat Pump Pilot Impact Evaluation Memo

Table 4. Research Objective Mapping

Conclusion	Research Objective: 1. Assess Cold-Climate Heat Pump Initiative Performance	2. Understand Market Readiness and Challenges	3. Determine Current Supply Chain Limitations	4. Understand Impacts on Low-Income Customers
There is low and varied awareness of cold-climate heat pumps by homeowners, property owners and their tenants, and commercial businesses and even lower awareness that Consumers Energy offers cold-climate heat pump rebates.		✓		
Because natural gas is the predominate heating fuel in Michigan, and current Michigan Public Service Commission policy limits fuel-switching, there are limited cost-effective cold-climate heat pump installation opportunities. This contrasts with other states such as Maine and Vermont where a higher percentage of homes use more costly heating fuels such as propane and oil and where state policies incentivize fuel-switching.		✓		
Participants were generally satisfied with their experience and gave very high ratings for the Cold-Climate Heat Pump Initiatives offering. However, multifamily tenants' satisfaction was split, largely based on whether the tenant received education on how to operate the new equipment.	✓			✓
Some participants received a new thermostat with their cold-climate heat pump. Participants who received a new thermostat had varied knowledge about how to use it to optimize operation of their heat pump and some could have benefitted from additional instructions and training.		✓		
Participants reported better working equipment and increased home and business comfort levels after the installation of their cold-climate heat pump.	✓			✓
Distributors generally had heat pump inventory on hand, so delivery times were either not impacted or were only impacted temporarily by manufacturing delays.			✓	
Most residential participants realized heating and cooling utility bill savings after the installation of their cold-climate heat pump. However, bill savings largely depends on heating fuel prior to the heat pump installation, as well as how the homeowner used their new equipment.	✓			✓

Recommendation Priority

To assist Consumers Energy in prioritizing the actions needed to address these recommendations, the Evaluation team organized each evaluation recommendation by topic and prioritized them based on the following definitions.

- ***High Priority:*** The evaluation revealed compelling and conclusive data on a concern or a current initiative strength that are likely to have a significant impact on customer satisfaction, achievement of participation goals, or initiative savings if not addressed or maintained.
- ***Medium Priority:*** The evaluation revealed data that are inconclusive and require additional investigation or the issue is likely to have a moderate impact on initiative effectiveness or efficiency.
- **Low Priority:** The issue is likely to have little impact on initiative effectiveness or efficiency.

Table 5 lists the CCHP initiatives evaluation recommendations.

Table 5. Summary of Heat Pump Pilot Recommendations and Priorities

Priority	Summary of Recommendations
High Priority	Identify opportunities for Consumers Energy to promote the Cold-Climate Heat Pump technology and incentives. Consider providing materials, such as one-page initiative summaries, for distributors to leave with contractors during their interactions. Continue to promote cold-climate heat pumps through events like the Annual Trade Ally Kickoff or identify larger distribution events or trainings where Consumers Energy can interact with trade allies.
	Increase contractor and customer education of cold-climate heat pump benefits and technology. Consider increasing the promotion of cold-climate heat pumps through planned marketing campaigns (such as bill inserts and online advertising) and through cross-program promotions.
	Because contractors reported that it is not always simple to determine when cold-climate heat pumps are economically more beneficial than traditional equipment, provide them with sales tools, such as a cost-effectiveness calculator, that can assist them in identifying when a cold-climate heat pump makes financial sense for their customers.
	Consider increasing follow up and support after the installation to ensure participants understand their new technology. Sending follow-up emails with resources and providing high-touch support after the installation engenders a positive equipment experience, which is critical for word-of-mouth testimonial marketing. Encourage contractors to provide set up and programming instructions and provide contractor training to ensure they are familiar with different types of thermostats and systems.
	Provide multifamily property owners who had cold-climate heat pumps installed with information for how continued use of baseboard heating systems will minimize the tenant's ability to achieve the highest potential heating and cost savings.
	Provide multifamily property owners with handouts they can distribute to tenants with simple operational instructions to ensure all new tenants understand how to operate their heat pump heating systems. Additional follow up and coordination with maintenance staff to review proper operations would ensure persistence of heat pump savings.
	If the Michigan Public Service Commission policy on fuel switching should change, natural gas heating customers should be screened prior to approval to ensure the heat pump has potential to reduce energy use.
Medium Priority	Promote the increased home and business comfort that cold-climate heat pumps can provide during both the heating and cooling seasons. Developing and using home and business testimonials could be an effective way Consumers Energy can promote the benefits of cold-climate heat pumps such as increased comfort, lower energy bills, and for some the addition of space cooling.
Low Priority	Promote the space cooling benefits associated with a cold-climate heat pump. Cold-climate heat pumps are a good option to add cooling where there was not previously a whole-home space cooling system or where the cold-climate heat pump can replace inefficient central air and room air conditioners.

Contractor, Distributor, and Manufacturer Findings

Consumers Energy launched the CCHP initiatives just prior to the start of the COVID-19 pandemic, which as reported by Consumers Energy staff, created unique challenges such as long delays in project timelines due to back-ordered equipment. In addition, trade ally participation was low, with only one trade ally completing the vast majority of installations across these offerings in the early months of the initiative. To determine the sources of these barriers and understand the challenges associated with adopting CCHPs in Consumers Energy's service territory, the Evaluation team interviewed eleven contractors, two manufacturers, and five distributors involved in the installation, production, and distribution of CCHPs in Michigan.

Contractors' awareness and perceptions of CCHPs varied, and a contractor's interest in heat pump technologies in general depended largely on the availability of different heating fuels in their service territories. Contractors in rural areas, where delivered fuels are more common, had more awareness of and a greater affinity for ducted systems and heat pumps in general. Contractors in urban areas had more awareness of ductless systems, but overall lower levels of familiarity with and affinity for heat pump technologies.

Among all contractors, the pervading theme regarding CCHPs (and heat pumps in general) is that of uncertainty. In order to confidently promote heat pump technologies, contractors must be able to determine the operating cost of the equipment compared to a customer's existing equipment. Currently, there are no readily available tools that allow contractors to accurately model and compare the energy consumption of a heat pump to other heating sources; combined with the comparatively higher up-front cost of heat pumps, this inability to accurately model potential energy savings commonly makes heat pumps a non-starter. Furthermore, several contractors expressed a hesitancy to promote electric heating sources to their customers, as they perceived the price of electricity to be less static and more prone to price increases than other fuel sources. Additionally, some contractors were unaware that CCHPs were effective in cold climates. The confluence of uncertainty around CCHPs is commonly too significant of a barrier for contractors to abandon the status quo of a like-for-like equipment replacement.

Although there were manufacturing and transportation delays, distributors reported having stock on hand that was sufficient to meet current demand. Manufacturers and distributors noted that some contractors maintained the belief that heat pumps were not effective in cold climates (a finding that may be correlated with a contractor's location, given that the contractor interviews found that contractors in urban areas were less aware and less in favor of heat pumps compared to those in rural areas). Aside from this contractor barrier, manufacturers and distributors pointed to customer hesitation due to large up-front or long-term costs associated with CCHPs. In Michigan, CCHPs are less cost-effective than in other states due to the low cost of natural gas, but demand seems to be increasing, especially in rural areas where homes are predominantly heated with propane or oil.

This chapter provides contractor findings separately from manufacturer and distributor findings.

Contractor Findings

The Evaluation team interviewed eleven HVAC contractors to address three research objectives:

- Determine current awareness and perceptions of heat pump technologies.
- Identify the main barriers to installing heat pumps in Michigan.
- Identify marketing and outreach best practices.

The key findings corresponding to each research objective are outlined below.

Cold-Climate Heat Pump Awareness and Perceptions

Contractors' overall awareness of and attitudes toward CCHP technologies were largely correlated with the type of fuel available to the contractor's customer base. Contractors serving rural populations were more familiar with ducted systems, displayed an overall greater affinity for heat pump technologies, and reported higher levels of customer awareness and demand. Conversely, contractors serving urban populations were more familiar with ductless systems and displayed comparatively lower levels of familiarity with improvements in CCHP capabilities.

Contractors indicated that general awareness of heat pump technologies among customers was low but increasing. Contractors reported a marginal increase in the number of customers asking for the technology in recent months, and a more substantial increase in customers who were aware once the contractor presents CCHPs as an option. Similarly with contractor awareness, customer awareness is largely correlated with location and the availability of natural gas.

> "The typical customer is not aware it [CCHPs] is a heating option."
> - Contractor

Best Cold-Climate Heat Pump Applications

Contractors detailed the various scenarios in which CCHPs are currently being adopted by customers, or where they make the most sense for future adoption. For ducted systems, contractors reported the three best applications:

- Customers with propane or delivered fuels who have no access to natural gas
- Green-motivated customers who are not as cost conscious
- New construction

The best applications for ductless mini splits differ by heating versus cooling:

- Heating
  - Customers with electric baseboard heat—especially multifamily customers
  - Customers with hot or cold spots not served well by the existing system (and who could use heat pumps for supplementary heat)
- Cooling
  - Customers with no existing duct work (such as those with a boiler or electric baseboard heat)
  - Commercial applications, such as computer server rooms or elevator rooms
  - Vacation homes (that are not occupied in the winter)[12]

[12] Note that secondary or vacation homes were not eligible for the pilot.

Barriers to Adoption

Contractors provided a variety of reasons for the relatively slow adoption of heat pump technologies to date. Barriers primarily relate to financial constraints, either the up-front cost of the equipment or the comparatively higher operating cost (where natural gas is available). Adding to concerns over the operating cost is the idea that electric rates can be somewhat variable, so even if a contactor is able to project the operating cost of equipment for their customer, there is no guarantee that the projection will be accurate in the future. Furthermore, even when projecting operating costs using a fixed cost of electricity, there are no readily available tools by which contractors or customers can make accurate projections of the total system cost (equipment and operation). Several barriers were identified:

- Higher equipment cost versus other systems
- Relative higher cost of electricity compared to natural gas
- Variability in electric rates
- Inability to make accurate comparisons between the operating costs of CCHP systems to traditional heating systems
- Lack of education and awareness for the public and contractors alike
- Contractor perceptions of poor performance in the Michigan climate (less common)

Installation complexity and cost, supply chain robustness, and previous experiences with heat pumps are not seen as barriers among contractors. Contractors detailed how heat pumps generally require minimal additional work compared to traditional systems, and that relative to the additional cost of the equipment itself, the additional installation costs are negligible.

> "ASHPs [air-source heat pumps] have fallen off [become less common] for a couple reasons: most homes lately have a natural gas option, so we feel it is more to their advantage to use the gas furnace than air-to-air heat pumps."
>
> - Contractor

Overcoming Barriers to Adoption

There was no consensus among interviewed contractors as to what would be most influential in increasing CCHP adoption. Two contractors referenced a different rate structure for customers who use electric heat: Consumers Energy used to offer a special rate for customers with electric heat, and one contractor said the number of heat pumps they install has decreased since this rate was rescinded. These contractors believe that introducing an electric heating rate would potentially help to price CCHPs more similarly to natural gas–fired systems and lead to increased adoption:

- "If you choose a certain heating system, they used to offer a heating energy price decrease. If Consumers [Energy] could bring something like this back, demand would explode. Offer special rates for HP [heat pump] use for heating."
- "Used to do heat pumps more when they offered an electric heating rate, but we've switched to mostly natural gas due to cost of use."

Two contractors indicated that additional customer education is necessary to increase CCHP adoption, with one proposing a potential marketing campaign similar to the thermostat promotions that Consumers Energy currently offers. Other suggestions included offering increased rebates and a tool that helps customers more accurately project the lifetime operating costs of heat pumps against other space heating options:

- "Messaging would be a big bonus for all the contractors. It would help with promoting them [CCHPs]. Like the thermostat promotions that have produced a lot of positive feedback, [a campaign promoting heat pumps] would be very helpful."
- "Just educating people about that they've gotten the bugs out of these things [CCHPs] and they're working great."
- "Better rebates on them [CCHPs] for sure. With the [heat pumps] we have had a hard time meeting Consumers Energy's rebate requirements to qualify; our basic ASHP [air-source heat pump] doesn't qualify [and would] need to get up into the second or third level of efficiency, and with the increased cost the low [$100] rebates are not effective."
- "[It would be great] if Consumers [Energy] were able to come up with a tool comparing purchase and operational costs of electricity versus natural gas systems, showing savings of switching over when customers have dual fuel systems."

Marketing and Outreach Suggestions

As previously noted, two contractors said that increased customer education would be the most impactful way to increase customer demand for CCHP technologies. Each interviewed contractor suggested specific comparisons or promotional strategies to present the equipment to customers:

- Two suggested direct promotional campaigns from Mitsubishi that have been successful within Michigan
- One suggested using smart thermostat promotions from Consumers Energy
- One suggested promoting heat pumps as an air conditioner (AC) that also provides free heat
- One suggested offering a winter electric heating rate for owners with a CCHP
- One suggested providing tools to demonstrate savings compared to other systems

Income-Qualified Considerations

Two contractors indicated that unique circumstances may prevent the widespread adoption of heat pumps for income-qualified customers:

- The potential for theft of the costly units
- Low-income property managers' aversion to potential equipment issues and ensuing repairs

Distributor and Manufacturer Findings

The Evaluation team interviewed five distributors and two manufacturers of CCHPs in Michigan to address several research objectives:

- Confirm and document the supply chain for CCHPs in Michigan
- Identify the barriers leading to extended timelines for CCHP installation
- Identify sources of differences in CCHP installation costs across states
- Explore the cause of low participation by trade allies
- Identify any additional barriers and challenges delaying the widespread adoption of CCHPs in Michigan, like training or education
- Identify ways in which Consumers Energy can influence market adoption

The key findings corresponding to each research objective are outlined below.

Cold-Climate Heat Pump Supply Chain

Manufacturers and distributors confirmed that CCHPs follow a traditional supply chain structure, with no difference compared to traditional air-source heat pumps (ASHPs) or other types of HVAC equipment. While this typically means that units move from the manufacturer to the distributor and then to a contractor before reaching customers, there are exceptions for national corporate customers, who may purchase equipment directly from a distributor rather than through a contractor (see Figure 1).

Many CCHPs are manufactured abroad and shipped to ports in the United States, primarily to California or Georgia, before being trucked to regional destinations.

Figure 1. Heat Pump Supply Chain

Installation Timelines

Distributors reported it takes from one to 20 weeks to receive inventory from manufacturers, depending on whether the manufacturer is overseas or domestic and whether they placed a rush order. Manufacturers and distributors reported experiencing manufacturing delays as a result of COVID-19, as

well as ongoing transportation delays that included backups at ports and a truck driver shortage that began in 2018, prior to the pandemic.

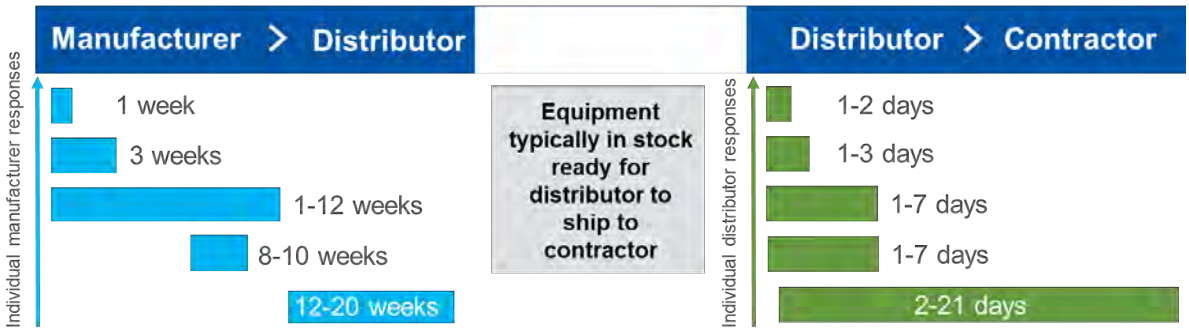
Despite manufacturing and transportation delays, distributors generally reported having stock on hand, so installation times were either not impacted or were only impacted temporarily. For the most part, distributors had learned how to manage around these constraints by being proactive and front-loading inventory. With enough inventory in stock, they can prevent delivery delays from impacting installation timelines:

- "With COVID-19, a lot of the supply chains have been broken. We were very responsive and proactive this year by buying up huge amounts of inventory. If we were to stop purchasing equipment now (March 2021), we would have enough equipment to last through November." – Distributor
- "This whole COVID thing really threw a wrench in a lot of this, and so I think a lot of it, the success that we have seen, having a little bit of inventory in Michigan, has to be to the credit of the distributor being proactive." – Manufacturer

When distributors have stock on hand, they reported that they typically deliver equipment to the contractor within one week, as shown in Figure 2. For a custom system or for equipment not in stock, the delivery timeline can stretch to three weeks or more, and one distributor had seen delays reach as long as six to eight weeks at points earlier in the pandemic, saying, "Much like everything else in the world, COVID really wreaked some havoc on manufacturing, so you know there were some times when it was six to eight weeks, but thankfully with good planning, we had enough stock that we really didn't have to deal too much with it [delays]." One distributor stated that custom equipment requires roughly 30 days to get to the contractor. Note that with the exception of this one distributor, timelines for custom equipment were not discussed in the interviews. It is possible that timelines for custom equipment could be different.

Notably, manufacturers and distributors have not observed any issues with the supply chain or with installation timelines that are unique to CCHPs or to Michigan.

Figure 2. Equipment Delivery Timelines Reported by Distributors



Note: The range in times for equipment to be delivered from the manufacturer to the distributor is due to differences between oversees versus land shipping and rush versus standard orders. One distributor also noted that COVID-19 led to six- to eight-week delays in equipment getting from the distributor to the contractor.

Cold-Climate Heat Pump Cost Differences across States

Most interviewed distributors and manufacturers did **not** report CCHP cost differences between Michigan and other states. One exception was a distributor who reported that installation costs in Michigan are higher compared to the Northeast. The distributor linked this difference to lower familiarity among installers in Michigan and said they expect costs to go down as installers become more familiar with the technology.

Within Michigan, interviewees observed differences in cost based on location in the state, with labor costs in urban areas being higher than costs in more rural areas. As one distributor stated, "Michigan prices are pretty average compared to Ohio [prices]. If you're in a more rural area, installation prices tend to go down, and if you're in a bigger, more metropolitan area then prices tend to go up."

One manufacturer also pointed out cost differences depending on whether contractors are union or non-union: "We go from $85 an hour that a contractor will charge a consumer to $140, especially if they are [in] a union. Or [when] you get into the Motor City, they seem to think they can charge a lot more."

Four of the five distributors reported increased CCHP costs over the last six months, and two interviewees noted that the cost of materials is rising—particularly for sheet metal, steel, and copper—which could lead to further cost increases down the road. As one distributor said, "[Internal costs] are going through the roof, [and] manufacturers can't eat it all."

Contractor Engagement

All five of the interviewed distributors shared the perception that there are still contractors in Michigan who do not have a full understanding of CCHPs and need to become more familiar with the technology and benefits. All five distributors also reported offering trainings to contractors to further their knowledge of CCHPs, including installation and service trainings as well as sales-oriented trainings: "We do training at every level possible, from technical service/installation to sales, and we have even offered business training."

Reports of attendance at trainings varied, with three who said their trainings were well-attended, one who said there was a mix of well-attended and less well-attended trainings, and another who said they were not well-attended, which they attributed to a lack of awareness of CCHP technology. One distributor also reported that, in their experience, one-on-one trainings work better than trainings offered in a group setting. Many training offerings have been moved to virtual platforms like Zoom due to the pandemic, which two distributors noted has been more challenging than in-person trainings.

Interviewees noted that trainings do not differ by state, e.g., they do not address specific climate, available programs, or current policies.

Barriers to Adoption

Four distributors mentioned that one barrier to CCHPs becoming more common in Michigan is that awareness of and trust in CCHP technology is not yet widespread among contractors in the state.

Instead, they reported that many contractors continue to hold an outdated perception that heat pumps are not a viable option in cold climates:

- "A lot of the contractors, especially a lot of the old timers... They don't see heat pumps as a viable option in Michigan. We hear that so many times." – Distributor
- "As technology continues to get better and heat pumps can operate at lower temperatures, you're always going to have an old service tech or installer that absolutely does not believe in the new technology." – Distributor
- "A lot of contractors are not as informed as they could be." – Distributor

Other barriers mentioned include concerns about up-front and long-term costs and, relatedly, the lack of incentives (since current policies in Michigan do not allow utilities to incentivize customers to switch from natural gas heat to electric heat).

Interviewees reported that demand for CCHPs is higher in other states than in Michigan. One attributed this lower demand in Michigan to the lack of widespread understanding among contractors and customers that heat pumps can be effective in cold climates. Others discussed the trade-offs in switching from different fuel sources. One distributor pointed out that natural gas is cheaper in Michigan than in other states, making CCHPs less cost-effective, and therefore less appealing, for those who currently use natural gas heating.[13] For those who use more expensive propane or fuel oil systems, however, distributors felt switching to a heat pump *would* be more cost-effective: "All-electric heat is a no-brainer. If they have propane or fuel oil, [heat pumps] make sense. With a natural gas system, it is a tougher sell."

Overcoming Barriers

Although interviewees reported that demand for heat pumps is lower in Michigan than elsewhere, they have also observed that demand in the state is increasing. Two distributors reported seeing major growth in CCHP adoption in recent years: one reported that their 2021 quarter 1 CCHP sales were greater than CCHP sales in the previous two years combined, and another reported having record demand in 2020, with sales doubling from 2019.

> "Ductless mini-splits are a huge, growing market, [with] the largest growth potential of any [technology], and everyone is saying the same thing."
>
> - Distributor

While there are still awareness and education gaps, interviewees reported that contractors and customers are becoming increasingly familiar as CCHPs have become more technically viable. As mentioned above, CCHPs are also increasingly *economically* viable in rural areas where there is a reliance on propane and oil heat.

[13] The proportion of households in Michigan with natural gas heating (82%) is higher than in most other states (Consumers Energy. 2018 Residential Saturation Study. Not available online).

The two biggest tools that interviewees noted as key to increasing CCHP adoption are incentives and increasing contractor and customer education. Several distributors emphasized that incentives and rebates are highly appealing to customers, making them an important tool for increasing adoption:

- "Customers would be willing to switch with an incentive." – Distributor
- "Incentives help to drive adoption." – Distributor

> "[It's] all about making the contractors aware of the benefits." – Distributor

Contractor education is also seen as a need, both to increase awareness of the viability of CCHPs in the state and to improve contractors' understanding of the benefits and cost-effectiveness of CCHPs.

Increasing Adoption

Distributers and manufacturers mentioned that Consumers Energy has been actively working to increase CCHP adoption, and they see the role of utilities as critical in helping this new technology gain a foothold.

> "The role of the utility is very important because they are the ones that can accelerate the [adoption of CCHP] technology." – Distributor

Distributers and manufacturers suggested that Consumers Energy can further encourage adoption in three ways: through education and training, by providing sales tools, and by offering incentives. Additional education and marketing directed at customers is needed to increase their awareness of the benefits of CCHPs.

> "There is a lack of information about the difference between costs for gas and electric." – Distributor

Similarly, interviewees suggested providing in-person trainings to contractors about rebates and the benefits of CCHP technology, including targeted trainings for technicians who may need more help to transition to a new technology. Three interviewees also said it would be useful to have a calculator tool that helps contractors easily demonstrate cost savings for switching to CCHP technology.

Interviewees also suggested that higher incentives would be instrumental in increasing CCHP adoption, and primarily felt that incentives should be offered via a midstream strategy. While one interviewee said rebates should be directed to contractors, all the other interviewees suggested that rebates should be directed to distributors, with one saying it would be helpful to have automatic incentives that minimize paperwork. One interviewee also suggested that incentives should be provided for CCHPs that have equivalent seasonal energy efficiency ratio (SEER) ratings as incentivized air conditioners.

> "Utility rebates really help. In some cases, the rebate has been able to cover the difference [between an AC and a heat pump]." – Distributor

Residential Market Rate Initiative Findings

In November 2021, the Evaluation team sent a survey invitation to 29 Residential Market Rate pilot participants who had valid emails. The email survey invitation included a $15 incentive for taking the survey. Nine of the 29 participants completed the survey, for a 31% response rate; with such a small sample size, the results should be interpreted with caution and only viewed as directional indications (not intended to be analyzed with statistical confidence).

In addition to the participant survey, the Evaluation team conducted an engineering analysis to determine market rate CCHP participants' energy and utility bill cost savings. The Evaluation team used data collected from the Consumers Energy initiative team and calculations that can be found in the *Michigan Energy Measures Database* (MEMD).[14]

This chapter first provides details of Residential Market Rate pilot participants, then covers the engineering analysis findings.

Market Rate Participant Survey

The Evaluation team designed the participant survey to address several key objectives:

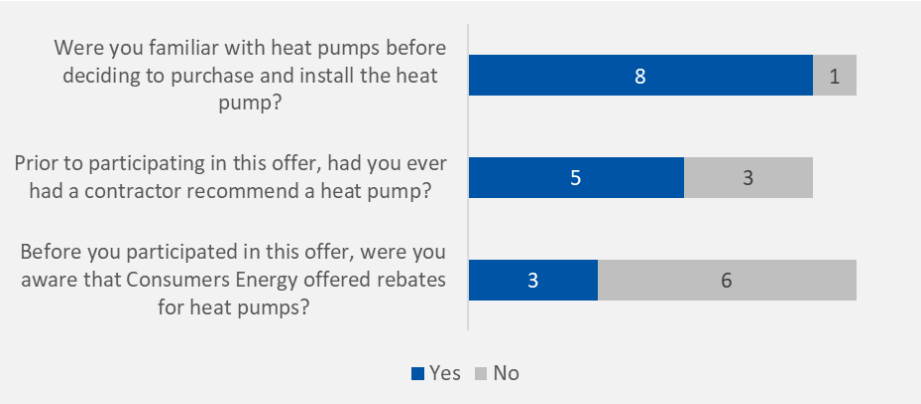
- Assess awareness of and motivation for installing heat pumps
- Assess the participant installation experience
- Document perceptions of heat pumps, energy or cost savings, and comfort levels
- Document participant usage behavior
- Assess satisfaction with the offering and with Consumers Energy

Awareness and Motivation

All nine respondents confirmed that they received a rebate for their heat pump and that they were present when the heat pump was installed. While most (eight of nine) were familiar with heat pumps before deciding to purchase one for their home, few (three of nine) were aware that Consumers Energy provided heat pump rebates (Figure 3). Respondents first learned about Consumers Energy's heat pump rebate primarily through their contractor (four of nine) or from a Consumers Energy email (two of nine). About half (five of nine) said a contractor had recommended a heat pump before they learned about and applied for the Consumers Energy heat pump rebate.

[14] Michigan Public Service Commission. *Michigan Energy Measures Database.* https://michigan.gov/mpsc/regulatory/ewr/michigan-energy-measures-database

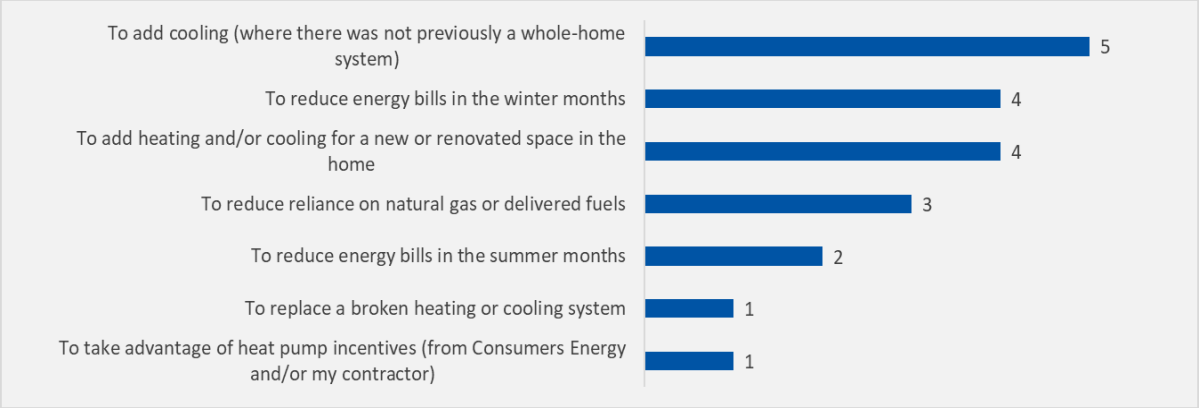
Figure 3. Heat Pump Awareness



Source: Heat Pump Market Rate Customer Survey Questions B3, B4, and B5 (n=9).

Although respondents could indicate several different motivations for installing a heat pump, responses were most frequently associated with space cooling needs and saving money on energy bills. Most respondents (n=5) installed a heat pump to add cooling where there was not previously a whole-home space cooling system. Four respondents each wanted to reduce energy bills in winter months and wanted to add space heating or cooling for a new or renovated space. Three respondents wanted to reduce their reliance on natural gas or delivered fuels (Figure 4).

Figure 4. Motivations for Installing a Heat Pump



Source: Heat Pump Market Rate Customer Survey Question B7. "What were the main reason(s) you decided to install a heat pump in your home?" (n=9; multiple responses accepted)

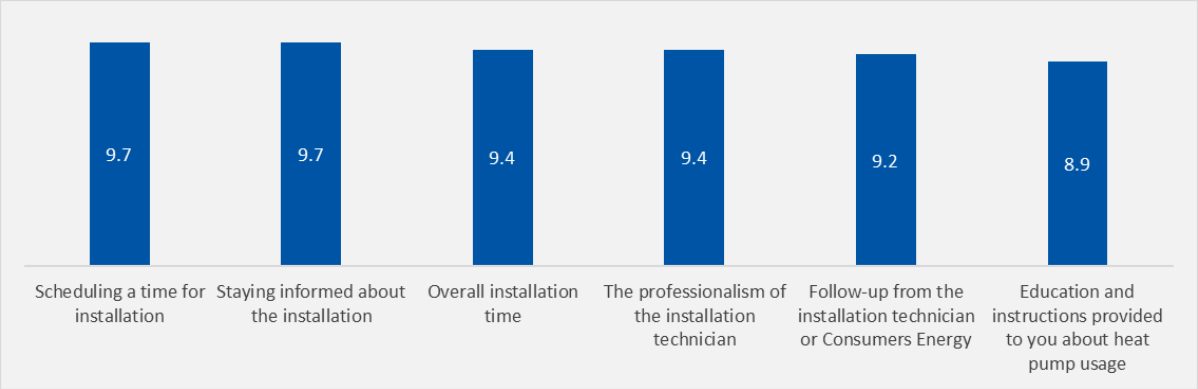
When asked to rate the importance of several factors in their decision to install a heat pump, respondents rated energy savings (over the previous heating/cooling system) as the most important (with a mean rating of 9.1 on a 10-point scale, where 1 meant *not at all important* and 10 meant *extremely important*). The contractor's recommendation received a mean rating of 8.0, and the rebate amount received the lowest rating of all decision factors, at 7.6.

Installation Experience

Respondents were engaged with the installation experience: all of them were present during the installation. Most (eight of nine) received instructions on how to set up and control the heating and cooling schedule on their heat pump at the time of installation. Only one respondent said the installation contractor set up a heating and cooling schedule for them but said they had adjusted that original schedule to address changes in their home's conditioning needs.

Respondents provided very high ratings for aspects of the installation experience, with scheduling and staying informed about the installation receiving the highest mean ratings (of 9.7 on a 10-point scale, where 1 meant *unacceptable* and 10 meant *outstanding*; see Figure 5).

Figure 5. Installation Experience Ratings



Source: Heat Pump Market Rate Customer Survey Question D2. "How would you rate each of the following installation experiences with the heat pump offering?" (n=9)

The lowest rating (of 5) was provided by one respondent for the "education and instructions provided about heat pump usage," but that person did not answer the follow-up question about why they gave that rating.

Heat Pump Perceptions

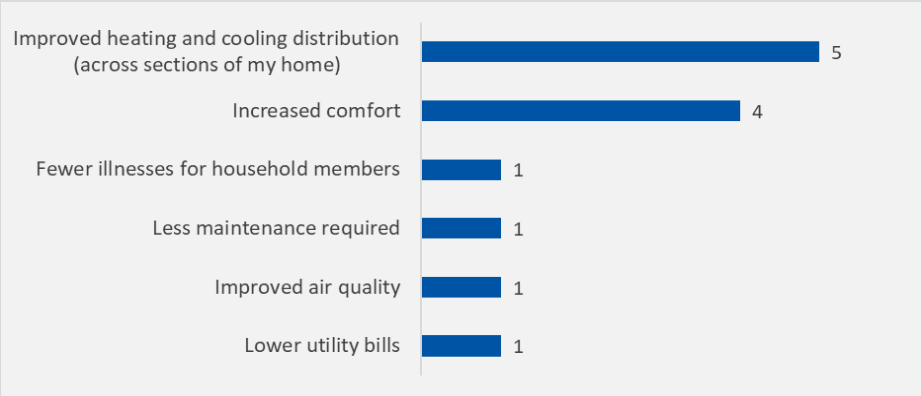
Most respondents (seven of nine) said their home is more comfortable after installing the heat pump, while the other two respondents said their home is equally as comfortable as before the heat pump was installed. One respondent also volunteered that their home air quality was vastly improved, which was also a primary reason they installed the heat pump.

Five respondents rated the comfort level provided by the heat pump in winter months, providing a mean rating of 8.6 on a 10-point scale, where 1 meant *unacceptable* and 10 meant *outstanding*. None indicated any concerns with the heat pump's ability to heat to a preferred comfort level. Comfort ratings for summer months were higher, at an average of 9.1 with ratings from all nine respondents.

Overall, perceptions were mixed about whether respondents had seen savings on their energy bill since the heat pump was installed. Four respondents said it was too soon to tell if their energy bill was affected, while two said they had a lower-than-expected energy bill and two said they had not seen a lower-than-expected energy bill.

In addition to energy savings, respondents reported several additional benefits that they value in their heat pump. With several response options provided, the most frequent benefit selected (by five respondents) was improved heating and cooling distribution across sections of the home (Figure 6). This was followed by four respondents who said the heat pump provided increased comfort. One respondent each indicated having lower utility bills, less required maintenance, improved air quality, and fewer illnesses for household members.

Figure 6. Heat Pump Benefits

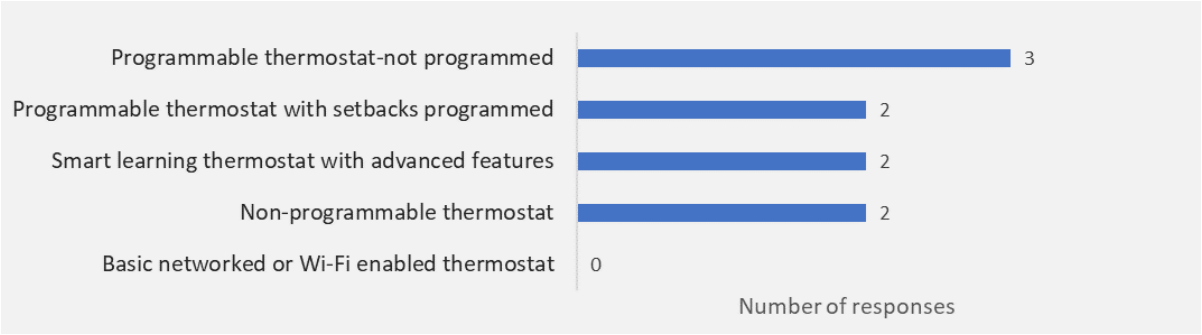


Source: Heat Pump Market Rate Customer Survey Question D13. "In addition to energy savings, if any, are there any other benefits you have experienced or observed from the installation of a heat pump?" (n=9; multiple responses accepted)

Thermostat Usage Behavior and Experience

While five of nine respondents had programmable thermostats, only two of those five used programmed temperature setbacks to control their heat pump temperature settings. Two respondents had smart learning thermostats with occupancy sensing and schedule learning capabilities, and two others had non-programmable thermostats with manual-only controls (Figure 7).

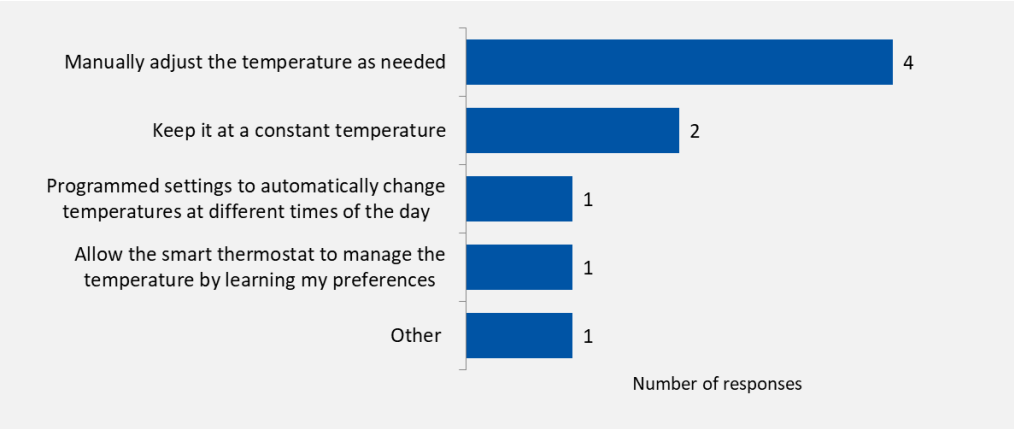
Figure 7. Respondent Thermostat Types



Source: Heat Pump Market Rate Customer Survey Question C1. "What type of thermostat do you have in your home?" (n=9)

Respondents, either singularly or with other household members, monitor and adjust the home heating and cooling settings. Despite most having programming capability through their thermostats, four of nine said they adjust the temperature manually (Figure 8).

Figure 8. Thermostat Management



Source: Heat Pump Market Rate Customer Survey Question C3. "How did your household most frequently manage your thermostat to control the temperature in your home this summer?" (n=9)

Satisfaction with the Offering and with Consumers Energy

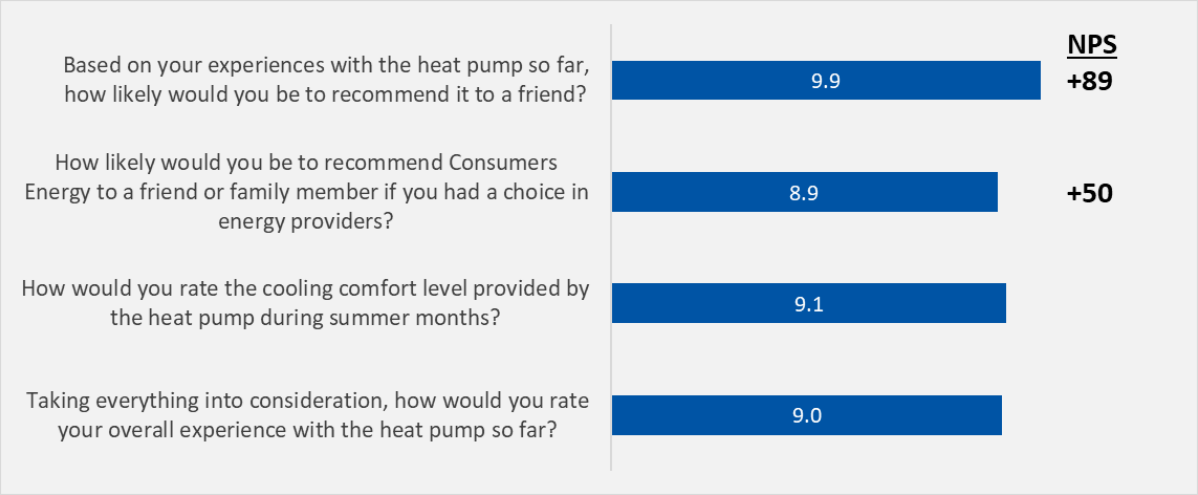
Overall, respondents were highly satisfied with the heat pump (giving a mean rating of 9.0 on a 10-point scale, where 1 meant *unacceptable* and 10 meant *outstanding*), with all nine respondents giving a rating of 8 or higher for their overall experience with the heat pump.

Another key measure of customer satisfaction is the percentage of customers who are highly willing to recommend a product, service, or company after subtracting the percentage of customers who are highly unlikely to recommend that same product, service, or company. The net percentage of those willing to promote the product is the net promoter score (NPS), expressed as an absolute number between -100 and +100 that represents the difference between the percentage of promoters (respondents giving a rating of 9 or 10) and the percentage of detractors (respondents giving a rating of 1 to 6). The Evaluation team calculated a NPS for the two likelihood to recommend questions (likelihood to recommend the initiative and likelihood to recommend Consumers Energy).

Based on their experiences, respondents were highly likely to recommend the heat pump to a friend. As shown in Figure 9, nearly all respondents (eight of nine) gave a rating of 9 or higher (with a mean of 9.9), with three indicating that they had already recommended the heat pump rebate to a friend. The resulting NPS for the heat pump is +89.

Five of eight respondents (63%) provided a rating of 9 or 10 for their likelihood to recommend Consumers Energy to a friend. Only one respondent rated their likelihood to recommend as a 5. The resulting NPS for Consumers Energy is +50, with a mean rating of 8.9.

Figure 9. Market Rate Heat Pump Participant Satisfaction



Source: Heat Pump Market Rate Customer Survey Questions D10, B1, D7, and D9. All questions used a 10-point rating scale, where 1 meant *extremely unlikely* and 10 meant *extremely likely*, with an "already did" response option as a 10 rating (n=9).

The NPS for recommending the heat pump is considered very high and compares favorably to other efficiency programs with similar measures. For example, HVAC participants provided a program NPS of +76 and a Consumers Energy NPS of +63 in 2021. Again, caution is recommended in interpreting numeric results due to the small sample size with the Residential Market Rate pilot response population.

When asked to elaborate on their rating for recommending Consumers Energy, respondents gave positive comments:

- "Consumers Energy has been a good power company. They keep us informed on rebates, power outages, etc. During power outages they are great at restoring power quickly and keeping us informed on time frames. The rebate for heat pumps was one of the reasons we decided to try a heat pump. Our power bill has gone up, but we are using our heat pump a fair amount. It is still a better option than the window air conditioner that we had before."
- "It's been a great company. I grew up in a Consumers [Energy] home and have had one [a heat pump] my entire adult life."
- "High marks for programs and communication."
- "Very happy with service and energy offers."
- "[I] like that Consumers [Energy] is trying to help on heating costs that are going up every year."
- "We don't really have much choice, but I think that Consumers Energy does a good job providing (mostly) reliable electric service (which is all you [they] provide to my area)."

Two respondents said they do not have a choice in energy company, so they do not have a point of comparison, and one commented on high rates.

The only improvement suggestion respondents provided did not directly pertain to the heat pump initiative: "Allow me to change the energy conservation program I want more than once a year. We would like to 'follow the rules' imposed during the summer year-round but cannot change because we cancelled the program we had been on (Consumers [Energy] could limit our AC during peak periods) because our contractor did not want Consumers [Energy] to be able to change our now Wi-Fi–capable system (the old one was not [Wi-Fi]) in May/early June. We did not find out about the option we'd like until later in the summer but were not allowed to use it."

Impact Analysis

The Evaluation team conducted an engineering analysis of the impacts from the Residential Market Rate pilot and relied on MEMD assumptions and information we had collected from customers such as home vintage, presence of central cooling, installed system coefficient of performance (COP)[15] at 5°F, rated heating seasonal performance factor (HSPF) and SEER, tonnage, and other data. The Evaluation team relied on the MEMD weighting tool, which generates a single measure output based on home vintage, climate zone, sizing, and efficiency levels. Since the MEMD weighting tool does not allow for varying the baseline equipment type or system efficiency, the Evaluation team used MEMD building simulation output data to develop site-specific consumption values. MEMD staff provided underlying MEMD 2019 weighting tool building simulation results for ASHPs in single-family buildings.[16] This section summarizes key findings from the engineering analysis.

There were 42 Residential Market Rate pilot CCHPs installed in homes with electric and propane heating, making up the largest percentage of pre-installation heating fuels (Table 6). Approximately half of the CCHPs were installed in homes built before 1979 (n=25) and most of the other half were installed in homes built between 1980 and 2004 (n=23). The remaining CCHPs were installed in homes built between 2005 and present day (n=3).

Table 6. Home Construction Vintage Distribution by Pre-Installation Heating Fuels

Pre-Installation Heating Fuel	1979 or older	1980 to 2004	2005 to Present	Total
Electricity	10	6	0	**16**
Propane	9	15	2	**26**
Fuel Oil	3	1	0	**4**
Natural Gas	3	1	1	**5**
Totals	**25**	**23**	**3**	**51**

[15] Coefficient of performance is simply the ratio of power (kW) in heating (or cooling) Btus generated by the CCHP, and the power (kW) that is supplied to the compressor. The higher the COP, the greater the heating energy generated for each kilowatt consumed by the CCHP.

[16] The MEMD 2021 building simulations for this measure have not been updated since 2019 and therefore reflect the latest building simulation results.

Table 7 shows the average Residential Market Rate pilot participant' annual energy and utility bill savings by pre-installation heating fuel type. Customers heating with delivered fuels (propane and oil) realized the highest heating energy savings, while customers heating with electricity prior to installation of the CCHP had the highest utility bill savings.

Table 7. Average Market Rate Cold-Climate Heat Pump Energy and Fuel Cost Savings per CCHP

Pre-Installation Heating Fuel	Number of Installed Units	Average Savings per CCHP		Average Annual Utility Bill Savings per CCHP
		Heating (MMBtu) [a]	Cooling (kWh) [b]	
Electricity	16	35	-108	$1,680
Propane	26	68	-27	$1,223
Fuel Oil	4	70	-46	$910
Natural Gas	5	54	-228	-$451

[a] Due to the different heating fuel types, savings are represented in MMBtu to allow for better comparisons.

[b] Negative savings mean that electric consumption increased rather than decreased.

The five homes that heated with natural gas will likely see an increase in their utility bill of $451 per year on average due to the relative costs of electricity and natural gas at the time of the analysis, as well as the fact that four of five homes did not have existing central AC (which will likely increase their electric usage in the summer).

As shown below in Table 8, only 22 of the 51 participants had central AC prior to the CCHP installation. For homes without central cooling, the Evaluation team assumed a portion of the homes use room or window AC units to provide some cooling. Due to the low number of homes without conditioned cooling, electric consumption increased, on average, across all baseline heating fuel types. However, homes that did have central cooling before the CCHP installation saw savings from $20 to $96.

Table 8. Central Cooling Presence Distribution and Associated Cooling Savings

Pre-Installation Heating Fuel	Central Cooling?	Number of Installed CCHPs	Annual Cooling Electric Savings per CCHP
Electricity	Yes	5	$33
	No	11	-$37
Propane	Yes	15	$57
	No	11	-$69
Fuel Oil	Yes	1	$96
	No	3	-$35
Natural Gas	Yes	1	$20
	No	4	-$50

Table 9 shows the total Residential Market Rate pilot annual energy and utility bill savings by pre-installation heating fuel type for all CCHPs.

CADMUS

Table 9. Total Market Rate Heat Pump Energy and Fuel Cost Savings

Pre-Installation Heating Fuel	Count of Installed CCHP Units	Savings		Annual Fuel Costs [b]		Pre-Installation Central Cooling Saturation [c]
		Heating (MMBtu) [a]	Cooling (kWh)	Heating	Cooling	
Electricity	16	565	-1,729	$27,124	-$247	31%
Propane	26	1,774	-704	$31,701	$85	58%
Fuel Oil	4	279	-183	$3,652	-$10	25%
Natural Gas	5	270	-1,142	-$2,072	-$182	20%

[a] Due to the different heating fuel types, savings are represented in MMBtu to allow for better comparisons.

[b] The Evaluation team calculated annual heating and cooling costs based on rates and distributed fuel cost shown in *Appendix B*.

[c] Not every home was equipped with central cooling before the CCHP installation.

Income Qualified Multifamily Initiative Findings

There are two key groups of participants in the Income Qualified Multifamily initiative: property owners and managers (PMO) and tenants. PMOs are active participants who sign up for the initiative and are the primary contacts of the initiative. The tenants are indirect participants; they are not decision-makers, yet they directly benefit from the CCHP Initiatives' equipment and energy savings in their living units and they most frequently pay the resulting energy bills from CCHP operation. The Evaluation team sought feedback from both groups, conducting telephone interviews with PMOs and online surveys with tenants. The Evaluation team also sought to understand the Income Qualified Multifamily initiative's performance by analyzing electric energy savings impacts during the heating and cooling seasons through a statistical billing analysis of participating initiative properties.

This chapter outlines the results of PMO interviews, tenant surveys, and the statistical billing analysis.

Property Manager and Owner Interviews

The Evaluation team conducted telephone interviews with multifamily PMOs who participated in the CCHP initiative to gain insight into their experience. The Evaluation team designed the interview to address several key objectives:

- Document the participant installation experience
- Document participant usage behavior and experience
- Document awareness and perceptions of heat pumps
- Document participant decision-making around participating in the heat pump offering
- Identify marketing and outreach best practices
- Assess satisfaction with the offering and with Consumers Energy

As of Q3 2021, seven multifamily properties had participated in the Income Qualified Multifamily initiative. While the Evaluation team attempted to recruit all seven of the multifamily PMO initiative participants, we completed three phone-based in-depth interviews. Two of the multifamily PMO participants were from existing buildings (retrofit installations) and therefore had broad insights into the full initiative experience. The third interviewee was with a newly constructed property, which meant they had a more limited view on the tenant and installation experience.

Installation Experience

Overall, the multifamily PMOs had a positive early-stage initiative experience with scheduling, installation, and follow-up. Two of the three PMOs reported that COVID-19 caused some delays with the installation and equipment, but overall reported positive experiences. In one case, the PMO commented that the completion time was fast considering the number of units and installs: "We had something like 48 units, some large enough for multiple installations…so two-and-a-half months to install over 50 units was fast." The third PMO, the owner of a new construction property, noted the while installations were all completed on time, they did not have feedback on the tenant experience during installation (as installation happened before tenants occupied the units). For the other two PMOs with tenants living in

the units, the installer worked directly with management to notify the tenants of the installations and work around their schedules. According to these two PMOs, their tenants were generally satisfied with the heat pump installation.

Heat Pump Usage Behavior and Experience

The multifamily PMOs reported that prior to installation, tenants relied on inefficient electric baseboard systems and, in one case, had specifically requested new a HVAC system during a tenant meeting. One of the primary benefits for tenants is the ability to use AC as well as heating—while the heat pump replaced baseboard heat, there was no existing AC to replace outside of window units purchased by tenants. One PMO mentioned that nearly all tenants enjoyed the new heat pumps, with only a few tenants being confused about how to use the new system.

Two of the multifamily PMOs received direct feedback from their tenants regarding the heat pump usage and experience. According to one PMO, “the residents considered it a huge plus for them, because of all the extra benefits that the heat pumps provided them.” Another PMO remarked that the heat pumps provided significantly greater comfort, and improved air circulation, compared to the baseboard equipment, and went on to state, “the heating itself is just more efficient for the tenants; it seems to keep the apartments warmer.”

Awareness and Perceptions of Heat Pumps

Multifamily PMOs were generally aware of heat pumps prior to being approached by Consumers Energy about the rebate initiative, though they were not aware of Consumers Energy incentives or programs until their involvement in the initiative. One PMO previously had contractors recommend heat pumps, while another had heat pumps installed in other apartments in the Southeast United States (where heat pumps are more common). One of the PMOs had some hesitation about installing the CCHPs, as they noted, “historically, my understanding was that [heat pumps] didn’t do so well in cold climates. A green consultant and several HVAC engineers turned me on to them and then [I] became comfortable [that] they would be sufficient.”

PMOs generally did not report any perceived benefits of heat pumps prior to installation but were happy to report both energy and non-energy benefits, particularly tenant happiness and reduced maintenance and tenant comfort needs, after installation. As an added benefit, the simplicity of a single heating and cooling system was beneficial for both tenants and the PMOs: the number one benefit is providing heat, but efficient heat is the next important thing. As one PMO said, “There is always some kind of system [to heat], but it doesn’t always work. It’s always our number one concern to provide heating and cooling to the tenants.”

Decision-Making around Participating in the Heat Pump Offering

In both existing retrofit cases, the PMOs primarily decided to improve the existing HVAC systems due to energy efficiency and tenant comfort. One PMO cited a tenant meeting as a primary factor, where tenants explicitly requested an improved HVAC system. Generally, all PMOs wanted to improve tenant comfort, replace old equipment, improve electric efficiency, and lower electricity bills. The biggest barrier to switching over to heat pumps was cost: because the multifamily buildings already had existing

heating systems, it was a matter of prioritizing which are the most in need and how to fit that into the budget: "… if there is an existing heating system that is working, that's not necessarily something we can improve because it meets [the need for] having a functioning system, and it's harder and more expensive to switch out than other properties… so the biggest barrier is a matter of prioritizing it [CCHP installation] in the budget." According to the other retrofit PMO, the rebate allowed them to fit improved HVAC systems into the budget for that year. Tenant comfort, energy efficiency, and an improved system were the key motivations for PMOs.

For the new construction PMO, heat pumps were an attractive investment for their property, and the initiative made it "a slam dunk" for the project. The initiative allowed the property to meet LEED certification while also managing to keep the construction within budget. As the new construction PMO noted, "for our LEED-certified property, which was an all-electric building, and given [that] the units were smaller apartments, it was hard to find a furnace that would work well and integrate into the units and not be oversized. The heat pumps can really work well and are adapted to lower need, relative to [a] gas furnace. The simplicity of only electric, with no gas, requiring less piping, meant that construction was easier." This PMO went on to remark, "with the rebate, the heat pump was actually the cheaper option [relative to a gas furnace]."

Marketing and Outreach Best Practices

Multifamily PMOs agreed that the best way to conduct outreach about CCHPs is to directly contact contractors or developers. According to two PMOs, they primarily get their recommendations from contractors, who do not always provide information on CCHPs and higher-efficiency opportunities to the developers. One existing building PMO said, "if I had someone directly to talk to, I would bring this up to [building owners] more…I confer with architects and specialists on building recommendations, but they don't necessarily know all the tenant benefits. So, I would recommend reaching out to more developers, like myself, directly." Both PMOs recommended emails or pamphlets with the overall costs and energy savings and direct information as a convincing outreach strategy: "Anything that involves a description, some costs, energy savings…I think those are the highlights," the construction manager said.

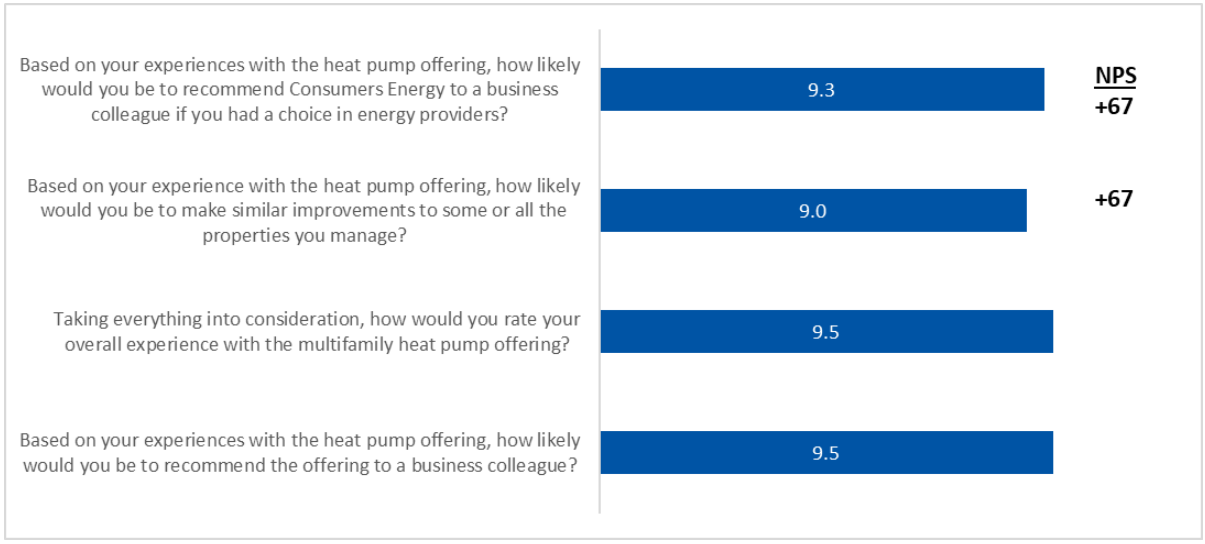
Two of the PMOs learned about the heat pump offering through direct contact with Consumers Energy, while one learned about it from their LEED consultant. When asked what the preferred means of communicating future offerings, all three PMOs tended to prefer email, but also noted phone calls.

One interviewee (the resident manager) mentioned that his property manager was the decision-maker in the process, and that energy companies should do more to contact property managers directly, because most are not aware. "[The property manager] was different," the resident manager said, "He was always searching for rebates and things like that…both to improve the apartments for the tenants, but also because of the resource—using less energy is good for the economy, that kind of thing. But most property managers aren't searching like he was." Another PMO said, "Most people don't know enough and aren't aware [that heat pumps] can work on their own in colder climates. We have now had a full winter with new tenants and the CCHPs and received no complaints: it all went well."

Satisfaction with the Offering and with Consumers Energy

Overall, the participating PMOs were highly satisfied with their initiative experience and with Consumers Energy (Figure 10). The three PMOs provided an average rating of 9.5 on a 10-point scale (where 1 meant *unacceptable* or *extremely unlikely* and 10 meant *outstanding* or *extremely likely*) for their satisfaction with the initiative and their likelihood to recommend heat pumps to a colleague. The PMOs also rated their likelihood to recommend Consumers Energy as a 9.3 and rated their likelihood to adopt similar CCHP equipment in their other properties as a 9.0 (Figure 10).

Figure 10. Multifamily Property Manager Owner Cold-Climate Heat Pump Satisfaction



Source: Heat Pump Property Owner and Manager Interview Guide Questions G1–G4.

Income Qualified Multifamily Tenant Survey

In November 2021, the Evaluation team surveyed a group of multifamily tenants who resided in units that received CCHPs as part of Consumers Energy's CCHP initiatives and 32 completed the survey

The Evaluation team designed the survey to address several key objectives:

- Document awareness of heat pumps
- Understand the participant installation experience
- Assess tenant perceptions of heat pump impacts on comfort levels and electricity bills
- Document participant usage behavior and experience
- Assess satisfaction with the offering and with Consumers Energy

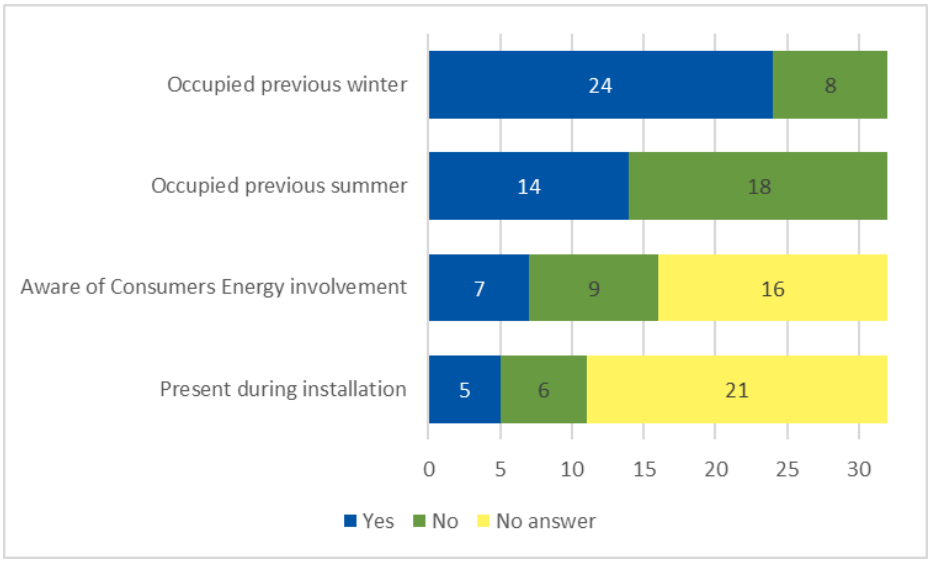
Tenant Survey Background

The multifamily tenant survey included questions about topics such as whether respondents manage the temperature of their unit, whether they pay their bills, and how long they have resided in their unit. Additionally, the team asked questions about the installation and performance of the CCHP.

All tenants who responded to the CCHP survey managed the temperature of their home personally and all said they pay their own energy bills (n=32). Most tenants (n=17) had lived in the apartment for between six months and one year while 11 others had occupied their apartment for more than one year. Additionally, three respondents said the heat pumps had not yet been completely installed and they could not provide answers about installation or post-installation.

Other participant characteristics are summarized in Figure 11. A minority of respondents were present during installation (n=5) and were aware of Consumers Energy involvement in the CCHP (n=7). Three-quarters of respondents were occupants last winter (n=24), before the installation, while one-quarter (n=8) were not present in their units to experience the old heating system, and thus could not provide comparative responses about new versus old heating system performance. Respondents' tenancy term and other factors resulted in around one-third (30%) of the responses to all questions that provided little to no insight into their experience in this initiative. Because of the low response count to many of the tenant survey questions, the results should be considered indicative but inconclusive.

Figure 11. Summary Respondent Characteristics



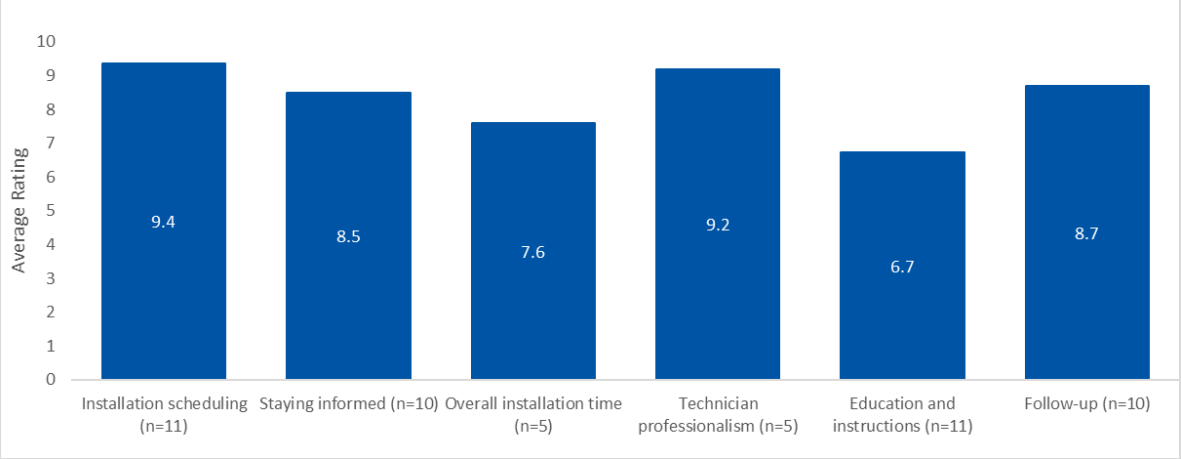
Source: Heat Pump Multifamily Tenant Survey Guide Questions C5, C8, B3, and C1. Please see *Appendix E* for specific question wording.

Participant Installation Experience

A successful equipment installation can provide tenants with a positive initiative experience; such an installation should include providing helpful information and operational details for a better managed heating and cooling experience. One-third of respondents (n=11) provided installation experience ratings. Overall, participants were largely satisfied with the installation experience, rating most installation elements above an 8 on a 10-point scale, where 1 meant *unacceptable* and 10 meant *outstanding* (Figure 12). Respondents provided the lowest average rating to the education and instructional aspects of installation, which impacted their overall satisfaction with the heat pump

offering, as well as with Consumers Energy overall (these metrics are featured further below in Figure 19).

Figure 12. Tenant Installation Satisfaction

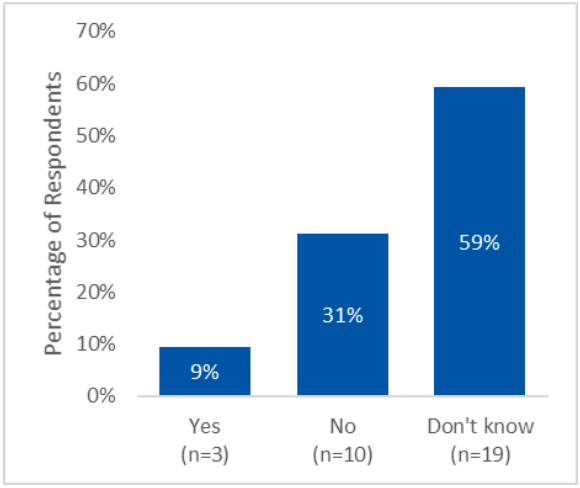


Source: Heat Pump Multifamily Tenant Survey Guide Question C2. "How would you rate each of the following installation experiences with the heat pump offering?"

Participant Usage, Behavior, and Experience

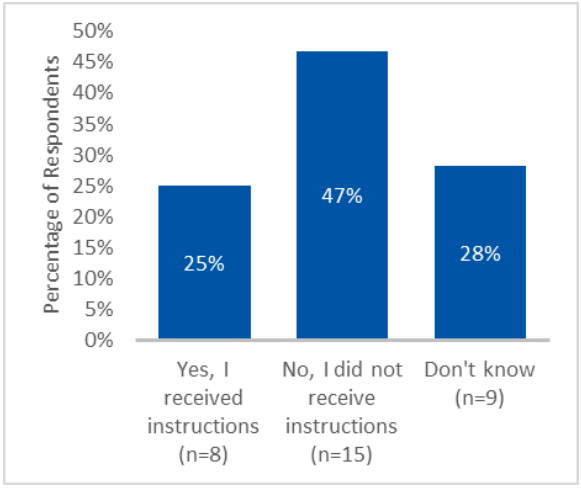
Participant usage, behavior, and experience with this offering were influenced by the installation technicians and education surrounding the CCHP equipment installation. Only three respondents could confirm with certainty that the technician set up a heating and cooling schedule for their heat pump (Figure 13). These three participants also confirmed that the heating and cooling schedule set up by the contractor is still in operation. Lack of heat pump education, materials, and follow up were common among respondents. Forty-seven percent of participants (n=15) reported not receiving documentation or instructions about the heat pumps, while 28% (n=9) did not know if they received instructions and 25% (n=8) did receive instructions (Figure 14). Other survey respondents indicated in open-ended responses that there was a lack of information relayed about the heat pumps, either from installation technicians, the PMOs, Consumers Energy, or a combination of the three.

Figure 13. Heating and Cooling Schedules



Source: Heat Pump Multifamily Tenant Survey Guide Question C16. "Did the installation technician set up your heat pump on a heating and cooling schedule?"

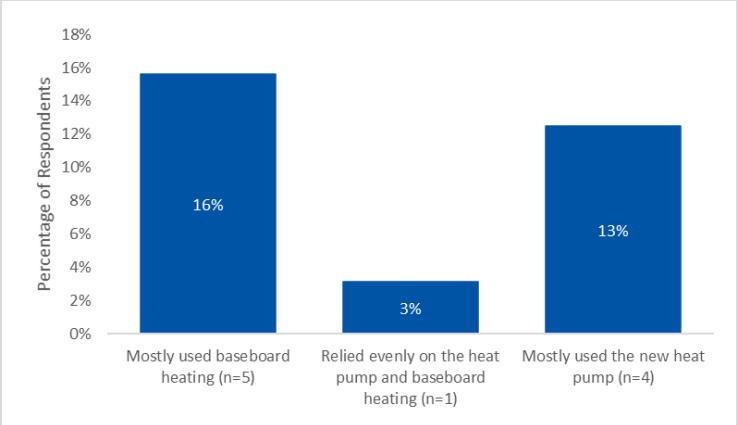
Figure 14. Instructions Provided at Installation



Source: Heat Pump Multifamily Tenant Survey Guide Question C18. "Have you been provided with instructions on how to set up and control your heating and cooling schedule on your heat pump?"

Sixteen percent (n=5) of participants reported using mostly baseboard heating after installation, while 13% (n=4) reported using mostly the newly installed heat pump and 3% (n=1) reported using both evenly. Another 68% (n=22) of participants did not know which heating source they relied on.

Figure 15. Primary Multifamily Tenant Apartment Heating Source



Source: Heat Pump Multifamily Tenant Survey Guide Question C12. "Which of the following best describes how you heated your apartment last winter?"

In open-ended responses, some tenants were unhappy with the lack of information:

- "After the installation, there was not follow up. Also, there are many in our complex that have no idea on how to set up the mobile app."
- "Manager of my complex did not [educate] me on how to use all the features. Also, when and who changes the filters, if any."

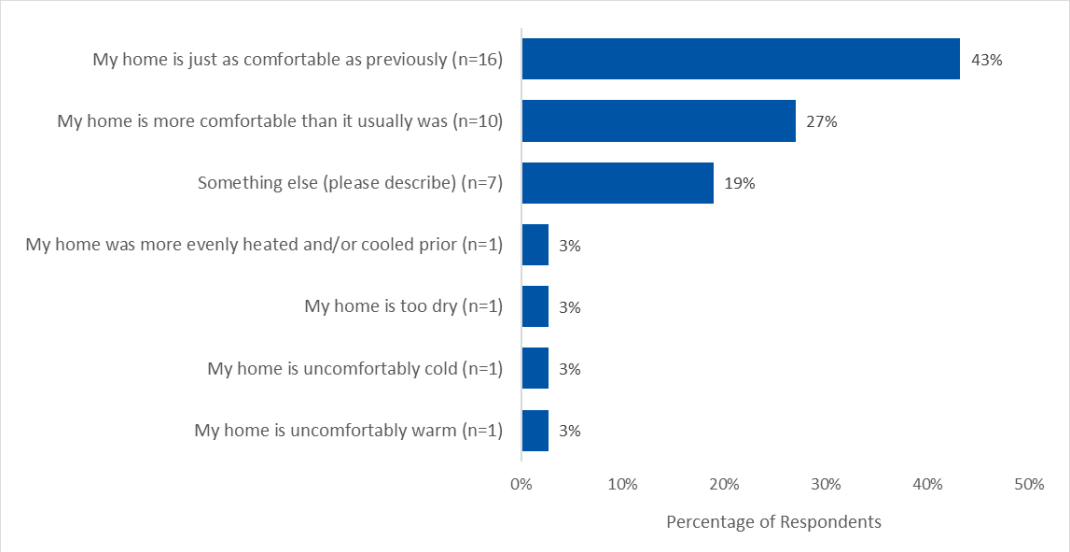
Awareness and Perceptions of Heat Pumps

Most participants (68%; n=21) reported a complete lack of knowledge regarding heat pumps, even after installation. More interestingly, half were not aware that there was a heat pump installed in their apartment, despite having occupied the unit at the time of installation. Of the half that were aware of the heat pump installation, 56% (n=9) did not know Consumers Energy was involved in the project. In an open-ended response, one participant was surprised: "I didn't know anything about how to run the heat pump or maintenance needed. We weren't told anything. We didn't even know Consumers [Energy] funded it."

Perceptions of Heat Pump Impact on Comfort Levels and Electricity Bills

As noted above, PMOs indicated tenant comfort was a key factor in the decision to participate in the heat pump initiative—some tenants supported this perception. Post-installation, although 43% of tenants reported their homes to be as comfortable as before, one-quarter of tenant survey respondents reported increased comfort (27%). Specifically, few tenants reported issues with temperature or humidity regulation, as shown in Figure 16.

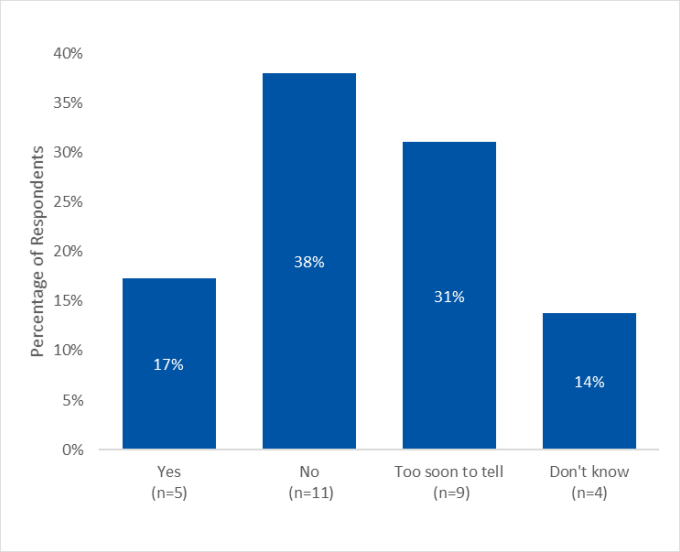
Figure 16. Heat Pumps and Home Comfort



Source: Heat Pump Multifamily Tenant Survey Guide Question C11. "In general, how did the heat pump affect your home comfort?"

Over twice as many income-qualified multifmaily respondents believed they did not experience any savings on their energy bills as those who believed they did experience savings: 38% of respondents (n=11) reported no savings on their energy bills, compared to 17% (n=5) who reported savings (Figure 17).

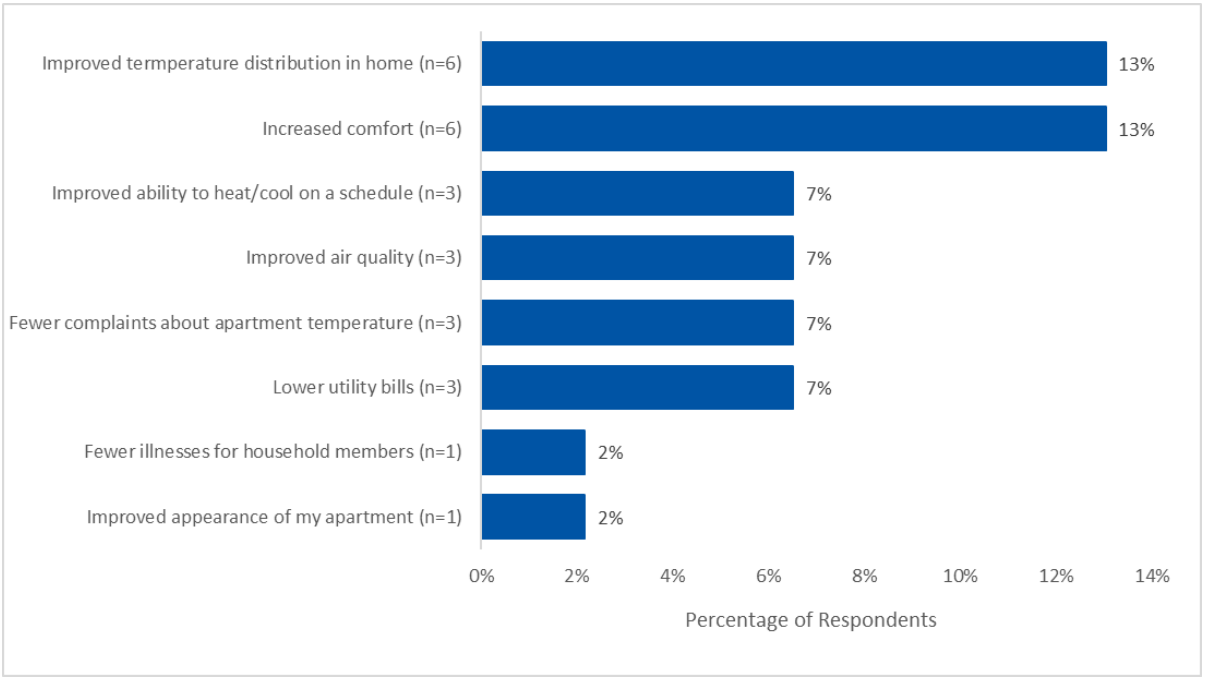
Figure 17. Multifamily Tenant Energy Bill Savings



Source: Heat Pump Multifamily Tenant Survey Guide Question D2. "Have you seen a lower-than-expected energy bill?"

Even with few respondents believing the CCHPs resulted in bill savings, a high number reported non-energy saving benefits of the CCHPs, primarily related to temperature distribution and comfort (Figure 18).

Figure 18. Non-Energy Benefits



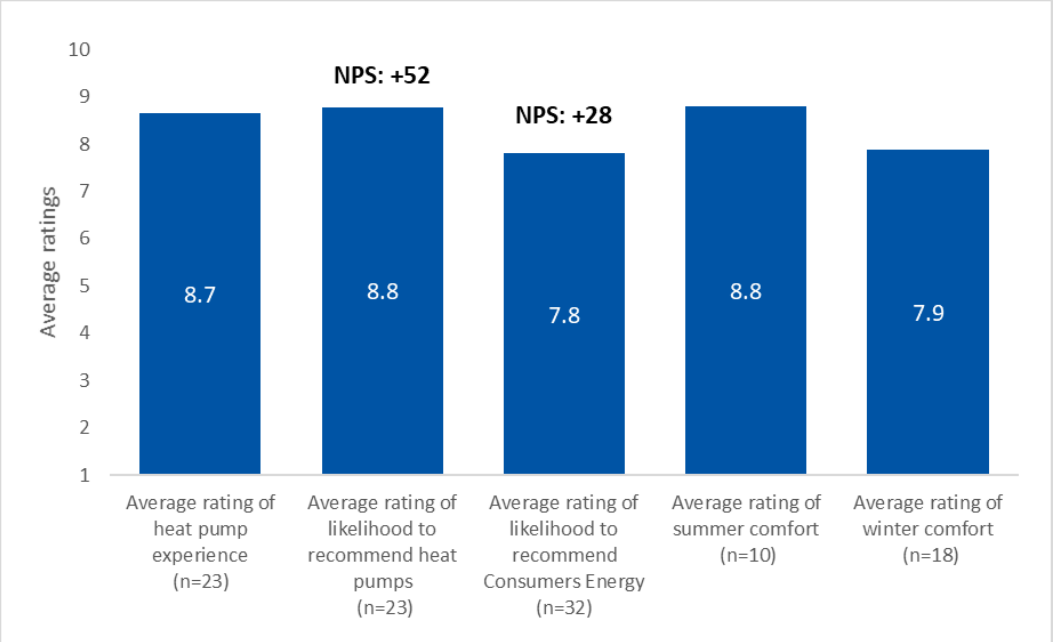
Source: Heat Pump Multifamily Tenant Survey Guide Question D3. "In addition to energy savings, if any, are there other benefits that you have experienced or observed from the installation of heat pumps?"

Satisfaction with the Offering and with Consumers Energy

Income-qualified multifamily tenants were satisfied with the CCHP experience, and generally felt that the heat pumps provided improved winter heating and summer cooling comfort. CCHP multifamily tenant participants reported an average rating of 8.7 regarding their overall experience with the heat pump, an average of 8.8 rating on likelihood to recommend a heat pump to a friend, and an average of 7.8 rating on likelihood to recommend Consumers Energy, all on a 10-point scale where 1 meant *unacceptable* or *extremely unlikely* and 10 meant *outstanding* or *extremely likely* (Figure 19). Respondents also reported an average rating of 8.8 regarding summer comfort and 7.9 regarding winter comfort.

Another key measure of customer satisfaction is the percentage of customers who are highly likely to recommend a product, service, or company after subtracting the percentage of customers who are highly unlikely to recommend that same product, service, or company. The net percentage of those willing to promote the product is the net promoter score (NPS), expressed as an absolute number between -100 and +100 that represents the difference between the percentage of promoters (respondents giving a rating of 9 or 10) and the percentage of detractors (respondents giving a rating of 1 to 6). The Cadmus team calculated a NPS for the two likelihood to recommend questions (likelihood to recommend the CCHPs and likelihood to recommend Consumers Energy – see Figure 19 below).

Figure 19. Satisfaction with Cold-Climate Heat Pump Experience and Comfort



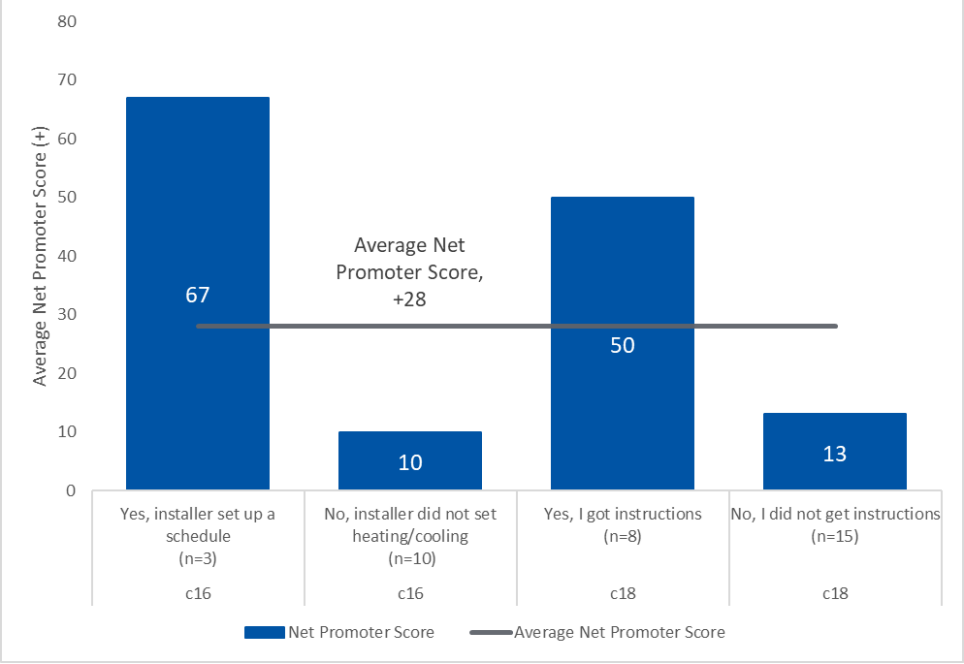
Source: Heat Pump Multifamily Tenant Survey Guide Questions E1, E2, A1, C9, and C6. Please see *Appendix E* for specific question wording.
This figure reflects combined average satisfaction ratings of heat pump experience and comfort.

The Evaluation team also calculated a NPS for the two likelihood to recommend questions (likelihood to recommend the CCHPs and likelihood to recommend Consumers Energy). As shown in Figure 19, based

on experiences with the heat pump, respondents were somewhat likely to recommend the heat pump to a friend. Though 14 respondents were promoters (providing ratings of 10) and only two were detractors, nine respondents did not provide a rating and seven were passives. The resulting NPS for the heat pump was +52. Sixteen respondents provided a 9 or 10 rating for likelihood to recommend Consumers Energy to a friend while seven provided ratings below a 7 and were classified as detractors (nine respondents were classified as passives). The resulting NPS for Consumers Energy was +28.

The Evaluation team compared the Consumers Energy NPS across different participant groups (Figure 20). Participants who provided low ratings on installation communication and instructions and provided verbatim feedback around lack of education materials and instructions were more likely to provide a lower overall Consumers Energy NPS. In fact, this cohort on average provided the lowest ratings of all participants. Additionally, participants who received instructions or had their heating and cooling schedule set by installation technicians had a higher NPS on average than both the survey average and the average of those who had no instructions or schedule set.

Figure 20. Average Consumers Energy Net Promoter Score and Installation Satisfaction



Source: Heat Pump Tenant Survey Guide Questions A1, C16, and C18. “How likely would you be to recommend Consumers Energy to a friend or family member if you had a choice in energy providers?” “Did the installation technician set up your heat pump on a heating and cooling schedule?” and “Have you been provided with instructions on how to setup and control your heating and cooling schedule on your heat pump?”

Open-ended responses regarding Consumers Energy were primarily positive in nature, though some were frustrated with Consumers Energy's service, mostly reporting high bills:

- "Great customer service and payment plans. But the cost in the winter is way higher than I think it should be."
- "My bill was all over the place last winter reaching almost $300 between two small school-aged kids who were gone most of the day and myself who unplugs everything."
- "Because I'm low income with social security income where there's no assistance help for my electric bill, the bill can be extremely expensive."

Nearly all positive responses cited great customer service and the ease of payment:

- "Service has been great for me in as long as I've been with them."
- "Good service and consistent customer service."
- "Very easy online payments and very easy outage center updates. It's also nice to have those text and email reminders about billing."

Impact Analysis

This section summarizes findings from the Evaluation team's statistical billing analysis, conducted to determine electric energy savings resulting from the Income Qualified Multifamily initiative. While the focus of the initiative and the billing analysis were on electric-heated properties (and therefore on electric impacts on heating use during the winter heating season), the Evaluation team also used the billing analysis to determine the electric energy impacts associated with summer cooling season. *Appendix B* has a detailed discussion of the methodological approach we used to determine the energy savings.

Key Findings

The Evaluation team estimated the electric energy impacts of CCHP installations separately for winter electric heating and summer cooling impacts. The Income Qualified Multifamily initiative participant electric savings results, presented in Table 10, show winter electric heating energy savings of 832 kWh, equivalent to 22.9% of baseline weather-sensitive electric heating use.

Table 10. Multifamily Income Qualified Heat Pump Electric Energy Savings

Group	Weather-Sensitive Electric Usage (kWh)		Weather-Sensitive Electric Savings		Precision at 90%
	Pre-Period	Post-Period	kWh	Percentage	
Winter heating	3,626	2,794	832	22.9%	±9%
Summer cooling	234	170	64	27.1%	±24%
Total Annual (Weather Sensitive)	3,860	2,964	896	23.2%	±8%

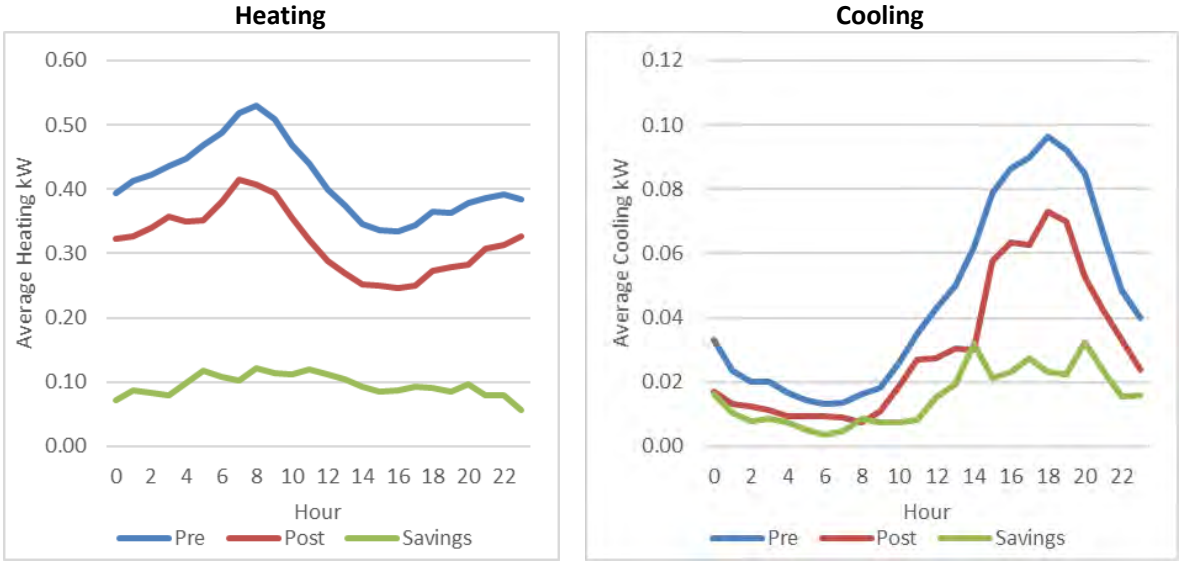
Source: Evaluation team billing analysis.

The billing analysis estimate of 64 kWh savings per unit during the summer cooling season reflected a similar percentage reduction in weather-sensitive electric usage attributable to the CCHPs (at 27%

relative to the 23% for winter heating). The heating electric analysis produced savings estimates within the ±10% precision threshold at a 90% confidence interval and therefore the results were statistically significant. Given the lower cooling load and therefore more variable signal, the cooling savings were outside the ±10% precision target. Overall, the Income Qualified Multifamily initiative resulted in a statistically significant annual reduction of 896 kWh for each participant tenant unit, representing 23.2% of the annual weather-sensitive electric energy use and translating into approximately $147 in annual bill savings for each CCHP participant.

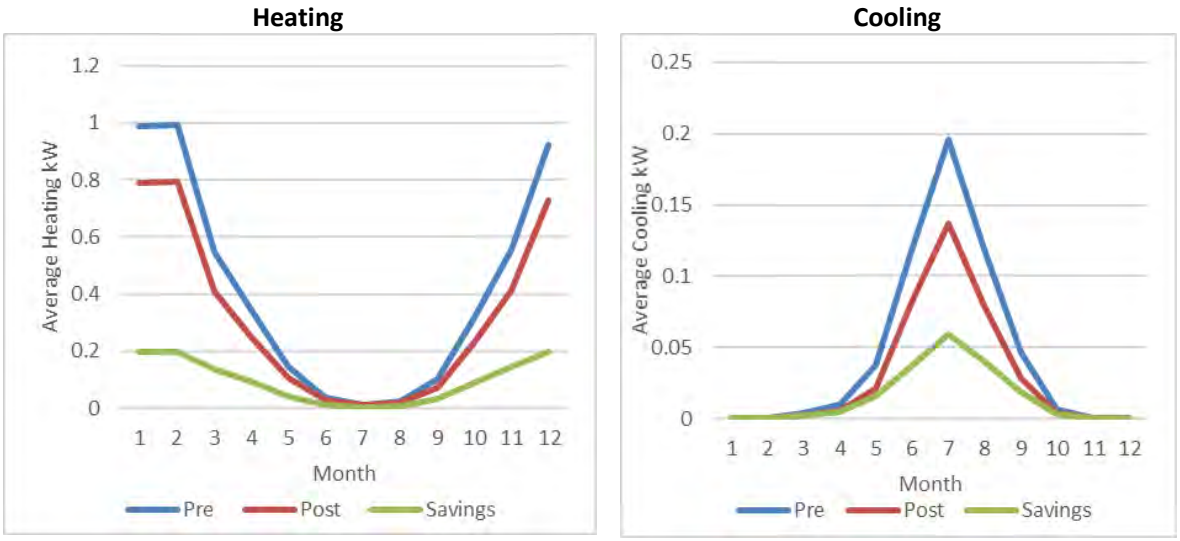
An examination of the heating and cooling load shapes and accompanying savings profile offers insight into how the CCHP impacted heating and cooling usage. Figure 21 shows the average winter and summer daily load shape and resulting CCHP savings profiles. In the winter, participants' CCHP electric energy savings were relatively consistent throughout the day. In the summer, the CCHP cooling savings were coincident with the cooling load periods of mid-to-late afternoons.

Figure 21. Participant Hourly Heating and Cooling Load and Resulting Savings



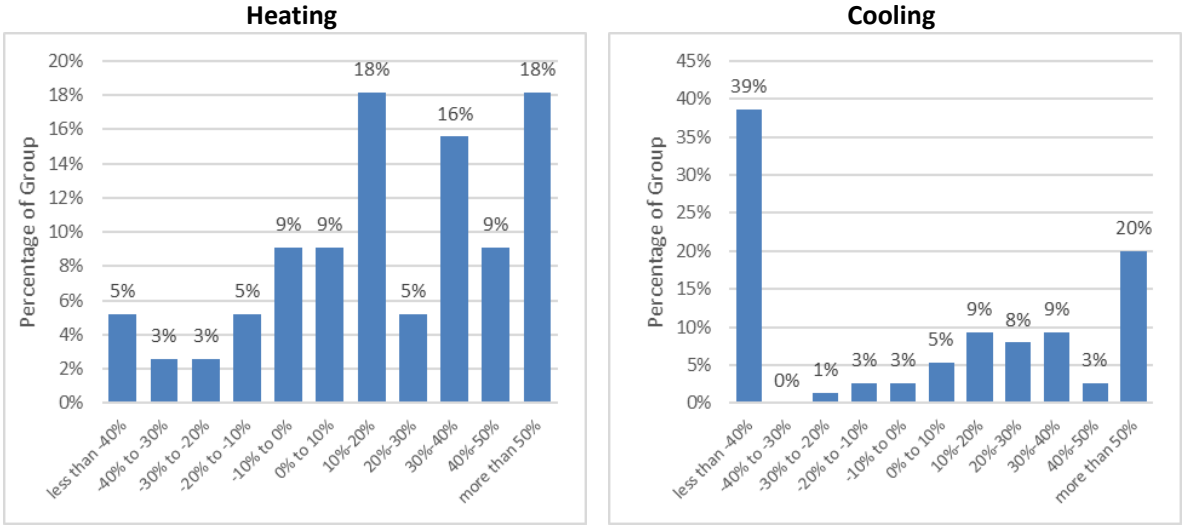
An examination of the average *monthly* load and savings profiles also showed that the savings were consistent with the monthly load shapes (Figure 22).

Figure 22. Monthly Heating and Cooling Load and Resulting Savings



The Evaluation team also explored the variability of savings across the tenant units by grouping the percentage of tenant units according to decile savings bins (incremental steps of 10% savings; see Figure 23). More than 40% of the Income Qualified Multifamily tenants saved over 30% of their pre-installation electric energy during the winter heating season, while the largest group of customers (18%) saved over 50%. On the summer cooling analysis, close to 40% of Income Qualified Multifamily customers had a net increase in summer electric use. These customers likely lacked any pre-installation cooling equipment (no room ACs) or were unlikely to have used their equipment. The second largest group of customers were also the highest saving group, with 20% of the tenants saving over 50% of their pre-installation summer cooling electricity usage.

Figure 23. Percentage Distribution of Annual Heating and Cooling Savings by Savings Bin



Benchmarking of Results

The Evaluation team compiled results from three recent multifamily heat pump retrofit program evaluations in other regions to understand how the results compared to the Consumers Energy Income Qualified Multifamily initiative. A majority of the evaluations were focused on income-qualified properties. As shown by the summary benchmark data in Table 11, the Income Qualified Multifamily initiative findings are consistent with other multifamily income-qualified billing analysis results.

Table 11. Benchmarking of Multifamily Heat Pump Billing Analysis Results

Utility and Program	Percentage Savings	Home Type	Income	Analysis Type
Consumers Energy Income Qualified Multifamily initiative	**23.2%**	**Multifamily**	**IQ**	**Billing Analysis**
2020 Commonwealth Edison Multifamily Income-Qualified Heat Pump pilot (full report not yet public but summary report is here)	25%	Multifamily	IQ	Billing Analysis
2016 Efficiency Maine Low-Income Multifamily Weatherization program (report)	22.2%	Multifamily	IQ	Billing Analysis
2014 Connecticut Energy Efficiency Fund Home Energy Services (Income Eligible) (report available online)	11% [a]	Multifamily	IQ	Billing Analysis
2014 Energy Trust of Oregon Multifamily Ductless Retrofits (report available online)	15% [a]	Multifamily	Any	Billing Analysis
Puget Sound Energy Heat Pump Dealer Channel (not public)	18% [a]	Single Family	Any	Billing Analysis

[a] This represents the percentage of annual load, not the percentage of weather-sensitive load (which was not reported).

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Commercial and Industrial Cold-Climate Heat Pump Pilot Findings

Consumers Energy developed its Commercial and Industrial Cold Climate Heat Pump Pilot initiative in 2020 in response to the 2020 Consumers Energy Settlement Agreement with the Michigan Public Service Commission and other stakeholders. Beginning in early 2021, Consumers Energy launched the initiative targeting small commercial and industrial customers, defined as customers with facilities under 20,000 square feet. Initiative staff reached out to customers who did not have access to natural gas or were suspected to have propane heat. Staff then helped these customers choose a contractor to install a CCHP, addressed any questions the participants had throughout the installation process, and provided significant financial support to install new CCHPs; all but one customer had the entire cost fully covered.

For this research, the Evaluation team conducted in-depth telephone interviews with initiative participants to address several key research objectives:

- Explore key factors in customer decision-making regarding CCHP installations
- Explore customer experiences during the CCHP installation process
- Explore customer experiences using their CCHP
- Explore customer experiences with the initiative offering
- Identify opportunities to best support CCHP technology moving forward

In the fall of 2021, the Evaluation team conducted in-depth interviews with seven of the nine initiative participants, asking about heat pump technology awareness and motivations for participation, as well as participant experiences and satisfaction throughout the initiative process and with their new heat pump technology. During the winter of 2021/2022, the Evaluation team also metered the equipment to assess energy savings. Findings from this research are found in the 2021 Cold Climate Heat Pump Pilot Impact Evaluation Memo submitted as part of Consumers Energy's 2021 reconciliation. Metering for the 2022 cooling season is still in progress as of the writing of the report, and analysis and reporting will take place later in 2022.The remainder of this section presents findings from the participant interviews.

Participant Interviews Findings

In Fall 2021, the Evaluation team conducted in-depth interviews with seven Small C&I Initiative participants who were either the business owner or a key decision-maker related to the business. The subsections below describe how customers heard of and then decided to participate in the initiative offering, followed by installation experiences, heat pump use experiences, and overall initiative experiences and satisfaction. Additional details are available in the *C&I 2021 Cold Climate Heat Pump Pilot Customer Interview Results Presentation* submitted as part of Consumers Energy's 2021 reconciliation.

Decision-Making Processes

The Evaluation team asked participants about their awareness and understanding of heat pump technology, their plans to replace existing heating equipment, as well as their concerns, considerations, and motivations for installing the heat pumps.

Participants in the Small Commercial initiative were generally not familiar with heat pumps prior to being contacted by Consumers Energy staff. Over two-thirds of respondents (71%; n=5) were *not at all familiar* with heat pumps prior to the initiative. One respondent said they were *somewhat familiar* and had read some articles about heat pumps, but not enough to have purchased a heat pump without the support from the initiative. Another respondent said they were *very familiar* with the technology, but was under the impression that heat pumps were not suitable for Michigan winters.

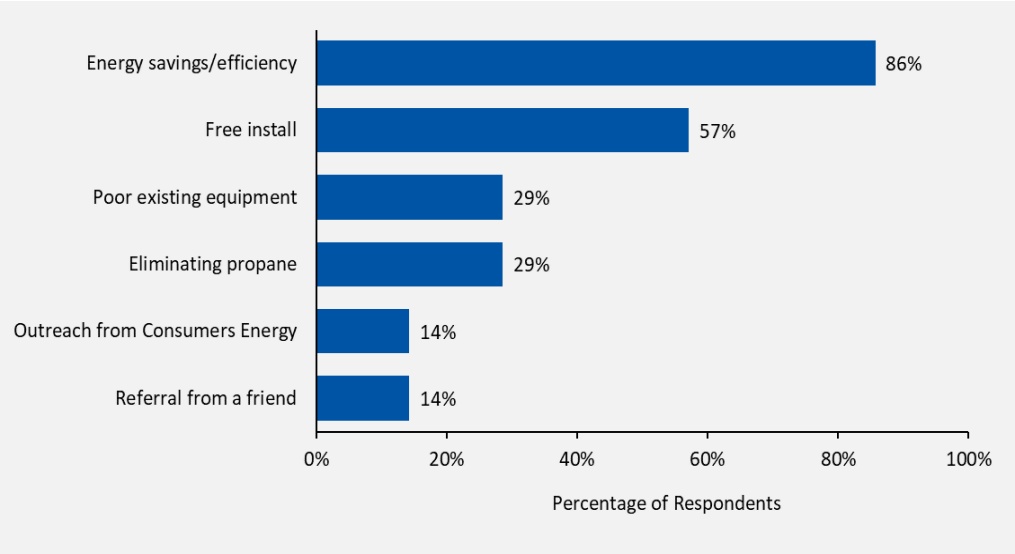
When asked about their existing heating and cooling equipment, all respondents reported having a propane furnace prior to installing their heat pumps, and 86% (n=6) had central AC. While four respondents had no immediate plans to replace their existing equipment, 43% (n=3) had planned to replace their heating equipment within the next one to three years, and all three would likely have replaced their furnace with a new propane furnace. This finding suggests that customers likely would not have considered a heat pump as an option if not for the initiative, despite some respondents reporting low satisfaction with their propane service.

When asked about their concerns and considerations when deciding to install a heat pump, respondents were primarily concerned about cost and technical considerations, while two respondents (29%) initially thought the offer was a scam: one said, “My main thing was, to be honest, I was scratching my head if it was too good to be true. I was suspicious; there are so many scams. My biggest concern [was that] I just wasn’t quite sure what was actually going on. It’s quite a good deal to get that kind of equipment.”

Respondents’ cost considerations included not knowing how much more money they would pay by switching to a heat pump, as well as how much lower their energy bill would be and how much less energy they would use. Three respondents also expressed concerns about how reliable the heat pumps would be during the winter. The following quote exemplifies this sentiment and demonstrates how this hesitancy is related to a lack of knowledge about CCHPs: “…Without knowing about the technology, we were a little concerned…about how well would the systems work in the really cold weather.”

When asked what motivated them to install their heat pump, respondents reported several motivations, mainly saving energy and the free installation, followed by the fact that the cost was largely if not completely covered by Consumers Energy (Figure 24).

Figure 24. Respondent Motivations to Install Heat Pumps



Source: Heat Pump Commercial Interview Guide Question C4. "What motivated you to agree to install the heat pump?" (n=7; multiple responses allowed)

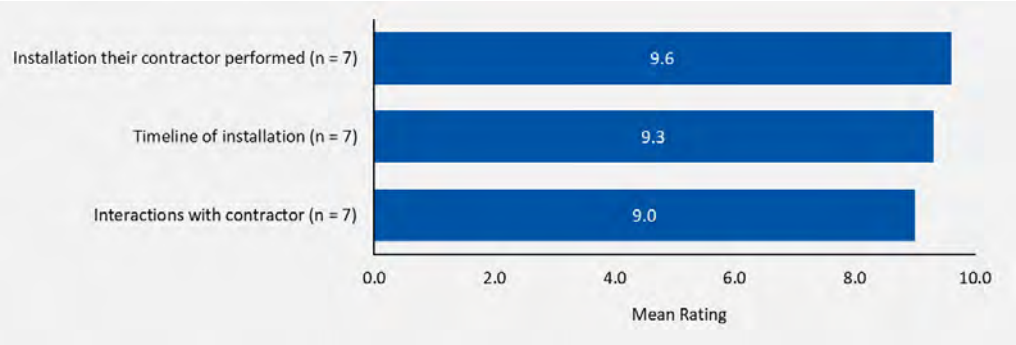
Installation Experiences

The Evaluation team also asked respondents about their experiences with finding a contractor and with having the heat pump installed. All respondents reported that it was easy to find a contractor, and none asked for multiple bids. About half of respondents (43%; n=3) preferred to use their own contractor and one respondent (14%) asked a friend who had also participated in the initiative for their contact. The other three respondents (43%) relied on contractor contacts provided by Consumers Energy: two chose a contractor they were familiar with from the list (and, as mentioned previously, Consumers Energy tailored this list to include trade partners they knew had experience with heat pumps). These findings indicate that the initiative resources for finding a contractor were effective.

Overall, respondents reported having a positive experience with their contractor, with 86% (n=6) saying they would use the same contractor again. All the respondents also reported that the contractors they worked with appeared to be knowledgeable about heat pumps, and 57% (n=4) said the contractor was *very knowledgeable*: "Extremely [knowledgeable] and very helpful and explained it all to me very well… They were fast, efficient, and did exactly what they were going to do in the time they said they were going to do it. They did a great job."

Average satisfaction with contractor interactions was a 9 on 10-point scale, where 1 meant *unacceptable* and 10 meant *outstanding* (as shown in Figure 25). Though respondents were generally satisfied with their contractors, two of the seven respondents (29%) expressed some dissatisfaction. One of these respondents specified that the contractor should have been more communicative about the project schedule and timeline but said they would still hire the contractor again because they would not know who else to hire. The other respondent was less satisfied with their interactions with the contractor and were not sure they would hire them again.

Figure 25. Installation Experiences Satisfaction Averages



Source: Heat Pump Commercial Interview Guide Questions G1a, G1b, and G1d. Please see *Appendix F* for specific question wording.

Respondents were also satisfied with the timeline of their installation. While about half of respondents (57%; n=4) reported some delay with their project timeline, it did not impact their overall satisfaction. However, some reported that if the installation had occurred during a time when they needed their heating or cooling, they would have been more dissatisfied. Heating or cooling needs were not pressing since these customers either had working equipment or their installation was completed in the shoulder season, as evident by the following statements:

- "It might have been different if we didn't have heat or air and every day was a struggle, but it was early spring… so it wasn't an issue, so we weren't pressed to hurry up and get this into service."
- "I'm glad they didn't do it in the winter, because then I would have been irritated [with the delayed project timeline]."

Most of the heat pump installations went smoothly, with respondents rating their satisfaction with the installation process as an average of 9.6 out of 10, as shown in Figure 25. When asked if there were any challenges with installing their heat pump, only two respondents reported some minor challenges related to the equipment not functioning properly at first and unforeseen installation issues. All respondents said that they received a new thermostat as part of their CCHP installation, and about half (43%; n=3) required new duct work. Slightly more than half of respondents (57%; n=4) reported that they have a back-up heating system in addition to the CCHP system. Of those four, two kept their old heating and cooling equipment, one just kept their old back-up heating, and one installed a new propane furnace as a back-up.

Experiences Using Heat Pumps

Due to the timing of this initiative and the research effort, respondents had primarily used their heat pump during the summer months and had used only the cooling function; however, some respondents (71%; n=5) reported that the heating function had come on during colder mornings in September or said they had been able to use the heat briefly in early spring. In general, respondents were very satisfied with their new heat pump and its operation, with an average satisfaction rating of 9.3 out of 10. While respondents were already generally satisfied with the equipment, a few customers noted being hesitant

to give the heat pump a higher rating until after using the heating function more consistently in colder weather. The Evaluation team conducted follow up interviews with Small Commercial initiative participants as part of on-site impact evaluations completed following the 2021/2022 winter heating season to assess participant experiences with the heat pumps in cold weather. [17]

Despite high satisfaction with heat pump performance, almost half of respondents (43%; n=3) reported some minor issues with their heat pumps, including not cooling down to the expected temperature and two issues with the installation that required a contractor to fix. The biggest challenge customers reported was needing to learn how to use their new smart thermostat; this finding was echoed in the winter heating impact analysis, which revealed that some customers would benefit from additional training or support to optimize heat pump controls and settings to maximize savings. These findings suggests that customers easily adapted to their new technology but could use some higher touch support during the first few weeks or months after installation to confirm that all the equipment is performing well and that the customer knows how to use the equipment properly.

Initiative Experiences and Satisfaction

When asked about their overall initiative experience, most respondents said they were *very satisfied* with their participation in the initiative. Most respondents (86%, n=6) had initially learned about the initiative offering from Consumers Energy staff and all seven reported that they had received excellent support throughout their participation. While respondent motivations for deciding to participate in the initiative included the fact that the equipment and installation were free, the support and persistence from Consumers Energy staff was also a motivating factor.

> "Just the willingness that they had to do this for just a small [facility] was huge […] People don't just give stuff away, and [a new heating system] was definitely something that was needed, and we would have had to purchase it in the future."
>
> -Respondent

Respondents' overall satisfaction with the pilot was an average of 9.9 out of 10, and 86% of respondents (n=6) *strongly agreed* that Consumers Energy made it easy to participate in the initiative. When asked if they were likely to recommend Consumers Energy to a friend or colleague if they had a choice in energy providers, most respondents (71%; n=5) said they were extremely likely to do so. The two respondents who gave lower ratings said that it was only because their utility is not something they really think or talk about. One satisfied respondent compared Consumers Energy to the utility that provides electricity at their home: "I've always had great service with Consumers [Energy]. I've had less outages and …anything I need for my business, I'm able to get immediate responses."

[17] TRC. 2022. C&I 2021 Cold Climate Heat Pump Pilot Impact Evaluation Memo.

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Appendix A. Survey and Interview Methodology and Details

This appendix provides survey and interview details and methodologies by initiative or stakeholder.

Contractor Interviews

Consumers Energy provided the Evaluation team with a sample of 177 contractors who had engaged with Consumers Energy HVAC energy waste reduction offerings at some point, but who had not participated in the CCHP Initiatives. The sample did not include any information regarding the number or type of projects completed by the contractor, so the Evaluation team was unable to stratify the sample in any meaningful way. As such, recruitment of contractors proceeded randomly until research quotas were satisfied. We interviewed a total of 11 contractors for this research.

Table A-1 includes contractors' company information such as type, number of projects per year, and products offered.

Table A-1. Interviewed Contractor List

Company Location	Customer Base	Number of Projects/Year	Average Heat Pump Installation/Year
Ada	Primarily residential, more high-end homes	~100	<5 ducted systems >20 mini-splits
Allen Park	Residential multifamily, some single family, very little commercial	1,000–1,500	75 since last fall
Allendale	Data not collected	Data not collected	Data not collected
Benzonia	90% to 95% residential, lots of big homes on shore of Lake Michigan used as seasonal residences; a little bit of multifamily, a little low income	200 installs	20–30
Dearborn Heights	Mostly residential, some multifamily	100	3 last year
Jackson	50% residential, 50% commercial	200–225	6–8 ducted systems >50 mini-splits
Livonia	Primarily (75% or more) income-qualified multifamily, with client that is the largest affordable housing provider in Michigan	5–10 projects per year 100–300 pieces of equipment	10–20 mini-splits per year (primarily server rooms and elevator machine rooms)
Okemos	60% residential and 40% commercial, lots in the city, also lots of dual-fuel applications with propane and lots of air-to-air and geothermal projects	~1,000	~100 in 2020, 80% air-to-air 24 mini-splits in the past year
Parma	Residential and some multifamily (very little commercial)	150–200 pieces of equipment	<10
Sparta	75% residential, commercial is mostly service maintenance, with a rare design/build	~100	12–15 per year for ASHPs and mini-splits.
Warren	50% residential and 50% commercial	200	<5

Distributor and Manufacturer Interviews

The Evaluation team interviewed five distributors and two manufacturers involved in the production and distribution of CCHPs (including mini-split heat pumps) in Michigan. We fielded the interviews via telephone, and each took 30 to 45 minutes to complete. The team recorded and transcribed each interview to assist with our analysis. To motivate manufacturers and distributors to participate, we offered a $75 incentive to each respondent in the form of an Amazon, Target, or Meijer gift card or a donation to a local United Way.

Sampling

For this effort, the Evaluation team specifically targeted manufacturers who have supplied equipment for Consumers Energy programs and associated distributors in Michigan that supply CCHPs produced by these manufacturers. The list of manufacturers and distributors interviewed is shown in Table A-2.

Table A-2. Interviewed Distributor and Manufacturer List

Company Type	Role of Interviewee	Primary Brands Offered	Primary Types Offered	States/Regions Served
Manufacturer	Manager, Utility & Efficiency Programs	(Confidential)	Mini-split	Central U.S.
Manufacturer	Regional Representative	(Confidential)	Mini-split	MI, OH, PA, WV
Distributor	President	Robur	Absorption	MI, OH, IN
Distributor	Director of HVAC Services	Mitsubishi, Rheem, Trane	Mini-split	MI, OH, Eastern U.S.
Distributor	Territory Manager	Trane, Mitsubishi	Mini-split, unitary	MI
Distributor	Regional Sales Manager	LG, Rheem, Bosch	Mini-split, unitary	MI, OH, IN, PA, WV
Distributor	Owner	Daikin, Amana	Mini-split, unitary	MI, WI, IL, IN, OH, PA

The team sampled distributors from a contact list provided by Consumers Energy staff as well as from internet searches for distributors associated with key manufacturers. Additionally, the Evaluation team asked for referrals for distributors during interviews with contractors. We targeted distributors such that representation across manufacturers was roughly equal (ensuring that interviewed distributors do not represent one manufacturer more than another).

Recruiting

The Evaluation team reached out to manufacturers and distributors by phone to schedule interviews. During phone recruitment, we explained the research and provided an Evaluation team contact person so the organization could reach out if they had additional questions or were interested in scheduling an interview. The team primarily used email to recruit referrals, which similarly included an explanation of the research and a request for scheduling an interview.

Profile of Distributors and Manufacturers

Table A-2 above shows respondent information including company type, the role of the interviewee at the company, primary brands offered, types of CCHPs offered, and regions served. Most interviewees represented mini-split CCHP technology and were responsible for operations in several states.

Residential Market Rate Participant Surveys

The Evaluation team sent a survey invitation to the census of 29 Residential Market Rate pilot participants in November 2021. The email survey invitation included a $15 incentive for taking the survey. The Evaluation team sent two reminder emails; after one week and after two weeks. Nine of the 29 participants completed the survey, for a 31% response rate: with such a small sample size, the results should be interpreted with caution and only viewed as directional indications (not intended to be analyzed with statistical confidence).

Income Qualified Multifamily Property Manager and Owner Interviews

The Evaluation team conducted in-depth telephone interviews with three site contacts (a construction manager, a resident manager, and an owner) in November 2021. Each interview lasted approximate 30 minutes. We targeted owners and managers of income-qualified multifamily properties who had participated in the Consumers Energy Income Qualified Multifamily initiative. Franklin Energy provided PMO contact information, including email address and phone numbers, for Evaluation team outreach and recruitment.

The Evaluation team initially distributed emails to six property site contacts and attempted phone recruitment for the seventh due to a missing email address. Though the team made three email attempts, the emails did not result in any successful recruitment for the interviews. The Evaluation team then pivoted to making recruitment calls from Monday through Friday, mid-morning to early evening, calling each number a maximum of five times.

With an interview target for a census (seven) of participating PMOs, the actual number of three interviewed PMOs was consistent with expectations, even with an increased incentive of $150 to make the interview more attractive for potential participants.

Income Qualified Single Family and Multifamily Participant Surveys

The Evaluation team collected feedback from 32 multifamily tenant surveys in November 2021. The email survey invitation included a $15 incentive for taking the online survey. We targeted tenants of income-qualified multifamily properties who had participated in the Consumers Energy heat pump offering. The Evaluation team did not have access to participating tenant contact information, so we attempted to identify tenants through two distinct efforts. First, the team relied on existing income-qualified tenant records to match CCHP properties based on physical address. Using this approach, the team identified 46 potential income-qualified multifamily tenants to recruit. Second, during the team's interviews with multifamily PMOs, we asked and all three PMOs if they were willing to distribute the survey recruitment email to their tenants. This second approach resulted in the potential for 90 additional tenant respondents, though the Evaluation team is unsure of the final count of emails distributed by the PMOs.

The Evaluation team solely relied on email distribution to recruit tenants for the online-only survey. Though the team made three email attempts for the address-matched income-qualified tenant group, the emails combined with the PMO email recruitment effort resulted in 32 successful recruitments for the surveys, for a response rate of 24% (32 of 136).

Small Commercial Participant Interviews

The Evaluation team conducted in-depth telephone interviews with seven business owners and decision-makers in September and October 2021. Each interview lasted approximately 30 to 45 minutes and we offered respondents a $75 gift card for their time. We targeted owners and decision-makers of small commercial and industrial facilities (<20,000 square feet) who had participated in the Consumers Energy Small Commercial initiative offering. Consumers Energy provided these decision-makers' contact information, including email address and phone numbers, for Evaluation team outreach and recruitment. The interview guide was reviewed and approved by Consumers Energy staff to ensure that questions were consistent with their expectations and reflected the issues of interest to Consumers Energy.

The Evaluation team recruited customers via email and phone. Due to the small sample size of nine participants, we attempted to recruit the entire sample with a minimum goal of five completes. The Evaluation team was able to recruit seven of the nine participants, with a response rate of 78%. An eighth participant was interested in participating but their heat pump had not been installed yet, so they were not able to answer questions about the full experience. The ninth participant was unreachable after a total of five contact attempts via email and voicemail.

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Appendix B. Impact Analysis Methodology and Details

This appendix provides the methodology and details related to the Residential Market Rate pilot engineering analysis and the Income Qualified Multifamily initiative billing analysis.

Market Rate Engineering Methodology

The Evaluation team conducted an engineering analysis of the impacts from the Residential Market Rate pilot and relied on MEMD assumptions and information we had collected on customer data such as such as home vintage, presence of central cooling, installed system COP at 5°F, rated HSPF and SEER, tonnage, and other data. The Evaluation team relied on the MEMD weighting tool, which generates single measure outputs based on home vintage, climate zone, sizing, and efficiency levels.

The MEMD building simulation data provided end-use level consumption details broken out by the seven Michigan climate zones (Alpena, Detroit, Lansing, Muskegon, Saginaw, Sault Ste. Marie, and Traverse City) and three building vintages (old, average, and new). The Evaluation team used the MEMD building simulation end-use consumptions for ASHP heating, ASHP electric resistance back-up heating, and ASHP cooling to calculate pre– and post–CCHP equipment consumption on a per-ton basis. We then adjusted these end-use consumptions using COP from ASHP federal standard HSPF and SEER values to reflect site-specific equipment. We used several types of CCHP-collected site data in the analysis:

- Home vintage
- Presence of central AC
- Home heating fuel type
- Home heating equipment type
- Premise zip code
- CCHP details: quantity, COP at 5°F, HSPF, SEER, and tons

Since existing space heating equipment data collection was limited to fuel type, the team assumed that existing equipment represents federal standard equipment (in AFUE) and represents a 50/50 average of boilers and furnaces, if applicable. The Evaluation team created this split because the data field for system type collected was either “Furnace/Boiler” or “Resistance.” The difference in federal standard efficiency is minimal: 0.8 for furnaces and 0.82 for boilers. Therefore, the team used 0.81 AFUE.

We also assumed that existing central cooling equipment represents the federal standard SEER value. For homes without central cooling, we assumed that a portion of homes use room or window AC units to provide a portion of cooling, and we based this portion of homes on *2015 Residential Energy Consumption Survey*[18] data for the East North Central census division. The Evaluation team used data

[18] U.S. Energy Information Administration Residential Energy Consumption Survey 2015 Data Website: https://www.eia.gov/consumption/residential/data/2015/

from the Consumers Energy 2021 *Electric Energy Waste Reduction Potential Study*[19] to develop a ratio of room AC tonnage for single family homes when compared to a central system (since the room AC unit likely did not provide cooling load equivalent to the CCHP system). Like with central ACs, we assumed the room AC efficiency to represent the federal standard EER value.

Since no sizing information was collected on the sites about the existing HVAC systems, the Evaluation team assumed equivalent kBtu per hour heating or cooling tonnage as the CCHP, except for existing room AC sizing (for which we made an adjustment). Therefore, results only reflect offset heating and cooling load by the CCHP, and not total household heating and cooling load.

We used two data points to map MEMD 2019 data to the site-specific data: "Approximate House Age" and "Premise Zip." The household age was a one-to-one match with MEMD vintages, and therefore was a simple mapping lookup. The Evaluation team mapped the zip codes nearest to the available MEMD weather station based on distance and engineering judgment for weather impacts. With these two site-specific data points—vintage and zip code—we were able to map the MEMD 2019 building simulation consumptions to each specific site.

To adjust the MEMD 2019 ASHP end-use consumptions to reflect the existing equipment on a per ton basis, the team applied COP adjustments using the federal standard definitions outlined above. To adjust the MEMD 2019 ASHP end-use consumptions to reflect the CCHP equipment, we performed a more detailed analysis (as additional equipment data was available). Using typical meteorological year version 3 (TMY3) 8760 hourly data for each MEMD modeled reference city, we performed hourly bin analysis to determine hours based on temperature bins in 5°F buckets. Assuming the HSPF value reflected performance at 47°F, the team developed a linear relationship using the COP at 5°F system performance data. We capped this linear relationship during cold temperatures to not be less than 1 COP, representing 100% electric resistance performance. Using the hourly bin analysis data by 5°F buckets and assuming CCHP heating did not occur above 65°F, the Evaluation team developed a weighted average CCHP HSPF efficiency to represent annual heating performance of the CCHP specific to the unit installed. We then used the weighted average CCHP HSPF and SEER values to adjust MEMD 2019 ASHP end-use consumptions to reflect CCHP performance on a per-ton basis. In order to represent total heating and cooling load, we multiplied the CCHP installed tonnage by the pre/post heating and cooling loads per ton.

The Evaluation team relied on Consumers Energy 2021 residential natural gas and electric marginal rates (per kilowatt-hour and per therm), which include all surcharges for single-family customers. The team used previously developed load shapes to reflect equipment usage during peak and non-peak periods for the electric bill impacts. We created annual electric fuel costs by applying each specific equipment type's consumption load shape to the peak and off-peak rates. For fuel oil and propane costs, the

[19] 2021 Energy Waste Reduction Electric Potential Study Report: https://cadmus.sharepoint.com/sites/collaboration/6409-P01/ces/Shared%20Documents/Final%20Reports/2021/Electric%20Potential%20Study/2021%20Energy%20Waste%20Reduction%20Electric%20Potential%20Study%20Report%20FINAL%202021.06.10.pdf

Evaluation team used the latest Michigan monthly data from U.S. Department of Energy resources. These fuel costs utilized in the impact analysis are shown below in Table B-1.

Table B-1. Market Rate Fuel Costs Utilized in Impact Analysis

Fuel Type	Cost
AC_Central Loadshape - Electricity with Surcharge	$0.18
AC_WallWindow Loadshape - Electricity with Surcharge	$0.18
ASHP Loadshape - Electricity with Surcharge	$0.17
ZONAL_ER_HEAT Loadshape - Electricity with Surcharge	$0.16
AC Central Load Shape - Electricity with Surcharge	$0.18 per kWh / $52.48 per MMBtu
AC Wall Window Load Shape - Electricity with Surcharge	$0.18 per kWh / $52.19 per MMBtu
ASHP Load Shape - Electricity with Surcharge	$0.17 per kWh / $48.57 per MMBtu
Zonal Heat Load Shape - Electricity with Surcharge	$0.16 per kWh / $48.18 per MMBtu
Propane	$2.44 per gallon / $26.71 per MMBtu
Fuel Oil	$3.10 per gallon / $22.56 per MMBtu
Natural Gas	$7.91 per thousand cubic feet / $7.62 per MMBtu

Sources: U.S. Energy Information Administration. Accessed on January 14, 2022. Heating Oil and Propane Update https://eia.gov/petroleum/heatingoilpropane/#itn-tabs-1
Electric and natural gas rates used from Consumers Energy.

Multifamily Billing Analysis Methodology

To estimate electric energy usage changes within the Income Qualified Multifamily initiative projects, the Evaluation team designed and conducted a statistical billing analysis. The team relied on historical advanced metering infrastructure (AMI) interval data to estimate facility-wide and per-tenant-unit savings associated with CCHP installations using the Princeton Scorekeeping Method. The team incorporated TMY3 data to normalize usage and control for weather. We also included a nonparticipant comparison group, selected from other income-qualified electrically heated multifamily nonparticipants to control for the impacts of nonprogrammatic factors (such as changes in economic conditions including COVID-19–related behavior changes).

Data Sources

The Evaluation team requested and compiled participant and household data for the CCHP billing analysis from several sources:

- ***Heat pump initiative tracking data.*** The team received initiative tracking data from the implementation contractor to identify CCHP properties. These initiative tracking data included all participants from March 2020 to December 2020, including property name, participation dates, building square footage, and heat pump efficiency and capacity ratings. The tracking data did not include specific tenant unit addresses or the specific account information connected with each tenant.
- ***Multifamily composite database.*** The team developed a multifamily database to identify multifamily properties based on property size for prior 2020 evaluation research, which we used to identify all unique addresses (and all accounts associated with each property), including tenant units.

- ***Electric AMI data.*** Consumers Energy provided electric AMI data for all properties that had identifiable account data. This included meter read dates and times and all kilowatt-hour usage, by account, between June 2019 and September 2021.
- ***Michigan weather data.*** The team collected average hourly temperatures from June 2019 through September 2021 for four weather stations corresponding to the nearest monitoring station locations associated with CCHP participants. We matched hourly heating degree hours (HDHs) and cooling degree hours (CDHs) to AMI data read dates and times, and compiled hourly TMY3 15-year normal weather averages from 1991 through 2005 from the National Oceanic and Atmospheric Administration to assess energy usage under normal weather conditions.

Data Processing

The Evaluation team conducted several data processing steps to review, validate, and transform the raw AMI and tracking data into an analysis dataset:

- Imported and cleaned the tracking, AMI, and weather station datasets into Statistical Analysis System software
- Merged tracking and AMI datasets using account ID
- Filled in missing or zero AMI data readings with averages based on similar day-types or as the average of the previous and following hours
- Checked the hourly AMI histories for problems such as vacancies, outliers, and too many missing/interpolated readings
- Mapped each property to the nearest weather station using the property zip code
- Used hourly temperatures to determine variable base HDHs and CDHs for each station
- Merged the HDHs and CDHs onto the AMI and tracking data, using respective dates and times for each account
- Matched TMY3 HDHs and CDHs from the nearest station to weather-normalize the AMI data

Participant and Nonparticipant Groups

For the AMI analysis, the Evaluation team assigned properties into participant and nonparticipant groups. To be selected for the participant group, all multifamily heat pump properties had to have a continuous nine-month period of available usage data both before and after their participation in the pilot. The team used a rolling specification to assign pre- and post-periods, identifying a range of months around the installation period for each participant. Starting with a census of participants from the March through December 2020 period (initially seven properties), the Evaluation team identified a final participant group for analysis (after screening for participants who had at least nine months of pre-period and post-period billing data). We conducted account-level reviews of pre- and post-period usage for all individual participants to identify anomalies (periods of vacancies or other anomalies) that could bias the results. The team also applied additional screening criteria, described in detail in the *Data Screening and Model Attrition* section.

The team used a comparison group of nonparticipants to account for exogenous factors that may have occurred coincident with heat pump initiative activities. These factors can include macroeconomic effects, COVID-related behavior or occupancy changes, or other interactions that may have affected energy usage outside the heat pump influence. The Evaluation team identified comparison groups using customers who we had identified as living in income-qualified electrically heated multifamily properties. After creating the eligible group of nonparticipants, we further refined the nonparticipant group by matching each property to a participant property based on pre-installation usage. This assisted us in creating groups with baseline usage profiles as similar as possible to those of participants.

Disaggregation

Consumers Energy had the Evaluation team focus the heat pump analysis on electric-heated properties to create savings associated with reducing electric heating and cooling loads. Because of the focus on electric heating and cooling loads, the Evaluation team disaggregated the billing data to isolate the weather-sensitive electric heating and cooling usage from overall annual electric usage (which may include water heating, cooking, plug load, and lighting usage). First, we estimated weather-normalization models for each customer in the pre- and post-installation periods using actual observed weather data. Then we estimated the weather-sensitive components of electric usage using TMY3 data. Finally, we estimated the heating- and cooling-related components of usage.

Data Screening and Model Attrition

Data anomalies, outliers, missing data points, incomplete records, and other data issues all introduce potential bias into a billing analysis. The Evaluation team used several rules to flag and then remove accounts that failed to meet certain conditions:

- ***Must have sufficient pre- and post-installation billing data for analysis.*** All accounts had to contain a minimum of nine months of pre- and post-installation usage data.
- ***Must have a pre- and post-installation change within 70%.*** All accounts showing post-installation usage changes of up to 70% of pre-installation usage were retained in the analysis.
- Must not be an outlier or vacancy. The Evaluation team performed account-level reviews of pre- and post-installation period usage for all individual participants and removed anomalies (such as periods of vacancies) that could bias the savings results. We also removed units that participated in another energy-efficiency program from the analysis, as we could not determine which project created the observed savings.

The data screening resulted in a final analysis sample of three unique participant properties representing 77 tenant units. This corresponds to just under half (43%) of the original participating properties. As shown in Table B-2, the largest source of attrition for the billing analysis of participants originated from removing vacancies from the analysis, primarily because the billing data was only available for accounts that were active at the time of the request. Many of the accounts that were currently active did not have the necessary historical usage data at the apartment unit level to be included in the analysis. For the nonparticipant group, the single largest source of attrition resulted from units that did not show an electric heating signature.

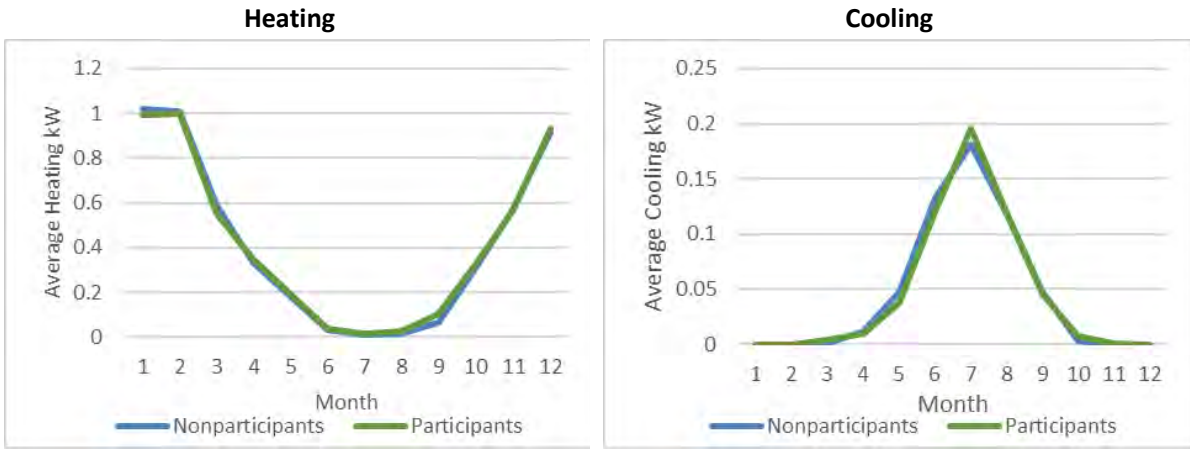
Table B-2. Income Qualified Multifamily Heat Pump Billing Analysis Summary Attrition

Screen	Participants	Nonparticipants
Initial Requested Sample	**97**	**2,329**
AMI Data Available	96	2,308
Sufficient Pre-Post Data	94	2,192
Removed Outliers/Vacancies	84	1,733
Matched Nonparticipant Property Type to Participant Property Type (such as removed high rise and mobile homes)	84	1,583
Determined that Dwelling Used Electric Heating	84	145
Passed Pre-Post Hourly PRISM Models/Hourly Prediction	84	132
Change within 70%	77	119
Matched Usage to Participants	77	112
Final	**77**	**112**

Baseline Electric Energy Use

Baseline multifamily building electric usage—the whole-building electric usage before installing energy-efficiency upgrades—is a critical input to whole-building energy savings estimation for electric-heated properties. The Evaluation team, using hourly PRISM (Princeton Scorekeeping Method) weather normalization and energy load disaggregation models, estimated the annual and monthly heating and cooling loads for the Income Qualified Multifamily participating tenant units. Additionally, estimating baseline heating and cooling energy usage across both participating and nonparticipating tenant units allows for isolating initiative-induced impacts specific to heat pump installation. This is important, as it accounts for non-programmatic influences on energy use, controlling for occupancy changes, behavior changes, changes attributable to COVID-19, and any other non-programmatic changes. A summary of the monthly average heating and cooling loads (in average kilowatts) across the participants and nonparticipant groups is shown in Figure B-1. There is little discernable difference—and, more importantly, no statistically significant difference—between participants' and nonparticipants' monthly heating and cooling loads.

Figure B-1. Baseline (Pre-Installation) Annual Heating and Cooling Load



The Evaluation team, with access to tenant apartment electric usage, estimated an average weather-normalized pre-installation baseline tenant unit usage of 3,860 kWh. Table B-3 shows the breakdown of the heating, cooling, and annual baseline pre-period annual weather-sensitive usage (per tenant apartment). As expected, given that multifamily tenant units in the CCHP were electrically heated, heating electric energy use is the predominant component (approximately 94%) of annual weather-sensitive use in these units.

Table B-3. Participant Tenant Unit Pre-Period Baseline Electric Weather-Normalized Per-Unit Usage

Usage Type	Weather-Sensitive Annual Usage (kWh)	Heating Usage (kWh)	Cooling Usage (kWh)
Billing Analysis	3,860	3,626	234

Source: Evaluation team AMI billing analysis.

Assess Change in Energy Use

As the final step in the analysis, the Evaluation team estimated real world changes to energy use between pre-and-post-installation usage patterns for participants and nonparticipants. Energy savings are the difference between participants' and nonparticipants' energy usage between the pre- and post-installation periods.

Engineering Calibration and Validation

The Evaluation team benchmarked the billing analysis findings relative to values produced from a simplified heat pump engineering model and the initiative-claimed savings (the initiative relied on current MEMD savings estimates). The goal of benchmarking was to help frame the billing analysis findings and understand how close the changes to energy usage tracked with alternative sources. The Evaluation team compiled initiative tracking claimed savings from eTracker and normalized the savings at the tenant apartment unit level by using the total number of installed heat pumps, the claimed savings, and the total number of apartment units. The team relied on the heating load requirement (3,626 kWh), assumed a CCHP COP of 2.75, and entered this data into a simple algorithm expressing continued baseboard heating, CCHP heating, and total heating demand based on several different displacement scenarios (Table B-4).

Table B-4. Cold-Climate Heat Pump Simplified Engineering Estimate

DHP Heating Load Displacement	Baseboard kWh	CCHP with COP of 2.75 (kWh)	Savings (kWh)	Total kWh
100%	-	1,319	2,307	3,626
75%	907	989	1,731	3,626
50%	1,813	659	1,154	3,626
36%	2,319	475	832	3,626

Bill Savings Estimation

To estimate the bill savings attributable to the CCHPs installed in the multifamily tenant units, the Evaluation team estimated the bill savings occurring during the time-differentiated bill periods across the year. According to residential rate data, peak period rates occur in summer months, from May 1 through September 30, during weekdays from 2 p.m. to 7 p.m. The Evaluation team then estimated the savings occurring during the peak and off-peak periods. Table B-5 shows a summary of the seasonal peak and off-peak rates and savings.

Table B-5. Cold-Climate Heat Pump Bill Savings Calculations

Residential Rate	Residential Billing Rate ($)	Income Qualified Multifamily CCHP Savings Occurring During Each Period (kWh)	Bill Savings ($)
Summer Peak	$0.213	6.1	$1.30
Off-Peak	$0.164	889.9	$145.94
Total Bill Savings			**$147.24**

Electric Savings: Engineering Comparison

The Evaluation team developed a simplified engineering estimate to compare how the evaluated electric savings compared with anticipated savings from a CCHP and added the initiative-claimed savings based on MEMD measures. Table B-6 shows a comparison of Income Qualified Multifamily initiative savings from the billing analysis sample, two engineering estimates based on two different displacement scenarios, and the initiative MEMD claimed savings estimate. The billing analysis estimate showed lower realized savings relative to the engineering estimate (assuming 50% of the electric baseboard heating was displaced by the CCHPs) and the MEMD estimate. In order for the engineering estimate to match the billing savings estimate of 832 kWh of heating load savings, the CCHPs would need to displace just over one-third (36%) of the heating load, which therefore assumes that the legacy baseboard heating systems still account for the majority of heating load for the apartments. The continued use of baseboard heat is consistent with feedback from the tenant survey, in which tenants reported continued use of baseboard heat as their primary heating source.

Table B-6. Annual Per–Tenant Unit Cold-Climate Heat Pump Electric Weather-Sensitive Savings Estimates Comparison

Source	Weather-Sensitive Usage (kWh) (A)	Weather-Sensitive Savings (kWh) (B)	Savings versus Weather-Sensitive Usage (%) (B / A)
Billing Analysis	3,860 (Annual)	896	23.2%
Billing Analysis	3,626 (Heating)	832	22.9%
Engineering @ 50% Displacement [a]	3,626 (Heating)	1,154	31.8%
Engineering @ 36% Displacement [a]	3,626 (Heating)	832	22.9%
MEMD/Pilot Claimed Savings [b]	3,860 (Annual)	1,474	38.2%

[a] This is an engineering estimate based on the heating season only and derived from AMI billing analysis.

[b] This represents annual weather-sensitive usage from the AMI billing analysis.

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Appendix C. Consumers Energy Heat Pump Market Rate Customer Survey

Objectives	Research Questions	Question Number
Assess customer awareness and motivations to install heat pumps	Were participants aware of heat pumps prior to participating in the offering? How do customers learn about heat pumps? What are participants' motivations for installing a heat pump? What are important decision factors for installing a heat pump? How much rebate is required to motivate participation?	Section B
Assess participant installation experience	How did participants experience the installation? Are there opportunities to improve the installation experience?	D1–D3
Document participant perceptions of heat pumps, energy or cost savings, comfort levels, and satisfaction	What are participants' experiences with heating/cooling comfort? How satisfied are participants with the heat pumps and the offering? How satisfied are participants with Consumers Energy?	D4–D12, B1, B2
	What non-energy benefits did the offering generate (such as reduced bill impacts, enhanced comfort levels, and improved operational issues)?	D11
Document participant usage behavior and home characteristics	How do respondents manage energy use at the thermostat?	Section C
	What are participants' home characteristics?	Section E

Survey Overview: The Evaluation team administered an online survey to residential customers who received a new heat pump. Then the team sent an email with a link to the survey, followed by reminder emails to encourage households to complete the survey withing the desired timeframe. In addition, the Evaluation team offered participants a $15 Meijer or Amazon.com gift card for completing the survey.

Target Audience: Census of Residential Market Rate pilot participants who installed a new heat pump as part of the Consumers Energy heat pump offering.

Survey Introduction and Purpose

Welcome, thank you for taking a few minutes to provide feedback about your cooling and heating equipment. Your feedback is very important to us and will help us improve rebates and incentives for new products that help customers save energy. This survey should take about 10 minutes. Your responses are confidential and will be used for research purposes only.

Be sure to enter your name and address at the end of the survey to receive your $15 Meijer or Amazon gift card as our thanks.

Click on the Next and Back buttons at the bottom of each page to navigate through the survey.

A. *Screener*

A1. Our records indicate that you received a rebate for a heat pump installed in your home. Is this correct?
1. Yes
2. No **[TERMINATE]**
98. Don't know **[TERMINATE]**

A2. Approximately how long have you lived in your current home?
1. Less than one year
2. One to three years
3. Over three years

A3. **[If A2=1]** Were you living in your current home when the heat pump was installed?
1. Yes
2. No **[TERMINATE]**

TERMINATION MESSAGE: This survey is for Consumers Energy customers who received a rebate for a heat pump through the heat pump rebate program and who were living in the home when the heat pump was installed. Thank you for your interest in participating in this survey.

B. *Current Company Metrics and Awareness*

We'd like to ask some questions about your opinions toward Consumers Energy.

B1. How likely would you be to recommend Consumers Energy to a friend or family member if you had a choice in energy providers?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
○	○	○	○	○	○	○	○	○	○	○	○

B2. Please describe in detail why you gave that rating. _____

With these next questions, we would like to know more about your experience with heat pumps.

B3. Were you familiar with heat pumps before deciding to purchase and install the heat pump?
1. Yes
2. No
98. Don't know

B4. **[DISPLAY IF B3=1]** Prior to participating in this offer, had you ever had a contractor recommend a heat pump?
1. Yes, I had a contractor recommend a heat pump
2. No, a contractor has never recommended a heat pump to me

B5. Before you participated in this offer, were you aware that Consumers Energy offered rebates for heat pumps?

1. Yes, I was aware of heat pump rebates
2. No, I was unaware of heat pump rebates

B6. How did you first learn about the heat pump rebate? Please select only one response. **[RANDOMIZE 1–6]**

1. Contractor recommendation
2. Consumers Energy website
3. Consumers Energy flyer or other marketing material
4. Friend, family, neighbor, or colleague
5. Email from Consumers Energy
6. Online search
7. Other (please specify)

98. Don't know

B7. What were the main reason(s) you decided to install a heat pump in your home? (Select up to three) **[RANDOMIZE 1–9]**

1. To reduce energy bills in the winter months
2. To reduce energy bills in the summer months
3. To distribute heating and cooling more evenly throughout the home
4. To add heating and/or cooling for a new or renovated space in the home
5. To replace a broken heating or cooling system
6. To reduce reliance on natural gas or delivered fuels
7. To add cooling (where there was not previously a whole-home system)
8. To take advantage of heat pump incentives (from Consumers Energy and/or my contractor)
9. To take advantage of electricity produced at my home by renewable sources (such as solar or wind)
10. Something else (please describe)

B8. Please rate the importance of the following items on your decision to install a heat pump. **[RANDOMIZE ITEMS]**

Items	Not at All Important 1	2	3	4	5	6	7	8	9	Extremely Important 10	Don't know
a. The amount of rebate from Consumers Energy (up to $1,000)	○	○	○	○	○	○	○	○	○	○	○
b. Recommendation from a contractor	○	○	○	○	○	○	○	○	○	○	○
c. Possible energy savings over the previous heating/cooling system	○	○	○	○	○	○	○	○	○	○	○

B9. Would you have installed a heat pump if Consumers Energy had not offered a heat pump rebate?
1. Yes (I would have installed a heat pump without a rebate)
2. No
98. Don't know

B10. **[IF B9>1]** Would you have installed a heat pump if the rebate had been one-quarter of the value you received (up to $250)?
1. Yes (I would have installed the heat pump with a $250 rebate)
2. No
98. Don't know

B11. **[IF B9>1]** Would you have installed a heat pump if the rebate had been half as much as the amount you received (up to $500)?
1. Yes (I would have installed the heat pump with a $500 rebate)
2. No
98. Don't know

C. *Thermostat Use*

Next, we have a few questions about how you typically use your thermostat to manage the level of comfort in your home.

C1. What type of thermostat do you have in your home? (Select one.)
1. **Non-programmable** thermostat (set temperature manually and it did not change automatically)
2. **Programmable** thermostat with **set-backs programmed** (thermostat set to automatically change temperature at specific times)
3. **Programmable** thermostat—**not programmed** (thermostat has programming capability, but these were not used.)
4. **Basic networked or Wi-Fi–enabled** thermostat (had remote control, but not occupancy sensing or learning features)
5. **Smart learning** thermostat that includes advanced features such as occupancy sensing and schedule learning (examples include Nest, Ecobee, Honeywell Lyric, and Emerson Sensi)
98. Don't know

C2. Who in your household tends to monitor and adjust your thermostat?
1. I mostly monitor and adjust my home thermostat
2. Everyone in my household monitors and adjusts my home thermostat
3. Other members of my household typically monitor and adjust my home thermostat

C3. How did your household **most frequently** manage your thermostat to control the temperature in your home this summer? (Select one)
1. Keep it at a constant temperature
2. Manually adjust the temperature as needed
3. Create customized/programmed settings to automatically change temperatures at different times of the day
4. Allow the smart thermostat to manage the temperature by learning my preferences and/or detecting when home or away
5. Other (please describe)
98. Don't know

C4. Your heat pump offers the ability to use heating and cooling schedules. Did the installation technician setup your heat pump on a heating and cooling schedule?
1. Yes, the installer set up a heating and cooling schedule
2. No, the installer did not set up a heating and cooling schedule
98. Don't know

C5. **[IF C4=1]** Are you still using this heating and cooling schedule?
1. Yes, I have kept the heating and cooling schedule
2. No, I (or someone in my household) turned off the heating and cooling schedule
3. No, I (or someone in my household) changed the heating and cooling schedule to my own
98. Don't know

C6. Have you been provided with instructions on how to set up and control your heating and cooling schedule on your heat pump?
1. Yes, I received instructions
2. No, I did not receive instructions
98. Don't know

D. *Installation and Usage Experience*

Next, we would like to know about your experience with the heat pump.

D1. Our records indicate that the heat pump was installed in your home around **[INSTALLATION-COMPLETE DATE]**. Were you present during the installation of the heat pump?
1. Yes
2. No

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D2. Using a rating scale from 1 to 10, where 1 is *unacceptable* and 10 is *outstanding*, how would you rate each of the following installation experiences with the heat pump offering?

Question	Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know / NA
Scheduling a time for installation	O	O	O	O	O	O	O	O	O	O	O
Staying informed about the installation	O	O	O	O	O	O	O	O	O	O	O
[If D1=1] Overall installation time	O	O	O	O	O	O	O	O	O	O	O
[If D1=1] The professionalism of the installation technician	O	O	O	O	O	O	O	O	O	O	O
Education and instructions provided to you about heat pump usage	O	O	O	O	O	O	O	O	O	O	O
Follow-up from the installation technician or Consumers Energy	O	O	O	O	O	O	O	O	O	O	O

D3. **[IF ANY QUESTION IN D2=6 OR LOWER]** If there was something unsatisfactory about the heat pump installation, please describe in detail why you gave that rating.

_____

D4. In general, how did the heat pump affect your home comfort? (Select all that apply)

1. My home is **just as comfortable** as it was previously
2. My home is **more comfortable** than it usually was
3. My home is uncomfortably warm
4. My home is uncomfortably cold
5. My home is **too humid**
6. My home is **too dry**
7. My home was more evenly heated and/or cooled prior to the installation
8. Something else (please describe)

D5. **[IF D1=1 AND COMPLETE DATE IS PRIOR TO APRIL 1, 2021]** How would you rate the heating comfort level provided by the heat pump during winter months?

Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
O	O	O	O	O	O	O	O	O	O	O

[If D5<6] What concerns do you have about the heat pump's ability to heat to your comfort level?

_____

D6. How would you rate the cooling comfort level provided by the heat pump during summer months?

Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
O	O	O	O	O	O	O	O	O	O	O

[If D7<6] What concerns do you have about the heat pump's ability to cool to your comfort level?

_____

D7. Taking everything into consideration, how would you rate your overall experience with the heat pump so far?

Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
O	O	O	O	O	O	O	O	O	O	O

D8. Based on your experiences with the heat pump so far, how likely would you be to recommend it to a friend?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
O	O	O	O	O	O	O	O	O	O	O	O

D9. Based on your experience so far, do you have any recommendations to improve the heat pump rebate offer? _____

98. Don't know

D10. Since the heat pump was installed, have you seen a lower-than-expected energy bill?

1. Yes
2. No
3. Too soon to tell
98. Don't know

D11. In addition to energy savings, if any, are there additional benefits you have experienced or observed from the installation of a heat pump? (Select all that apply) **[RANDOMIZE]**

1. Increased comfort
2. Lower utility bills
3. Improved appearance of my home
4. Improved air quality
5. Improved heating and cooling distribution (across sections of my home)
6. Less maintenance required

7. Improved ability to manage heating/cooling on a schedule
8. Fewer illnesses for household members
9. Other (please specify)
10. Too soon to know **[EXCLUSIVE OF OTHER RESPONSES]**
11. No other benefits **[EXCLUSIVE OF OTHER RESPONSES]**

98. Don't know **[EXCLUSIVE OF OTHER RESPONSES]**

D12. **[If D12=1 AND D11<10]** Considering that the heat pump offering provided both saved energy and some additional benefits to your home, please indicate which was the most important to you:

1. The energy savings
2. The other benefits previously identified
3. The energy savings are equal to the other benefits

98. Don't know

E. *Demographics*

Finally, we have a few questions about your home.

E1. How many people live in your household on a regular basis, year-round?

1. 1
2. 2
3. 3
4. 4
5. 5
6. More than 5

99. Prefer not to answer

E2. Approximately how many square feet of living space does your home have? Do not include the basement unless it is a space that you consider lived in.

1. Under 1,000 square feet
2. 1,000 to less than 1,500 square feet
3. 1,500 to less than 2,000 square feet
4. 2,000 to less than 2,500 square feet
5. 2,500 to less than 3,000 square feet
6. 3,000 to less than 4,000 square feet
7. 4,000 or more square feet

98. Don't know

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F. *Closing*

F1. On occasion, managers of the Consumers Energy programs may want to contact a customer to learn more about their participation experience. Please check here if you prefer not to be contacted by a program manager.
1. Do not contact me

F2. Do you have any recommendations for ways Consumers Energy can support you in helping you save energy?
1. Please describe_____

F3. To thank you for your time spent completing this survey, we would like to send you a $15 gift card to either Meijer or Amazon.com. Please choose which gift card you would like to receive.
1. $15 Meijer gift card
2. $15 Amazon.com gift card
3. Neither – I do not wish to receive a gift card

F4. **[IF F3=1 OR 2]** Please provide your name, address, and email to receive your gift card. This information will only be used to mail your gift card.
1. Name:_____
2. Address:_____
3. Address 2:_____
4. City:_____
5. State:_____
6. Zip:_____
7. Email**:** _____

Please click Next to submit the survey.

[END OF SURVEY MESSAGE] Those are all the questions we have at this time. Thank you for your participation in the Consumers Energy heat pump offer.

For more information on energy efficiency, here's where to find it:

- **Want Online Information about Our Other Energy-Efficiency Rebates and Programs?** For details of additional ways Consumers Energy may be able to help you make your home more energy efficient and help you manage your monthly energy bills, please visit us online at ConsumersEnergy.com/myhome.
- **Want to Speak to an Energy-Efficiency Advisor by Phone?** To talk to someone about additional rebates and programs, please contact one of our Energy Advisors at (888) 652-1237.

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Appendix D. Consumers Energy Heat Pump Property Owner and Manager Interview Guide

Research Questions

Objectives	Research Questions	Interview Section
Document participant installation experience	How well did the offering manage the user installation experience? Are there opportunities to improve the installation experience?	B1, B3
Document participant usage behavior and experience	How are tenants using and operating the heat pumps? Did customers retain secondary or supplemental heating equipment after the heat pump was installed?	B2, B4
Document awareness and perceptions of heat pumps	What is the current perception of heat pump technologies? Were participants aware of heat pumps prior to being approached by Consumers Energy or the contractor? What are the perceived energy benefits of heat pumps? What non-energy benefits did the offering generate (such as reduced bill impacts, enhanced comfort levels, or improved operational issues)?	C1–C4, E2–E5
Document participant decision-making around participating in the heat pump offering	What key factors affected participants' decisions to install a heat pump? What are the key barriers to adopting heat pumps?	D1–D4
Identify marketing and outreach best practices	How did the participant learn about the offering?	C3
	What are the most effective means of marketing heat pumps?	F1–F3
Assess satisfaction with the offering and with Consumers Energy	How satisfied are property owners and managers with the heat pump offering? How satisfied are tenants with the heat pumps and the offering? How satisfied are property owners and managers with Consumers Energy?	G1–G4

Target Audience: The target audience for these interviews was multifamily PMOs who participated in the CCHP initiatives. The Evaluation team attempted to interview a census of participating PMOs.

A. General Introduction

A1. To begin, please tell me about your multifamily properties.

1. How many unique multifamily properties do you own or manage?
2. How many of them are located in Michigan?
3. Do you own/manage only subsidized or income eligible housing or do you also own/manage market rate properties?

B. Installation and Usage Experience

B1. Please describe your experience, including any positive or negative elements, of the heat pump installation for each of the following installation components (please note if you are not aware of any of these elements):

1. Scheduling a time for the installation
2. Informing the tenants
3. Overall installation time
4. Professionalism of the installation technicians
5. Education and instructions provided to management about heat pump usage
6. Education and instructions provided to tenants about heat pump usage **[PROBE: WERE YOU INFORMED ABOUT PRIORITIZING HEAT PUMP USAGE OVER BASEBOARD HEATING?]**
7. Follow up

B2. Have you received any feedback from your tenants about the new heat pumps? **[PROBE: DO THE COMMENTS TEND TO BE POSITIVE, COMPLAINTS, OR QUESTIONS?]**

B3. Have you had any concerns or issues with the heat pumps installed in your property? **[PROBE: HAVE TENANTS COMPLAINED, DO MAINTENANCE STAFF HAVE ANY FEEDBACK ABOUT THEM?]**

B4. It is our understanding that the existing baseboard heating equipment was left in tenant apartments. Are you aware of whether tenants are continuing to use their baseboard heaters or if they rely mostly on the new heat pumps for heating?

1. Are you aware if the tenants received educational materials or training on the use of the heat pumps? **[PROBE: HAVE TENANTS SEEN THESE MATERIALS? HOW WERE THEY DISTRIBUTED? DO THEY FIND THE MATERIALS TO BE USEFUL?]**

C. Heat Pump Awareness and Perceptions

C1. Before participating in this heat pump offering, were you familiar with heat pumps?

C2. Prior to participating in this offering, had you ever had a contractor recommend heat pumps?

C3. Before you participated in this offering, were you aware that Consumers Energy offered rebates for heat pumps?

1. **[IF HEARD ABOUT OFFERING]** Where did you hear about the heat pump offering?
2. **[IF HEARD ABOUT OFFERING]** What were your immediate perceptions of the offering?

C4. Other than **[NAME OF PROPERTY IN THE HEAT PUMP OFFERING]**, do any of your properties currently have heat pumps installed for heating and cooling?

1. **[IF HAS HEAT PUMPS INSTALLED]** How many (if any) of the properties you own/manage use heat pumps? **[PROBE TO SEE IF THEY ARE IN MICHIGAN]**
2. For those properties, do residents typically retain secondary or supplemental heating equipment after the heat pump is installed? Please describe.

D. Motivators and Barriers

D1. What were the most important factors in your decision to participate in the heat pump offering? **[DO NOT READ OR PROMPT; SELECT ANY THAT ARE MENTIONED]**

1. Lower tenant utility costs
2. Lower owner utility costs
3. Improve the property appearance
4. Improve tenant comfort
5. Increase the property value
6. Replace old or broken equipment
7. Take advantage of low-cost/no-cost improvements
8. Reduce impact on the environment
9. Lower operating and maintenance costs
10. Improve property aesthetics
11. Improve health and safety
12. Satisfaction with previous Consumers Energy program experience
13. Turnkey and easy to participate
14. Other (Please specify)

98. Don't know

D2. Which of these factors was the most important to your decision? **[REPEAT THOSE MENTIONED IN PREVIOUS QUESTION TO ALLOW SELECTION FROM LIST]**

D3. What do you consider to be the primary barriers to adding heat pumps to other properties? **[DO NOT READ OR PROMPT; SELECT ANY THAT ARE MENTIONED]**

1. Overall upfront costs
2. Logistical effort required to deal with installation
3. Finding the right contractor
4. Getting management approval
5. Tenant disruption
6. Tenants' ability to use the equipment to reduce energy consumption
7. Other (Please specify)

98. Don't know

D4. Which of these factors is the most significant barrier to your decision? **[REPEAT THOSE MENTIONED IN PREVIOUS QUESTION TO ALLOW SELECTION FROM LIST]**

E. Savings and Benefits of Participation

E1. Do you or your tenants pay the electric utility bills?

E2. **[IF TENANTS PAY]** Have your tenants provided feedback about their bills since installation of the heat pumps? If so, please describe what this feedback has entailed.

E3. **[IF PROPERTY OWNER/MANAGER PAYS UTILITY BILLS]** Have you noticed any change in your utility bills since installation of the heat pumps? If so, please describe the change. **[PROBE: HAVE THERE BEEN ANY DIFFERENCES IN UTILITY BILL CHANGES BETWEEN WINTER HEATING AND SUMMER COOLING?]**

E4. In addition to energy savings, are there any other benefits that your property, your tenants, or property management have experienced from installing the heat pumps? **[DO NOT READ OR PROMPT; SELECT ANY THAT ARE MENTIONED]**

1. Lower maintenance costs
2. Improved operations
3. Increased property value
4. Decreased vacancy rates
5. Increased rental income
6. Increased net operating income
7. Increased tenant comfort
8. Decreased late or nonpayment of rent
9. Decreased tenant complaints
10. Improved property aesthetics
11. Health and safety improvements
12. Other (Please specify)
13. Too soon to tell
14. No other benefits

98. Don't know

E5. **[ASK IF E3=YES AND E4≠13, 14, OR 98]** Considering that the heat pump offering provided both energy savings and some other benefits to your property, please indicate which was the <u>most important</u> benefit:

1. The energy savings
2. The non-energy benefits (previously identified)
3. The energy savings benefits are equal to the non-energy benefits

98. Don't know

F. Outreach and Marketing

F1. What, in your opinion, could be done to increase the adoption of heat pumps in the multifamily market?

F2. What are the most effective ways to let other multifamily property owners and managers know about the benefits of heat pumps?

F3. What information would be helpful for other property managers and owners to become interested in heat pumps?

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G. Opinion of Heat Pump Offering and Consumers Energy

G1. Taking everything into consideration, how would you rate your overall experience with the multifamily heat pump offering, where 1 means *unacceptable* and 10 means *outstanding*?

Unacceptable 1	2	3	4	Average 5	6	7	8	9	Outstanding 10	Don't know
○	○	○	○	○	○	○	○	○	○	○

G2. Based on your experiences with the heat pump offering, how likely would you be to recommend the offering to a business colleague, where 1 means *extremely unlikely* and 10 means *extremely likely*?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
○	○	○	○	○	○	○	○	○	○	○	○

G3. Based on your experiences with the heat pump offering, how likely would you be to recommend Consumers Energy to a business colleague if you had a choice in energy providers, where 1 means *extremely unlikely* and 10 means *extremely likely*?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
○	○	○	○	○	○	○	○	○	○	○	○

G4. Based on your experience with the heat pump offering, how likely would you be to make similar improvements to some or all the properties you manage, where 1 means *extremely unlikely* and 10 means *extremely likely*?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
○	○	○	○	○	○	○	○	○	○	○	○

H. Wrap Up

H1. In what ways can Consumers Energy programs better help you manage your multifamily properties' energy use?

H2. Our research also includes a tenant survey to capture their experience and usage with the heat pumps, but we do not have tenant contact information to recruit them for this effort. Would you be interested in **[OPTION A]** securely sharing tenant emails with us so they can receive an email link to complete an online survey or **[OPTION B]** would you be willing to forward an email invitation to your tenants to complete the online survey? Tenants will receive a $15 gift card for their time. [**ENTER WILLINGNESS RESPONSE OPTION AND BE SURE TO REQUEST THE PMO EMAIL ADDRESS TO ENSURE EITHER OPTION CAN BE SHARED**]

Those are all the questions we have. Thank you very much for taking the time to assist us with this evaluation. Your contribution is a very important part of the process. We are planning to send you your choice of a $50 Amazon or Meijer card (if you choose Meijer, we will need your mailing address, as there is no e-card option). Please let us know your choice of card **[ENTER CARD CHOICE AND REQUEST EMAIL ADDRESS IF AMAZON OR MAILING ADDRESS IF MEIJER]**.

Look for your gift card in the mail in the next three weeks. If you have any questions about this survey or about your gift card, please call **[APEX STAFF]** at **[303-590-9888 Ext XXX]**. Thank you for your time.

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Appendix E. Consumers Energy Heat Pump Multifamily Tenant Survey Guide

Objectives	Research Questions	Question Number
Document participant awareness of heat pump	Are tenants aware of what a heat pump is? Were tenants aware of a heat pump installed for their apartment? Are tenants who were aware of the heat pump also aware that Consumers Energy funded it?	Section B
Document participant installation experience	How did the heat pump offering help Consumers Energy to manage the tenant installation experience? Are there opportunities to improve the installation experience?	D1–C3
Assess participant perceptions of heat pump impact on comfort levels and electricity bills	What perceptions do tenants have of heating and cooling comfort levels? What are the perceived energy benefits of heat pumps? What non-energy benefits did the offering generate (such as reduced bill impacts, enhanced comfort levels, and improved operational issues)?	C4–C11, D2–D4
Document participant usage behavior and experience	How are tenants using and operating the heat pumps? Are tenants continuing to use their baseboard heating?	C12–C18
Assess participant satisfaction with the offering and with Consumers Energy	How satisfied are tenants with the heat pumps offering? How satisfied are tenants with Consumers Energy?	E1–G3, A1, A2

Survey Overview: The Evaluation team administered a web-based survey with multifamily tenants who received a new heat pump. Then the team sent an email with a link to the survey to participants who could be matched to participating multifamily buildings and had an email address, followed by reminder emails to encourage households to complete the survey within the desired timeframe. In addition, the Evaluation team offered participants a $15 Meijer or Amazon.com gift card for completing the survey.

Target Audience: Census of individual tenant dwellings that could be matched to the multifamily building and had an email address. The Evaluation team had 75 emails associated with the multifamily properties by linking an income-qualified survey contact database with the Income Qualified Multifamily incentive properties. Assuming a 10% response rate, we hoped to receive approximately eight completed surveys.

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A. Current Company Metrics

First, we'd like to ask some questions about your opinions toward Consumers Energy.

Consumers Energy Count on Us®

A1. How likely would you be to recommend Consumers Energy to a friend or family member if you had a choice in energy providers?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
O	O	O	O	O	O	O	O	O	O	O	O

A2. Please describe in detail why you gave that rating. _____

B. Awareness

B1. Are you familiar with what a heat pump is?

1. Yes, I am familiar
2. No, I do not know what a heat pump is

[IF B1=2, PROVIDE EXPLANATION ABOUT HEAT PUMPS: HEAT PUMPS ARE EQUIPMENT THAT PROVIDES BOTH HEATING AND COOLING FOR HOMES.]

B2. Our records indicate that the apartment you currently occupy received a new heat pump. Are you aware of this?

1. Yes
2. No

B3. **[If B2=1]** Were you aware that Consumers Energy funded this project and made the heat pump technology available in your home?

1. Yes, I was aware of Consumers Energy involvement
2. No, I was unaware of Consumers Energy involvement
98. Don't know

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C. Installation and Usage Experience

Next, we would like to know about your experience with the heat pump.

[SHOW QUESTIONS D1 TO C3 IF COMPLETE DATE IS NOT EMPTY]

C1. Our records indicate that the heat pump was installed in your apartment around **[COMPLETE DATE]**. Were you present during the installation of the heat pump?

1. Yes, I was present during installation
2. No, I was not present during installation

C2. Using a rating scale from 1 to 10, where 1 is *unacceptable* and 10 is *outstanding*, how would you rate each of the following installation experiences with the heat pump offering?

Question	Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
Scheduling a time for installation	○	○	○	○	○	○	○	○	○	○	○
Staying informed about the installation	○	○	○	○	○	○	○	○	○	○	○
[IF C1=1] Overall installation time	○	○	○	○	○	○	○	○	○	○	○
[IF C1=1] The professionalism of the installation technician	○	○	○	○	○	○	○	○	○	○	○
Education and instructions provided about heat pump usage	○	○	○	○	○	○	○	○	○	○	○
Follow-up from the installation technician or Consumers Energy	○	○	○	○	○	○	○	○	○	○	○

C3. **[IF ANY QUESTION IN C2≥6]** If there was something unsatisfactory about the heat pump installation, please describe in detail why you gave that rating.

_____

C4. Approximately how long have you lived in your current apartment?

1. Less than six months
2. Between six months and one year
3. Over one year

C5. Were you living in your apartment last winter, before the heat pump was installed?

1. Yes
2. No

C6. **[IF C5=1]** How would you rate the heating comfort level provided by the heat pump during winter months?

Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
○	○	○	○	○	○	○	○	○	○	○

C7. **[IF C6<7]** What concerns do you have about the heat pump's ability to heat to your comfort level? _____

C8. Were you living in your apartment last summer, before the heat pump was installed?

1. Yes
2. No

C9. **[IF C8=1]** How would you rate the cooling comfort level provided by the heat pump during summer months?

Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
○	○	○	○	○	○	○	○	○	○	○

C10. **[IF C9<7]** What concerns do you have about the heat pump's ability to cool to your comfort level? _____

C11. In general, how did the heat pump affect your home comfort? (Select all that apply)

1. My home is **just as comfortable** as it was previously
2. My home is **more comfortable** than it usually was
3. My home is uncomfortably warm
4. My home is uncomfortably cold
5. My home is **too humid**
6. My home is **too dry**
7. My home was more evenly heated and/or cooled prior to the installation
8. Something else (please describe)

C12. Our records indicate that the existing baseboard heating equipment was left in all apartments where heat pumps were installed.
Which of the following best describes how you heated your apartment last winter?
[RANDOMIZE 1-3]

1. Mostly used baseboard heating
2. Relied evenly on the heat pump and baseboard heating
3. Mostly used the new heat pump

98. Don't know

C13. Your baseboard heating should have a thermostat that controls your home's heating.
What type of thermostat do you have in your home?

1. **Non-programmable** thermostat (set temperature manually and it did not change automatically)
2. **Programmable** thermostat with **set-backs programmed** (thermostat set to automatically change temperature at specific times)
3. **Programmable** thermostat—**not programmed** (thermostat has programming capability, but these were not used.)
4. **Basic networked or Wi-Fi–enabled** thermostat (had remote control, but not occupancy sensing or learning features)
5. **Smart learning** thermostat that includes advanced features such as occupancy sensing and schedule learning (examples include Nest, Ecobee, Honeywell Lyric, and Emerson Sensi)

98. Don't know

C14. Who in your household tends to monitor and adjust your thermostat associated with your baseboard heating?

1. I mostly monitor and adjust my home baseboard thermostat
2. Everyone in my household monitors and adjusts my home baseboard thermostat
3. Members of my household (other than me) typically monitor and adjust my home baseboard thermostat

C15. How did your household **most frequently** manage your baseboard thermostat to control the temperature in your home this summer?
1. Keep it at a constant temperature
2. Manually adjust the temperature as needed
3. Create customized/programmed settings to automatically change temperatures at different times of the day
4. Allow the smart thermostat to manage the temperature by learning my preferences and/or detecting when home or away
5. Other (please describe)
98. Don't know

C16. Your heat pump offers the ability to use heating and cooling schedules. Did the installation technician set up your heat pump on a heating and cooling schedule?
1. Yes, the installer set up a heating and cooling schedule
2. No, the installer did not set up a heating and cooling schedule
98. Don't know

C17. **[IF C16=1]** Are you still using this heating and cooling schedule?
1. Yes, I have kept the heating and cooling schedule
2. No, I (or someone in my household) turned off the heating and cooling schedule
3. No, I (or someone in my household) changed the heating and cooling schedule to my own
98. Don't know

C18. Have you been provided with instructions on how to set up and control your heating and cooling schedule on your heat pump?
1. Yes, I received instructions
2. No, I did not receive instructions
98. Don't know

D. Savings and Benefits of Participation

D1. How would you describe how your electric utility use is billed?
1. I receive a monthly electric utility bill directly from the utility for my usage
2. My landlord receives an electric utility bill for the whole building's usage
3. The electricity use for my unit is billed some other way (please describe)
4. I'm not sure how the electric utility use is billed

D2. **[IF E1=1]** Have you seen a lower-than-expected energy bill?
1. Yes
2. No
3. Too soon to tell
98. Don't know

D3. In addition to energy savings, if any, are there other benefits that you have experienced or observed from the installation of heat pumps? (Select all that apply) **[RANDOMIZE 1–8]**

1. Increased comfort
2. Lower utility bills
3. Decreased complaints about my apartment temperature
4. Improved air quality
5. Improved appearance of my apartment
6. Improved heating and cooling distribution (across sections of my home)
7. Fewer illnesses for household members
8. Improved ability to manage heating/cooling on a schedule
9. Other (Please specify)
10. Too soon to tell [EXCLUSIVE OF OTHER RESPONSES]
11. No other benefits [EXCLUSIVE OF OTHER RESPONSES]

98. Don't know [EXCLUSIVE OF OTHER RESPONSES]

D4. **[ASK IF D2=1 AND D10≠10, 11, OR 98]** Considering that the heat pump offering provided both saved energy and some additional benefits to your apartment, please indicate which was <u>most important</u> to you:

1. The energy savings
2. The other benefits previously identified
3. The energy savings are equal to the other benefits

98. Don't know

E. Opinion of Heat Pump Offering and Consumers Energy

E1. Taking everything into consideration, how would you rate your overall experience with the heat pump?

Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
○	○	○	○	○	○	○	○	○	○	○

E2. Based on your experiences with the heat pump, how likely would you be to recommend a heat pump to a friend?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already Did Recommend	Don't know
○	○	○	○	○	○	○	○	○	○	○	○

E3. Do you have any recommendations for ways Consumers Energy can further support you in saving energy?
1. Please describe_____

F. Closing

F1. On occasion, managers of the Consumers Energy programs may want to contact a customer to learn more about their participation experience. **Please check here if you prefer not to be contacted by a program manager.**
1. Do not contact me

F2. To thank you for your time spent completing this survey, we would like to send you a $15 gift card to either Meijer or Amazon.com. Please choose which gift card you would like to receive.
1. $15 Meijer gift card
2. $15 Amazon.com gift card
3. Neither – I do not wish to receive a gift card

F3. **[ASK IF F2=1 OR 2]** Please provide your name, address, and email to receive your gift card. This information will only be used to mail your gift card.
1. Name:_____
2. Address:_____
3. Address 2:_____
4. City:_____
5. State:_____
6. Zip:_____
7. Email**:** _____

Please click Next to submit the survey.

Those are all the questions we have at this time. Thank you for your participation in the Consumers Energy heat pump offer.

For more information on energy efficiency, here's where to find it:

- **Want Online Information about Our Other Energy-Efficiency Rebates and Programs?** For details of additional ways Consumers Energy may be able to help you make your home more energy efficient and help you manage your monthly energy bills, please visit us online at ConsumersEnergy.com/myhome.
- **Want to Speak to an Energy-Efficiency Advisor by Phone?** To talk to someone about additional rebates and programs, please contact one of our Energy Advisors at (888) 652-1237.

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Appendix F. Consumers Energy Heat Pump Commercial Interview Guide

Cold-Climate Heat Pump Participant Interview Research Objectives and Questions

Objectives	Research Questions	Interview Questions
Explore key factors in customer decision-making regarding heat pump installations	Were customers aware of heat pumps prior to the pilot outreach?	C1, C1a, C1b, C1c
	What were customers' perceptions of heat pumps prior to installation? What barriers did customers face when considering the installation of heat pumps?	C3
	What motivated customers to install heat pumps?	C5, C5a, C5b
	What technology would customers have installed without the initiative intervention and why?	C4, C4a
Explore customer experiences during the heat pump installation process	How did participants find their contractor who installed the equipment? How did participants perceive their contractors knowledge of heat pump technology and installation methods? How did participants perceive the length of time to purchase and install the heat pump and how long did that process take?	D1, D2, D4, D4a, D5
	What type of equipment did customers use prior to the heat pump? Did participants need to install new duct work, a new thermostat, and/or back-up systems for their heat pump?	D6, D7, D8, D9, D10
	Were participants satisfied with their contractors (including their interactions with their contractors and the contractors' performance), the installation process, and the timeline? Why or why not? Would they use the contractor again?	G1a, G1b, G1d, D3
Explore customer experiences using their heat pump	Does the heat pump provide the level of heating required for comfort and meeting customer needs?	E2, E2a
	Does the heat pump provide the level of cooling required for comfort and meeting customer needs?	E3, E3a
	Can customers operate the heat pump easily, including the remote controls? Do they need to change their habits in any way?	E1, E4, E4a, E5, E5a, E5b, E6
	How does the heat pump compare to prior equipment with regards to air quality?	E7, E7a
	How does the heat pump compare to prior equipment with regard to noise?	E8, E8a
	Are participants satisfied with their heat pump? Why or why not?	G1c
Explore customer experiences with the initiative offering	How did participants learn of the initiative opportunity?	C2
	Did participants interact with program staff? If so, what were their experiences?	F1, F1a, F1b
	Were participants satisfied with the pilot offering?	G1e
Identify opportunities to best support heat pump technology moving forward	Which aspects of the initiative offering were most helpful to customers (such as the staff support versus the financial incentive)?	F4
	What additional support, if any, did participants need to pursue the installation and use of their heat pump?	F2, F2a, F3, F3a, D4b

Survey Overview. The Evaluation team attempted to interview the full population of participating customers, with a goal to complete at least five interviews. The team included a $75 incentive to increase the likelihood of response. The Evaluation team sent advance emails to all respondents with available email addresses and followed up with phone calls as needed to schedule interviews. This email explained the research and provided a Consumers Energy and Evaluation team contact person if the respondent had additional questions or wanted to schedule an interview. For phone recruitment, the

team left a voicemail or receptionist message on the first attempt whenever possible, then used discretion to determine any additional messages left on subsequent attempts (with a maximum of five attempts to each contact).

A. Introduction

A1. First, can you tell about the work you do at **[BUSINESS NAME]**?

A2. And what is your role at the business? **[PROBE FOR ROLE AND RESPONSIBILITIES]**

B. Consumers Energy

Next, we'd like to ask you a few questions about your opinions toward Consumers Energy.

B1. How likely is it that you would recommend Consumers Energy to a friend or colleague if you had a choice in energy providers using a scale from 1 to 10, where 1 means *extremely unlikely* and 10 means *extremely likely*?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
○	○	○	○	○	○	○	○	○	○	○	○

B2. Please describe why you gave that rating.

B3. To what extent do you agree that Consumers Energy made it easy to participate in the Cold-Climate Heat Pump Initiatives, using a scale from 1 to 5, where 1 means *strongly disagree* and 5 means *strongly agree*?

Strongly disagree 1	2	3	4	Strongly agree 5
○	○	○	○	○

C. Decision-Making

Next, I'd like to ask some questions about your decision to install a heat pump.

C1. Prior to Consumers Energy contacting you about the heat pump offering, how familiar were you with heat pump technology to heat and cool your facility?

1. **[IF AWARE, PROBE]** What were your perceptions of heat pumps?
2. **[IF AWARE, PROBE]** Had you heard anything about their performance in colder climates?
3. **[IF KNOW ABOUT HEAT PUMP PERFORMANCE IN COLD CLIMATES]** Where did you hear about it?
4. **[IF AWARE, PROBE]** Had you heard anything about their performance in colder climates?

C2. How did you first learn of the opportunity to receive a heat pump through Consumers Energy?

C3. What key concerns or considerations did you have when deciding whether or not to install the heat pump?

C4. What motivated you to agree to install the heat pump?
1. Were there any other factors? **[PROBE FOR COST, ENERGY SAVINGS, ENERGY-EFFICIENCY, REBATE FROM CONSUMERS ENERGY]**

C5. Did you have plans to install new heating or cooling equipment if Consumers Energy hadn't reached out to you?
1. **[IF WOULD HAVE INSTALLED NEW HVAC EQUIPMENT]** When would you have installed this new equipment?
2. What steps would you have taken to decide what equipment to purchase?

D. Experience with Contractor Selection and Installation Process

The next set of questions are about your experiences finding a contractor and installing of your new heat pump.

D1. So, once you decided to participate in Consumers Energy's Cold-Climate Heat Pump offering, can you talk me through the steps you took to find and select a contractor to perform the work?

D2. Did you have any difficulties finding a contractor to perform the work?

D3. How knowledgeable were the contractors you worked with about heat pumps? What about the installation process? **[PROBE IF ANY DID NOT SEEM TO BE KNOWLEDGEABLE ABOUT THE EQUIPMENT, WHERE THEY WERE LACKING KNOWLEDGE]**

D4. Once you found a contractor, how long did the project take from start to finish (purchasing to installing)? Did this timeline meet your expectations?
1. **[IF TIME EXPECTATIONS NOT MET]** What were your expectations?
2. **[IF TIME EXPECTATIONS NOT MET]** Is there anything that could have been done differently? **[PROBE IF ANY PART OF THE PROCESS TOOK LONGER THAN EXPECTED]**

D5. If you had to do it over again, would you work with the same contractor?

D6. Prior to the installation, what type of heating equipment did you use? Did you use electric or natural gas or another type of fuel to heat the property?

D7. What type of cooling equipment did you use?

D8. Did your contractor need to install new duct work, a new thermostat, or other infrastructure as part of the heat pump installation?

D9. What did your contractor do with the old heating system? **[PROBE IF REMOVED, KEPT IN PLACE AS BACKUP, CAPPED]**

D10. Did you need to install a new back-up system along with the heat pump? **[PROBE FOR HEATING OR COOLING SYSTEMS]**

E. Experience Using the Heat Pump

Next, I'd like to ask some questions about your experiences using the heat pump itself.

E1. What have been your experiences with operating the equipment to date?

E2. Have you had a chance to use the heating function on the heat pump that was installed at your facility?
   1. **[IF USED HEATING]** What time of year did you use the heating function? Did you have any issues with the heat pump providing sufficient heat for your comfort and meeting your needs? **[PROBE FOR IF THEY EVER HAD ISSUES PROVIDING HEAT]**

E3. Have you used the cooling function?
   1. **[IF USED COOLING]** Did you have any issues with the heat pump providing sufficient cooling for comfort and meeting your needs?

E4. Does the heat pump require any new operating procedures that you needed to learn how to use?
   1. How did that go?

E5. Does the equipment rely on a remote control or app?
   1. Do you use that feature?
   2. How has that gone?

E6. Have you had to change your heating/cooling habits in any way to accommodate the new technology?

E7. Have you noticed any changes in air quality since the heat pump was installed? **[PROBE: DECREASED AIR PARTICLES, NOXIOUS GASES, DEBRIS]**
   1. **[IF YES]** How so?

E8. How does the sound of the new equipment compare to your old heating/cooling equipment?
   1. **[IF SOUND WORSE]** What have you done to deal with the noise, if anything?

F. Experience with Pilot Offering

Next, I have a few questions about your experiences with Consumers Energy in relation to this pilot and then we'll be almost done.

F1. Did you interact with Consumers Energy program staff at any point in the process?
   1. **[IF YES]** What did you discuss?
   2. Did you get your questions answered?

F2. What additional support, if any, did you need *when considering to purchase and install* your heat pump?
   1. Who did you talk to? What questions did you have?

F3. Did you require any additional support—other than what you received from Consumers Energy—during the *installation process*?
   1. What about when using the equipment?

F4. Thinking about all the aspects of the initiative, from the support you received in picking equipment or a contractor to the financial rebate for the project, what aspect was most helpful in your decision to pursue the heat pump installation?

G. Satisfaction

I'd like to wrap up the conversation by asking you to rate your satisfaction on a few different factors.

G1. Feel free to expand on any answers you provide. Each of these items will be on a 1 to 10 scale, where 1 means *unacceptable* and 10 means *outstanding*.

Question	Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know / NA
The installation your contractor performed	○	○	○	○	○	○	○	○	○	○	○
The time it took to receive and install your equipment	○	○	○	○	○	○	○	○	○	○	○
The performance of the heat pump equipment	○	○	○	○	○	○	○	○	○	○	○
The interactions you had with your contractor	○	○	○	○	○	○	○	○	○	○	○
The overall Consumers Energy offering	○	○	○	○	○	○	○	○	○	○	○

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H. Closing

As we wrap up, I want to provide an opportunity for you to share anything I might have missed with my questions.

H1. Do you have any other comments or information you think might be useful for me to know given what we have talked about today?

H2. These are all the questions I have for you today. It is likely that one of our colleagues will be following up with you in a few months to better understand the energy use of your new cold-climate heat pumps during the winter months, so look out for that email or call. As a thank you for your input, we'd like to send you a $75 gift card redeemable at many businesses, including Amazon, Target, and Kroger. This gift card is called a Tango card and would be sent to your email address within the next five to 10 business days. Alternatively, we can donate the $75 to your local United Way. Which would you prefer?

H3. **[IF TANGO]** Could you please provide your preferred email address to receive the Tango virtual gift card? **[REPEAT BACK EMAIL ADDRESS]**
You should expect to receive your virtual gift card within the next five to 10 business days. The gift card will be emailed directly from **Tango,** with a reference to "Thank you for your participation!" If you have any questions, or have not received your gift card by then, please contact me at **[contact information]**.

H4. [IF UNITED WAY] In whose name should we make the donation to United Way? [INCLUDE FIRST AND LAST NAMES, COMPANY NAME, OR ANONYMOUS]
And what zip code should we use to find your local United Way?

On behalf of Consumers Energy, I want to thank you for taking time to provide input, and have a great day. **[END CALL]**

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Appendix G. Consumers Energy Heat Pump Contractor Interview Guide

Introduction and Purpose

Thank you for taking the time to talk with us today. This interview is a discussion about air source cold climate heat pumps, your businesses experience with the technology, and to assess the current status of the technology in the market. The intended outcome of this discussion is to document the perception, concerns, opportunities, critical decision points, and key outcomes involved with heat pump sales and installations. Consumers Energy can use this documentation to guide future decision making around their energy efficiency programs. We are offering a $75 gift card that can be redeemed at your choice of Amazon or Meijer for those that complete the 30-45 minute interview. We have four main objectives for this interview:

- Identify current levels of awareness and perceptions of heat pump technologies.
- Identify the main barriers to installing heat pumps in Michigan and if the Michigan market is ready for widespread adoption of heat pump technology.
- Identify any marketing or outreach best practices
- Document awareness of available heat pump incentive offerings

We expect this interview to take around 30 minutes.

A. General Introduction

A1. To begin, tell me about your business.
   1. What types of customers do you typically serve? [Standard residential? Income qualified? Multi-family? Commercial? Something else?]
   2. How many projects do you typically complete in a given year?
   3. How many employees does your company have?

A2. What type of equipment do you typically install? [Furnaces? Boilers? Heat pumps? Something else?]

A3. Do you have any experience participating in utility energy efficiency programs?
   1. Which utilities? Which programs? How often?

B. Heat Pump Awareness and Perceptions

B1. Does your company sell and install heat pumps?

1. **[If installs heat pumps]** How many (if any) heat pump sales or installations have you/your company had in the past year (2020)?
2. For those installations, do residents typically retain secondary or supplemental heating equipment after the heat pump is installed? Please describe.
3. What heat pump brands do you carry and install?
   Have you received any manufacturer-specific certifications for installing those brands?
4. How does the average warranty of a CCHP compare to gas furnaces or boilers?
5. **[If does not install heat pumps]** Why don't you install heat pumps?

B2. Do you promote CCHPs to your customers?

1. Are there specific applications or customer types that make good candidates for heat pumps? (i.e. retrofit vs. new construction)
2. Which ones?
3. Why?
4. Are small businesses good candidates for heat pumps?
   Are the barriers to entry different than the residential homeowner?

B3. Generally, what are your perceptions of CCHPs?

1. Do you think that CCHPs are a viable option for widespread adoption in Michigan?
2. Do you think that CCHPs are capable of generating energy savings for end users?
3. What has led to those perceptions of the equipment?
4. What do you think is the value proposition for you to want to install heat pumps? Why would you not want to?
5. Do you know other contractors who install CCHPs? What are their perceptions of the technology?

B4. What are customer perceptions of heat pumps?

1. Do they typically have any awareness of the technology?
2. What do you think is the value proposition for customers to install a heat pump? What are their motivations? If needed: Why would they not want to?
3. Do customers ever request to have the equipment installed without being prompted by your company? How do you respond to that request?
4. Is customer interest in heat pumps increasing, decreasing, or staying about the same? What would you say is causing that change?

B5. To what extent does a negative experience with older heat pump technologies affect your opinion about heat pumps? What about customers experiences?

C. Market Barriers and Regulatory Readiness

C1. **[If installs heat pumps]** How do procedures for a heat pump installation compare to installing other HVAC equipment in terms of:
1. Time required (actual installation time).
2. Sales process/discussions with customers.
3. Revenue/Profit Margin.
4. Equipment availability.
5. What factors can cause variations in these procedures? (e.g. conversion vs. replacing similar equipment).

C2. What would you say are the main barriers or challenges preventing more widespread heat pump adoption in Michigan? [Probe for: customer awareness, contractor perceptions, equipment availability, codes and standards, energy prices, finding good candidates, etc.]

C3. If demand for heat pumps increases, how well do you think the supply chain is prepared to meet that demand (increasing production) for cold climate heat pumps? Why?
1. Do you have any concerns about the availability or delivery timing of heat pump equipment for current or future projects? Why or why not?

D. Outreach and Marketing

D1. What can Consumers Energy do to help drive adoption of heat pumps in the market?

D2. Do you think that messaging is needed to educate people that CCHPs, or heat pumps in general, have improved?
1. **[IF YES]** What would effective messaging look like?

D3. **[If Promotes heat pumps]** When you have a good candidate for a heat pump, what information is most convincing for the customer to install a heat pump?

E. Wrap Up

E1. Before we wrap up, is there anything else you'd like us to know?

Those are all the questions we have for you. Thank you very much for taking the time to assist us with this evaluation. Your contribution is a very important part of the process. Do you mind if we follow-up with you by phone or e-mail later, if additional questions arise?

E2. To thank you for your time spent completing this survey, we would like to send you a $75 gift card to either Meijer or Amazon.com. Please choose which gift card you would like to receive.
1. $75 Meijer gift card
2. $75 Amazon.com gift card
3. Neither – I do not wish to receive a gift card

E3. Please provide your name, address, and email to receive your gift card. This information will only be used to mail your gift card.

1. Name:_____
2. Address:_____
3. Address 2:_____
4. City:_____
5. State:_____
6. Zip:_____
7. Email**:** _____

You should receive your gift card within four weeks. If you have not received it by then, please contact (contact person at Cadmus).

CADMUS

Appendix H. Consumers Energy Heat Pump Manufacturer and Distributor Interview Guide

Research Objectives and Questions

Research Objectives	Research Questions	Interview Questions
Confirm/document the supply chain for CCHPs in Michigan	Do CCHPs follow the typical supply chain structure (Manufacturer -> Distributor -> Contractor -> Customer)?	EE1, EE2
	Does the supply chain vary for small commercial, multifamily, and residential end uses?	EE1
Identify the barriers leading to extended timelines for CCHP installation	How long does it typically take from manufacturing to distribution? Distribution to contractors?	FF1
	What caused delays in the timeline in 2020? Have there been any changes to this timeline due to COVID-19? Were delays different across states? Did demand for CCHP in Michigan differ in 2020 compared to 2019?	FF1, FF2, GG2
	Are any delays expected to improve in 2021?	FF1
Identify sources of differences in CCHP installation costs across states	Are wholesale costs in Michigan comparable to other states?	FF3
	What factors drive pricing of CCHPs?	FF3
Explore the cause of low participation by trade allies	What have manufacturers and distributors done to promote heat pump technology?	GG5, GG6
	What feedback have contractors (distributors) offered to distributors (manufacturers) on perceptions of CCHP?	GG3, GG4
Identify any additional barriers and challenges delaying widespread adoption of CCHPs in Michigan, like training or education	What are the primary barriers or challenges faced by manufacturers / distributors in selling and distributing CCHP?	GG1, G1
Identify ways in which Consumers Energy can influence market adoption	How can utilities best support the adoption of CCHPs? Where is the correct place to offer an incentive (downstream, midstream, or upstream)?	II1
	Are there successful market influences in other states that could be promoted in Michigan?	HH1
	Are there technology advancements that Consumers Energy should be aware of?	HH2

A. Firmographics

First, I have just a couple questions about your organization and your role. Please note that I will keep your individual responses anonymous.

A1. What is your role in the company?

A2. What areas of the country does your company primarily serve?

A3. **[DISTRIBUTORS]** Do you serve as a distributor of heat pumps in states other than Michigan? **[PROBE FOR DETAIL]**

A4. **[MANUFACTURERS]** Do you work with particular states/regions or nationwide? **[PROBE FOR DETAIL]**

B. Supply Chain

Now I have some questions about the supply chain for the cold-climate air-source heat pump market. If possible, I would like you to focus your responses on the market in the state of Michigan.

B1. How does heat pump equipment typically get from the manufacturer to the end-use customer?
   1. What are the key roles in the cold-climate heat pump market from production to installation (such as manufacturers, distributors, contractors, and electricians)?
   2. Does the supply chain for cold-climate heat pumps differ from traditional air-source heat pumps? What about other types of mechanical equipment (such as furnaces, boilers, or water heaters)? If so, how?
   3. Does the supply chain vary depending on the type of building where the unit will be installed (single family, multifamily, or small commercial building)?

B2. Are there particular distributors, manufacturers, or contractors you work with for cold-climate heat pumps in Michigan? **[PROBE FOR DETAIL]**

C. Timeline/Costs

Next, we would like to ask you some questions specifically surrounding production and distribution timelines and costs.

C1. On average, what would you say is the length of time it normally takes for a cold-climate heat pump to reach the distributor or contractor after an order is placed?
Does the timeframe in Michigan differ from other states?
   1. **[MANUFACTURERS]** When fulfilling orders for cold-climate heat pumps, what specific manufacturing challenges, if any, have you experienced in the Michigan market? **[PROBE FOR DETAIL]**
   2. How does this compare to other states?
   3. Did production times change from 2019 to 2020? If so, how? What do you attribute this to?
   4. What do you think production times will look like in 2021?
   5. **[DISTRIBUTORS]** Have you experienced any issues with the availability of cold-climate heat pumps in Michigan? **[PROBE FOR DETAIL]**
   6. How does this compare to other states?
   7. Did availability change from 2019 to 2020? If so, how? What do you attribute this to?
   8. What do you think availability will look like in 2021?
   9. Does the timeline for cold-climate heat pumps vary by season? If so, how?

C2. **[DISTRIBUTOR]** Do you typically stock cold-climate heat pumps or do you place orders after a purchase is made?
   1. How many units do you typically have on-hand? What types? Are NEEP specifications considered? What led to your decision to stock these units?
   2. **[IF NOT]** What prevents you from stocking cold-climate heat pumps?

C3. Compared to other states, are cold-climate heat pumps in Michigan competitively priced?

1. Have costs been stable over time?
   [PROBE] Have costs differed from 2019 to 2020?
   [PROBE] Do you think that change is temporary?
2. **[MANUFACTURERS]** Has there been much variation in cost of parts and labor in the manufacturing of the cold-climate heat pumps?
3. **[DISTRIBUTORS]** Has there been much variation in cost based on availability of cold-climate heat pumps?

D. Demand/Adoption

I would now like to spend a few minutes talking about overall interest for cold-climate heat pumps in the market.

D1. Compared to other states, how much demand is there for cold-climate heat pumps in Michigan?

1. What do you see as the primary barriers or challenges that are restricting widespread adoption of heat pump technology in Michigan?
2. How do warranties for cold-climate heat pumps compare to warranties for other technologies (such as natural gas furnaces)?

D2. In 2020, did demand for cold-climate heat pumps in Michigan differ from 2019?

1. **[IF YES]** What do you think caused that change?
2. Do you think the change was temporary or will it be resolved?
3. Have there been any impacts on demand related to COVID-19, that you are aware of?
   [PROBE FOR DETAIL]

D3. **[MANUFACTURERS]** What feedback have you received from distributors in Michigan about heat pump technology adoption?

1. What about cold-climate heat pumps, specifically?
2. Is this different from other states?

D4. **[DISTRIBUTORS]** What feedback have you received from contractors in Michigan about heat pump technology?

1. Is this different from other states?

D5. Do you know of any promotions or trainings your organization does to increase awareness of cold-climate heat pumps among your customers in Michigan?

1. Does this differ from other states?
2. Is this different from other types of equipment?

D6. Specifically, what has your organization done to promote heat pump technology to distributors/contractors?

1. Have you offered trainings, informational pamphlets, sales/discounts, or something similar?

E. Solutions

In this final section, I'd like to shift gears a little to understand your thoughts on how Consumers Energy and other utilities could provide support to further the adoption of cold-climate heat pump technology.

E1. Is there anything you think utilities could do to improve the adoption of cold-climate heat pump technology in Michigan? **[PROBE FOR DETAIL; SOLUTIONS BEYOND INCREASING INCENTIVES]**
   1. In your opinion, where is the right place to offer an incentive to drive adoption of a newer product such as cold-climate heat pumps (downstream, midstream, or upstream)?
   2. Have you seen models for promoting the adoption of cold-climate heat pumps in other jurisdictions that Consumers Energy should consider?

E2. Are there any recent or upcoming advancements in heat pump technology that Consumers Energy should be aware of?

F. Closing

As we wrap up, I want to provide an opportunity for you to share anything I might have missed with my questions.

F1. Do you have any other comments or information you think might be useful for me to know given what we have talked about today?

F2. These are all the questions I have. As a thank you for your input, we'd like to send you a $75 gift card to Amazon, Target, or Meijer. Amazon and Target gift cards are virtual and would be sent to your email address within the next 5 to 10 business days. Meijer is offered as a physical gift card, which will be mailed to your preferred address. Alternatively, we can donate the $75 to your local United Way. Which would you prefer?
   1. Amazon
   2. Target
   3. Meijer
   4. Please donate to my local United Way

F3. **[IF G2=1 OR 2]** Could you please provide your preferred email address to receive the **[AMAZON OR TARGET]** virtual gift card?

F4. **[IF G2=3]** Let me ask the information we need to mail your gift card to the intended recipient—this could be you personally or anyone else of your choosing:
   1. First name of recipient:
   2. Last name of recipient:
   3. Could you please provide the street address we should use to send the gift card?

You should expect to receive your gift card by no later than **[DATE]**. If you have any questions, or have not received your gift card by **[DATE]**, please contact **[contact information]** and reference the Consumers Energy heat pump interview.

F5. **[IF G2=4]** In whose name should we make the donation to United Way? **[INCLUDE FIRST AND LAST NAMES OR COMPANY NAME]**

On behalf of Consumers Energy, I want to thank you for taking time to provide input, and have a great day. **[TERMINATE]**

Across building types, single-family homes could be most likely to convert to hybrid ASHP, though there are obstacles to conversion

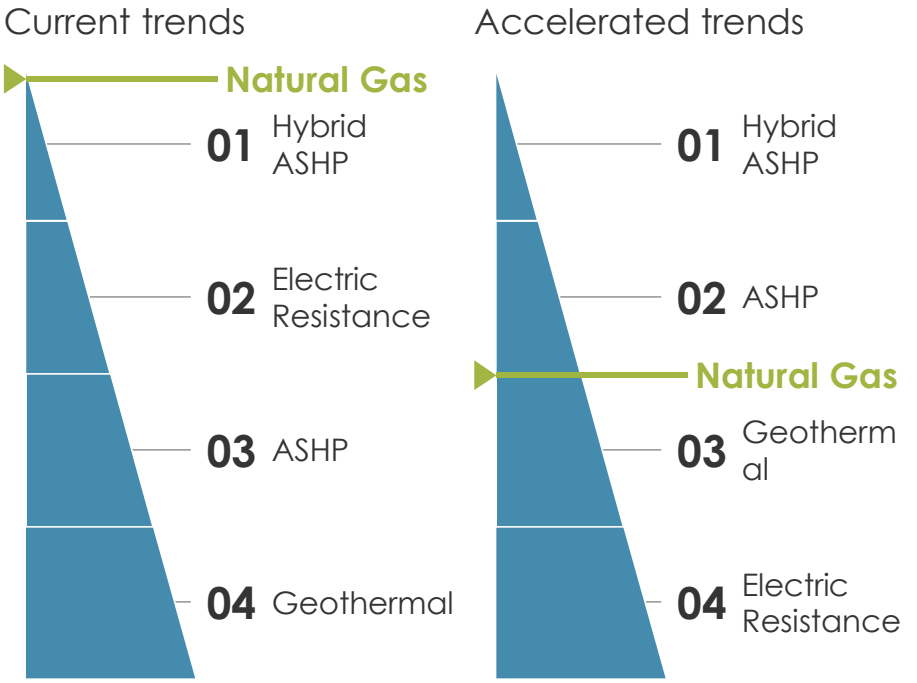
ILLUSTRATIVE ANALYSIS

Single-family homes – Urban

Considerations for converting away from natural gas space heating

- **Easier to convert**, due to less retrofit complexity
- **Individual decision-makers** (as compared to a co-op or HOA in a multi-unit building) enables more rapid decision-making to convert
- Lack of space may be a challenge, but **94% of single family homes are detached**, with more available space for heating appliances
- **Upfront cost of converting from natural gas to electric can be a deterrent** for many households
  - New gas furnace + installation: $ 4.500
  - New ASHP + installation: $12.000

Preferred technology based on trends assumptions



Compared to other building types, non-urban single-family homes may be able to more easily convert to geothermal space heating

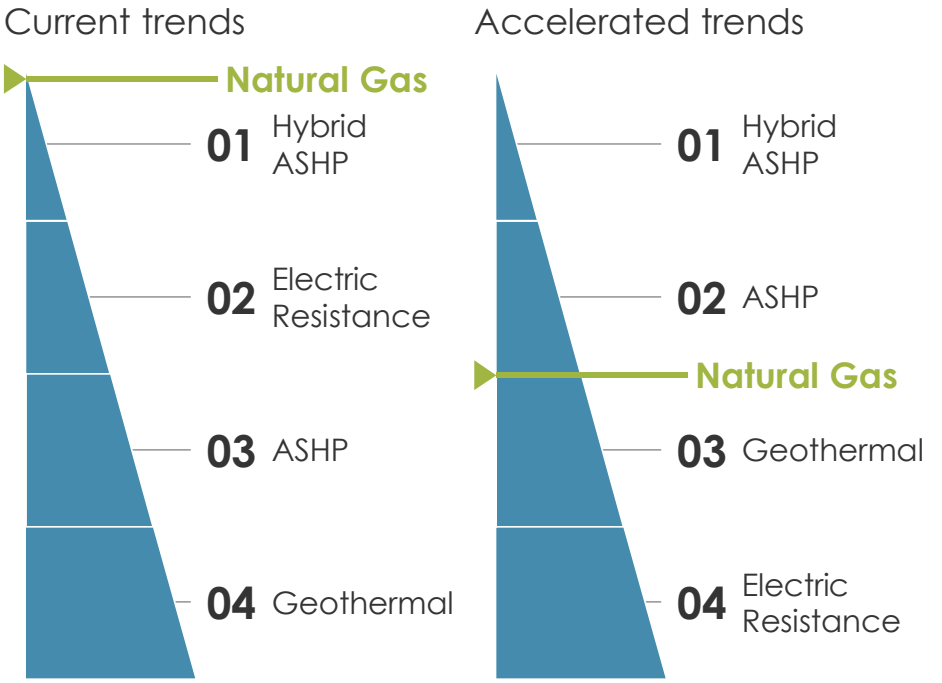
ILLUSTRATIVE ANALYSIS

Single-family homes – Non-urban

Considerations for converting away from natural gas space heating

- **Easier to convert**, due to less retrofit complexity
- **Available land** for technologies requiring more space
- **Individual decision-makers** (as compared to a co-op or HOA in a multi-unit building) enables more rapid decision-making to convert
- Located in least congestion areas, therefore **likely won't to require electric grid upgrade**
- **Upfront cost of converting from natural gas to electric can be a deterrent** for many households
  - New gas furnace + installation: $ 4.500
  - New ASHP + installation: $12.000

Preferred technology based on trends assumptions



Electrification is more challenging for multi-family home buildings compare to single-family homes due space constraints and stakeholder coordination

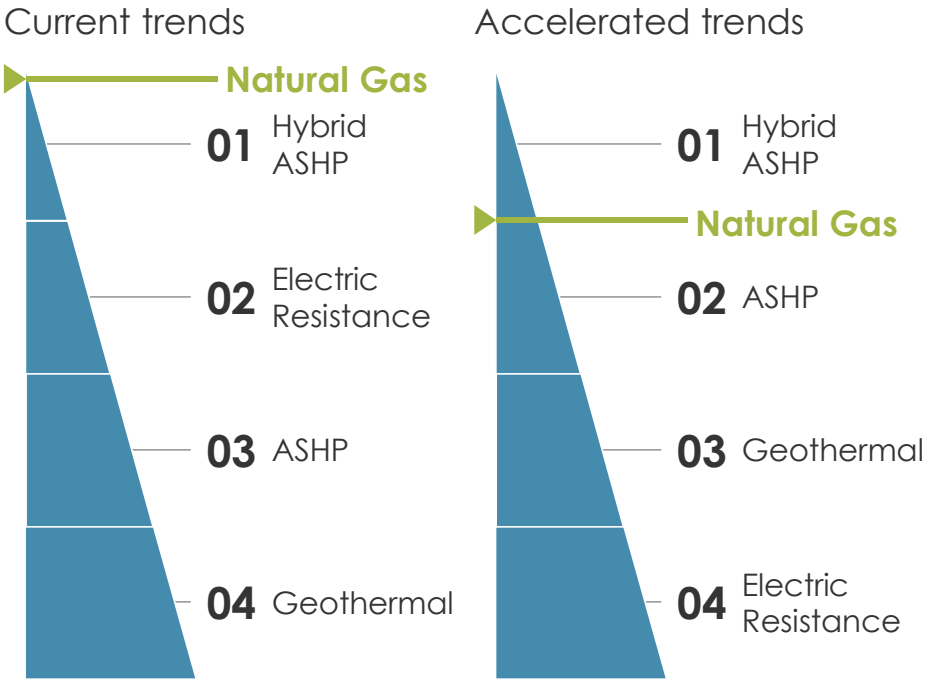
ILLUSTRATIVE ANALYSIS

Multi-family homes

Considerations for converting away from natural gas space heating

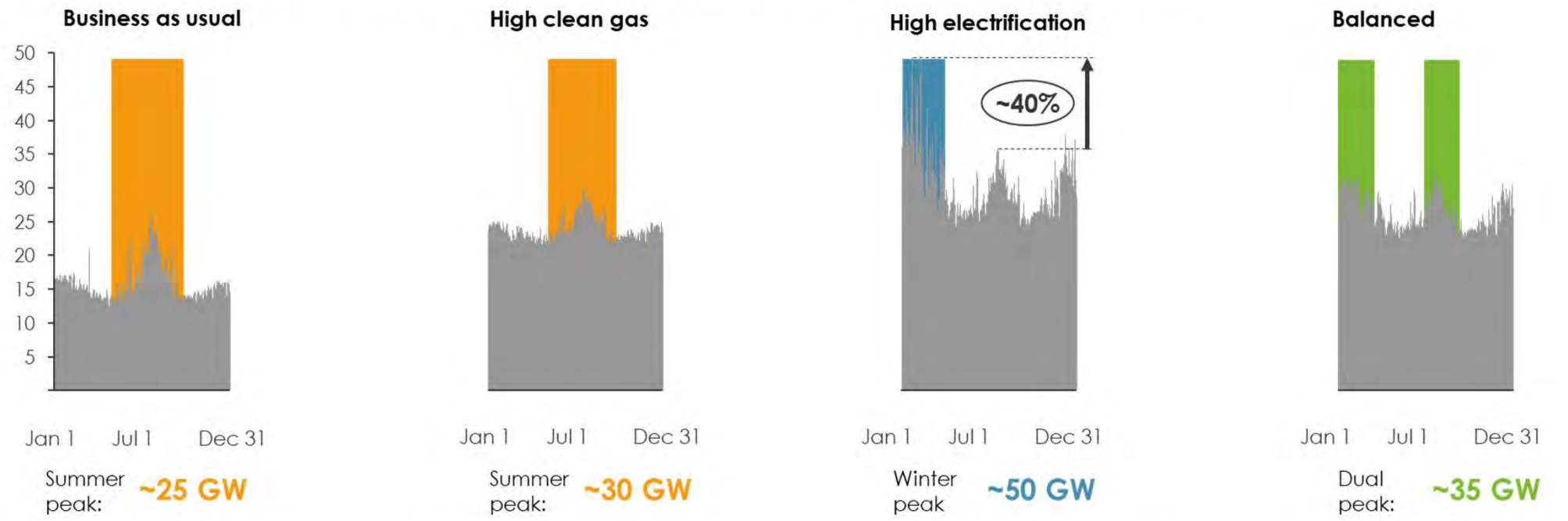
- Harder to convert, due to **complexity and costs associated with retrofit**
- **Lack of space** can make some technologies unfeasible
- **Collective decision** imposes additional challenge, as households with different preferences / willingness to invest, must agree upon technology
- Located in congestion areas, therefore **likely to require electric grid upgrade**

Preferred technology based on trends assumptions



Michigan Energy Load by Scenario

MI daily maximum electric load, from January 1 to December 31, 2050, GW

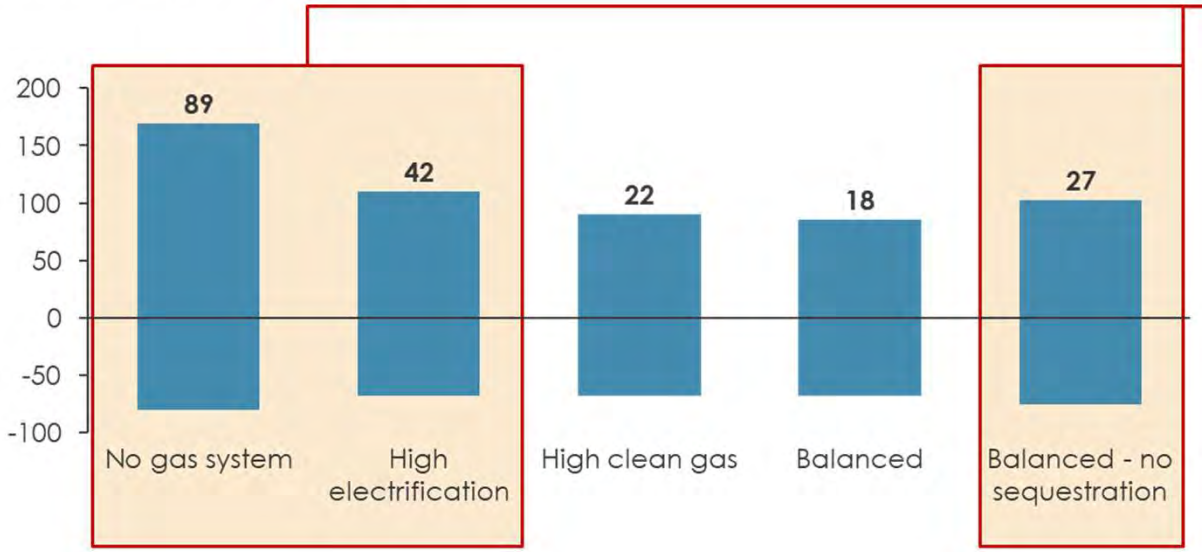


Winter peak with high electrification has significant cost implications due to additional electric T&D build out

Michigan Societal Cost Impact by Scenario

NPV of total system costs relative to reference case[1]

$B, 2020 – 2050, all of Michigan



Disallowing either the natural gas system or sequestration from the system results in **prohibitively expensive pathways**

1. **Gas distribution** enables cost effective heating
2. **Gas transmission is needed to supply gas to power plants that firm renewable power**
3. **Carbon sequestration** is needed to cost effectively negate emissions
4. Gas provides **system resiliency, diversification**, and energy for **hard-to-electrify end-uses**

1. Gas infrastructure costs based on high-level initial assessment. Granular data on Michigan-system pipeline inventory can be used to develop more detailed analyses

U21806-MNSC-CE-0039_ATT 4

State of Michigan
Department of Licensing and Regulatory Affairs

Michigan Public Service Commission

Renewable Energy and Electrification Infrastructure Enhancement and Development Grant

RESPONSE DOCUMENT

Bidder Name: Consumers Energy Company

ESTIMATED TIMELINE	
Issue Date	December 20, 2023
Inquiries Due (round one)	January 11, 2024
Reponses to Inquiries Posted	January 18, 2024
Inquiries Due (round two)	January 26, 2024
Responses to Inquiries Posted	February 5, 2024
Proposals Due	February 21, 2024
Proposals Posted Publicly	February 28, 2024
Public Comment Period End Date	April 12, 2024
Modified Proposals Due	April 29, 2024
Modified Proposals Posted Publicly	May 1, 2024
Anticipated Announcement of Grant Awards	September 2024
Anticipated Grant Start Date	November 15, 2024

PART III: WORK STATEMENT

III-A Purpose

The purpose of this Request for Proposals (RFP) is to obtain proposals from businesses, nonprofit organizations, local units of government, and tribal governments, for the purpose of planning, developing, designing, acquiring, or constructing renewable energy and electrification infrastructure projects. The MPSC may consider awarding up to 10% of the funding available to planning grants. The MPSC welcomes all technologies, project sizes, and locations to apply, consistent with the language outlined in Public Act 119 of 2023.

From the total amount of funding for grants awarded for electric vehicle fast-charging infrastructure, 25% of that total amount must be allocated for infrastructure that provides charging at a power level of 350 kilowatts or less and 75% of that total amount must be allocated for infrastructure that provides charging at a power level of more than 350 kilowatts.

NOTE: The MPSC reserves the right to award funds for an amount other than that requested and/or request changes to, or clarification of any and all proposals received as a result of this RFP.

III-B Problem Statement

This grant will support renewable energy and electrification infrastructure enhancement and development projects.

III-C Objectives

Prioritized infrastructure or planning projects funded hereunder will meet one or more of the MI Healthy Climate Plan goals, specifically to:

1. Commit to environmental justice and pursue a just transition
2. Clean the electric grid
3. Enable electric vehicle charging infrastructure and increase public transit
4. Repair and decarbonize homes and businesses
5. Drive clean innovation in industry
6. Protect Michigan's air, land, and water

III-D Tasks

The tasks outlined below must be included in an application for either a renewable energy and electrification facility or program (infrastructure) grant or a renewable energy and electrification planning grant.

A. Renewable Energy and Electrification Facilities or Program Infrastructure Grant applicant(s) must include the following to be considered for an award:

1. Submit an impact study of the project that includes an analysis of the following:
   a. Potential cost savings.
   b. Environmental impacts. In calculating the carbon emission reductions, a life cycle approach utilizing the Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) Model developed by Argonne National Laboratory is preferred. Emission must be expressed in terms CO2e (carbon dioxide equivalent).
   c. Local economic benefits.

   Note: A utility, at its sole discretion, may prepare a single impact study covering the utility's service territory that accounts for likely proposals, evaluates regional opportunities, and minimizes or eliminates the need for repetitive studies.

2. Submit details addressing how the proposed project will align with the governor's MI Healthy Climate Plan.
3. Submit a detailed project timeline and Gantt chart. The estimated grant start date is November 15, 2024. Projects must be completed by August 15, 2026 for the portion of the project being funded by the grant.

B. Renewable Natural Gas (RNG) Infrastructure Grant applicant(s) must include ALL of the following to be considered for an award:

"Renewable natural gas" or "RNG" means methane derived from organic material and degradable carbon sources, including, but not limited to, carbon sources and materials sourced from municipal solid waste, plant materials, or food waste. Renewable natural gas injected into a pipeline for downstream use must meet pipeline quality specifications.

1. Submit an impact study of the project that includes an analysis of the following:
   a. The project details, including the location of renewable natural gas and the proposed interconnection.
   b. The cost estimates for the interconnection, metering, and gas conditioning equipment needed to connect to an existing pipeline system.
   c. A summary of the environmental and health impacts of the project, including the forecasted emission reductions. In calculating the carbon emission reductions, a life cycle approach utilizing the Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) Model developed by Argonne National Laboratory is preferred. Emission must be expressed in terms CO2e (carbon dioxide equivalent).
   d. Any local economic impact from the RNG infrastructure development.
   e. The end-use application for the RNG infrastructure with a focus on projects being used for opportunities in this state.
2. Submit details addressing how the proposed project will align with the governor's MI Healthy Climate Plan.
3. Submit a detailed project timeline and Gantt chart. The estimated grant start date is November 15, 2024. Projects must be completed by August 15, 2026 for the portion of the project being funded by the grant.

C. Renewable Energy and Electrification Facilities or Program Planning Grant applicant(s) must include ALL of the following to be considered for an award:

1. Submit a narrative including all of the following information:
   a. Explanation of what planning will be taking place and how the grant award will be spent.
   b. Explanation of the future project(s) which the planning is being conducted for.
   c. Detailed Timeline and Gantt chart for the planning to be conducted and the future project being planned for. The estimated grant start date is November 15, 2024. Planning must be completed by August 15, 2026 for the portion of the project being funded by the grant.
   d. Potential impact to Michigan citizens and businesses, including how the planning grant applicant intends to engage affected or surrounding community members and stakeholders in planning and project design and/or implementation.
   e. How the future project(s) the planning is being conducted for will align with the governor's MI Healthy Climate Plan.

2. Identify potential funding sources to undertake construction of facilities or implementation of programs that a planning grant is being conducted for.

PART V: INFORMATION REQUIRED FROM APPLICANT(S)

Applicant(s) must submit one proposal. **Electronically submitted proposals must have a scanned signature or e-signature** and cannot exceed 15 MB.

Applicant(s) must provide responses to each section below. **The RFP Response Template document can be found on the Renewable Energy and Electrification Infrastructure Enhancement and Development Grant webpage.** Be as descriptive as possible and answer each question in its entirety; some questions have multiple components. In your responses, provide a straight-forward, concise description of the applicant(s)'s ability to meet the requirements of the RFP.

Questions that do not apply should be answered "N/A."

V-A Identification of Organization

Applicant will provide the following:

1. State the full name and address of the organization.
2. The organization's federal identification number.
3. The organization's telephone numbers.
4. What percentage of the organization is located in Michigan.
5. The organization's SIGMA ID number. Refer to Section I-B, Eligibility Requirements.
6. The organization's SIGMA ordering mail code Refer to Section I-B, Eligibility Requirements.
7. Name of the authorized signer(s) for any future grant agreements, their title, telephone number, fax number, and electronic mail address.

Bidder response:

1. Consumers Energy Company
   One Energy Plaza
   Jackson, MI 49201
2. Federal ID Number: 38-0442310
3. 800-477-5050
4. Company is 100% located in Michigan
5. SIGMA ID number, CV0018795
6. SIGMA Address Code: 008
7. Holly Bowers
   Vice President, Gas Engineering and Supply
   Phone: 517-740-3232
   Fax: 1-800-363-4806
   Email: holly.bowers@cmsenergy.com

V-B Authorized Negotiator

State the name of one (1) contact person and their title, telephone number, fax number, and electronic mail address. The contact person must be authorized to be the negotiator for the proposed Grant Agreement with the State of Michigan.

Bidder response:
Neal Dreisig
Sr. Strategy Manager
Phone: 989-239-8071
Fax: 1-800-363-4806
Email: neal.dreisig@cmsenergy.com

V-C Project Summary

Please provide a project summary not more than 500 characters in length.

Bidder response:
The proposed network geothermal Planning Project supports Public Act 119 of 2023 and objectives of the MI Healthy Climate Plan including environmental justice, decarbonizing homes and businesses, and clean innovation energy hubs. The Project seeks to site, configure, model and assess cost and benefits for a network geothermal system that best supports environmental justice, carbon reduction, energy efficiency, and energy cost savings.

V-D Method for Addressing the Problem

State in succinct terms how the applicant(s)'s proposed project will support renewable energy and electrification infrastructure enhancement and development. Refer to Section III-B, Problem Statement.

Bidder response:
The Planning Project is an electrification technology and infrastructure development project that will identify, assess and plan for the most cost effective and energy efficient location to electrify natural gas end uses using network geothermal system technologies that are mature and readily available today.

V-E Project Objectives

Explain how the applicant's infrastructure or planning project will meet the goals of the MI Healthy Climate Plan. Refer to Section III-C, Objectives. Also include any other identified project metrics that will be included in the project status reports as referenced in Section IV-B.

Bidder response:
The network geothermal Planning Project supports MI Healthy Climate Plan goals by reducing emissions related to heating Michigan homes and businesses 17 percent by 2030, and achieving economy-wide carbon neutrality by 2050. The MI Healthy Climate Plan says that "reaching our mid-century milestone will require particularly substantial effort and innovation in the sectors of our economy that are hardest to decarbonize, including industry, buildings and housing, and agriculture." Network geothermal uses mature technology innovatively to maximize energy efficiency and cost of energy in the most impacted regions.

1) **Commit to environmental justice and pursue a just transition**. With efficiencies up to 600%, network geothermal systems provide superior cost of energy savings and work best in regions with diverse energy loads and the patterns of those loads. Diverse load profiles makes low-

income neighborhoods often adjacent to industrial parks ideal for planning. Planning activities will assess these regions, using the Michigan Environmental Justice (MiEJ) screen, that best fit network geothermal system profiles. Additionally, planning activities support the Michigan State Housing Development Authority (MSHDA) 2022 Statewide Housing Plan goals, as described under "MI Healthy Climate Plan" section.

2) **Clean the electric grid.** The Planning Project will assess how network geothermal systems in specific locations mitigate seasonal peak electric loads and intermittency of renewable energy sources in an electrified future. With energy efficiencies upwards of 600%, network geothermal heating and cool capabilities could meaningfully mitigate increased costs associated with the buildout of electric infrastructure, therefore limiting the energy burden for cleaner electricity.

3) **Repair and Decarbonize homes and businesses.** The Planning Project directly supports eliminating emissions tied to the combustion of natural gas users using the most energy efficient technology available today. The network geothermal system will reduce approximately 8 tons of Carbon Dioxide equivalents (CO2e) per year per home using the Greenhouse Gases (GHG), Regulated Emissions, and Energy Use in Technologies (GREET) Model developed by the Argonne National Laboratory. The magnitude of overall carbon reduction will be assessed during planning and dependent on the size of the network.

4) **Drive clean innovation in industry.** As described in the MI Healthy Climate Plan, work should "encourage clean innovation hubs where private enterprises strategically co-locate and collaborate to develop and deploy new, cleaner manufacturing technologies and conduct research and development to reduce emissions from hard to decarbonize industries."[1] The essence of network geothermal systems is their hub-like ability to scale and pass benefits along to those connected to the network.

5) **Protect Michigan's air, land, and water.** The Planning Project supports air quality in Michigan by reducing emissions and mitigates environmental impacts associated with sourcing, transporting and burning fossil natural gas.

Primary metrics the Project will measure against include:

- Cost of energy savings per end user, measured in annual dollars saved
- Net energy efficiency impact, measured in the ratio of useful energy delivered to the amount of energy input into the system
- Carbon reduction, measured in tons CO2e and $/ton CO2e

V-F Work Plan

Provide a detailed work plan based on the requirements outlined in Part III-D Tasks. The applicant's impact study must be attached to the application. If applicant is applying for a Planning Grant, the Planning Narrative should be described in this section.

Bidder response:

1) Planning Project Narrative

[1] MI Healthy Climate Plan. (2022). Retrieved from MI Healthy Climate Plan (michigan.gov)

A. Planning Explanation

A networked geothermal system is a network of ground source heat pumps connected via common ground circuits as shown below in Figure 1. Network geothermal systems have two unique attributes. They share energy between demand centers, where a business that rejects heat for cooling purposes can be used down the street by a home for heating purposes, thereby greatly increasing energy efficiency. Secondly, these systems store excess heat in the earth during cooling seasons and withdraw that same heat months later during heating seasons just like a natural gas storage field. For these reasons, network geothermal systems drive energy efficiencies upwards of 600%.

Networked geothermal systems are mature technologies, used for decades on college campuses, and well considered the most energy efficient form of heating and cooling. Two natural gas utilities, Eversource and National Grid, have network geothermal demonstrations approved through public service commissions today with plans to expand.

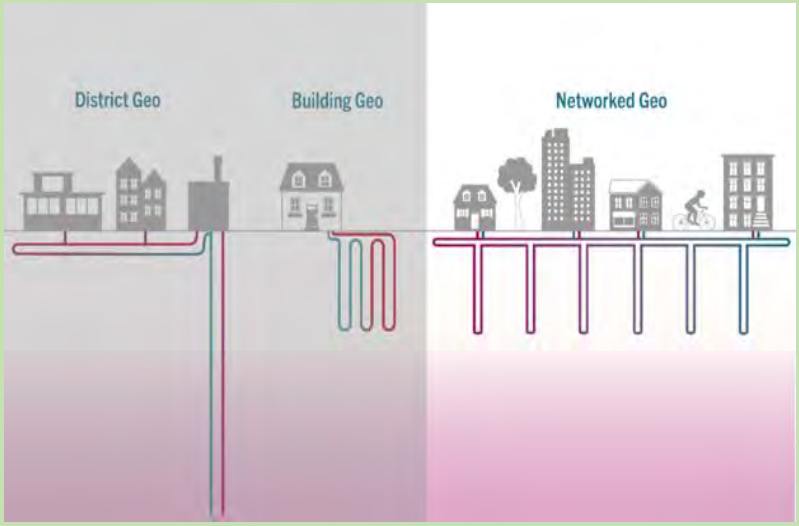


Figure 1 – Various geothermal system configurations

The outcome of the Planning Project is the following:

- Site and configure a network geothermal system in Consumers Energy's gas service territory given factors such as demographics, climate, geology, community interest, energy use diversity, and impacts to the existing system.
- Determine net energy impacts of the network geothermal system including incremental power consumption of heat pumps compared against energy efficiency gains.
- Determine additional costs to the electric distribution system and electric capacity needed to support a network geothermal system.
- Assess potential impacts to energy market prices due to additional energy demand.
- Determine how to best use existing tax subsidy incentives to reduce network geothermal system cost.
- Determine cost benefit analysis for homes and businesses on a network geothermal system including analysis for specific customer classes.
- Quantify the carbon reduction potential for the network geothermal system.
- Assess the scale of network geothermal systems throughout Consumers Energy's gas service territory.

Before the grant start date, a service territory wide assessment will occur to identify candidate locations ideal for network geothermal systems. Initial due diligence indicates Flint, Lansing, Jackson,

Battle Creek and Kalamazoo are potential sites. Initial community engagement activities will also occur before the grant start date to better understand community participation interest. Community engagement is described in further detail below.

Planning will occur in six (6) phases: site identification, site-specific geological evaluation, energy modeling, thermal resource assessment, infrastructure and implementation design and cost benefit planning. Grant award funds will be used to complete these six (6) phases.

i. **Site identification**: Site identification will be informed by service territory wide due diligence showing optimum locations for a network geothermal system based on MiEJ screen, population density, annual gross domestic product (GDP), GDP growth, demographic composition, diversity of energy load, current natural gas consumption, customer feedback and existing electric and gas infrastructure. These criteria will inform which location best supports disproportionately impacted communities, customer affordability and the MI Healthy Climate Plan. This phase will assess all criteria and select a site for further planning.

ii. **Geological evaluation**: Site specific geological evaluation will occur in two steps, deep (step one) and shallow (step two) evaluations. An initial deep test boring will evaluate geothermal capabilities of the site. Deep test borings will also evaluate glacial overburden and underlying bedrock characteristics to a depth of several hundred feet. The deep boring will provide thermal conductivity testing results to evaluate and obtain preliminary geothermal design characteristics.

Step two of the geotechnical evaluation will evaluate the shallow subsurface conditions to obtain parameters necessary for design of the overall system, including placement of network piping. Geotechnical investigations consisting of drilling soil test borings may include Standard Penetration Testing (SPT), undisturbed soil sampling using Shelby tubes, and other in-situ tests such as vane shear or groundwater monitoring. An overall subsurface geotechnical field assessment will be derived consisting of logging each test boring, performing soil/rock testing, and fluid testing.

Results of the field investigation and any corresponding recommendations will be documented in an engineering report including logs of test borings, a test boring location plan, results of thermal analysis, a summary of findings, and present evaluations, conclusions, and recommendations for the geothermal system.

iii. **Energy Modeling**: A thermal energy model will be developed using the determined geological characteristics. The thermal model will assess a network up to ten industrial/commercial structures and twenty residential structures. The model will be broken into clusters based on phasing and construction, which will be used in TRNSYS modeling software to determine the locations of all thermal energy resources within the system. The modeling software takes all energy load diversities and energy sharing into account when designing thermal resources.

This Phase will also look at incremental energy requirements for heat pumps and the associated energy load profiles across peak heating and cooling seasons to understand how the network geothermal system impacts electric loads, capacity requirements and market prices.

iv. **Thermal Resources**: This phase involves design and configuration of the network including geothermal heat exchangers to optimize energy and available space. This phase will also assess existing utilities within the street right of way (ROW). Other potential thermal resources such as water retention ponds, surface water systems or wastewater energy transfer (WET) systems that capture and reject heat into the community's main sewer line will also be assessed.

v. **Infrastructure Planning and Implementation**: This phase includes planning for mechanical and civil work to produce a conceptual distribution system design, geothermal fields, building interface, pumping stations, and central plant facilities as applicable. This phase also includes system descriptions, process diagrams, equipment lists, schematic arrangement drawings of central facilities, geothermal fields, and building interfaces. The outcome of this phase will be a schedule and conceptual execution plan including contracting methodology for development, construction, and operation of the system.

vi. **Cost benefit assessment**: Using the work in previous phases, this phase will develop a capital estimate, operations and maintenance estimate, infrastructure requirements, market price impacts, subsidy incentives, energy and associated cost savings, existing building retrofits required to connect to the network, and carbon reduction to determine the overall cost benefit attributable to specific customer classes. Capital cost estimates will include design, engineering, permitting, borehole drilling, drilling rig setup, ground circuit installation, heat pumps or circulating pumps, service connections to buildings, building envelope conversions and public ROW work.

B. Future project

Planning activities described above will provide the business case for a network geothermal system project at the selected site. A future project would continue with community engagement (described in detail below) and Michigan Public Service Commission collaboration to determine the appropriate path forward given results of planning activities.

Primary objectives from an initial project would be to demonstrate the reasonableness of scale, bill savings to customers, performance of shared energy circuits, energy efficiencies, and optimum configurations for Michigan's geology and the State's climate.

C. Timeline

See response box below for discussion on Planning Project timeline along with Attachment C, Gantt Chart.

D. **Impacts to Michigan citizens and businesses**

i. Planning activities and potential future projects have significant positive impacts to citizens and businesses, summarized below. Network geothermal is unique in that diverse energy loads are shared across the network, reducing energy consumption. In addition to energy sharing, network geothermal systems are preferred over air source heat pumps (ASHPs) due to superior energy efficiencies. The inherent properties and

heat transfer characteristics of water and soil allow network geothermal systems to provide efficiencies upwards of 600%. This is due to the ground maintaining stable temperatures all year, providing a reliable heat source compared to ambient air. Additionally, groundwater and soil are denser allowing better heat transfer characteristics than air. This means network geothermal systems obtain more heating energy per unit volume, which means greater energy efficiency. Further details are discussed in subpart E, MI Healthy Climate Plan.

Positive impacts to homes and businesses:

- Energy efficiencies upwards of 600%;
- Cost of energy savings due to high efficiencies;
- Less risk associated with water pipes as compared to natural gas pipelines;
- Emissions eliminated from combustion of fossil natural gas;
- Strong support for disproportionately and environmentally impacted communities;
- Economic development for businesses that support drilling, heating ventilation and air conditioning (HVAC), polyethylene pipe manufacturing and excavation.
- Excellent opportunity for clean energy job transition.

ii. A primary objective of planning activities and potential future project is understanding the willingness of existing natural gas customers to adopt geothermal heating technology. As noted, initial community engagement will occur ahead of the grant start date to educate on geothermal benefits, gauge participation interest and identify anchor users for specific locations. Anchor users are defined as higher load entities that reside near homes and other businesses.

As part of community engagement, a Community Stakeholder Engagement (CSE) Plan will be developed. A CSE uses a structured approach to building relationships with current stakeholders and disadvantaged communities. This framework is essential for proactively engaging potentially affected communities in upcoming projects, aiming to deliver community benefits, quality employment opportunities, and address any potential environmental concerns in a meaningful and impactful manner.

Upon reaching the grant start date, site selection will occur based on prior assessments and community feedback as described above. Concurrently with planning activities, a Stakeholder Engagement Group (SEG) will be created, ensuring a diverse representation of community priorities.

Throughout and after planning activities, CSE will be implemented. The two-way engagement will be dynamic, allowing for flexibility and adjustments based on insights gained through planning activities and engagement efforts. This approach will ensure a potential future project aligns with the evolving needs of community stakeholders. Feedback and insights collected from engagement activities will undergo a thorough analysis, serving as the foundation for continuous updates to engagement strategies and refining community priorities.

E. MI Healthy Climate Plan

The Planning Project directly contributes to the MI Healthy Climate goal of reducing emissions associated with heating homes and businesses 17% by 2030, achieving economy-wide carbon

neutrality by 2050 and maintaining net negative GHG emissions thereafter, while supporting disproportionately and environmentally impacted regions.

Environmental Justice and Pursue a Just Transition

As noted in the MI Healthy Climate Plan and research performed by Rewiring America, heat pump technology could provide immediate savings to Michigan homes. Network geothermal systems, which use heat pump technology, provide the highest cost of energy savings and are ideal for disproportionately impacted regions. The diverse energy load patterns of these regions where homes are near commercial and industrial sites make for ideal network geothermal systems.

In the coming decades, higher income residents are likely to adopt isolated electrified end uses first, leaving low-income customers subject to the fixed costs of the remaining natural gas network. Network geothermal evolves the natural gas system grid by grid, starting with low-income regions, so no one is left behind.

a. Michigan Environmental Justice (MiEJ) screen

The MiEJ screen will be used to help identify candidate locations for planning. The MiEJ screen uses 26 indicators summarized by 4 overall criteria to assess overall community impacts. Environmental indicators look at risk, pollution, or exposure to nearby facilities. Health and socioeconomic indicators look at a population's vulnerability or to pollution. As noted, "the screening tool is a useful first step in understanding or highlighting locations that require further review."[2] Based on initial screens, Flint, Lansing, Jackson, Battle Creek and Kalamazoo are potential sites for further evaluation.

b. MSHDA State-wide Housing Plan

Planning activities also support specific goals for the MSHDA 2022 Statewide Housing Plan. Planning activities will align with these goals throughout the process:

Goal 1.5: Increase opportunities for resident input throughout the development process.
Goal 4.3: Ensure that new housing development meets State climate and healthy housing goals and is affordable for the lifetime use of the building without increasing costs to residents.
Goal 4.5: Increase environmental sustainability, energy efficiency, and weatherization in housing rehabilitation and/or preservation.

c. Just transition of workforce

There are similarities between shared geothermal networks and natural gas networks, including materials, installation methods of underground pipe, permits, drilling boreholes, right of way work, and monitoring the system conditions to ensure safety and reliability service for customers. There are low barriers to transition due to these close similarities. For example, fluid pipes in network geothermal systems use the exact same polyethylene pipe material as natural gas distribution systems. This enables a quicker and more equitable transition than the current building-by-building approach for air source heat pumps.

Clean the Electric Grid

Network geothermal systems support a cleaner electricity grid by using the lowest total energy over the course of a year to heat and cool homes. Specifically, network geothermal systems reduce peak heating and cooling loads and mitigate the need to potentially expand electric infrastructure. This benefit will become more valuable as shoulder seasons potentially become shorter.

[2] MiEJ Screen. (2023), retrieved from MiEJScreen-Factsheet.pdf (michigan.gov)

Analysis performed by HEET in Figure 2 shows the incremental peak load in high demand seasons using various electrification technologies for space heating.[3] With efficiencies upwards of 600%, it is clear network geothermal systems have negligible impact to peak electric load in a highly electrified future. This ultimately helps citizens of Michigan avoid cost impacts of adding new electric capacity.

Like battery storage, network geothermal systems use the earth as a thermal battery. In this way, intermittency issues tied to solar and wind energy are mitigated by requiring less energy during off-peak hours.

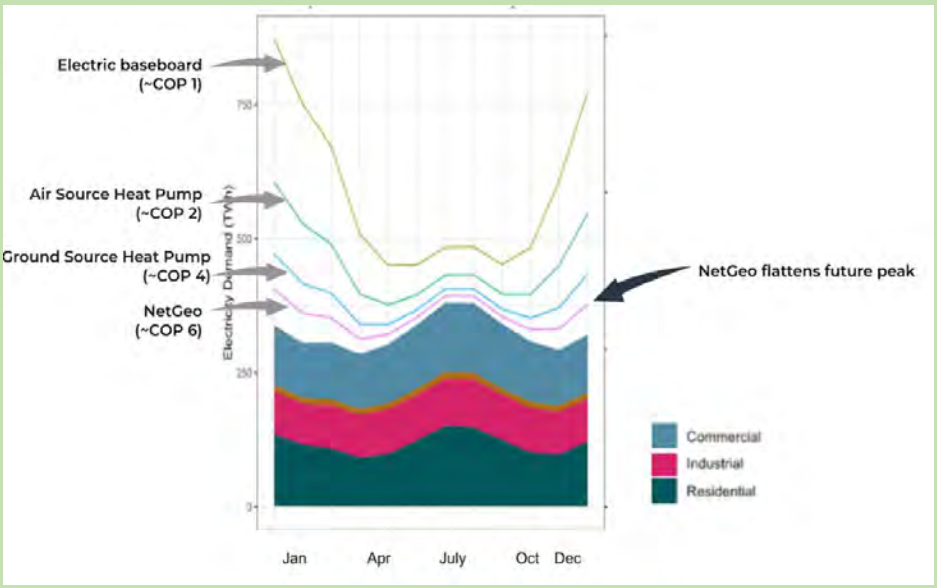


Figure 2 – Peak electric loads by technology

Repair and Decarbonize Homes and Businesses

The MI Healthy Climate Plan assessed that "replacing traditional fossil fuel use with cost-effective technologies that rely on electricity" can effectively decarbonize building heating.[4] The Planning Project will determine the extent of carbon reduction in Michigan using network geothermal systems. With natural gas showing a lifecycle emission of approx. 80 grams CO2e per megajoule, network geothermal systems could demonstrate meaningful impact in reducing carbon when scaled.

Prior analysis by Consumers Energy, confirmed by 3rd party experts, indicates that the combination of clean fuel technologies provides the most cost-effective solution to reaching the MI Healthy Climate Plan goals. Each technology including network geothermal, air source heat pumps, renewable natural gas, hydrogen, carbon capture, synthetic gas and long-term storage all reduce carbon affordably in unique sectors of society. Network geothermal systems may provide the most cost-effective form of electrification for low-income regions which this Planning Project seeks to understand.

Drive Clean Innovation in Industry

The Planning Project seeks to understand the scalability of network geothermal using a hub-like approach. Like municipal water and natural gas systems, network geothermal systems can be added onto making the system more diverse and energy efficient. Starting with a central hub network,

[3] HEET. (2023). Networked Geothermal. Retrieved from Networked Geothermal Wiki (gastogeo.wiki)
[4] Department of Environment, Great Lakes, and Energy. (2022). MI Healthy Climate Plan. Available at MI Healthy Climate Plan (michigan.gov)

planning activities will focus on the extent to which network geothermal can become scaled regional hubs.

Protect Michigan's Air, Land and Water

As noted above, the Planning Project supports air quality in Michigan by reducing emissions associated with sourcing, transporting and burning fossil natural gas. Network geothermal systems are ideally installed in existing rights of way for existing public utilities, which mitigates impact to undisturbed land and areas not already addressed with existing permits.

2) Potential funding sources to implement of project(s)

Specific for this planning grant request, Consumers Energy would seek funds for a future project through collaboration with the Michigan Public Service Commission and a potential future rate case.

Applicant must include a timeline and Gantt chart. Please attach as a separate document if necessary.

Bidder response:

Timeline for planning starts in December 2024 and continues through October 25. Prior to these planning efforts, a service territory wide assessment and initial community engagement will occur throughout 2024 to locate candidate sites and introduce the network geothermal technology to communities. At the start of the grant period, a site will be identified for detailed planning activities, which runs through geological assessment, energy modeling, thermal resource configuration and development of an implementation plan and cost benefit analysis. Planning work will complete on or before October 2025 with post community engagement occurring after. A Gantt Chart for these activities is shown on Attachment C.

	Finish
Identify and assess candidate sites	Dec-24
Establish stakeholder matrix	Dec-24
Site identification and conceptual network design	Feb-25
Engage community on assessment, technology and timeline	Feb-25
Engage key businesses with potential to serve as system anchors	Mar-25
Site-specific geological evaluation	Apr-25
Energy modeling	May-25
Thermal resource assessment	Jun-25
Infrastructure design	Aug-25
Implementation approach	Oct-25
Post-planning engagement with community	Jul-26

V-G Management Summary

(1) Describe management procedures that will be used by the organization to complete the proposed project.

(2) Describe the organization's quality control measures, including measures for ensuring compliance as well as eligibility determination. In your description, include information regarding separation of duties.

(3) Selected applicant(s) must provide fiscal control and financial accounting procedures that will

assure that grant funds will be accounted for and properly dispersed in a way that will allow the Issuing Office to clearly review and verify all grant related expenditures. Describe the organization's internal control policy:

- Identify the type of accounting system/software the organization will use to account for grant funds.
- Identify how duties will be separated.
- Describe how the organization will account for grant funds, i.e., will grant funds be placed in a separate bank account, will the grant funds be assigned a unique code(s) within the organization's overall accounting system. Ensure funds are maintained in a non-interest-bearing account.
- Indicate whether internal and external audits of the organization's operations are performed on an annual basis. Selected applicant(s) must provide a copy of the organization's most recent audited financial statement as well as a copy of the organization's most recent single audit as required by OMB Circular 200.36.

(4) Describe your agency's data security plan.

Bidder response:

1) Management procedures to be used include standard financial governance and project management practices. Financial governance refers to the review and potential approval of budgets, current year funding changes and financial management of contracts. Planning activities will also use standard project management practices referring the routine review of project status measured against their progress in achieving pre-defined metrics.

2) Consumers Energy is audited annually by a public accounting firm and has received unqualified opinions. Additionally, the Company has a separate public accounting firm, KPMG who performs internal audits annual based on a three-year risk assessment.

3) The Company will use our existing system SAP (System Applications and Products) to account for the potenial of grant funds. Proper internal controls, which would include segregation of duties, have been established and are reviewed as a part of the external and internal audits annually. The Company's management annually evaluates the effectiveness of its internal control over financial reporting and has deemed the controls effective. These controls are also audited annually by our external auditors. The Company will use various unique identifiers within our accounting system, SAP, to ensure all grant funds are properly accounting for and segregated from other funds. As noted above both external and internal audits are conducted on an annual basis. Below is a link to Consumers Energy's most recent financial filing.[5]

4) Consumers Energy has a comprehensive cybersecurity program aimed at securing our sensitive data and critical infrastructure. In addition, Consumers Energy has a privacy program aimed at ensuring data is handled appropriately at the company. Both programs include a number of technical controls, polices, procedures, standards and awareness activities.

V-H Personnel

Selected applicant(s) must be able to staff a project team that clearly possesses skill and experience relative to the project.

[5] Consumers Energy. (2024). Financial Information. Retrieved from CMS Energy Corporation - Investors - Financial Information - Annual Reports

1) Applicant(s) must identify the authorized contact person and key personnel to be involved with this project by name and title and provide a brief summary of their experience, qualifications, and the work to be performed.
2) If other organizations will be playing a role in the proposed project, provide sufficient background information that will give the MPSC a reasonable understanding of each organization's qualifications.
3) Include a detailed organizational chart including names, titles, and geographic location of all individuals that will contribute to the project.
4) If personnel or other organizations have signed a confidentiality agreement, attach a copy along with a list of personnel and the date that the confidentiality agreement was signed.

Bidder response:
The Planning Project will be staffed and managed with industry leading experts covering end to end details of the network geothermal technology. An organizational chart is shown in Figure 3 with qualifications for individuals described.

1) Authorized contact person: The following individual is the authorized contact person on behalf of Consumers Energy:

Neal Dreisig
Sr. Strategy Manager
989-239-8071
neal.dreisig@cmsenergy.com

2) Consumers Energy

- Neal Dreisig, Sr. Strategy Manager: Neal Dreisig is a Sr. Strategy Manager responsible for overseeing the decarbonization strategy for Consumers Energy's natural gas system. This includes renewable natural gas, hydrogen, carbon capture, electrification technologies and other alternative low carbon fuels. Prior to this, Neal held multiple roles within project management and generation operations. Neal holds a Bachelor of Science degree in construction management from Michigan State University and a Master of Science degree in Management from Colorado State University. Neal is also a certified Project Management Professional.

- Seth Epstein, System wide energy efficiency planning: Seth Epstein is Senior Product Manager at Consumers Energy where he leads the residential demand response product - AC Peak Cycling. Seth has deep knowledge of residential and commercial utility energy efficiency and demand response program design and delivery. He earned his master's degree in Natural Resources and Environment with a certificate in Industrial Ecology at the University of Michigan in Ann Arbor and his bachelor's degree in philosophy at St. Lawrence University in New York.

- Brian Snyder, Assessment Planning Engineer. Brian manages assessment planning, threat assignment, and risk analysis for the Transmission (gas pipeline) Integrity Management Program at Consumers Energy. This includes inline inspection, direct assessment and direct examination, and the analysis of probabilistic risk modeling to build forecasted work plans and budget. Previous experience includes HVAC design and energy modeling for commercial buildings specializing in healthcare applications. Brian has a Bachelors of Science, Mechanical Engineering, from the University of Michigan Dearborn, a licensed Professional Engineer in the State of Michigan, and a LEED Accredited Professional

- Dena Isabell, Community Engagement Manager. Dena leads statewide engagement internally and externally for major projects including coal plant decommissioning, gas pipeline projects, major hydro facility investments, significant electric reliability projects and all non-solar renewable energy development. Dena has an MBA from Ferris State University and a Bachelors in Biosystems Engineering from Michigan State University.

Salas O'Brien
Salas O'Brien is an engineering and technical services firm focused on advancing the human experience through the built environment. Salas O'Brien provides decarbonization expertise, leadership, and support to plan, design, and implement ground source heat exchange and solar photovoltaic systems that achieve exceptional operational cost savings and drastic carbon emissions reductions. To date, more than 400 geothermal projects are completed, providing over 84,000 tons of system capacity; and, over 100mW of installed solar, over 50mV of fuel cells, and over 200 central plant replacements and modernizations.

- Jeff Urlaub, Principal in Charge: Jeff has been responsible for the design and implementation of innovative, environmentally responsible solutions for clients across the United States. Jeff has more than 20 years of professional engineer experience in HVAC design, project management, design of engineered systems and mechanical services, with an emphasis in renewable energy, energy analysis and geothermal design.

- Rick Humphries, Project Manager: Rick is a mechanical engineer with a background in thermal systems design. Over the past decade he has focused on the creation of project companies to serve specific energy needs. Rick approaches projects in a holistic way, considering the application of technology, market drivers, and economic incentives to produce outcomes.

- Brian Urlaub, Geothermal Exchange Expert: Brian oversees Salas O'Brien's geothermal projects and is involved in procurement, design, and project management. He has 25 years of experience in the geothermal industry, beginning with installation and servicing in the field, then transitioning to design and sales. He is adept at working with clients to develop solutions that meet their goals while responding to site conditions, as well as schedule and budget expectations.

- Andy LaFerriere, Energy Analyst: Andy is an energy engineer with over a decade of experience in commercial, industrial, and institutional building analysis and campus energy master planning. His skillset ranges from basic screening of energy efficiency projects to advanced analysis, design, and optimization of large central plants, including an array of alternative energy technologies. Throughout his career he has played a key role in the development of some of the largest geothermal projects in the world.

NTH Consultants
NTH Consultants, Ltd. (NTH) provides practical and innovative solutions to a multitude of engineering challenges. A full service geotechnical, infrastructure and environmental engineering firm, NTH has been providing professional consulting services to public and private clients throughout the United States as a Michigan corporation since 1968. NTH Consultants' extensive knowledge of environmental regulations and conditions helps clients manage both state and federal environmental regulations for ecological, wetlands, habitat restoration, hazardous waste management, wastewater discharge, air emissions, hazardous materials storage, and health and safety issues.

- Craig Johnson, Senior Principal Engineer: Mr. Johnson offers 22 years of energy industry leadership, project management, and technical consulting, with 13 years of enterprise-wide utility operations, engineering, regulatory compliance, risk identification and mitigation, and overall program leadership. Within the utility roles, he had responsibility for all aspects of natural gas delivery

(production wells through customers burner tip), electric distribution operations and engineering, utility scale solar generation development and operation, and leadership of a coal-fired generation facility and associated landfill.

- Mark Hushebeck, Senior Project Geologist: Mr. Hushebeck has 37 years of experience in various geological aspects of geotechnical engineering, including: landslide evaluations and stabilizations, site feasibility, dams and levees, geologic mapping, field exploration, directional drilling studies, forensic evaluation and construction monitoring, land use planning, and preparation of bidding and specification packages. His experience includes large hillside residential developments, roads and highways, industrial / commercial structures, motor sports complex developments, geophysical and geotechnical instrumentation setup/monitoring, geologic field mapping, distressed single-family and multi-family residential building evaluations, resource potential evaluations and Level 1 environmental impact reports.

3) Organizational chart:

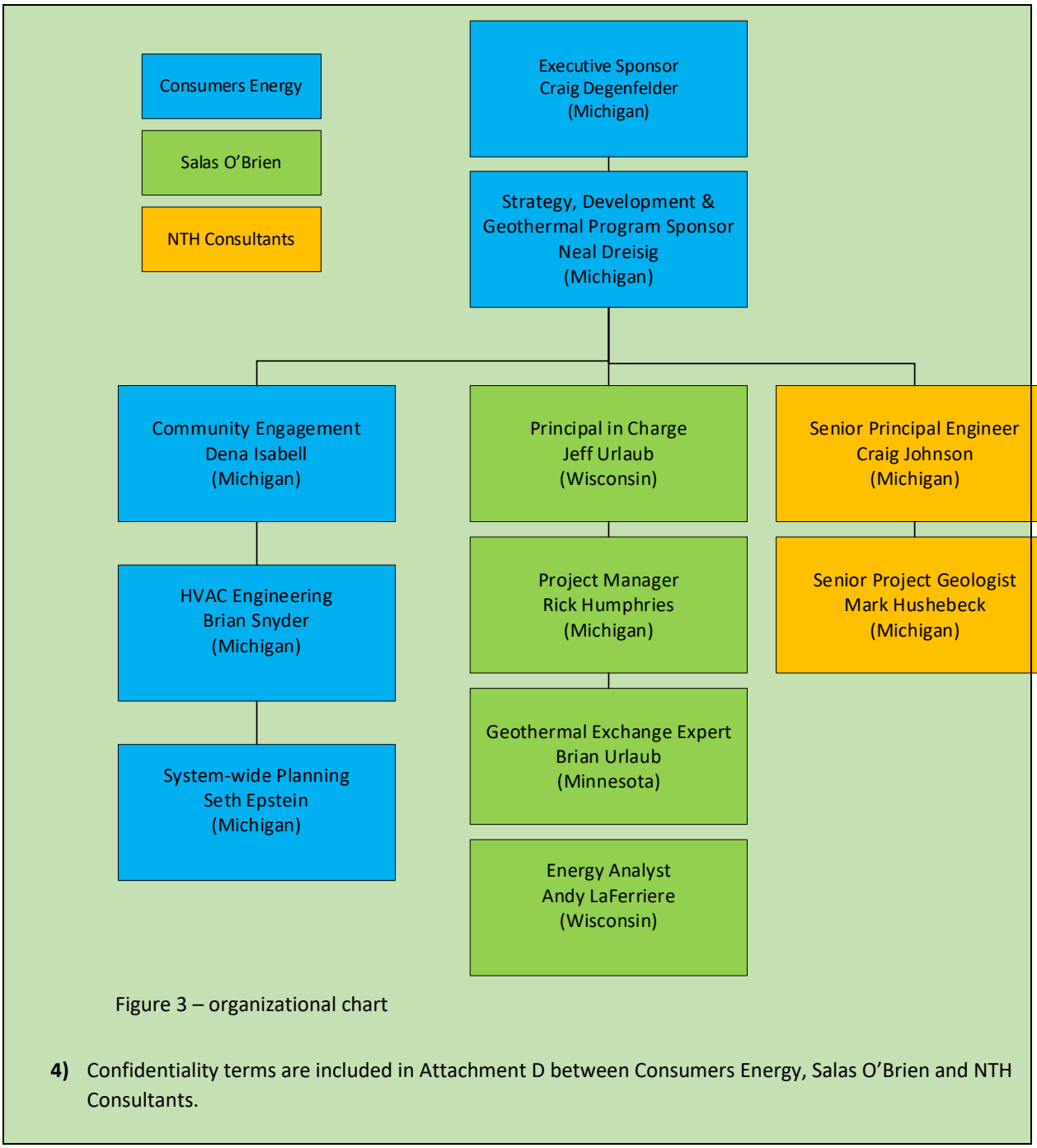


Figure 3 – organizational chart

4) Confidentiality terms are included in Attachment D between Consumers Energy, Salas O'Brien and NTH Consultants.

V-I Budget

To enable the MPSC to evaluate all project costs, applicant(s) will submit a proposed budget and corresponding budget narrative. Please see Attachment A for the required budget format. The budget and narrative must include only Renewable Energy and Electrification Infrastructure Enhancement and Development Grant Program funds in the budget; do not include matching, leveraged, cost share or any other type of supplemental funds. The budget narrative must identify the budget line item and number, provide a detailed description for each line, and include individual unit prices.

Selected applicant(s) will be required to provide supporting documentation for all grant expenditures incurred during the term of the grant. Accounting records must be supported by source documentation

including, but not limited to, general ledgers, time sheets, payroll registers, invoices, check copies and bank statements, or cancelled checks. Expenses will be verified based on actual expenditures incurred within the grant period that are supported by source documentation, not budgeted amounts.

1) **Budget Changes** – Any changes to the budget must be pre-approved by the MPSC Grant Administrator. Changes in the budget of less than 5% of the total line item amount, or $2,000 (whichever is greater), do not require a formal amendment; however, a revised budget should be submitted to the MPSC Grant Administrator for approval. The allowable transfer should be calculated as less than 5%, or $2,000 (whichever is greater), of the total line item that the funds are being transferred from.

   Cumulative changes in the budget equal to or greater than 5% of the total line item amount, or $2,000 (whichever is greater), may be permitted only upon prior review and written approval by the MPSC Grant Administrator. A formal grant amendment must be signed by both the Grantor and Grantee.

2) **Disallowed Costs** – Disallowed costs include but are not limited to the following: sick pay, vacation pay, holiday pay, bonuses, overtime, tuition reimbursement/remission, vehicle allowance, seminars, conferences, meetings, subscriptions, dues, and memberships.

3) **Administrative Costs** – Administrative costs cover expenses related to general administrative functions and coordination of functions and oversight directly related to the Renewable Energy and Electrification Infrastructure Enhancement and Development Grant Program administrative functions. Administrative costs should include costs of goods and services required for administrative functions of the program; travel costs incurred for official business in carrying out administrative activities or the overall management of the Renewable Energy and Electrification Infrastructure Enhancement and Development Grant Program; costs of information systems related to administrative functions; and contractual services related to sub-recipients or vendors that are solely for the performance of administrative functions. **Total direct administrative costs must be identified and labeled clearly.**

4) **Budget Requirements** – The proposed budget will display three (3) headings identified as the: Line Item, Budget Category, and Total Grant Request. The budget line items that need to be included, at a minimum, are listed below. The budget should reflect the best estimate of actual costs using whole numbers. Please refrain from using decimals or formulas. Refer to the budget example provided in Attachment A.

   - **Personnel** – In the budget, include the name, job title, and salary for each staff position to be paid for by the grant. Time sheets and payroll registers must be submitted for each staff position, and hours worked must be grant related. Fringe benefits may not exceed 35% of each employee's salary. Fringe benefits will be reimbursed based on actual expenditures per employee up to 35%, not on budgeted amounts. Allowable benefits include: health, dental, and optical insurance, employer-paid Social Security and Medicare tax, Michigan and Federal unemployment tax, and other miscellaneous fringe benefits (life insurance, long- and short-term disability insurance, worker's compensation, and retirement program contributions up to 4%). Within the budget narrative, applicant(s) must provide details on the organization's method of calculating fringe benefit expenses that will be charged to the grant including whether fringe benefits are calculated on an annualized basis or based on the length of the grant term.

     The budget narrative must include the number of weeks the individual will work on the grant; number of hours per week a full time employee of the organization is expected to work; a description of the work to be performed by each individual; the estimated hours to be worked; actual pay rate; the fringe benefit percentage being charged to the grant for each employee; the percentage of the employee's time allocated to the grant; whether each employee is salaried-exempt, salaried-non-exempt or hourly; and any other applicable information related to the individual's duties and responsibilities in connection with this grant.

     Individuals that are not on selected applicant(s)'s payroll, e.g., independent contractors, individuals

receiving a Form 1099, temporary workers, etc., must be placed under the Contractual Services budget category. Only employees on the selected applicant(s)'s payroll should be included in the Personnel budget category.

- **Supplies, Materials, and Equipment** – Specify item(s) and cost. The budget narrative should include the anticipated cost of each item, a detailed explanation of the item's purpose, and how it relates to the project being funded. Be as detailed as possible.

- **Contractual Services** – These services must be competitively bid. Individuals that are not on selected applicant(s)'s payroll, e.g., independent contractors, individuals receiving a Form 1099, temporary workers, etc., must be placed under **Contractual Services**. When competitive selection is not feasible or practical, the selected applicant(s) agrees to obtain the written approval of the MPSC Grant Administrator before making a sole source selection. Selected applicant(s) must provide a copy of contracts, memoranda of understanding or agreements signed by selected applicant(s) and contractors.

  Selected applicant(s) assumes responsibility to select subcontractors on a competitive basis. A minimum of three (3) bids must be solicited and proposals must include, at a minimum: (1) name of selected applicant(s), grant number, and grant period; and (2) the type, number, and description of projects as described in the proposal.

  Selected applicant(s) must provide the MPSC Grant Administrator with the solicitation, list of vendor responses (including amounts), and name of the selected vendor. Selected applicant(s) must maintain bids on file at their place of business according to Section II-H, Records Maintenance, Inspection, Examination, and Audit. The MPSC Grant Administrator will reserve the right to request a copy of all bids for services that are competitively bid.

  Selected applicant(s) must award the project to the lowest bid unless the MPSC Grant Administrator has given prior written approval for selection of a higher bid. Selected applicant(s) must provide a written justification for the selection of a higher bid. When awarding subcontracts, the selected applicant(s) must ensure that preference is given to products manufactured in or services offered by Michigan-based firms.

- **Other Expenses** – This category is solely for use by organizations charging a per-case fee for work performed by subunits or internal agencies within the organization that do not require a competitive bid, i.e. contract, memorandum of understanding or any other type of signed agreement.

- **Indirect Costs** – Indirect costs are costs not directly or specifically related to the grant program. Indirect costs are costs of administering the organization and must be spread over a number of products, services, or grant programs proportionately. Examples include office supplies and equipment, utilities, rent, maintenance and repair, insurance, accounting and bookkeeping services, and legal services. Non-cash expenses like depreciation, amortization, and depletion are not allowable indirect costs under this grant. **Total indirect costs must be identified, labeled clearly, and may not exceed an amount equal to 10% of the total direct costs.**

  Selected applicant(s) will be reimbursed for its proportional share of indirect costs. This means the MPSC should be allocated a portion of the selected applicant(s)'s indirect costs and not 100% of the organization's total indirect cost.

  Indirect costs should be displayed on the face of the budget on a single line item and the indirect rate should be rounded to six (6) decimal places. The budget narrative should contain a list of indirect costs, how the selected applicant(s) determined its indirect costs, and the percentage rate calculation for reimbursable indirect costs. Selected applicant(s) is not required to provide documentation supporting indirect costs; however, documentation verifying the costs must be retained by the selected applicant(s).

Indirect costs should be displayed on the face of the budget on a single line item and the indirect rate should be rounded to six (6) decimal places. The budget narrative should contain a list of indirect costs, how the selected applicant(s) determined its indirect costs, and the percentage rate calculation for reimbursable indirect costs. Selected applicant(s) is not required to provide documentation supporting indirect costs; however, documentation verifying the costs must be retained by the selected applicant(s).

5) **Grant Expenditure Guidelines** - To ensure efficient review and approval of grant expenditures, selected applicant(s) will be provided additional guidelines to assist with calculating and determining accurate and appropriate grant expenditures.

6) **Budget Subtotal** - Each budget category should have a subtotal displaying the total anticipated amount to be expended, and the budget should include a subtotal for total direct project costs and a sum of total project costs.

7) **Travel** - In the event that any necessary travel is anticipated, all expenses must be reflected in the applicant(s) hourly rate.

8) **Budget Modifications** - After grants are approved by the MPSC, modifications of proposals and budgets may be necessary. If the MPSC does not approve the total amount requested in the original proposal, selected applicant(s) will be required to submit a revised proposal, budget and budget narrative for the purpose of entering into a Grant Agreement. New line items to the revised budget are not allowed.

9) **Unexpended Grant Funds** - Selected applicant(s) assumes the responsibility of ensuring all unexpended grant funds are returned to the State of Michigan at the end of the grant period. Failure to do so may render selected applicant(s) ineligible for future grant awards and/or subject to legal action.

10) **Commingling Grand Funds** - Selected applicant(s) may not commingle grant award funds with current or future grant awards. All funding sources must be managed and accounted for separately.

Bidder response: Templates for the Budget and Budget Narrative are attached to the RFP Response document located on the Renewable Energy EIED webpage. In this bidder response, add any information not included in the Budget or Budget Narrative.

See below completed budget templates and narrative

V-J Current and Prior Experience and Funding Disclosure

Current and prior experience is important to the selection process. Proposals submitted by applicant(s) should include:

1) A description of the organization's experience in conducting the type of work proposed. Include current activities and activities for the previous ten years. Include project results.

2) If applicant(s) received a similar grant award from the State of Michigan in prior years for the type of project proposed, provide a summary of project accomplishments. Include a plan for addressing and resolving past problems.

3) Current funding source(s) and the level of funding for the current year and the previous ten years.

4) If additional dollars beyond these grant funds are being used for this project, indicate the source and amount.

5) If applying for a planning grant, identify potential funding sources (both internal and external) that

are secured to undertake construction of facilities or implementation of programs that a planning grant is intended to identify.

Bidder response:

1) Consumers Energy has assembled a team of highly experienced individuals and firms familiar with Michigan, its geological characteristics and demographics. This team includes Consumers Energy, Salas O'Brien and NTH Consultants.

Consumers Energy

Consumers Energy has over 100 years of experience with nearly all components of a network geothermal system including underground survey, drilling, energy efficiency, pipeline installation, right of way work, municipality coordination, and community engagement.

Salas O'Brien & NTH Consultants

Together Salas O'Brien are NTH Consultants are national leaders in the planning, design, and implementation of geothermal systems, central energy plants, and district energy systems, completing over 400 associated geothermal projects. Select project results are shown below.

U21806-MNSC-CE-0039_ATT 4

Converting Ford's Dearborn Campus to District Energy

Ford Motor Company Dearborn Campus - Low Entropy Campus Master Plan and Central Utility Plant DEARBORN, MI, USA

SERVICES
District Systems

COMPLETION YEAR
2020

CONSTRUCTION COST
Confidential

SIZE
100,000 square feet plant serving up to 9 million square feet of facilities

Redeveloping six million gross square feet of research, engineering, and design facilities, Ford is upgrading to a modern district energy system. Salas O'Brien developed a Low Entropy Campus Master Plan and provided design services for the new Central Energy Plant and distribution systems. As the project prime, we managed all design disciplines including architectural services and structural engineering.

The facility includes: a 34 MW combined heat and power system with two Solar Titan 130s; a 16,000-ton chiller plant with heat pumps and high-efficiency cooling-only chillers; and, 40,000 ton-hours of thermal energy storage.

Results

- 40,000 ton-hours of thermal energy storage
- 16,000 ton chiller plant
- 34 MW combined heat and power system

U21806-MNSC-CE-0039_ATT 4

Scalable single-family neighborhood geothermal

Mattamy Homes, Berczy Glen MARKHAM, ON, CANADA

SERVICES
Geothermal and Renewables

SIZE
500,000 square feet; 312 Homes

COMPLETION YEAR
2024

PROJECT PARTNERS
Enwave Energy Corporation

Upon completion, Ontario's 327-home Berczy Glen development will be the first residential neighborhood in Canada to have its heating and cooling needs met by a central geothermal system. Salas O'Brien designed a net zero carbon system, 3.5 to 4 times more efficient than the conventional natural gas alternatives. Homeowners are expected to see 30-50% reduction in monthly utility bills.

The geothermal system consists of 170 vertical loop boreholes, 850' deep, distributed entirely under neighborhood streets in twelve pods, connected by a two-mile ambient water loop. Circulation pumps serving the loop and individual pods are housed in subgrade vaults, eliminating visible infrastructure.

The system will be maintained by Enwave Energy Corporation, demonstrating the feasibility of community-scale geothermal systems for Berczy Glen developers, Mattamy Homes.

80% reduction
in system carbon emissions

100% reduction
in household carbon emissions

U21806-MNSC-CE-0039_ATT 4

Evaluating conversion options

Xcel Energy Denver DENVER, CO, USA

SERVICES
District Systems

SIZE
120 Buildings

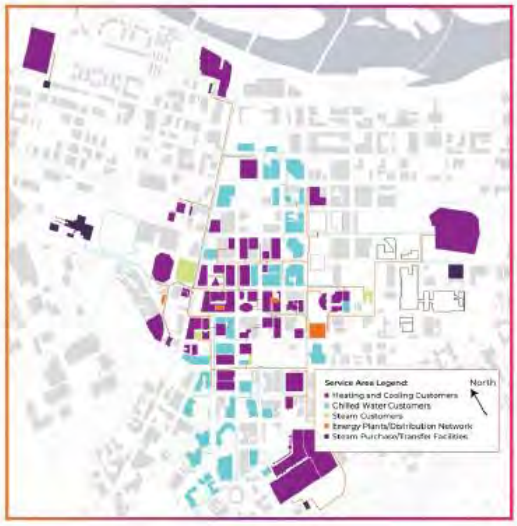
COMPLETION YEAR
In Progress

CONSTRUCTION COST
Confidential

Our team is currently performing a study on Xcel Energy's district steam system to review technological options, technical feasibility, and costs for converting to an ambient temperature heating/cooling system. Xcel would convert the existing steam system to an ambient temperature system and the second would utilize the chilled water system as an ambient temperature loop. The study will evaluate options to temper the ambient loop fluid including, the use of a community ground source heat exchanger, integration with the central steam plant, integration with the district chilled water system, use of system renewable electricity that would otherwise be curtailed, waste heat recovery, and thermal balancing that leverages customer loads.

The study will consider whether the steam system can serve existing service customers with a technology or technologies that align with state sector-based and state-wide GHG reduction targets as well as any requirements of Energize Denver. The study will provide a baseline of information on the technical feasibility and costs of the ambient temperature heating/cooling system.

Minneapolis



District energy solution to serve a new mixed-use development

Harmonia - Mixed Use Building MINNEAPOLIS, MI, USA

SERVICES
District Systems

SIZE
1,300,000 square feet

COMPLETION YEAR
Expected xxxxx

CONSTRUCTION COST
Confidential

The project through Cordia Energy aims to investigate a solution to serve a proposed development, dubbed "Harmonia" will cover a city block in downtown Minneapolis and will include two residential buildings with mixed use on the ground floor and one commercial office building.

Our team is developing a thermal profile based on current project concepts and programming to asses thermal needs of the future district and gain a preliminary understanding of geothermal system feasibility. We are evaluating three general geothermal system concepts which include open loop production and re-injection wells, open loop Darcy system, and closed loop vertical bore for ground heat exchange. A unique challenge is that below grade parking consumes the entire footprint of the property up to and below the sidewalks that border the city block, which would require both open and closed loop systems to be installed. While open loop looks like a promising solution from a thermal energy perspective; regulatory constraints will prevent locating well heads below grade without a variance. The variance will not likely be granted, thus eliminating the feasibility.

2) Consumers Energy received two grant awards in 2023 for the Swisslane and TDI Farm renewable natural gas Projects. These projects remain on schedule for in-service in 2026. Since award, both projects actively engaged the community achieving ordinance approval for the Swisslane Project to apply for a special land use permit. The Projects are managed through Consumers Energy's Enterprise Project Management Office, which requires due diligence and oversight reviews to highlight problems, incorporate lessons learned and ensure projects remain on track to achieve business case results.

3) Funding sources for the current year and previous 10 years is through our regulated rates to customers. The funding for this work is intended to be covered directly by the planning grant award.

4) The funding for this work is intended to be covered entirely by the planning grant award. Funding for work prior to the grant start date including community outreach and service territory wide assessments for potential network geothermal sites will use funds in a study-based balance sheet account until a capital asset or O&M expense is determined.

5) Specific for this planning grant request, Consumers Energy would seek potential funds to undertake construction of a potential project through collaboration with the Michigan Public Service Commission and a future rate case.

V-K Additional Information and Comments

Include in this section any other information that is believed to be pertinent but not specifically requested elsewhere in this RFP.

Bidder response:
N/A

V-L Certification of Proposal

Please sign the proposal including the following language:

I certify that all information contained in the proposal is true to the best of my knowledge and belief, and that the organization is in compliance and agreement with all sections of the Request for Proposal. Failure to comply with grant terms may result in termination.

Certified by: 2/12/2024
Date

Sarah Hollis Bowers
Vice President of Gas Engineering & Supply
Authorized Signatory Name and Title

Consumers Energy
Name of Organization

ATTACHMENT A - BUDGET

Renewable Energy and Electrification Infrastructure Enhancement and Development (EIED) Grant
Bidder Name: Consumers Energy Company
Submission Date: February 21, 2024

Please insert actual proposed budget amounts in the blank table provided below. Extra lines may be added as appropriate.

Line Item	Budget Category	TOTAL GRANT REQUEST
1	**Administrative Expenses**	
2	**Administrative Personnel (Grant Administration Staff)**	
3	*Salary*	
4	Employee 1 (Job Title) (___ Hrs. @ $xxxx/hour)	$ 0
5	Employee 2 (Job Title) (___ Hrs. @ $xxxx/hour)	$ 0
6	**Total Salary**	$ 0
7	*Fringe Benefits*	
8	Employee 1 (Job Title) (___ Hrs. @ $xxxx/hour)	$ 0
9	Employee 2 (Job Title) (___ Hrs. @ $xxxx/hour)	$ 0
10	**Total Fringe Benefits**	$ 0
11	***Total Administrative Personnel***	$ 0
12	**Administrative Supplies, Materials, and Equipment**	
13	General Office Supplies	$ 0
14	***Total Administrative Supplies, Materials, & Equipment***	$ 0
15	**Total Administrative Expenses**	**$ 0**
16	**Contractual Services**	
17	**Contractual Services Personnel Salary**	
18	*Salary*	
19	Employee 1 (Job Title)	$ 0
20	Employee 2 (Job Title)	$ 0
21	**Total Salary**	$ 0
22	*Fringe Benefits*	
23	Employee 1 (Job Title)	$ 0
24	Employee 2 (Job Title)	$ 0
25	**Total Fringe Benefits**	$ 0
26	***Total Contractual Services Personnel Salary***	$ 0
27	**Contractual Services Supplies, Materials, and Equipment**	
28	Supplies, Materials, and Equipment	$0
29	***Total Contractual Services Supplies, Materials, and Equipment***	$0
30	**Total Contractual Services Expenses**	**$0**

31	**Sub-contractual Services, Large Equipment, Customer Rebates, Other Direct Costs**	
32	**Sub-contractual Services**	
33	Vendor 1 – Salas O'Brien	$ 325,000
34	Vendor 2 – NTH Consultants	$ 100,000
35	Independent Contractor 1	$ 0
36	Independent Contractor 2	$ 0
37	***Total Sub-contractual Services***	$ 0
38	**Large Equipment Costs (Infrastructure Grants)**	
39	Type of Equipment	$ 0
40	***Total Large Equipment Costs***	$ 0
41	**Customer Rebates (Program Grants)**	
42	Payments to Residential Customers (___ @ $xxxx)	$0
43	Payments to Commercial Customers (___ @ $xxxx)	$0
44	***Total Customer Rebates***	$0
45	**Other Direct Costs**	
46	Other Direct Costs Detailed	$0
47	***Total Other Direct Costs***	$0
48	**Total Sub-Contractual Services, Large Equipment, Customer Rebates, Other Direct Costs Expenses**	**$425,000**
49	**Total Direct Cost**	**$ 425,000**
50	**Indirect Costs**	
51	*Indirect Cost (0.10) – May not exceed 10% of total direct costs.*	$ 0
52	***Total Indirect Costs***	**$0**
53	**TOTAL GRANT FUNDS REQUESTED**	**$ 425,000**

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ATTACHMENT B – BUDGET NARRATIVE

The narrative below may be updated with the applicant's own line description as appropriate. If extra lines were added in the Budget Table, add them in the narrative as well. Include a budget narrative for each partnering organization or subcontractor working on the project.

1	**Administrative Expenses** Category Not Applicable (N/A)
2	**Administrative Personnel (Grant Administration Staff)** Category Not Applicable (N/A) In the event that any necessary travel is anticipated, all expenses must be reflected in the applicant(s) hourly rate.
3	*Salary* Category Not Applicable (N/A)
4	Employee 1 Name (Job Title) Category Not Applicable (N/A)
5	Employee 2 Name (Job Title) Category Not Applicable (N/A)
6	**Total Salary = $0** Category Not Applicable (N/A)
7	*Fringe Benefits (Fringe benefit for Employees should match named salary employees listed above)* Category Not Applicable (N/A)
8	Employee 1 Name (Job Title) Category Not Applicable (N/A) Fringe benefits for Employee 1 <Name> should equal not more than 35% of his/her grant-related salary. These fringe benefits include <list fringe benefits received by Employee 1>. The cash basis of accounting is used to calculate Fringe Benefit expenses applicable to the grant. Our organization will use the accrual basis of accounting method for all transactions in the general ledger. The approximate cost for this line item number is $0. *Note: Allowable fringe benefits include the following: Health, Dental, and Optical Insurance, employer- paid Social Security and Medicare Tax, Michigan and Federal unemployment tax, and other miscellaneous fringe benefits (i.e., life insurance, long-and short-term disability insurance, workers' compensation, and retirement program contributions up to 4%). Only include benefits the employee is actually receiving or is expected to receive. If each employee receives the same fringe benefit package, list the items under the first employee and refer to the line item where they are listed for each additional employee.*

9	Employee 2 Name (Job Title) Category Not Applicable (N/A) Fringe benefits for Employee 1 <Name> should equal not more than 35% of his/her grant-related salary. These fringe benefits include <list fringe benefits received by Employee 2>. The cash basis of accounting is used to calculate Fringe Benefit expenses applicable to the grant. Our organization will use the accrual basis of accounting method for all transactions in the general ledger. The approximate cost for this line item number is $0.
10	**Total Fringe Benefits = $0** Category Not Applicable (N/A)
11	***Approximate Total Administrative Personnel = $0*** Category Not Applicable (N/A)
12	**Administrative Supplies, Materials, and Equipment** Category Not Applicable (N/A)
13	General office supplies, for example paper and general office supplies, are estimated at $0. Category Not Applicable (N/A)
14	***Approximate Total Administrative Supplies, Materials, and Equipment = $0*** Category Not Applicable (N/A)
15	**Total Administrative Expenses = $0** *(Lines 6, 10, 14)* Category Not Applicable (N/A)
16	**Contractual Services** Category Not Applicable (N/A)
17	**Contractual Services Personnel Salary** In the event that any necessary travel is anticipated, all expenses must be reflected in the applicant(s) hourly rate. Category Not Applicable (N/A)
18	*Salary* Category Not Applicable (N/A)
19	Employee 1 Name (Job Title) Category Not Applicable (N/A)
20	Employee 2 Name (Job Title) Category Not Applicable (N/A)
21	**Total Contractual Services Salary = $0** Category Not Applicable (N/A)
22	*Fringe Benefits*

23	Employee 1 Name (Job Title) Category Not Applicable (N/A) The approximate cost for this line item number is $0. *Note: Allowable fringe benefits include the following: Health, Dental, and Optical Insurance, employer- paid Social Security and Medicare Tax, Michigan and Federal unemployment tax, and other miscellaneous fringe benefits (i.e., life insurance, long-and short-term disability insurance, workers' compensation, and retirement program contributions up to 4%). Only include benefits the employee is actually receiving or is expected to receive. If each employee receives the same fringe benefit package, list the items under the first employee and refer to the line item where they are listed for each additional employee.*
24	Employee 2 Name (Job Title) Category Not Applicable (N/A) The approximate cost for this line item number is $0.
25	**Total Fringe Benefits = $0** Category Not Applicable (N/A)
26	***Approximate Total Contractual Services Personnel Salary = $0*** Category Not Applicable (N/A)
27	**Contractual Services Supplies, Materials, and Equipment** Category Not Applicable (N/A)
28	Supplies, Materials, and Equipment includes <provide detailed description of supplies, materials, and equipment> and are estimated at $0. Category Not Applicable (N/A)
29	***Approximate Total Contractual Services Supplies, Materials, and Equipment = $0*** Category Not Applicable (N/A)
30	**Total Contractual Services Expenses = $0** *(Lines 21, 25, 29)* Category Not Applicable (N/A)
31	**Sub-contractual Services, Large Equipment, Customer Rebates, and Other Direct Costs**
32	**Sub-Contractual Services**

33	Vendor 1 Salas O'Brien. Services include consultation on site identification using criteria such as GDP, demographics, energy load diversity, current energy consumption and existing infrastructure; energy modeling to understand the effectiveness of energy sharing across users on the network; thermal resource assessment which includes initial design and configuration of the network; infrastructure planning which involves detailed mechanical and civil designs to support the network; energy and capacity assessments; implementation approach which involves a future project execution plan, capital cost estimate, cost of energy estimate, carbon reduction estimate, impacts and connections to existing buildings and work involved with public rights of way. Salas O'Brien will be actively engaged on in phases 1, 3, 4, 5 and 6. The first phase accounts for $25,000, while the remaining 4 phases estimated at $75,000 each. Total approximate cost for this line item is $325,000.
34	Vendor 2 NTH Consultants. NTH Consultants will perform Phase 2, the geological evaluation including test bores, soil testing, fluid testing and overall thermal conductivity testing. Total approximate cost for this line item is $100,000.
35	Independent Contractor 1 Category Not Applicable (N/A) Total approximate cost for this line item is $0.
36	Independent Contractor 2 Category Not Applicable (N/A) Total approximate cost for this line item is $0.
37	***Approximate Total Sub-Contractual Services = $425,000***
38	**Large Equipment Costs (Infrastructure Grants)**
39	Category Not Applicable (N/A) Total approximate cost for this line item is $0.
40	***Approximate Total Large Equipment Costs = $0*** Category Not Applicable (N/A)
41	**Customer Rebates (Program Grants)** Category Not Applicable (N/A)
42	Payments to Residential Customers (0 @ $0) Category Not Applicable (N/A) Total approximate cost for this line item is $0.

43	Payments to Commercial Customers (0 @ $0) Category Not Applicable (N/A) Total approximate cost for this line item is $0.
44	***Approximate Total Customer Rebates = $0***
45	**Other Direct Costs** Category Not Applicable (N/A)
46	Other Direct Costs Detailed Category Not Applicable (N/A) Total approximate cost for this line item is $0.
47	***Approximate Total Other Direct Costs = $0*** Category Not Applicable (N/A)
48	**Total Sub-Contractual Services, Large Equipment, Customer Rebates, and Other Direct Cost Expenses = $425,000** *(Lines 37, 40, 44, 47)*
49	**Total Direct Costs = $425,000** *(Lines 15, 30, 48)*
50	**Indirect Costs** Category Not Applicable (N/A)
51	Indirect Cost (0.1) Category Not Applicable (N/A) Indirect Costs account for expenditures that are unforeseen and are not considered part of direct costs. Provide a list of indirect costs, how the indirect costs are determined, and the percentage rate calculation for reimbursable indirect costs. This line item is not to exceed 10% (0.1) of the direct costs.
52	***Total Indirect Costs = $0***
53	**Total Grant Funds Requested (direct plus indirect costs) = $425,000**

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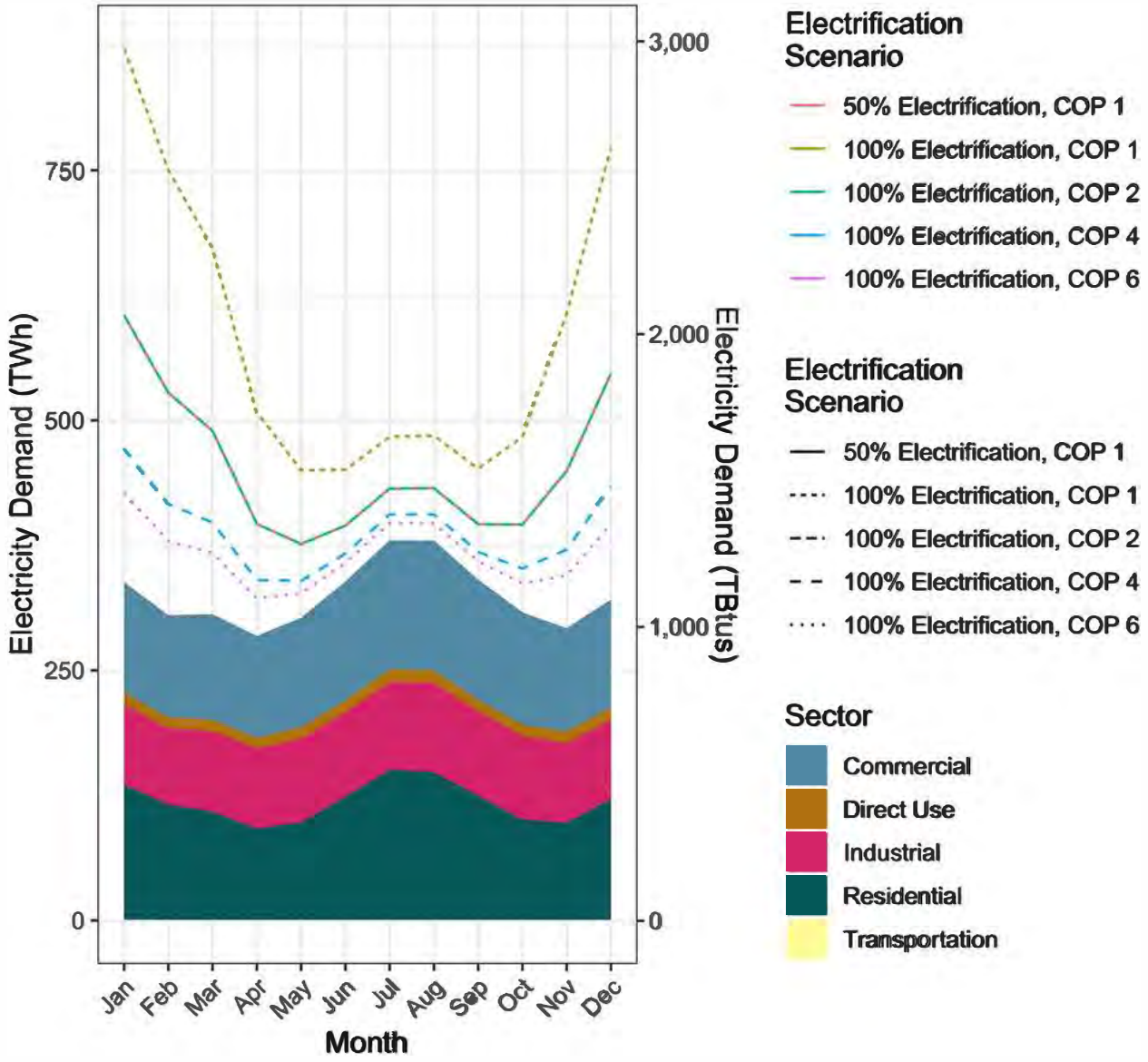

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U21806-MNSC-CE-0573_Att 1

Consumers Energy Count on Us®

CADMUS

2021 Cold-Climate Heat Pump Initiatives Evaluation Report

August 26, 2022

Presented to:
Consumers Energy
Joseph Forcillo
Director of Evaluation, Measurement & Verification
One Energy Plaza
Jackson, MI 49201

Presented by:
Cadmus
2490 Junction Place, Suite 400
Boulder, CO 80301

TRC
807 Roy Street, Suite 301
Seattle, WA 98102

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Prepared by:

Cadmus Team

Steve Cofer
Cheryl Winch
Matai Perussi
Andrew Mielcarek
Noah Lieb

TRC Companies

Donna Whitsett
Hannah Justus
Sagar Deo

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Acronyms and Abbreviations

Acronym	Definition
AC	Air conditioner
AMI	Advanced metering infrastructure
ASHP	Air-source heat pump
CCHP	Cold-climate heat pump
CDH	Cooling degree hour
COP	Coefficient of performance
HDH	Heating degree hour
HSPF	Heating seasonal performance factors
MEMD	*Michigan Energy Measures Database*
NPS	Net promoter score
PMOs	Property owners and managers
SEER	Seasonal energy efficiency ratio
TMY3	Typical meteorological year version 3

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Executive Summary

In its March 5, 2020 Order Approving Settlement Agreement in Consumers Energy's *2020-2023 Energy Waste Reduction (EWR) Plan*, the Michigan Public Service Commission (MPSC) authorized the Company to invest in cold-climate heat pump (CCHP) initiatives for both income-qualified and non-income-qualified residential customers and business customers to test the efficacy, performance, and customer experience, among other factors. The Settlement Agreement[1] required the Company to submit an interim and final report delineating cold-climate heat pump (CCHP) initiative findings with the Company's 2020 and 2021 EWR Reconciliation filings, respectively. This report supplements the CCHP final report submitted as required by the March 5 Order and documents 2021 evaluation activities.[2]

The approved Settlement Agreement included both increased investment to support the income-qualified program performance metric associated with CCHP installations and a CCHP retrofit pilot initiative targeted to residential homes and businesses heated with electricity or heating fuels not regulated by the Michigan Public Service Commission, such as delivered propane or fuel oils. Given the challenges with implementing the CCHP initiatives, as well as unanticipated delays due to COVID-19, participation for income-qualified single-family and small commercial customers in 2021 occurred late in the year. This late participation has delayed the evaluation impact analysis for these two initiatives. All impact evaluation efforts will be completed in 2022 and the report will be filed in the case docket.

The main objective of these CCHP Initiatives was to demonstrate the potential for energy savings by replacing inefficient heating and cooling equipment with CCHPs. Consumers Energy targeted four distinct customer groups:

- Residential customers with electric or delivered fuel heating
- Income-qualified single-family customers with electric or delivered fuel heating
- Income-qualified multifamily customers with electric heating
- Small commercial customers with electric or delivered fuel heating

Consumers Energy designed its CCHP Initiatives to address both the supply and demand for CCHPs. The initiatives were implemented through Consumers Energy's existing residential, income qualified and small business product offerings. They aimed to strengthen trade allies' capabilities to install and service advanced heat pumps while increasing customers' awareness of and confidence in heat pumps as a viable, affordable, and environmentally friendly home heating source.

The CCHP Initiatives' incentives varied by customer type and ranged from $1,000 for market-rate customers to the full cost of installation for income-qualified and small business customers.

---

[1] Original settlement agreement: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000009hu1HAAQ at page 2
Settlement agreement amendment: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000CGUIcAAP

[2] Cadmus. 2020-2021 Cold-Climate Heat Pump Initiatives Final Report. May 18, 2022.

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Consumers Energy marketed the initiatives through participating contractors, who were familiar with heat pump technology and had been educated about the offering, as well as through mass marketing campaigns and other Consumers Energy network partners like Habitat for Humanity. Table 1 through Table 3 shows participation and investments through December 31, 2021, by customer group and year.

Table 1. 2020 and 2021 Cold-Climate Heat Pump Participation and Investment

	Residential Market Rate	Income Qualified		Small Commercial	Total
		Single-Family	Multifamily		
2020 - 2021 Target	50 [a, b]	160	558	25 [b]	**793**
2020 - 2021 Installations	53	179	663	26 [c]	**921**
Percentage of Target	106%	112%	119%	88%	**116%**
Total Investment	$579,297	$3,184,143	$3,664,670	$999,000	**$8,427,110**

[a] The original Settlement Agreement targeted 100 heat pumps. Per the end of July 2020 reforecast; this was adjusted to 50 heat pumps.

[b] While the income qualified targets are specific to each year and summed in this table, the residential market rate and small commercial targets represent the total adjusted targets for the two-year period.

[c] This is updated from the 2020–2021 Cold Climate Heat Pump Initiatives Final Report.

Table 2. 2020 Cold-Climate Heat Pump Participation and Investment

	Residential Market Rate	Income Qualified		Small Commercial [a]	Total
		Single-Family	Multifamily		
2020 Target	100 [b]	100	225	25	**450**
2020 Installations	5	78 [c]	276	0	**359**
Percentage of Target	5%	78%	123%	0%	**80%**
2020 Investment	$258,771	$1,447,290	$1,523,558	$225,204	**$3,454,823**

[a] The small commercial initiative had eight commitments with three customers at the end of 2020, but no completed installations.

[b] The original Settlement Agreement targeted 100 heat pumps. Per the end of July reforecast, this was adjusted to 50 heat pumps.

[c] Of the 78 heat pumps, 74 were installed for a large group of duplexes owned by one landlord. Duplexes are classified as single-family homes.

Table 3. 2021 Cold-Climate Heat Pump Participation and Investment

	Residential Market Rate	Income Qualified		Small Commercial	Total
		Single-Family	Multifamily		
2021 Target	50	60	333	25	**468**
2021 Installations	48	101	387	26 [a]	**562**
Percentage of Target	96%	168%	116%	112%	**120%**
2021 Investment	$320,526	$1,736,853	$2,141,112	$773,796	**$4,972,287**

[a] This is updated from the 2020-2021 Cold-Climate Heat Pump Initiatives Final Report.

In addition to persistent market barriers to the adoption of CCHPs documented in the first-year summary of pilots, the Settlement Agreement imposed eligibility restrictions for Consumers Energy CCHP initiatives, requiring heat pump systems to displace at least 50% of a customer's heating load from delivered fuels or electric resistance heating systems and limiting residential eligibility to primary residences only (i.e. secondary or vacation homes were ineligible).

Consumers Energy continued to encounter several challenges with encouraging heat pump adoption across all income levels and all residential and multifamily building types. These challenges resulted in lower participation than expected and are attributed to a lack of consumer awareness, difficulty identifying eligible customers, lack of contractor participation, and, in some cases, high incremental costs. Consumers Energy encountered fewer challenges with small business owners given that the Initiative covered the full installation cost of the CCHP, but Consumers Energy recognizes this is not a sustainable program option and expects to encounter similar challenges as the residential market when the incentive no longer covers the full equipment and installation cost for customers.

Despite these challenges, participants were generally satisfied with their experience and gave high satisfaction ratings for the overall performance of their new heat pump. Participants also reported better working equipment and increased comfort compared to their previous equipment. In addition, the Evaluation team's impact analysis for market rate and income-qualified multifamily customers show most participants will save energy, and in turn, money on their heating and cooling bills; however, the ranges of savings vary based on the heating fuel type of the replaced equipment. An engineering analysis for income-qualified single-family customers and metering analysis for small commercial customers is currently underway and will be completed by end of 2022.

Consumers Energy contracted with independent teams led by Cadmus and TRC to evaluate its respective residential and commercial program portfolios (referred to jointly as the Evaluation team throughout this report). The Evaluation team focused on providing Consumers Energy with the necessary details to inform later phases of the CCHP Initiatives and on monitoring early performance in 2021 to comply with the evaluation and reporting requirements in its Settlement Agreement.

Research Objectives

The Cadmus team focused our evaluation on providing Consumers Energy with the necessary details to inform later phases of promoting CCHPs. Following discussions with Consumers Energy's program management staff, the Cadmus team identified several research objectives regarding the evaluation.

Cadmus assessed four research objectives:

Assess the CCHP Initiatives' performance according to energy savings, customer satisfaction, impacts to customer bills, operational issues, and customer comfort.

Understand market readiness to adopt heat pump technology on a large scale and learn about the challenges of installing CCHPs.

Determine current limitations in the CCHP supply chain and their potential implications for the CCHP Initiatives.

Understand how CCHPs impact low-income customers and property managers who own income-qualified housing on non-energy factors such as changes in energy bills, heating and cooling equipment operation, and comfort levels.

Research Approach

Starting in 2021, the Evaluation team conducted several research and evaluation activities:

- Interviews with Consumers Energy CCHP Initiatives managers and implementation contractors (n=7)
- Interviews with HVAC contractors, distributors, and CCHP manufacturers (n=18)
- Billing analysis, engineering reviews, site visits, and metering for commercial participants (n=9)
- Surveys or interviews with Initiative participants and property owners (n=51)
- Residential Market Rate Participant Engineering Analysis (n=51)
- Multifamily and Income Qualified Billing Analysis (n=77 participants and 112 comparison buildings)

Participation was limited across all initiatives. This meant there were small populations to survey, interview, and perform billing analysis activities even using the census of participants. Therefore, the generated results, in most cases, are not statistically significant and while the evaluation team has made some conclusions and recommendations in this report, there is remaining uncertainty about the technology performance and market potential of CCHPs in Michigan. In addition, participation for small business customers occurred later in 2021, which delayed the metering of small business CCHPs.[3] Results from this activity will be prepared for Consumers Energy in Q4 2022.

Report Organization

We organized this report as follows:

- Summary of Key Findings, Conclusions, and Recommendations
- Contractor, Distributor, and Manufacturer Findings
- Residential Market Rate Initiative Findings
- Income Qualified Multifamily Initiative Findings
- Commercial and Industrial Cold-Climate Heat Pump Pilot Findings
- Appendices
  - Appendix A: Survey and Interview Methodology and Details
  - Appendix B: Impact Analysis Methodology and Details
  - Appendix C: Consumers Energy Heat Pump Market Rate Customer Survey
  - Appendix D: Consumers Energy Heat Pump Property Owner and Manager Interview Guide
  - Appendix E: Consumers Energy Heat Pump Multifamily Tenant Survey Guide
  - Appendix F: Consumers Energy Heat Pump Commercial Interview Guide
  - Appendix G: Consumers Energy Heat Pump Contractor Interview Guide
  - Appendix H: Consumers Energy Heat Pump Manufacturer and Distributor Interview Guide

[3] Initial impact analysis for commercial customers is reported in " 2021 Cold Climate Heat Pump Pilot Impact Evaluation Results Memo submitted to Consumers Energy by TRC. Updated cooling savings will be provided at the conclusion of additional metering in November 2022.

Summary of Key Findings, Conclusions, and Recommendations

This section presents the Evaluation team's key research findings, conclusions, and recommendations associated with the four cold-climate heat pump (CCHP) research objectives, which informed our evaluation tasks. The remaining chapters of this report provide further explanation of these findings and support for our conclusions and recommendations.

Key Findings and Recommendations

CONCLUSION 1. There is low and varied awareness of cold-climate heat pumps by homeowners, property owners and their tenants, and commercial businesses and even lower awareness that Consumers Energy offers cold-climate heat pump rebates.

Participants' awareness of CCHPs and Consumers Energy rebates was largely driven by HVAC contractors and Consumers Energy. However, awareness varied among contractors and within the territories they served. Where contractors were aware of CCHPs, they were a driving force of information dissemination about heat pumps and Consumers Energy rebates for both residential and commercial customers.

TRADE ALLIES: Contractors' overall awareness of heat pump technologies was largely correlated with the heating fuels used by their customer base. Contractors serving rural populations (where delivered fuels are more common) were more familiar with ducted heat pump systems, while contractors serving urban populations (where electric resistance heating is more prevalent) were more familiar with ductless heat pump systems. Contractors indicated that Consumers Energy could be instrumental in driving awareness of heat pump technologies, citing the success of the campaigns used to promote smart thermostats.

MARKET RATE: Most Residential Market Rate pilot participants reported being familiar with CCHPs before deciding to purchase one for their home (eight of nine), but few (three of nine) were aware that Consumers Energy provided heat pump rebates. While CCHP rebates were new in 2020, respondents' awareness of heat pumps came primarily from contractors, with about half (five of nine) indicating that a contractor had recommended a heat pump before they learned about and applied for the Consumers Energy heat pump rebate. A small number of participants (two of nine) heard about the rebate through Consumers Energy email communications.

INCOME QUALIFIED MULTIFAMILY: Multifamily property owners and managers were generally aware (31%, or n=10 of 32) of CCHPs prior to being approached by Consumers Energy, though they were not aware of Consumers Energy incentives until their involvement. However, the property owners and managers' tenants reported a lack of knowledge regarding heat pumps, with 66% of tenant respondents (n=21 of 32) saying they did not know about CCHPs, and half saying they were not aware that there was a CCHP installed in their apartment at the time of the survey. Of the half that were aware of the heat pump installation, 56% (n=9 of 16) did not know that Consumers Energy was involved in the project.

COMMERCIAL: Only two out of seven interviewed commercial respondents were familiar with cold-climate heat pump technology prior to participation. Those who had heard of cold-climate heat

pumps were unaware of the advancements in technology that made heat pumps more feasible for regions, like Michigan, with very cold winters. After learning about the new cold-climate heat pumps and Consumers Energy's pilot, most respondents were motivated to participate, but still held reservations about performance during the winter, prompting some to ask to keep their old heating system as a back-up.

RECOMMENDATIONS

High Priority: Identify opportunities for Consumers Energy to promote the cold-climate heat pump technology and incentives. Consider providing materials, such as one-page initiative summaries, for distributors to leave with contractors during their interactions. Continue to promote cold-climate heat pumps through events like the Annual Trade Ally Kickoff or identify larger distribution events or trainings where Consumers Energy can interact with trade allies.

High Priority: Increase contractor and customer education of cold-climate heat pump benefits and technology. Consider increasing the promotion of cold-climate heat pumps through planned marketing campaigns (such as bill inserts and online advertising) and through cross-program promotions.

CONCLUSION 2. Because natural gas is the predominate heating fuel in Michigan, and current Michigan Public Service Commission policy limits fuel-switching, there are limited cost-effective cold-climate heat pump installation opportunities. This contrasts with other states such as Maine and Vermont where a higher percentage of homes use more costly heating fuels such as propane and oil and where state policies incentivize fuel-switching.

TRADE ALLIES: While demand is increasing, trade allies reported that multiple barriers have limited demand for CCHPs in Michigan compared to other states. Manufacturers and distributors noted that awareness of and affinity for CCHPs among contractors varied and some maintain the belief that heat pumps are not effective in cold climates. Contractors and distributors also reported that increased customer awareness would help increase adoption; however, the cost of new CCHPs remains prohibitive. A homeowner likely needs to financially benefit from switching to a CCHP to be interested, but the lifecycle cost of a new CCHP compared to alternative heating technologies supplied by natural gas (the predominate heating fuel in Michigan) likely does not financially benefit the homeowner at a time when natural gas rates are low. Contractors acknowledged this fuel-switching challenge and said that even when they identify a potential cold-climate heat pump customer, there are few tools available for the contractor or customer to make accurate projections of the total system lifetime cost savings.

MARKET RATE AND COMMERCIAL CUSTOMERS: During 2021 and 2022, the Michigan Public Service Commission allowed Consumers Energy to target market rate and commercial customers who receive non-regulated fuels and those with electric heating systems. Consumers Energy's *2018 Residential Appliance Saturation and Home Characteristics Study* found that approximately 82% of customers in single-family homes across Consumers Energy's natural gas, electric and combination fuel

service territory heat their homes with natural gas, while 4% use electric heat and 14% use another source such as propane, fuel oil, or wood. This heating fuel distribution creates a significant challenge with identifying homeowners and businesses that may be eligible for a CCHP under the current regulatory rules (i.e., heat their homes or buildings with electric or distributed fuels), and limits market potential. Of the residential market rate participants for which baseline analysis was conducted (n=51), the majority (59%) used propane or oil, while 31 % used electric heat and 10% used natural gas heat prior to installing their heat pump[4].

Four of the seven commercial respondents interviewed discussed wanting to move away from using propane, and two of the respondents were motivated to participate in the pilot specifically so they could stop using propane. While respondents appreciated the opportunity to move from propane to electric heating, it is unclear whether Consumers Energy can continue with this targeted approach beyond the pilot phase. Future negotiations between the Michigan Public Service Commission and Consumers Energy and its stakeholders will determine whether Consumers Energy can continue to rely on this targeted approach in future initiative cycles.

RECOMMENDATIONS

High Priority: Because contractors reported that it is not always simple to determine when cold-climate heat pumps are economically more beneficial than traditional equipment, provide them with sales tools, such as a cost-effectiveness calculator, that can assist them in identifying when a cold-climate heat pump makes financial sense for their customers.

Low Priority: Promote the space cooling benefits associated with a cold-climate heat pump. Cold-climate heat pumps are a good option to add cooling where there was not previously a whole-home space cooling system or where the cold-climate heat pump can replace inefficient central air conditioners and room air conditioners.

CONCLUSION 3. Participants were generally satisfied with their experience and gave very high ratings for the CCHP Initiatives offering. However, multifamily tenants' satisfaction was split, largely based on whether the tenant received education on how to operate the new equipment.

MARKET RATE: Market rate customers gave high satisfaction ratings, with all nine respondents giving a rating of 8 or higher for their overall experience with the heat pump. In addition, market rate customers were highly likely to recommend the heat pump to a friend (with a net promoter[5] score of +89).

[4] Consumers Energy excluded most customers that used natural gas for space heating from the CCHP initiative, but a small number of participants recruited by contractors used natural gas prior to installation of the CCHP.

[5] The net promoter score is expressed as an absolute number between -100 and +100 that represents the difference between the percentage of promoters (respondents giving a rating of 9 or 10) and the percentage of detractors (respondents giving a rating of 1 to 6).

INCOME QUALIFIED MULTIFAMILY: The three interviewed income qualified multifamily property owners and managers provided an average rating of 9.5 (on a 10-point scale) for their satisfaction with the CCHP Initiatives and their likelihood to recommend heat pumps to a colleague. The property owners and managers also rated their likelihood to adopt similar CCHP equipment in their other properties as a 9.0 on a 10-point scale.

Income-qualified multifamily tenants (n=23 of 32) were *very satisfied* with their CCHP experience, and generally felt that the heat pumps provided improved winter heating and summer cooling comfort. Multifamily tenant participants gave an average rating of 8.7 for their overall experience with the heat pump, though some may not have been aware of their heat pump until they were contacted for the survey. Respondents also gave an average rating of 8.8 regarding summer comfort and 7.9 regarding winter comfort. However, tenants' willingness to recommend Consumers Energy was dependent on the level of communication and instruction provided to them regarding equipment operation. Tenants who provided verbatim feedback around lack of instruction were more likely to provide a lower overall net promoter score (averaging +13) than those who received instructions (averaging +50). Similarly, tenants who reported that the installer did not set up their heating and cooling schedule were also more likely to provide a lower overall net promoter score (averaging +10) than those who had the installer set up a schedule (averaging +67).

COMMERCIAL: Commercial participants rated their overall satisfaction with the CCHP Initiatives as an average of 9.9 out of 10, and 86% (six out of seven interviewees) strongly agreed that Consumers Energy made it easy to participate in the initiative.[6] In follow up interviews with participants, four out of five interviewees reported being satisfied with their heat pump's performance during the winter.[7]

CONCLUSION 4. Some participants received a new thermostat with their CCHP. Participants who received a new thermostat had varied knowledge about how to use it to optimize operation of their heat pump and some could have benefitted from additional instructions and training.

MARKET RATE: Seven of the nine residential market rate participants had a programmable or smart thermostat, while two reported having a non-programmable thermostat. Of those who had a programmable thermostat, only two programmed temperature setbacks. Despite most having thermostat programming capability, four of nine tended to adjust the temperature manually.

INCOME QUALIFIED MULTIFAMILY: Only three income qualified multifamily respondents could confirm with certainty that the contractor set up a heating and cooling schedule for their heat pump. These three participants also confirmed that the heating and cooling schedule set up by the

[6] Commercial participants were interviewed prior to experiencing a full heating season and some respondents listed this uncertainty about how the equipment would perform during the heating season as a reason for not giving a higher satisfaction rating for their heat pump, though the average rating was still 9.3 out of 10.

[7] The one respondent who was displeased, noted that the heat pump took a while to turn on, they often felt a cool breeze that was discharged directly onto an employee, and they had to adjust their thermostat higher than usual in order to achieve their preferred temperature.

contractor was still in operation. Only 25% (n=8) reported receiving instructions or documentation about the heat pump or use of their thermostat with the heat pump.

COMMERCIAL: Most respondents needed additional time to learn how to use their new thermostats and a few had minor issues operating their heat pumps. While most respondents did not have any problems with their new heat pumps, some (43%; n=3) reported that learning how to use their new thermostat was the most challenging aspect of their new equipment. Two respondents (29%) also reported needing a contractor's assistance with minor issues related to operating their heat pump. These minor issues included resolving an installation error and adjusting the cooling so that the air temperature was reaching the thermostat's temperature setpoint. Another finding from the follow up interviews was that some customers needed additional support understanding the controls and settings of the heat pumps to maximize the value, especially when sites have overlapping building controls with multiple heating units.

RECOMMENDATION

High Priority: Consider increasing follow up communications and support after the installation to ensure participants understand their new technology. Sending follow-up emails with resources and providing high-touch support after the installation engenders a positive equipment experience, which is critical for word-of-mouth testimonial marketing. Encourage contractors to provide set up and programming instructions and provide contractor training to ensure they are familiar with different types of thermostats and systems.

CONCLUSION 5. Participants reported better working equipment and increased home and business comfort levels after the installation of their CCHP.

MARKET RATE: Most market rate participants surveyed (seven of nine) said their home was more comfortable after installing the heat pump. The nine respondents rated their comfort level as 9.1 on average during the summer, with a slightly lower rating of 8.6 (n=5) during the winter. None of the respondents indicated any concerns with the heat pump's ability to heat to a preferred comfort level. Five respondents also mentioned improved heating and cooling distribution across sections of the home.

INCOME QUALIFIED MULTIFAMILY: Income-qualified multifamily tenants said their homes were as comfortable with the CCHPs as before (43%), with one-quarter reporting increased comfort levels. A few tenants said their home was too hot or too cold after the heat pump installation. Property owners and managers indicated that tenant comfort was a key decision factor to install CCHPs.

COMMERCIAL: Customers were very satisfied with heat pump performance overall , though three interviewees (43%) reported some minor initial issues with their heat pumps, including one who said it did not cool down to the expected temperature and two who had issues with the installation that required a contractor to fix.

RECOMMENDATION

Medium Priority: Promote the increased home and business comfort that cold-climate heat pumps can provide during both the heating and cooling seasons. Developing and using home and business testimonials could be an effective way Consumers Energy can promote the benefits of cold-climate heat pumps such as increased comfort, lower energy bills, and for some, the addition of space cooling.

CONCLUSION 6: Distributors generally had heat pump inventory on hand, so delivery times were either not impacted or were only impacted temporarily by manufacturing delays.

While manufacturers and distributors reported manufacturing delays as a result of COVID-19, as well as on-going transportation delays, distributors generally reported having sufficient stock on hand to meet current demand. Only one distributor reported a delay (6 to 8 weeks) in getting equipment to the customer. Note that custom equipment was generally not discussed in the interviews with manufacturers and distributors, and it is possible that timelines for custom equipment could be different. It is also worth noting that the manufacturer and distributor interviews were conducted in April of 2021, and the factors influencing supply chains may have changed since this time.

CONCLUSION 7: Most residential market rate and income-qualified Multifamily participants realized heating and cooling utility bill savings after the installation of their CCHP. However, bill savings largely depends on heating fuel prior to the heat pump installation, as well as how the homeowner used their new equipment.

MARKET RATE: The majority of market rate participants replaced propane heating systems (51%), followed by electric heating (31%), natural gas heating (10%), and fuel oil heating (8%).[8] Based on engineering estimates, market rate participants who replaced propane or electric heating systems will realize approximately $910 to $1,680 in heating and cooling savings per year[9]. The five homes that previously heated with natural gas will likely see an increase in their utility bill of $450 per year on average due to the higher cost of electricity compared to natural gas; also, four of the five homes did not have existing central air conditioning, which means they will add electrical load in the summer.

INCOME QUALIFIED MULTIFAMILY: Income-qualified multifamily tenants, even though retaining their original baseboard heating systems, experienced annual savings of 896 kWh, which translates to approximately $147 in annual bill savings. Most of the savings (93%) were realized during the heating season (largely October-April). These savings during the heating season were equivalent to approximately 23% of baseline weather-sensitive electric heating use. Income qualified multifamily tenants experienced lower than anticipated savings attributable to the heat pumps because they continued use of their baseboard heating systems, consistent with other recent evaluation findings.

[8] At the time of conducting the engineering analysis the evaluation team had a sample of 51 CCHP installations.

[9] Based on fuel costs at the time of the analysis in January 2022.

INCOME QUALIFIED SINGLE FAMILY: Due to low participation and delays due to COVID, the Income Qualified Single-Family Impact analysis will be completed in 2022. The Evaluation team is currently conducting an engineering analysis of the impacts for the income-qualified single-family installations, relying on MEMD parameters and assumptions collected from customers such as home vintage, presence of central cooling, equipment efficiencies, tonnage, and other data. The analysis will be completed later in 2022 and filed in the case docket.

COMMERCIAL: Because participation in the small business pilot occurred later in 2021, the impact evaluation was delayed. The impact evaluation is based on metered data, and TRC is keeping the meters in place to collect data for at least one complete heating season and one complete cooling season for each site.[10] The results of the heating season impact analysis are presented in a separate memo that is included in the filing of 2021 studies made on August 31, 2022.[11] Metering for the 2022 cooling season is still in progress as of the writing of the report, and analysis will take place in later in 2022.

RECOMMENDATIONS

High Priority: Provide multifamily property owners who had cold-climate heat pumps installed with information for how continued use of baseboard heating systems will minimize the tenant's ability to achieve the highest potential heating, and cost savings.

High Priority: Provide multifamily property owners with handouts they can distribute to tenants with simple operational instructions to ensure all new tenants understand how to operate their heat pump systems. Additional follow up and coordination with maintenance staff to review proper operations would ensure persistence of heat pump savings.

High Priority: If the Michigan policy on fuel switching should change, natural gas heating customers should be screened prior to approval to ensure the heat pump has potential to reduce energy bills.

Table 4 shows the Evaluation team's conclusion for each research objective outlined above.

[10] Metering analysis was performed for 22 CCHP installations.

[11] TRC. 2022. C&I 2021 Cold Climate Heat Pump Pilot Impact Evaluation Memo

Table 4. Research Objective Mapping

Conclusion	Research Objective			
	1. Assess Cold-Climate Heat Pump Initiative Performance	2. Understand Market Readiness and Challenges	3. Determine Current Supply Chain Limitations	4. Understand Impacts on Low-Income Customers
There is low and varied awareness of cold-climate heat pumps by homeowners, property owners and their tenants, and commercial businesses and even lower awareness that Consumers Energy offers cold-climate heat pump rebates.		✓		
Because natural gas is the predominate heating fuel in Michigan, and current Michigan Public Service Commission policy limits fuel-switching, there are limited cost-effective cold-climate heat pump installation opportunities. This contrasts with other states such as Maine and Vermont where a higher percentage of homes use more costly heating fuels such as propane and oil and where state policies incentivize fuel-switching.		✓		
Participants were generally satisfied with their experience and gave very high ratings for the Cold-Climate Heat Pump Initiatives offering. However, multifamily tenants' satisfaction was split, largely based on whether the tenant received education on how to operate the new equipment.	✓			✓
Some participants received a new thermostat with their cold-climate heat pump. Participants who received a new thermostat had varied knowledge about how to use it to optimize operation of their heat pump and some could have benefitted from additional instructions and training.		✓		
Participants reported better working equipment and increased home and business comfort levels after the installation of their cold-climate heat pump.	✓			✓
Distributors generally had heat pump inventory on hand, so delivery times were either not impacted or were only impacted temporarily by manufacturing delays.			✓	
Most residential participants realized heating and cooling utility bill savings after the installation of their cold-climate heat pump. However, bill savings largely depends on heating fuel prior to the heat pump installation, as well as how the homeowner used their new equipment.	✓			✓

Recommendation Priority

To assist Consumers Energy in prioritizing the actions needed to address these recommendations, the Evaluation team organized each evaluation recommendation by topic and prioritized them based on the following definitions.

- ***High Priority:*** The evaluation revealed compelling and conclusive data on a concern or a current initiative strength that are likely to have a significant impact on customer satisfaction, achievement of participation goals, or initiative savings if not addressed or maintained.
- ***Medium Priority:*** The evaluation revealed data that are inconclusive and require additional investigation or the issue is likely to have a moderate impact on initiative effectiveness or efficiency.
- **Low Priority:** The issue is likely to have little impact on initiative effectiveness or efficiency.

Table 5 lists the CCHP initiatives evaluation recommendations.

Table 5. Summary of Heat Pump Pilot Recommendations and Priorities

Priority	Summary of Recommendations
High Priority	Identify opportunities for Consumers Energy to promote the Cold-Climate Heat Pump technology and incentives. Consider providing materials, such as one-page initiative summaries, for distributors to leave with contractors during their interactions. Continue to promote cold-climate heat pumps through events like the Annual Trade Ally Kickoff or identify larger distribution events or trainings where Consumers Energy can interact with trade allies.
	Increase contractor and customer education of cold-climate heat pump benefits and technology. Consider increasing the promotion of cold-climate heat pumps through planned marketing campaigns (such as bill inserts and online advertising) and through cross-program promotions.
	Because contractors reported that it is not always simple to determine when cold-climate heat pumps are economically more beneficial than traditional equipment, provide them with sales tools, such as a cost-effectiveness calculator, that can assist them in identifying when a cold-climate heat pump makes financial sense for their customers.
	Consider increasing follow up and support after the installation to ensure participants understand their new technology. Sending follow-up emails with resources and providing high-touch support after the installation engenders a positive equipment experience, which is critical for word-of-mouth testimonial marketing. Encourage contractors to provide set up and programming instructions and provide contractor training to ensure they are familiar with different types of thermostats and systems.
	Provide multifamily property owners who had cold-climate heat pumps installed with information for how continued use of baseboard heating systems will minimize the tenant's ability to achieve the highest potential heating and cost savings.
	Provide multifamily property owners with handouts they can distribute to tenants with simple operational instructions to ensure all new tenants understand how to operate their heat pump heating systems. Additional follow up and coordination with maintenance staff to review proper operations would ensure persistence of heat pump savings.
	If the Michigan Public Service Commission policy on fuel switching should change, natural gas heating customers should be screened prior to approval to ensure the heat pump has potential to reduce energy use.
Medium Priority	Promote the increased home and business comfort that cold-climate heat pumps can provide during both the heating and cooling seasons. Developing and using home and business testimonials could be an effective way Consumers Energy can promote the benefits of cold-climate heat pumps such as increased comfort, lower energy bills, and for some the addition of space cooling.
Low Priority	Promote the space cooling benefits associated with a cold-climate heat pump. Cold-climate heat pumps are a good option to add cooling where there was not previously a whole-home space cooling system or where the cold-climate heat pump can replace inefficient central air and room air conditioners.

Contractor, Distributor, and Manufacturer Findings

Consumers Energy launched the CCHP initiatives just prior to the start of the COVID-19 pandemic, which as reported by Consumers Energy staff, created unique challenges such as long delays in project timelines due to back-ordered equipment. In addition, trade ally participation was low, with only one trade ally completing the vast majority of installations across these offerings in the early months of the initiative. To determine the sources of these barriers and understand the challenges associated with adopting CCHPs in Consumers Energy's service territory, the Evaluation team interviewed eleven contractors, two manufacturers, and five distributors involved in the installation, production, and distribution of CCHPs in Michigan.

Contractors' awareness and perceptions of CCHPs varied, and a contractor's interest in heat pump technologies in general depended largely on the availability of different heating fuels in their service territories. Contractors in rural areas, where delivered fuels are more common, had more awareness of and a greater affinity for ducted systems and heat pumps in general. Contractors in urban areas had more awareness of ductless systems, but overall lower levels of familiarity with and affinity for heat pump technologies.

Among all contractors, the pervading theme regarding CCHPs (and heat pumps in general) is that of uncertainty. In order to confidently promote heat pump technologies, contractors must be able to determine the operating cost of the equipment compared to a customer's existing equipment. Currently, there are no readily available tools that allow contractors to accurately model and compare the energy consumption of a heat pump to other heating sources; combined with the comparatively higher up-front cost of heat pumps, this inability to accurately model potential energy savings commonly makes heat pumps a non-starter. Furthermore, several contractors expressed a hesitancy to promote electric heating sources to their customers, as they perceived the price of electricity to be less static and more prone to price increases than other fuel sources. Additionally, some contractors were unaware that CCHPs were effective in cold climates. The confluence of uncertainty around CCHPs is commonly too significant of a barrier for contractors to abandon the status quo of a like-for-like equipment replacement.

Although there were manufacturing and transportation delays, distributors reported having stock on hand that was sufficient to meet current demand. Manufacturers and distributors noted that some contractors maintained the belief that heat pumps were not effective in cold climates (a finding that may be correlated with a contractor's location, given that the contractor interviews found that contractors in urban areas were less aware and less in favor of heat pumps compared to those in rural areas). Aside from this contractor barrier, manufacturers and distributors pointed to customer hesitation due to large up-front or long-term costs associated with CCHPs. In Michigan, CCHPs are less cost-effective than in other states due to the low cost of natural gas, but demand seems to be increasing, especially in rural areas where homes are predominantly heated with propane or oil.

This chapter provides contractor findings separately from manufacturer and distributor findings.

Contractor Findings

The Evaluation team interviewed eleven HVAC contractors to address three research objectives:

- Determine current awareness and perceptions of heat pump technologies.
- Identify the main barriers to installing heat pumps in Michigan.
- Identify marketing and outreach best practices.

The key findings corresponding to each research objective are outlined below.

Cold-Climate Heat Pump Awareness and Perceptions

Contractors' overall awareness of and attitudes toward CCHP technologies were largely correlated with the type of fuel available to the contractor's customer base. Contractors serving rural populations were more familiar with ducted systems, displayed an overall greater affinity for heat pump technologies, and reported higher levels of customer awareness and demand. Conversely, contractors serving urban populations were more familiar with ductless systems and displayed comparatively lower levels of familiarity with improvements in CCHP capabilities.

Contractors indicated that general awareness of heat pump technologies among customers was low but increasing. Contractors reported a marginal increase in the number of customers asking for the technology in recent months, and a more substantial increase in customers who were aware once the contractor presents CCHPs as an option. Similarly with contractor awareness, customer awareness is largely correlated with location and the availability of natural gas.

> "The typical customer is not aware it [CCHPs] is a heating option."
> - Contractor

Best Cold-Climate Heat Pump Applications

Contractors detailed the various scenarios in which CCHPs are currently being adopted by customers, or where they make the most sense for future adoption. For ducted systems, contractors reported the three best applications:

- Customers with propane or delivered fuels who have no access to natural gas
- Green-motivated customers who are not as cost conscious
- New construction

The best applications for ductless mini splits differ by heating versus cooling:

- Heating
  - Customers with electric baseboard heat—especially multifamily customers
  - Customers with hot or cold spots not served well by the existing system (and who could use heat pumps for supplementary heat)
- Cooling
  - Customers with no existing duct work (such as those with a boiler or electric baseboard heat)
  - Commercial applications, such as computer server rooms or elevator rooms
  - Vacation homes (that are not occupied in the winter)[12]

[12] Note that secondary or vacation homes were not eligible for the pilot.

Barriers to Adoption

Contractors provided a variety of reasons for the relatively slow adoption of heat pump technologies to date. Barriers primarily relate to financial constraints, either the up-front cost of the equipment or the comparatively higher operating cost (where natural gas is available). Adding to concerns over the operating cost is the idea that electric rates can be somewhat variable, so even if a contactor is able to project the operating cost of equipment for their customer, there is no guarantee that the projection will be accurate in the future. Furthermore, even when projecting operating costs using a fixed cost of electricity, there are no readily available tools by which contractors or customers can make accurate projections of the total system cost (equipment and operation). Several barriers were identified:

- Higher equipment cost versus other systems
- Relative higher cost of electricity compared to natural gas
- Variability in electric rates
- Inability to make accurate comparisons between the operating costs of CCHP systems to traditional heating systems
- Lack of education and awareness for the public and contractors alike
- Contractor perceptions of poor performance in the Michigan climate (less common)

Installation complexity and cost, supply chain robustness, and previous experiences with heat pumps are not seen as barriers among contractors. Contractors detailed how heat pumps generally require minimal additional work compared to traditional systems, and that relative to the additional cost of the equipment itself, the additional installation costs are negligible.

> "ASHPs [air-source heat pumps] have fallen off [become less common] for a couple reasons: most homes lately have a natural gas option, so we feel it is more to their advantage to use the gas furnace than air-to-air heat pumps."
>
> - Contractor

Overcoming Barriers to Adoption

There was no consensus among interviewed contractors as to what would be most influential in increasing CCHP adoption. Two contractors referenced a different rate structure for customers who use electric heat: Consumers Energy used to offer a special rate for customers with electric heat, and one contractor said the number of heat pumps they install has decreased since this rate was rescinded. These contractors believe that introducing an electric heating rate would potentially help to price CCHPs more similarly to natural gas–fired systems and lead to increased adoption:

- "If you choose a certain heating system, they used to offer a heating energy price decrease. If Consumers [Energy] could bring something like this back, demand would explode. Offer special rates for HP [heat pump] use for heating."
- "Used to do heat pumps more when they offered an electric heating rate, but we've switched to mostly natural gas due to cost of use."

Two contractors indicated that additional customer education is necessary to increase CCHP adoption, with one proposing a potential marketing campaign similar to the thermostat promotions that Consumers Energy currently offers. Other suggestions included offering increased rebates and a tool that helps customers more accurately project the lifetime operating costs of heat pumps against other space heating options:

- "Messaging would be a big bonus for all the contractors. It would help with promoting them [CCHPs]. Like the thermostat promotions that have produced a lot of positive feedback, [a campaign promoting heat pumps] would be very helpful."
- "Just educating people about that they've gotten the bugs out of these things [CCHPs] and they're working great."
- "Better rebates on them [CCHPs] for sure. With the [heat pumps] we have had a hard time meeting Consumers Energy's rebate requirements to qualify; our basic ASHP [air-source heat pump] doesn't qualify [and would] need to get up into the second or third level of efficiency, and with the increased cost the low [$100] rebates are not effective."
- "[It would be great] if Consumers [Energy] were able to come up with a tool comparing purchase and operational costs of electricity versus natural gas systems, showing savings of switching over when customers have dual fuel systems."

Marketing and Outreach Suggestions

As previously noted, two contractors said that increased customer education would be the most impactful way to increase customer demand for CCHP technologies. Each interviewed contractor suggested specific comparisons or promotional strategies to present the equipment to customers:

- Two suggested direct promotional campaigns from Mitsubishi that have been successful within Michigan
- One suggested using smart thermostat promotions from Consumers Energy
- One suggested promoting heat pumps as an air conditioner (AC) that also provides free heat
- One suggested offering a winter electric heating rate for owners with a CCHP
- One suggested providing tools to demonstrate savings compared to other systems

Income-Qualified Considerations

Two contractors indicated that unique circumstances may prevent the widespread adoption of heat pumps for income-qualified customers:

- The potential for theft of the costly units
- Low-income property managers' aversion to potential equipment issues and ensuing repairs

Distributor and Manufacturer Findings

The Evaluation team interviewed five distributors and two manufacturers of CCHPs in Michigan to address several research objectives:

- Confirm and document the supply chain for CCHPs in Michigan
- Identify the barriers leading to extended timelines for CCHP installation
- Identify sources of differences in CCHP installation costs across states
- Explore the cause of low participation by trade allies
- Identify any additional barriers and challenges delaying the widespread adoption of CCHPs in Michigan, like training or education
- Identify ways in which Consumers Energy can influence market adoption

The key findings corresponding to each research objective are outlined below.

Cold-Climate Heat Pump Supply Chain

Manufacturers and distributors confirmed that CCHPs follow a traditional supply chain structure, with no difference compared to traditional air-source heat pumps (ASHPs) or other types of HVAC equipment. While this typically means that units move from the manufacturer to the distributor and then to a contractor before reaching customers, there are exceptions for national corporate customers, who may purchase equipment directly from a distributor rather than through a contractor (see Figure 1).

Many CCHPs are manufactured abroad and shipped to ports in the United States, primarily to California or Georgia, before being trucked to regional destinations.

Figure 1. Heat Pump Supply Chain

Installation Timelines

Distributors reported it takes from one to 20 weeks to receive inventory from manufacturers, depending on whether the manufacturer is overseas or domestic and whether they placed a rush order. Manufacturers and distributors reported experiencing manufacturing delays as a result of COVID-19, as

well as ongoing transportation delays that included backups at ports and a truck driver shortage that began in 2018, prior to the pandemic.

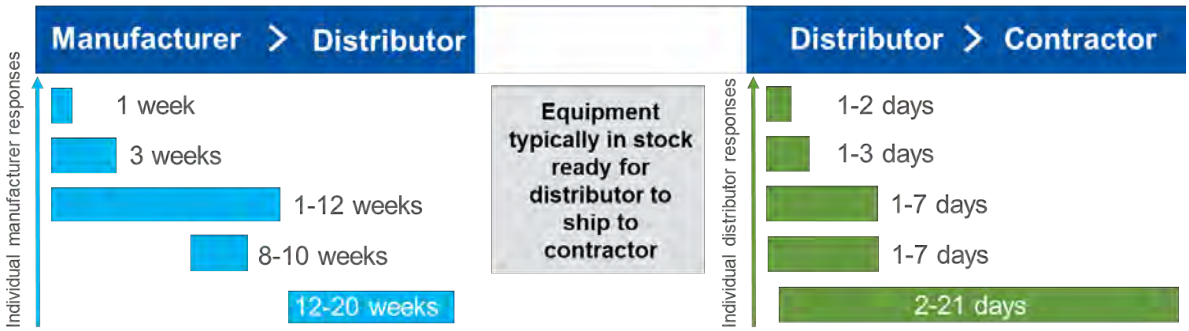
Despite manufacturing and transportation delays, distributors generally reported having stock on hand, so installation times were either not impacted or were only impacted temporarily. For the most part, distributors had learned how to manage around these constraints by being proactive and front-loading inventory. With enough inventory in stock, they can prevent delivery delays from impacting installation timelines:

- "With COVID-19, a lot of the supply chains have been broken. We were very responsive and proactive this year by buying up huge amounts of inventory. If we were to stop purchasing equipment now (March 2021), we would have enough equipment to last through November." – Distributor
- "This whole COVID thing really threw a wrench in a lot of this, and so I think a lot of it, the success that we have seen, having a little bit of inventory in Michigan, has to be to the credit of the distributor being proactive." – Manufacturer

When distributors have stock on hand, they reported that they typically deliver equipment to the contractor within one week, as shown in Figure 2. For a custom system or for equipment not in stock, the delivery timeline can stretch to three weeks or more, and one distributor had seen delays reach as long as six to eight weeks at points earlier in the pandemic, saying, "Much like everything else in the world, COVID really wreaked some havoc on manufacturing, so you know there were some times when it was six to eight weeks, but thankfully with good planning, we had enough stock that we really didn't have to deal too much with it [delays]." One distributor stated that custom equipment requires roughly 30 days to get to the contractor. Note that with the exception of this one distributor, timelines for custom equipment were not discussed in the interviews. It is possible that timelines for custom equipment could be different.

Notably, manufacturers and distributors have not observed any issues with the supply chain or with installation timelines that are unique to CCHPs or to Michigan.

Figure 2. Equipment Delivery Timelines Reported by Distributors



Note: The range in times for equipment to be delivered from the manufacturer to the distributor is due to differences between oversees versus land shipping and rush versus standard orders. One distributor also noted that COVID-19 led to six- to eight-week delays in equipment getting from the distributor to the contractor.

Cold-Climate Heat Pump Cost Differences across States

Most interviewed distributors and manufacturers did **not** report CCHP cost differences between Michigan and other states. One exception was a distributor who reported that installation costs in Michigan are higher compared to the Northeast. The distributor linked this difference to lower familiarity among installers in Michigan and said they expect costs to go down as installers become more familiar with the technology.

Within Michigan, interviewees observed differences in cost based on location in the state, with labor costs in urban areas being higher than costs in more rural areas. As one distributor stated, "Michigan prices are pretty average compared to Ohio [prices]. If you're in a more rural area, installation prices tend to go down, and if you're in a bigger, more metropolitan area then prices tend to go up."

One manufacturer also pointed out cost differences depending on whether contractors are union or non-union: "We go from $85 an hour that a contractor will charge a consumer to $140, especially if they are [in] a union. Or [when] you get into the Motor City, they seem to think they can charge a lot more."

Four of the five distributors reported increased CCHP costs over the last six months, and two interviewees noted that the cost of materials is rising—particularly for sheet metal, steel, and copper—which could lead to further cost increases down the road. As one distributor said, "[Internal costs] are going through the roof, [and] manufacturers can't eat it all."

Contractor Engagement

All five of the interviewed distributors shared the perception that there are still contractors in Michigan who do not have a full understanding of CCHPs and need to become more familiar with the technology and benefits. All five distributors also reported offering trainings to contractors to further their knowledge of CCHPs, including installation and service trainings as well as sales-oriented trainings: "We do training at every level possible, from technical service/installation to sales, and we have even offered business training."

Reports of attendance at trainings varied, with three who said their trainings were well-attended, one who said there was a mix of well-attended and less well-attended trainings, and another who said they were not well-attended, which they attributed to a lack of awareness of CCHP technology. One distributor also reported that, in their experience, one-on-one trainings work better than trainings offered in a group setting. Many training offerings have been moved to virtual platforms like Zoom due to the pandemic, which two distributors noted has been more challenging than in-person trainings.

Interviewees noted that trainings do not differ by state, e.g., they do not address specific climate, available programs, or current policies.

Barriers to Adoption

Four distributors mentioned that one barrier to CCHPs becoming more common in Michigan is that awareness of and trust in CCHP technology is not yet widespread among contractors in the state.

Instead, they reported that many contractors continue to hold an outdated perception that heat pumps are not a viable option in cold climates:

- "A lot of the contractors, especially a lot of the old timers... They don't see heat pumps as a viable option in Michigan. We hear that so many times." – Distributor
- "As technology continues to get better and heat pumps can operate at lower temperatures, you're always going to have an old service tech or installer that absolutely does not believe in the new technology." – Distributor
- "A lot of contractors are not as informed as they could be." – Distributor

Other barriers mentioned include concerns about up-front and long-term costs and, relatedly, the lack of incentives (since current policies in Michigan do not allow utilities to incentivize customers to switch from natural gas heat to electric heat).

Interviewees reported that demand for CCHPs is higher in other states than in Michigan. One attributed this lower demand in Michigan to the lack of widespread understanding among contractors and customers that heat pumps can be effective in cold climates. Others discussed the trade-offs in switching from different fuel sources. One distributor pointed out that natural gas is cheaper in Michigan than in other states, making CCHPs less cost-effective, and therefore less appealing, for those who currently use natural gas heating.[13] For those who use more expensive propane or fuel oil systems, however, distributors felt switching to a heat pump *would* be more cost-effective: "All-electric heat is a no-brainer. If they have propane or fuel oil, [heat pumps] make sense. With a natural gas system, it is a tougher sell."

Overcoming Barriers

Although interviewees reported that demand for heat pumps is lower in Michigan than elsewhere, they have also observed that demand in the state is increasing. Two distributors reported seeing major growth in CCHP adoption in recent years: one reported that their 2021 quarter 1 CCHP sales were greater than CCHP sales in the previous two years combined, and another reported having record demand in 2020, with sales doubling from 2019.

> "Ductless mini-splits are a huge, growing market, [with] the largest growth potential of any [technology], and everyone is saying the same thing."
>
> - Distributor

While there are still awareness and education gaps, interviewees reported that contractors and customers are becoming increasingly familiar as CCHPs have become more technically viable. As mentioned above, CCHPs are also increasingly *economically* viable in rural areas where there is a reliance on propane and oil heat.

[13] The proportion of households in Michigan with natural gas heating (82%) is higher than in most other states (Consumers Energy. 2018 Residential Saturation Study. Not available online).

The two biggest tools that interviewees noted as key to increasing CCHP adoption are incentives and increasing contractor and customer education. Several distributors emphasized that incentives and rebates are highly appealing to customers, making them an important tool for increasing adoption:

- "Customers would be willing to switch with an incentive." – Distributor
- "Incentives help to drive adoption." – Distributor

> "[It's] all about making the contractors aware of the benefits."
> – Distributor

Contractor education is also seen as a need, both to increase awareness of the viability of CCHPs in the state and to improve contractors' understanding of the benefits and cost-effectiveness of CCHPs.

Increasing Adoption

Distributers and manufacturers mentioned that Consumers Energy has been actively working to increase CCHP adoption, and they see the role of utilities as critical in helping this new technology gain a foothold.

> "The role of the utility is very important because they are the ones that can accelerate the [adoption of CCHP] technology."
> – Distributor

Distributers and manufacturers suggested that Consumers Energy can further encourage adoption in three ways: through education and training, by providing sales tools, and by offering incentives. Additional education and marketing directed at customers is needed to increase their awareness of the benefits of CCHPs.

> "There is a lack of information about the difference between costs for gas and electric."
> – Distributor

Similarly, interviewees suggested providing in-person trainings to contractors about rebates and the benefits of CCHP technology, including targeted trainings for technicians who may need more help to transition to a new technology. Three interviewees also said it would be useful to have a calculator tool that helps contractors easily demonstrate cost savings for switching to CCHP technology.

Interviewees also suggested that higher incentives would be instrumental in increasing CCHP adoption, and primarily felt that incentives should be offered via a midstream strategy. While one interviewee said rebates should be directed to contractors, all the other interviewees suggested that rebates should be directed to distributors, with one saying it would be helpful to have automatic incentives that minimize paperwork. One interviewee also suggested that incentives should be provided for CCHPs that have equivalent seasonal energy efficiency ratio (SEER) ratings as incentivized air conditioners.

> "Utility rebates really help. In some cases, the rebate has been able to cover the difference [between an AC and a heat pump]."
> – Distributor

Residential Market Rate Initiative Findings

In November 2021, the Evaluation team sent a survey invitation to 29 Residential Market Rate pilot participants who had valid emails. The email survey invitation included a $15 incentive for taking the survey. Nine of the 29 participants completed the survey, for a 31% response rate; with such a small sample size, the results should be interpreted with caution and only viewed as directional indications (not intended to be analyzed with statistical confidence).

In addition to the participant survey, the Evaluation team conducted an engineering analysis to determine market rate CCHP participants' energy and utility bill cost savings. The Evaluation team used data collected from the Consumers Energy initiative team and calculations that can be found in the *Michigan Energy Measures Database* (MEMD).[14]

This chapter first provides details of Residential Market Rate pilot participants, then covers the engineering analysis findings.

Market Rate Participant Survey

The Evaluation team designed the participant survey to address several key objectives:

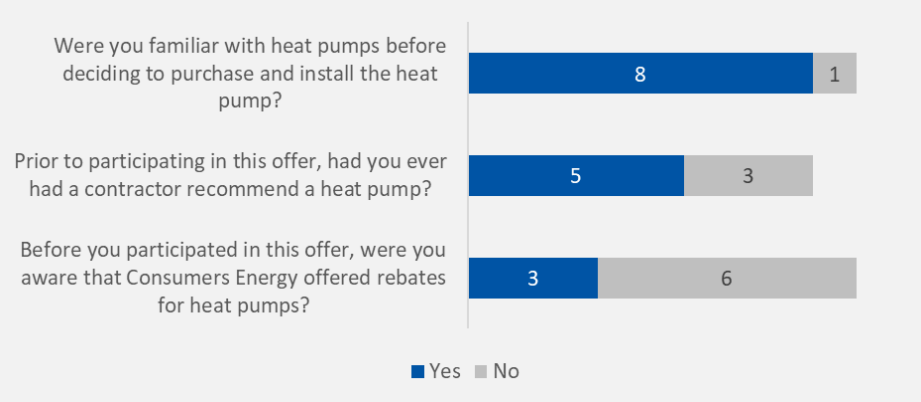
- Assess awareness of and motivation for installing heat pumps
- Assess the participant installation experience
- Document perceptions of heat pumps, energy or cost savings, and comfort levels
- Document participant usage behavior
- Assess satisfaction with the offering and with Consumers Energy

Awareness and Motivation

All nine respondents confirmed that they received a rebate for their heat pump and that they were present when the heat pump was installed. While most (eight of nine) were familiar with heat pumps before deciding to purchase one for their home, few (three of nine) were aware that Consumers Energy provided heat pump rebates (Figure 3). Respondents first learned about Consumers Energy's heat pump rebate primarily through their contractor (four of nine) or from a Consumers Energy email (two of nine). About half (five of nine) said a contractor had recommended a heat pump before they learned about and applied for the Consumers Energy heat pump rebate.

[14] Michigan Public Service Commission. *Michigan Energy Measures Database.* https://michigan.gov/mpsc/regulatory/ewr/michigan-energy-measures-database

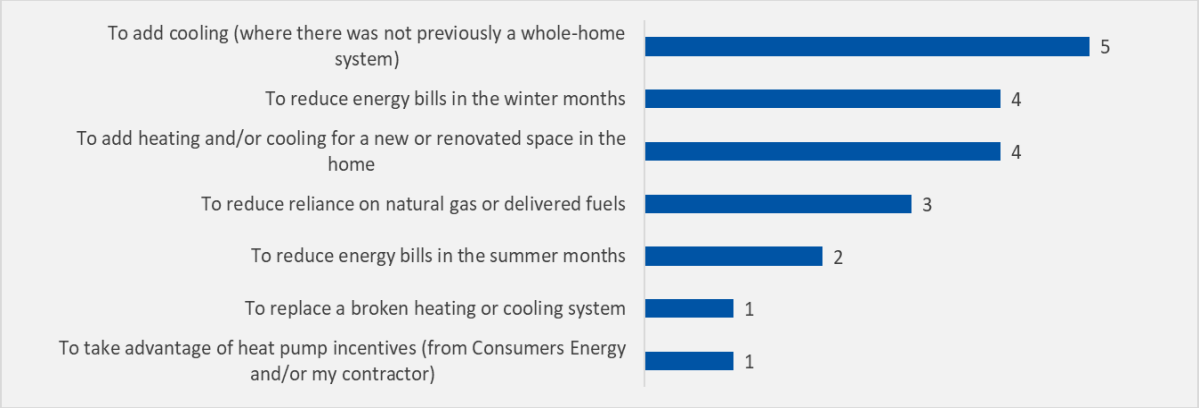
Figure 3. Heat Pump Awareness



Source: Heat Pump Market Rate Customer Survey Questions B3, B4, and B5 (n=9).

Although respondents could indicate several different motivations for installing a heat pump, responses were most frequently associated with space cooling needs and saving money on energy bills. Most respondents (n=5) installed a heat pump to add cooling where there was not previously a whole-home space cooling system. Four respondents each wanted to reduce energy bills in winter months and wanted to add space heating or cooling for a new or renovated space. Three respondents wanted to reduce their reliance on natural gas or delivered fuels (Figure 4).

Figure 4. Motivations for Installing a Heat Pump



Source: Heat Pump Market Rate Customer Survey Question B7. "What were the main reason(s) you decided to install a heat pump in your home?" (n=9; multiple responses accepted)

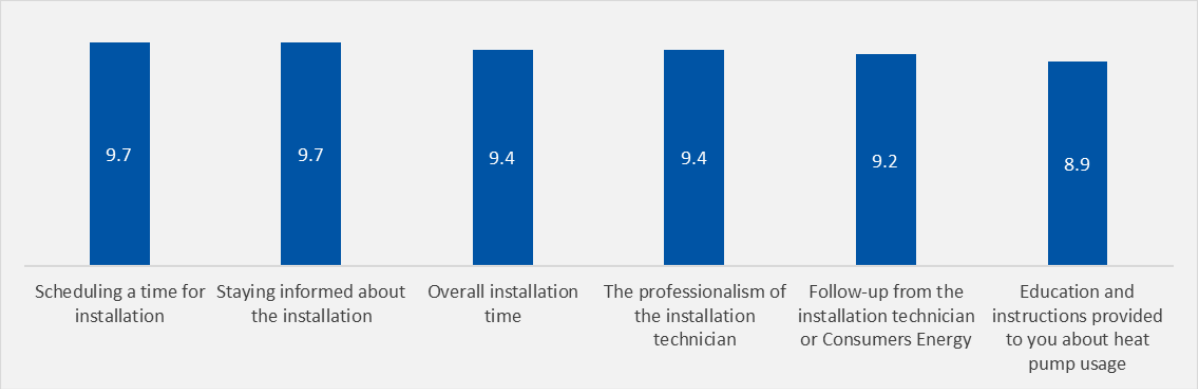
When asked to rate the importance of several factors in their decision to install a heat pump, respondents rated energy savings (over the previous heating/cooling system) as the most important (with a mean rating of 9.1 on a 10-point scale, where 1 meant *not at all important* and 10 meant *extremely important*). The contractor's recommendation received a mean rating of 8.0, and the rebate amount received the lowest rating of all decision factors, at 7.6.

Installation Experience

Respondents were engaged with the installation experience: all of them were present during the installation. Most (eight of nine) received instructions on how to set up and control the heating and cooling schedule on their heat pump at the time of installation. Only one respondent said the installation contractor set up a heating and cooling schedule for them but said they had adjusted that original schedule to address changes in their home's conditioning needs.

Respondents provided very high ratings for aspects of the installation experience, with scheduling and staying informed about the installation receiving the highest mean ratings (of 9.7 on a 10-point scale, where 1 meant *unacceptable* and 10 meant *outstanding*; see Figure 5).

Figure 5. Installation Experience Ratings



Source: Heat Pump Market Rate Customer Survey Question D2. "How would you rate each of the following installation experiences with the heat pump offering?" (n=9)

The lowest rating (of 5) was provided by one respondent for the "education and instructions provided about heat pump usage," but that person did not answer the follow-up question about why they gave that rating.

Heat Pump Perceptions

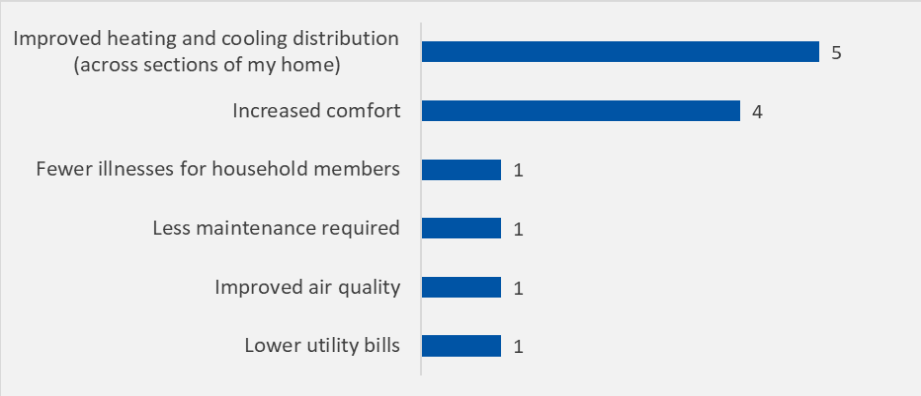
Most respondents (seven of nine) said their home is more comfortable after installing the heat pump, while the other two respondents said their home is equally as comfortable as before the heat pump was installed. One respondent also volunteered that their home air quality was vastly improved, which was also a primary reason they installed the heat pump.

Five respondents rated the comfort level provided by the heat pump in winter months, providing a mean rating of 8.6 on a 10-point scale, where 1 meant *unacceptable* and 10 meant *outstanding*. None indicated any concerns with the heat pump's ability to heat to a preferred comfort level. Comfort ratings for summer months were higher, at an average of 9.1 with ratings from all nine respondents.

Overall, perceptions were mixed about whether respondents had seen savings on their energy bill since the heat pump was installed. Four respondents said it was too soon to tell if their energy bill was affected, while two said they had a lower-than-expected energy bill and two said they had not seen a lower-than-expected energy bill.

In addition to energy savings, respondents reported several additional benefits that they value in their heat pump. With several response options provided, the most frequent benefit selected (by five respondents) was improved heating and cooling distribution across sections of the home (Figure 6). This was followed by four respondents who said the heat pump provided increased comfort. One respondent each indicated having lower utility bills, less required maintenance, improved air quality, and fewer illnesses for household members.

Figure 6. Heat Pump Benefits

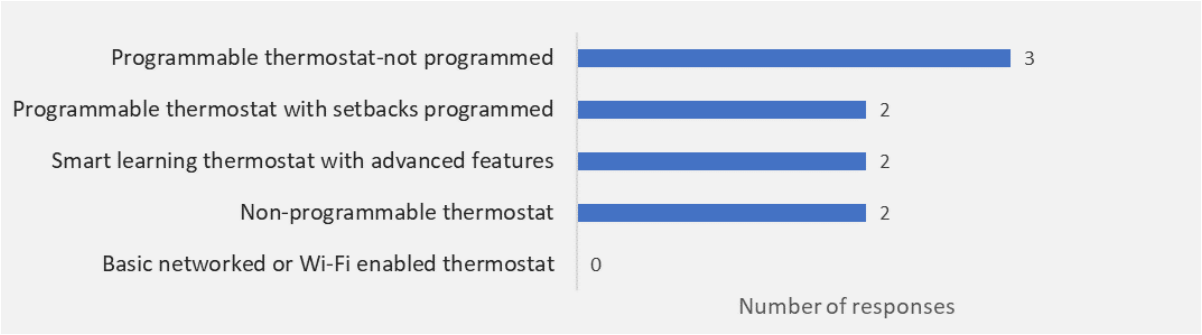


Source: Heat Pump Market Rate Customer Survey Question D13. "In addition to energy savings, if any, are there any other benefits you have experienced or observed from the installation of a heat pump?" (n=9; multiple responses accepted)

Thermostat Usage Behavior and Experience

While five of nine respondents had programmable thermostats, only two of those five used programmed temperature setbacks to control their heat pump temperature settings. Two respondents had smart learning thermostats with occupancy sensing and schedule learning capabilities, and two others had non-programmable thermostats with manual-only controls (Figure 7).

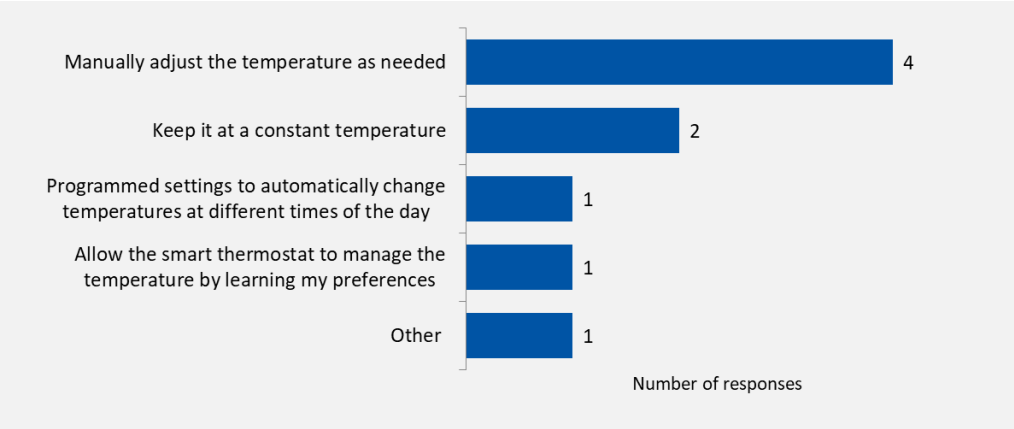
Figure 7. Respondent Thermostat Types



Source: Heat Pump Market Rate Customer Survey Question C1. "What type of thermostat do you have in your home?" (n=9)

Respondents, either singularly or with other household members, monitor and adjust the home heating and cooling settings. Despite most having programming capability through their thermostats, four of nine said they adjust the temperature manually (Figure 8).

Figure 8. Thermostat Management



Source: Heat Pump Market Rate Customer Survey Question C3. "How did your household most frequently manage your thermostat to control the temperature in your home this summer?" (n=9)

Satisfaction with the Offering and with Consumers Energy

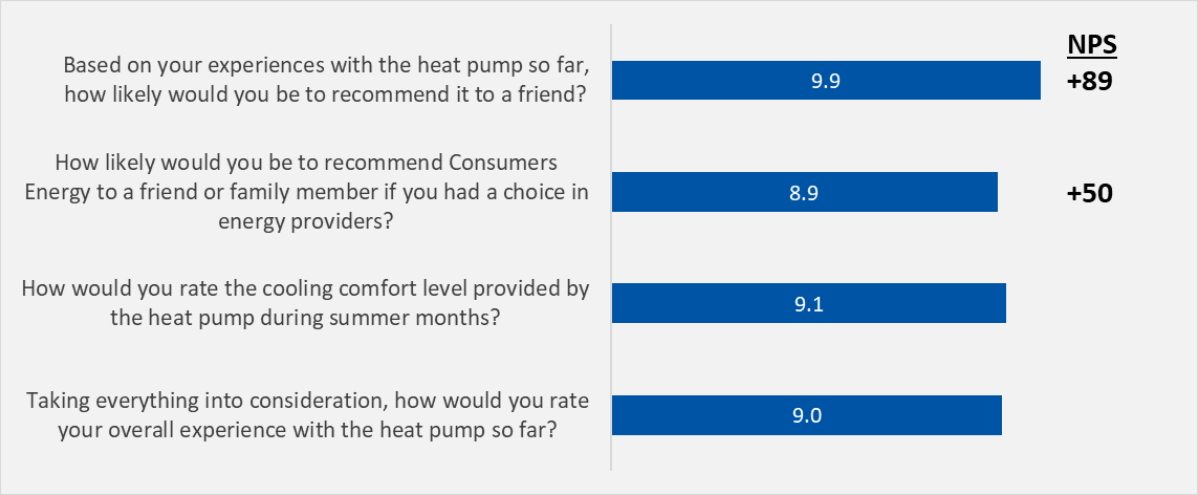
Overall, respondents were highly satisfied with the heat pump (giving a mean rating of 9.0 on a 10-point scale, where 1 meant *unacceptable* and 10 meant *outstanding*), with all nine respondents giving a rating of 8 or higher for their overall experience with the heat pump.

Another key measure of customer satisfaction is the percentage of customers who are highly willing to recommend a product, service, or company after subtracting the percentage of customers who are highly unlikely to recommend that same product, service, or company. The net percentage of those willing to promote the product is the net promoter score (NPS), expressed as an absolute number between -100 and +100 that represents the difference between the percentage of promoters (respondents giving a rating of 9 or 10) and the percentage of detractors (respondents giving a rating of 1 to 6). The Evaluation team calculated a NPS for the two likelihood to recommend questions (likelihood to recommend the initiative and likelihood to recommend Consumers Energy).

Based on their experiences, respondents were highly likely to recommend the heat pump to a friend. As shown in Figure 9, nearly all respondents (eight of nine) gave a rating of 9 or higher (with a mean of 9.9), with three indicating that they had already recommended the heat pump rebate to a friend. The resulting NPS for the heat pump is +89.

Five of eight respondents (63%) provided a rating of 9 or 10 for their likelihood to recommend Consumers Energy to a friend. Only one respondent rated their likelihood to recommend as a 5. The resulting NPS for Consumers Energy is +50, with a mean rating of 8.9.

Figure 9. Market Rate Heat Pump Participant Satisfaction



Source: Heat Pump Market Rate Customer Survey Questions D10, B1, D7, and D9. All questions used a 10-point rating scale, where 1 meant *extremely unlikely* and 10 meant *extremely likely*, with an "already did" response option as a 10 rating (n=9).

The NPS for recommending the heat pump is considered very high and compares favorably to other efficiency programs with similar measures. For example, HVAC participants provided a program NPS of +76 and a Consumers Energy NPS of +63 in 2021. Again, caution is recommended in interpreting numeric results due to the small sample size with the Residential Market Rate pilot response population.

When asked to elaborate on their rating for recommending Consumers Energy, respondents gave positive comments:

- "Consumers Energy has been a good power company. They keep us informed on rebates, power outages, etc. During power outages they are great at restoring power quickly and keeping us informed on time frames. The rebate for heat pumps was one of the reasons we decided to try a heat pump. Our power bill has gone up, but we are using our heat pump a fair amount. It is still a better option than the window air conditioner that we had before."
- "It's been a great company. I grew up in a Consumers [Energy] home and have had one [a heat pump] my entire adult life."
- "High marks for programs and communication."
- "Very happy with service and energy offers."
- "[I] like that Consumers [Energy] is trying to help on heating costs that are going up every year."
- "We don't really have much choice, but I think that Consumers Energy does a good job providing (mostly) reliable electric service (which is all you [they] provide to my area)."

Two respondents said they do not have a choice in energy company, so they do not have a point of comparison, and one commented on high rates.

The only improvement suggestion respondents provided did not directly pertain to the heat pump initiative: "Allow me to change the energy conservation program I want more than once a year. We would like to 'follow the rules' imposed during the summer year-round but cannot change because we cancelled the program we had been on (Consumers [Energy] could limit our AC during peak periods) because our contractor did not want Consumers [Energy] to be able to change our now Wi-Fi–capable system (the old one was not [Wi-Fi]) in May/early June. We did not find out about the option we'd like until later in the summer but were not allowed to use it."

Impact Analysis

The Evaluation team conducted an engineering analysis of the impacts from the Residential Market Rate pilot and relied on MEMD assumptions and information we had collected from customers such as home vintage, presence of central cooling, installed system coefficient of performance (COP)[15] at 5°F, rated heating seasonal performance factor (HSPF) and SEER, tonnage, and other data. The Evaluation team relied on the MEMD weighting tool, which generates a single measure output based on home vintage, climate zone, sizing, and efficiency levels. Since the MEMD weighting tool does not allow for varying the baseline equipment type or system efficiency, the Evaluation team used MEMD building simulation output data to develop site-specific consumption values. MEMD staff provided underlying MEMD 2019 weighting tool building simulation results for ASHPs in single-family buildings.[16] This section summarizes key findings from the engineering analysis.

There were 42 Residential Market Rate pilot CCHPs installed in homes with electric and propane heating, making up the largest percentage of pre-installation heating fuels (Table 6). Approximately half of the CCHPs were installed in homes built before 1979 (n=25) and most of the other half were installed in homes built between 1980 and 2004 (n=23). The remaining CCHPs were installed in homes built between 2005 and present day (n=3).

Table 6. Home Construction Vintage Distribution by Pre-Installation Heating Fuels

Pre-Installation Heating Fuel	1979 or older	1980 to 2004	2005 to Present	Total
Electricity	10	6	0	**16**
Propane	9	15	2	**26**
Fuel Oil	3	1	0	**4**
Natural Gas	3	1	1	**5**
Totals	**25**	**23**	**3**	**51**

[15] Coefficient of performance is simply the ratio of power (kW) in heating (or cooling) Btus generated by the CCHP, and the power (kW) that is supplied to the compressor. The higher the COP, the greater the heating energy generated for each kilowatt consumed by the CCHP.

[16] The MEMD 2021 building simulations for this measure have not been updated since 2019 and therefore reflect the latest building simulation results.

Table 7 shows the average Residential Market Rate pilot participant' annual energy and utility bill savings by pre-installation heating fuel type. Customers heating with delivered fuels (propane and oil) realized the highest heating energy savings, while customers heating with electricity prior to installation of the CCHP had the highest utility bill savings.

Table 7. Average Market Rate Cold-Climate Heat Pump Energy and Fuel Cost Savings per CCHP

Pre-Installation Heating Fuel	Number of Installed Units	Average Savings per CCHP		Average Annual Utility Bill Savings per CCHP
		Heating (MMBtu) [a]	Cooling (kWh) [b]	
Electricity	16	35	-108	$1,680
Propane	26	68	-27	$1,223
Fuel Oil	4	70	-46	$910
Natural Gas	5	54	-228	-$451

[a] Due to the different heating fuel types, savings are represented in MMBtu to allow for better comparisons.

[b] Negative savings mean that electric consumption increased rather than decreased.

The five homes that heated with natural gas will likely see an increase in their utility bill of $451 per year on average due to the relative costs of electricity and natural gas at the time of the analysis, as well as the fact that four of five homes did not have existing central AC (which will likely increase their electric usage in the summer).

As shown below in Table 8, only 22 of the 51 participants had central AC prior to the CCHP installation. For homes without central cooling, the Evaluation team assumed a portion of the homes use room or window AC units to provide some cooling. Due to the low number of homes without conditioned cooling, electric consumption increased, on average, across all baseline heating fuel types. However, homes that did have central cooling before the CCHP installation saw savings from $20 to $96.

Table 8. Central Cooling Presence Distribution and Associated Cooling Savings

Pre-Installation Heating Fuel	Central Cooling?	Number of Installed CCHPs	Annual Cooling Electric Savings per CCHP
Electricity	Yes	5	$33
	No	11	-$37
Propane	Yes	15	$57
	No	11	-$69
Fuel Oil	Yes	1	$96
	No	3	-$35
Natural Gas	Yes	1	$20
	No	4	-$50

Table 9 shows the total Residential Market Rate pilot annual energy and utility bill savings by pre-installation heating fuel type for all CCHPs.

CADMUS

Table 9. Total Market Rate Heat Pump Energy and Fuel Cost Savings

Pre-Installation Heating Fuel	Count of Installed CCHP Units	Savings		Annual Fuel Costs [b]		Pre-Installation Central Cooling Saturation [c]
		Heating (MMBtu) [a]	Cooling (kWh)	Heating	Cooling	
Electricity	16	565	-1,729	$27,124	-$247	31%
Propane	26	1,774	-704	$31,701	$85	58%
Fuel Oil	4	279	-183	$3,652	-$10	25%
Natural Gas	5	270	-1,142	-$2,072	-$182	20%

[a] Due to the different heating fuel types, savings are represented in MMBtu to allow for better comparisons.

[b] The Evaluation team calculated annual heating and cooling costs based on rates and distributed fuel cost shown in *Appendix B*.

[c] Not every home was equipped with central cooling before the CCHP installation.

Income Qualified Multifamily Initiative Findings

There are two key groups of participants in the Income Qualified Multifamily initiative: property owners and managers (PMO) and tenants. PMOs are active participants who sign up for the initiative and are the primary contacts of the initiative. The tenants are indirect participants; they are not decision-makers, yet they directly benefit from the CCHP Initiatives' equipment and energy savings in their living units and they most frequently pay the resulting energy bills from CCHP operation. The Evaluation team sought feedback from both groups, conducting telephone interviews with PMOs and online surveys with tenants. The Evaluation team also sought to understand the Income Qualified Multifamily initiative's performance by analyzing electric energy savings impacts during the heating and cooling seasons through a statistical billing analysis of participating initiative properties.

This chapter outlines the results of PMO interviews, tenant surveys, and the statistical billing analysis.

Property Manager and Owner Interviews

The Evaluation team conducted telephone interviews with multifamily PMOs who participated in the CCHP initiative to gain insight into their experience. The Evaluation team designed the interview to address several key objectives:

- Document the participant installation experience
- Document participant usage behavior and experience
- Document awareness and perceptions of heat pumps
- Document participant decision-making around participating in the heat pump offering
- Identify marketing and outreach best practices
- Assess satisfaction with the offering and with Consumers Energy

As of Q3 2021, seven multifamily properties had participated in the Income Qualified Multifamily initiative. While the Evaluation team attempted to recruit all seven of the multifamily PMO initiative participants, we completed three phone-based in-depth interviews. Two of the multifamily PMO participants were from existing buildings (retrofit installations) and therefore had broad insights into the full initiative experience. The third interviewee was with a newly constructed property, which meant they had a more limited view on the tenant and installation experience.

Installation Experience

Overall, the multifamily PMOs had a positive early-stage initiative experience with scheduling, installation, and follow-up. Two of the three PMOs reported that COVID-19 caused some delays with the installation and equipment, but overall reported positive experiences. In one case, the PMO commented that the completion time was fast considering the number of units and installs: "We had something like 48 units, some large enough for multiple installations…so two-and-a-half months to install over 50 units was fast." The third PMO, the owner of a new construction property, noted the while installations were all completed on time, they did not have feedback on the tenant experience during installation (as installation happened before tenants occupied the units). For the other two PMOs with tenants living in

the units, the installer worked directly with management to notify the tenants of the installations and work around their schedules. According to these two PMOs, their tenants were generally satisfied with the heat pump installation.

Heat Pump Usage Behavior and Experience

The multifamily PMOs reported that prior to installation, tenants relied on inefficient electric baseboard systems and, in one case, had specifically requested new a HVAC system during a tenant meeting. One of the primary benefits for tenants is the ability to use AC as well as heating—while the heat pump replaced baseboard heat, there was no existing AC to replace outside of window units purchased by tenants. One PMO mentioned that nearly all tenants enjoyed the new heat pumps, with only a few tenants being confused about how to use the new system.

Two of the multifamily PMOs received direct feedback from their tenants regarding the heat pump usage and experience. According to one PMO, "the residents considered it a huge plus for them, because of all the extra benefits that the heat pumps provided them." Another PMO remarked that the heat pumps provided significantly greater comfort, and improved air circulation, compared to the baseboard equipment, and went on to state, "the heating itself is just more efficient for the tenants; it seems to keep the apartments warmer."

Awareness and Perceptions of Heat Pumps

Multifamily PMOs were generally aware of heat pumps prior to being approached by Consumers Energy about the rebate initiative, though they were not aware of Consumers Energy incentives or programs until their involvement in the initiative. One PMO previously had contractors recommend heat pumps, while another had heat pumps installed in other apartments in the Southeast United States (where heat pumps are more common). One of the PMOs had some hesitation about installing the CCHPs, as they noted, "historically, my understanding was that [heat pumps] didn't do so well in cold climates. A green consultant and several HVAC engineers turned me on to them and then [I] became comfortable [that] they would be sufficient."

PMOs generally did not report any perceived benefits of heat pumps prior to installation but were happy to report both energy and non-energy benefits, particularly tenant happiness and reduced maintenance and tenant comfort needs, after installation. As an added benefit, the simplicity of a single heating and cooling system was beneficial for both tenants and the PMOs: the number one benefit is providing heat, but efficient heat is the next important thing. As one PMO said, "There is always some kind of system [to heat], but it doesn't always work. It's always our number one concern to provide heating and cooling to the tenants."

Decision-Making around Participating in the Heat Pump Offering

In both existing retrofit cases, the PMOs primarily decided to improve the existing HVAC systems due to energy efficiency and tenant comfort. One PMO cited a tenant meeting as a primary factor, where tenants explicitly requested an improved HVAC system. Generally, all PMOs wanted to improve tenant comfort, replace old equipment, improve electric efficiency, and lower electricity bills. The biggest barrier to switching over to heat pumps was cost: because the multifamily buildings already had existing

heating systems, it was a matter of prioritizing which are the most in need and how to fit that into the budget: "… if there is an existing heating system that is working, that's not necessarily something we can improve because it meets [the need for] having a functioning system, and it's harder and more expensive to switch out than other properties… so the biggest barrier is a matter of prioritizing it [CCHP installation] in the budget." According to the other retrofit PMO, the rebate allowed them to fit improved HVAC systems into the budget for that year. Tenant comfort, energy efficiency, and an improved system were the key motivations for PMOs.

For the new construction PMO, heat pumps were an attractive investment for their property, and the initiative made it "a slam dunk" for the project. The initiative allowed the property to meet LEED certification while also managing to keep the construction within budget. As the new construction PMO noted, "for our LEED-certified property, which was an all-electric building, and given [that] the units were smaller apartments, it was hard to find a furnace that would work well and integrate into the units and not be oversized. The heat pumps can really work well and are adapted to lower need, relative to [a] gas furnace. The simplicity of only electric, with no gas, requiring less piping, meant that construction was easier." This PMO went on to remark, "with the rebate, the heat pump was actually the cheaper option [relative to a gas furnace]."

Marketing and Outreach Best Practices

Multifamily PMOs agreed that the best way to conduct outreach about CCHPs is to directly contact contractors or developers. According to two PMOs, they primarily get their recommendations from contractors, who do not always provide information on CCHPs and higher-efficiency opportunities to the developers. One existing building PMO said, "if I had someone directly to talk to, I would bring this up to [building owners] more…I confer with architects and specialists on building recommendations, but they don't necessarily know all the tenant benefits. So, I would recommend reaching out to more developers, like myself, directly." Both PMOs recommended emails or pamphlets with the overall costs and energy savings and direct information as a convincing outreach strategy: "Anything that involves a description, some costs, energy savings…I think those are the highlights," the construction manager said.

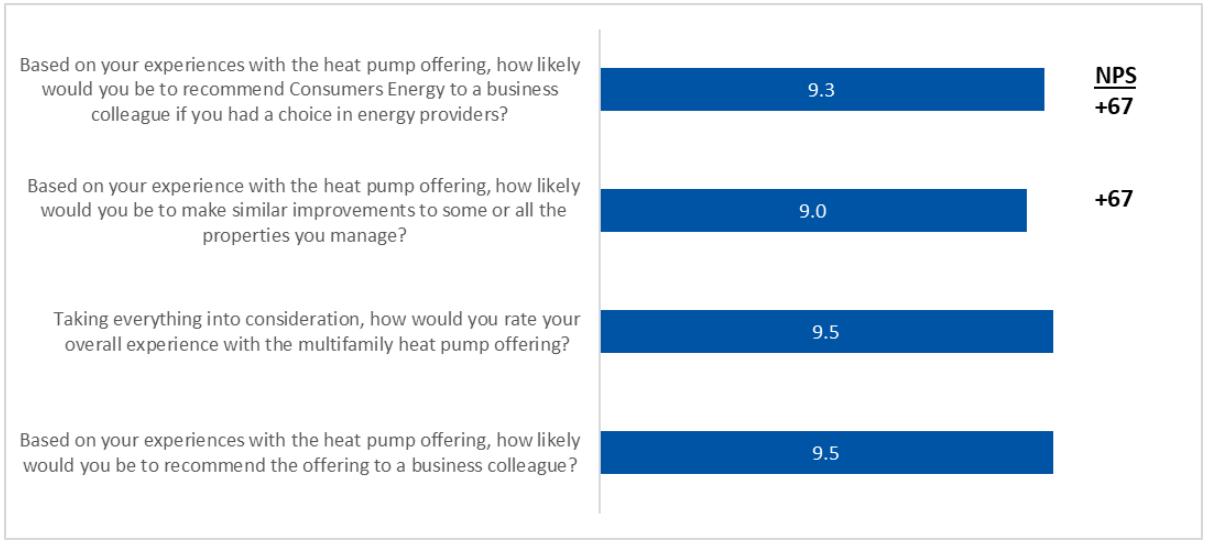
Two of the PMOs learned about the heat pump offering through direct contact with Consumers Energy, while one learned about it from their LEED consultant. When asked what the preferred means of communicating future offerings, all three PMOs tended to prefer email, but also noted phone calls.

One interviewee (the resident manager) mentioned that his property manager was the decision-maker in the process, and that energy companies should do more to contact property managers directly, because most are not aware. "[The property manager] was different," the resident manager said, "He was always searching for rebates and things like that…both to improve the apartments for the tenants, but also because of the resource—using less energy is good for the economy, that kind of thing. But most property managers aren't searching like he was." Another PMO said, "Most people don't know enough and aren't aware [that heat pumps] can work on their own in colder climates. We have now had a full winter with new tenants and the CCHPs and received no complaints: it all went well."

Satisfaction with the Offering and with Consumers Energy

Overall, the participating PMOs were highly satisfied with their initiative experience and with Consumers Energy (Figure 10). The three PMOs provided an average rating of 9.5 on a 10-point scale (where 1 meant *unacceptable* or *extremely unlikely* and 10 meant *outstanding* or *extremely likely*) for their satisfaction with the initiative and their likelihood to recommend heat pumps to a colleague. The PMOs also rated their likelihood to recommend Consumers Energy as a 9.3 and rated their likelihood to adopt similar CCHP equipment in their other properties as a 9.0 (Figure 10).

Figure 10. Multifamily Property Manager Owner Cold-Climate Heat Pump Satisfaction



Source: Heat Pump Property Owner and Manager Interview Guide Questions G1–G4.

Income Qualified Multifamily Tenant Survey

In November 2021, the Evaluation team surveyed a group of multifamily tenants who resided in units that received CCHPs as part of Consumers Energy's CCHP initiatives and 32 completed the survey

The Evaluation team designed the survey to address several key objectives:

- Document awareness of heat pumps
- Understand the participant installation experience
- Assess tenant perceptions of heat pump impacts on comfort levels and electricity bills
- Document participant usage behavior and experience
- Assess satisfaction with the offering and with Consumers Energy

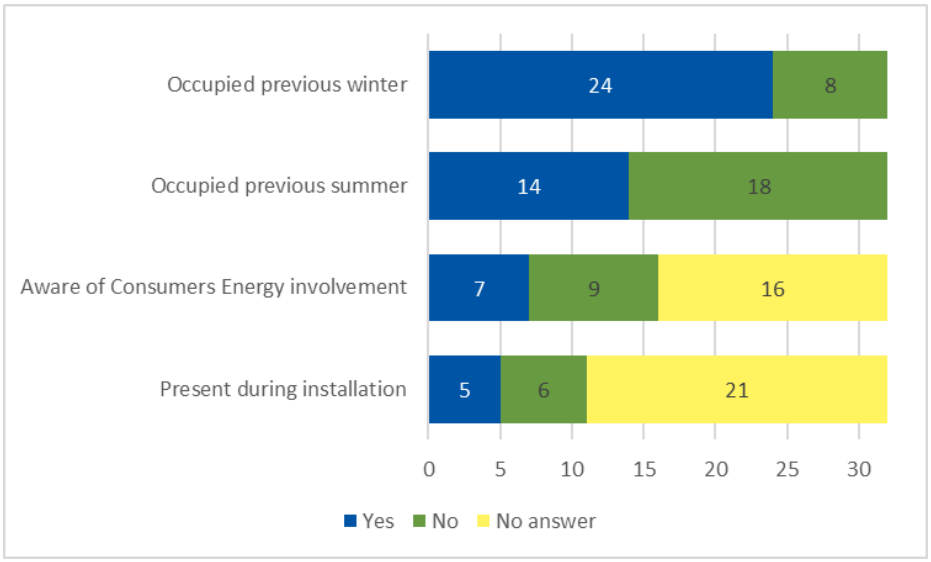
Tenant Survey Background

The multifamily tenant survey included questions about topics such as whether respondents manage the temperature of their unit, whether they pay their bills, and how long they have resided in their unit. Additionally, the team asked questions about the installation and performance of the CCHP.

All tenants who responded to the CCHP survey managed the temperature of their home personally and all said they pay their own energy bills (n=32). Most tenants (n=17) had lived in the apartment for between six months and one year while 11 others had occupied their apartment for more than one year. Additionally, three respondents said the heat pumps had not yet been completely installed and they could not provide answers about installation or post-installation.

Other participant characteristics are summarized in Figure 11. A minority of respondents were present during installation (n=5) and were aware of Consumers Energy involvement in the CCHP (n=7). Three-quarters of respondents were occupants last winter (n=24), before the installation, while one-quarter (n=8) were not present in their units to experience the old heating system, and thus could not provide comparative responses about new versus old heating system performance. Respondents' tenancy term and other factors resulted in around one-third (30%) of the responses to all questions that provided little to no insight into their experience in this initiative. Because of the low response count to many of the tenant survey questions, the results should be considered indicative but inconclusive.

Figure 11. Summary Respondent Characteristics



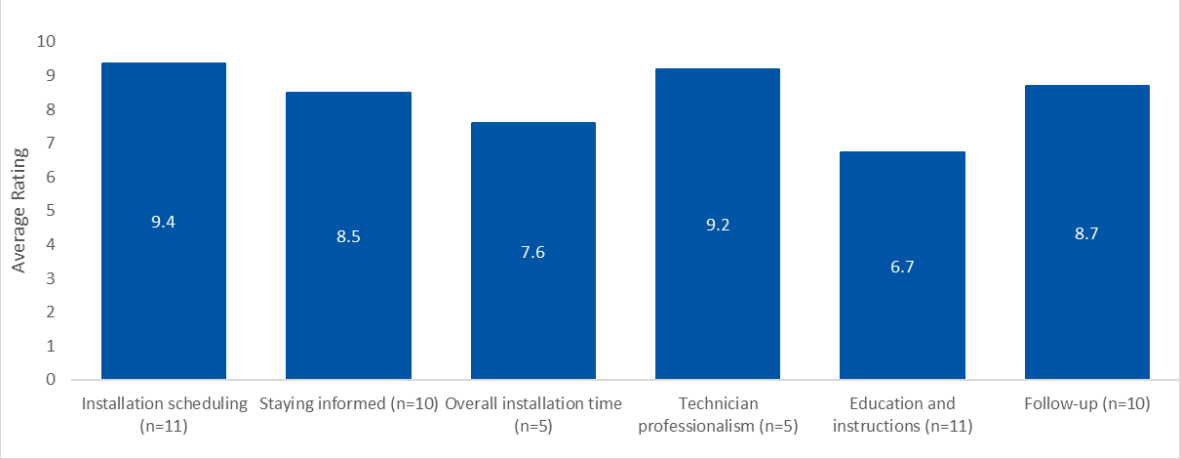
Source: Heat Pump Multifamily Tenant Survey Guide Questions C5, C8, B3, and C1. Please see *Appendix E* for specific question wording.

Participant Installation Experience

A successful equipment installation can provide tenants with a positive initiative experience; such an installation should include providing helpful information and operational details for a better managed heating and cooling experience. One-third of respondents (n=11) provided installation experience ratings. Overall, participants were largely satisfied with the installation experience, rating most installation elements above an 8 on a 10-point scale, where 1 meant *unacceptable* and 10 meant *outstanding* (Figure 12). Respondents provided the lowest average rating to the education and instructional aspects of installation, which impacted their overall satisfaction with the heat pump

offering, as well as with Consumers Energy overall (these metrics are featured further below in Figure 19).

Figure 12. Tenant Installation Satisfaction

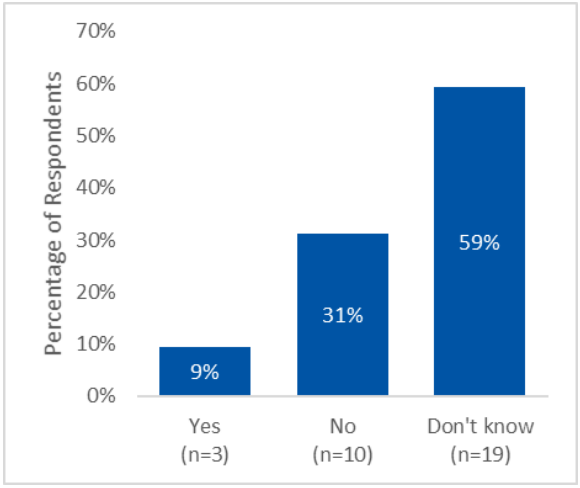


Source: Heat Pump Multifamily Tenant Survey Guide Question C2. "How would you rate each of the following installation experiences with the heat pump offering?"

Participant Usage, Behavior, and Experience

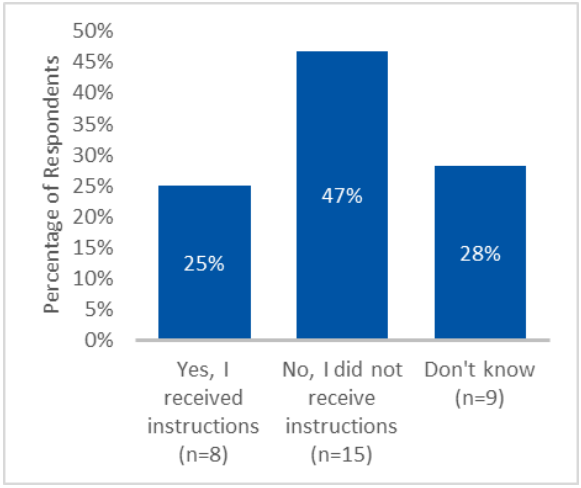
Participant usage, behavior, and experience with this offering were influenced by the installation technicians and education surrounding the CCHP equipment installation. Only three respondents could confirm with certainty that the technician set up a heating and cooling schedule for their heat pump (Figure 13). These three participants also confirmed that the heating and cooling schedule set up by the contractor is still in operation. Lack of heat pump education, materials, and follow up were common among respondents. Forty-seven percent of participants (n=15) reported not receiving documentation or instructions about the heat pumps, while 28% (n=9) did not know if they received instructions and 25% (n=8) did receive instructions (Figure 14). Other survey respondents indicated in open-ended responses that there was a lack of information relayed about the heat pumps, either from installation technicians, the PMOs, Consumers Energy, or a combination of the three.

Figure 13. Heating and Cooling Schedules



Source: Heat Pump Multifamily Tenant Survey Guide Question C16. "Did the installation technician set up your heat pump on a heating and cooling schedule?"

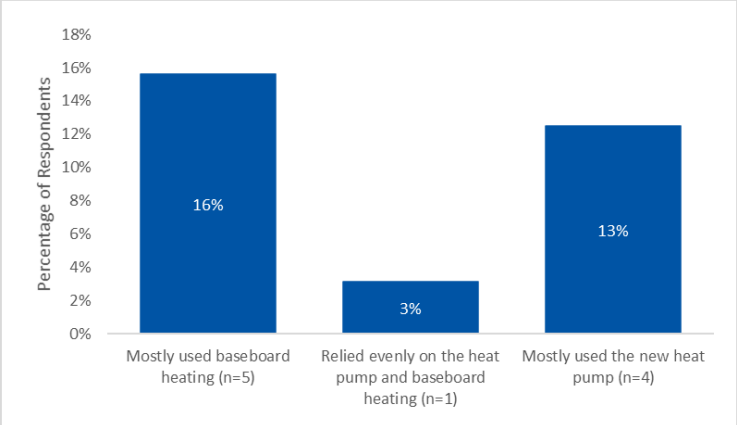
Figure 14. Instructions Provided at Installation



Source: Heat Pump Multifamily Tenant Survey Guide Question C18. "Have you been provided with instructions on how to set up and control your heating and cooling schedule on your heat pump?"

Sixteen percent (n=5) of participants reported using mostly baseboard heating after installation, while 13% (n=4) reported using mostly the newly installed heat pump and 3% (n=1) reported using both evenly. Another 68% (n=22) of participants did not know which heating source they relied on.

Figure 15. Primary Multifamily Tenant Apartment Heating Source



Source: Heat Pump Multifamily Tenant Survey Guide Question C12. "Which of the following best describes how you heated your apartment last winter?"

In open-ended responses, some tenants were unhappy with the lack of information:

- "After the installation, there was not follow up. Also, there are many in our complex that have no idea on how to set up the mobile app."
- "Manager of my complex did not [educate] me on how to use all the features. Also, when and who changes the filters, if any."

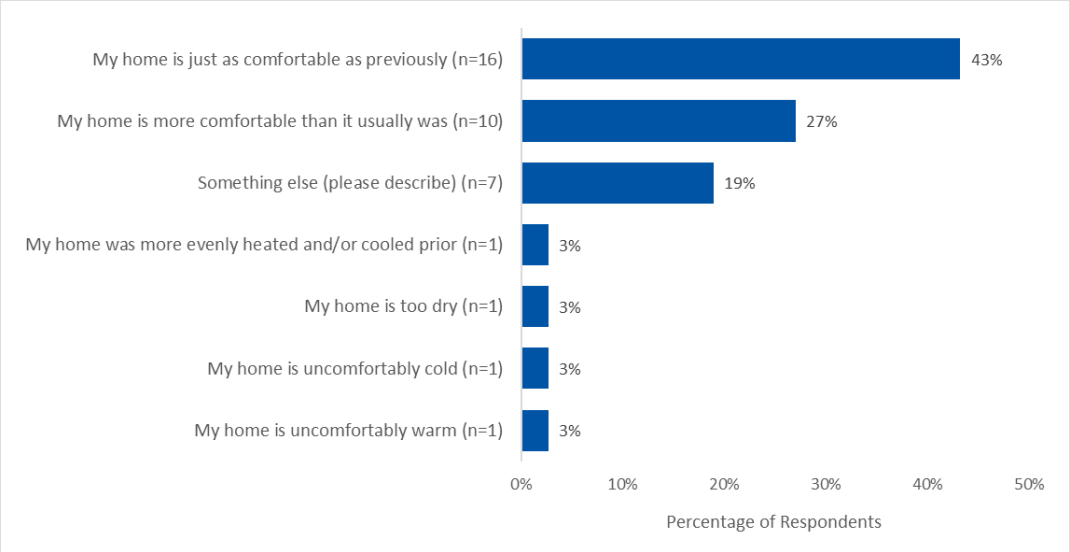
Awareness and Perceptions of Heat Pumps

Most participants (68%; n=21) reported a complete lack of knowledge regarding heat pumps, even after installation. More interestingly, half were not aware that there was a heat pump installed in their apartment, despite having occupied the unit at the time of installation. Of the half that were aware of the heat pump installation, 56% (n=9) did not know Consumers Energy was involved in the project. In an open-ended response, one participant was surprised: "I didn't know anything about how to run the heat pump or maintenance needed. We weren't told anything. We didn't even know Consumers [Energy] funded it."

Perceptions of Heat Pump Impact on Comfort Levels and Electricity Bills

As noted above, PMOs indicated tenant comfort was a key factor in the decision to participate in the heat pump initiative—some tenants supported this perception. Post-installation, although 43% of tenants reported their homes to be as comfortable as before, one-quarter of tenant survey respondents reported increased comfort (27%). Specifically, few tenants reported issues with temperature or humidity regulation, as shown in Figure 16.

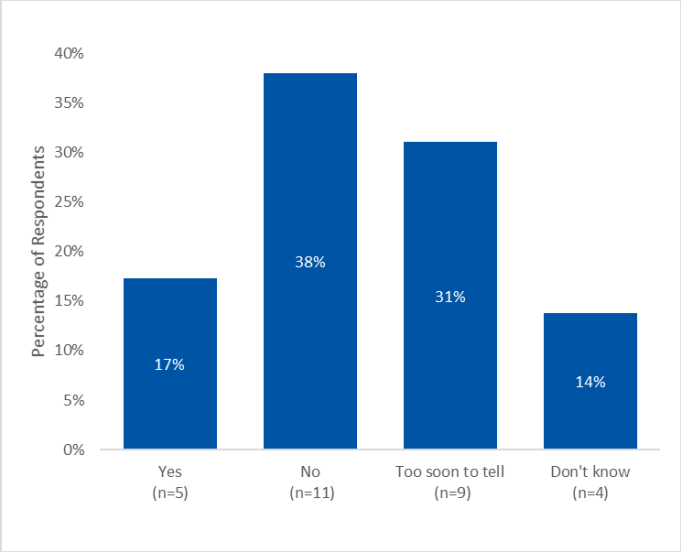
Figure 16. Heat Pumps and Home Comfort



Source: Heat Pump Multifamily Tenant Survey Guide Question C11. "In general, how did the heat pump affect your home comfort?"

Over twice as many income-qualified multifmaily respondents believed they did not experience any savings on their energy bills as those who believed they did experience savings: 38% of respondents (n=11) reported no savings on their energy bills, compared to 17% (n=5) who reported savings (Figure 17).

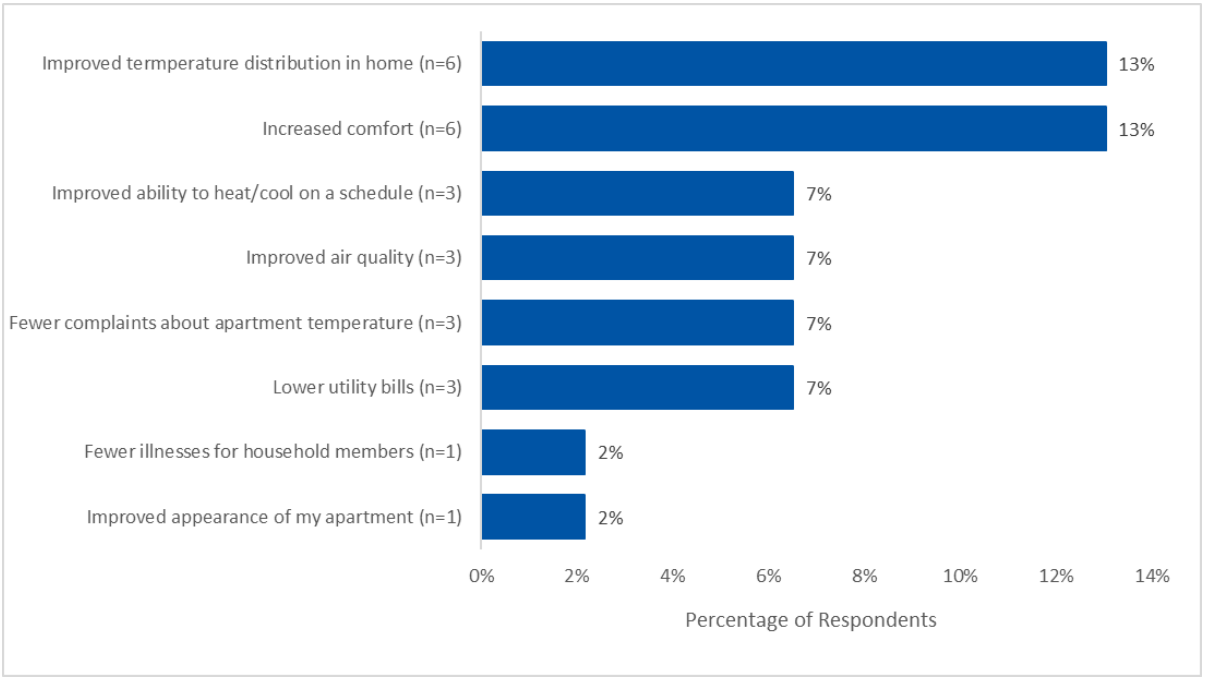
Figure 17. Multifamily Tenant Energy Bill Savings



Source: Heat Pump Multifamily Tenant Survey Guide Question D2. "Have you seen a lower-than-expected energy bill?"

Even with few respondents believing the CCHPs resulted in bill savings, a high number reported non-energy saving benefits of the CCHPs, primarily related to temperature distribution and comfort (Figure 18).

Figure 18. Non-Energy Benefits



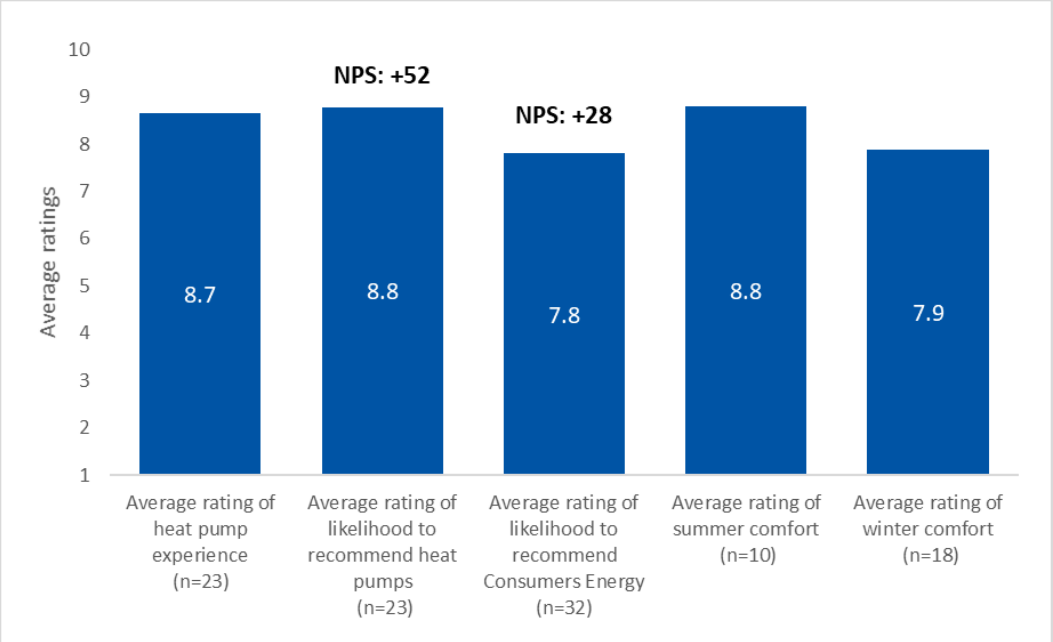
Source: Heat Pump Multifamily Tenant Survey Guide Question D3. "In addition to energy savings, if any, are there other benefits that you have experienced or observed from the installation of heat pumps?"

Satisfaction with the Offering and with Consumers Energy

Income-qualified multifamily tenants were satisfied with the CCHP experience, and generally felt that the heat pumps provided improved winter heating and summer cooling comfort. CCHP multifamily tenant participants reported an average rating of 8.7 regarding their overall experience with the heat pump, an average of 8.8 rating on likelihood to recommend a heat pump to a friend, and an average of 7.8 rating on likelihood to recommend Consumers Energy, all on a 10-point scale where 1 meant *unacceptable* or *extremely unlikely* and 10 meant *outstanding* or *extremely likely* (Figure 19). Respondents also reported an average rating of 8.8 regarding summer comfort and 7.9 regarding winter comfort.

Another key measure of customer satisfaction is the percentage of customers who are highly likely to recommend a product, service, or company after subtracting the percentage of customers who are highly unlikely to recommend that same product, service, or company. The net percentage of those willing to promote the product is the net promoter score (NPS), expressed as an absolute number between -100 and +100 that represents the difference between the percentage of promoters (respondents giving a rating of 9 or 10) and the percentage of detractors (respondents giving a rating of 1 to 6). The Cadmus team calculated a NPS for the two likelihood to recommend questions (likelihood to recommend the CCHPs and likelihood to recommend Consumers Energy – see Figure 19 below).

Figure 19. Satisfaction with Cold-Climate Heat Pump Experience and Comfort



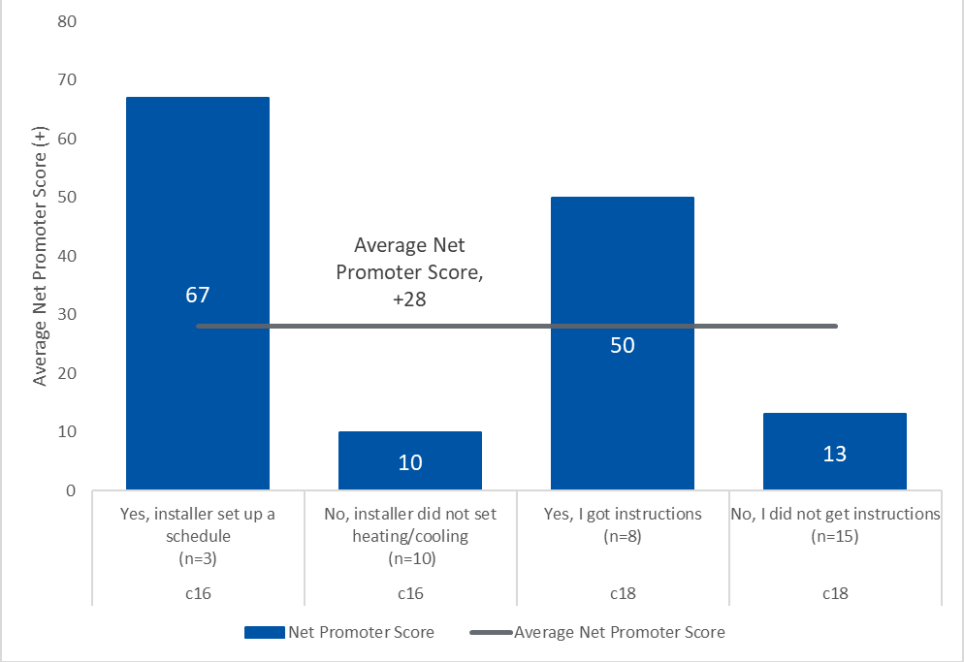
Source: Heat Pump Multifamily Tenant Survey Guide Questions E1, E2, A1, C9, and C6. Please see *Appendix E* for specific question wording.
This figure reflects combined average satisfaction ratings of heat pump experience and comfort.

The Evaluation team also calculated a NPS for the two likelihood to recommend questions (likelihood to recommend the CCHPs and likelihood to recommend Consumers Energy). As shown in Figure 19, based

on experiences with the heat pump, respondents were somewhat likely to recommend the heat pump to a friend. Though 14 respondents were promoters (providing ratings of 10) and only two were detractors, nine respondents did not provide a rating and seven were passives. The resulting NPS for the heat pump was +52. Sixteen respondents provided a 9 or 10 rating for likelihood to recommend Consumers Energy to a friend while seven provided ratings below a 7 and were classified as detractors (nine respondents were classified as passives). The resulting NPS for Consumers Energy was +28.

The Evaluation team compared the Consumers Energy NPS across different participant groups (Figure 20). Participants who provided low ratings on installation communication and instructions and provided verbatim feedback around lack of education materials and instructions were more likely to provide a lower overall Consumers Energy NPS. In fact, this cohort on average provided the lowest ratings of all participants. Additionally, participants who received instructions or had their heating and cooling schedule set by installation technicians had a higher NPS on average than both the survey average and the average of those who had no instructions or schedule set.

Figure 20. Average Consumers Energy Net Promoter Score and Installation Satisfaction



Source: Heat Pump Tenant Survey Guide Questions A1, C16, and C18. “How likely would you be to recommend Consumers Energy to a friend or family member if you had a choice in energy providers?” “Did the installation technician set up your heat pump on a heating and cooling schedule?” and “Have you been provided with instructions on how to setup and control your heating and cooling schedule on your heat pump?”

Open-ended responses regarding Consumers Energy were primarily positive in nature, though some were frustrated with Consumers Energy's service, mostly reporting high bills:

- "Great customer service and payment plans. But the cost in the winter is way higher than I think it should be."
- "My bill was all over the place last winter reaching almost $300 between two small school-aged kids who were gone most of the day and myself who unplugs everything."
- "Because I'm low income with social security income where there's no assistance help for my electric bill, the bill can be extremely expensive."

Nearly all positive responses cited great customer service and the ease of payment:

- "Service has been great for me in as long as I've been with them."
- "Good service and consistent customer service."
- "Very easy online payments and very easy outage center updates. It's also nice to have those text and email reminders about billing."

Impact Analysis

This section summarizes findings from the Evaluation team's statistical billing analysis, conducted to determine electric energy savings resulting from the Income Qualified Multifamily initiative. While the focus of the initiative and the billing analysis were on electric-heated properties (and therefore on electric impacts on heating use during the winter heating season), the Evaluation team also used the billing analysis to determine the electric energy impacts associated with summer cooling season. *Appendix B* has a detailed discussion of the methodological approach we used to determine the energy savings.

Key Findings

The Evaluation team estimated the electric energy impacts of CCHP installations separately for winter electric heating and summer cooling impacts. The Income Qualified Multifamily initiative participant electric savings results, presented in Table 10, show winter electric heating energy savings of 832 kWh, equivalent to 22.9% of baseline weather-sensitive electric heating use.

Table 10. Multifamily Income Qualified Heat Pump Electric Energy Savings

Group	Weather-Sensitive Electric Usage (kWh)		Weather-Sensitive Electric Savings		Precision at 90%
	Pre-Period	Post-Period	kWh	Percentage	
Winter heating	3,626	2,794	832	22.9%	±9%
Summer cooling	234	170	64	27.1%	±24%
Total Annual (Weather Sensitive)	3,860	2,964	896	23.2%	±8%

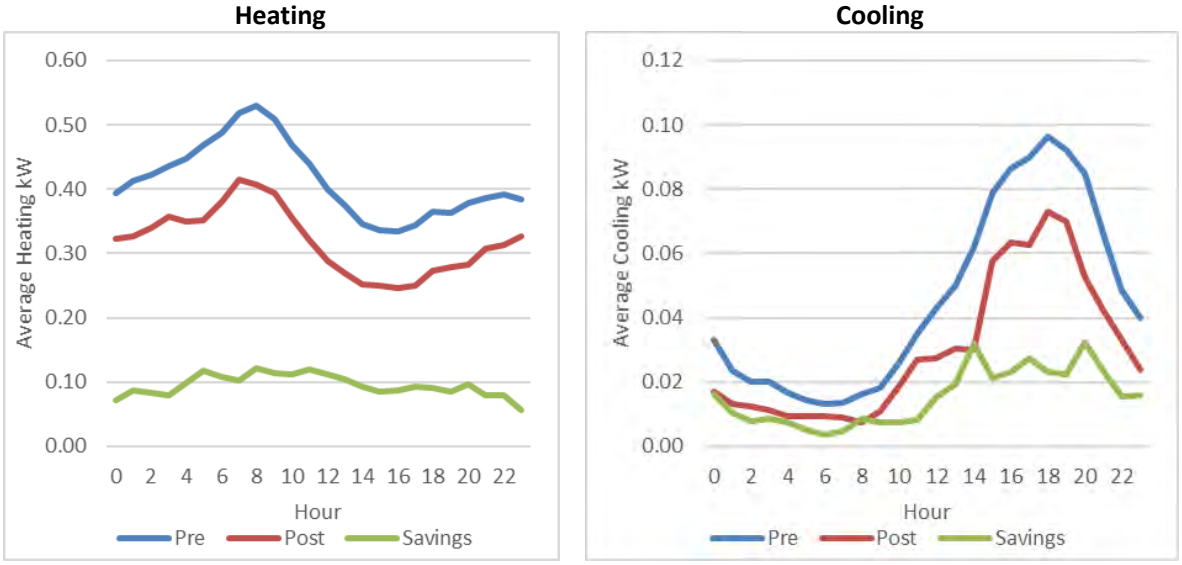
Source: Evaluation team billing analysis.

The billing analysis estimate of 64 kWh savings per unit during the summer cooling season reflected a similar percentage reduction in weather-sensitive electric usage attributable to the CCHPs (at 27%

relative to the 23% for winter heating). The heating electric analysis produced savings estimates within the ±10% precision threshold at a 90% confidence interval and therefore the results were statistically significant. Given the lower cooling load and therefore more variable signal, the cooling savings were outside the ±10% precision target. Overall, the Income Qualified Multifamily initiative resulted in a statistically significant annual reduction of 896 kWh for each participant tenant unit, representing 23.2% of the annual weather-sensitive electric energy use and translating into approximately $147 in annual bill savings for each CCHP participant.

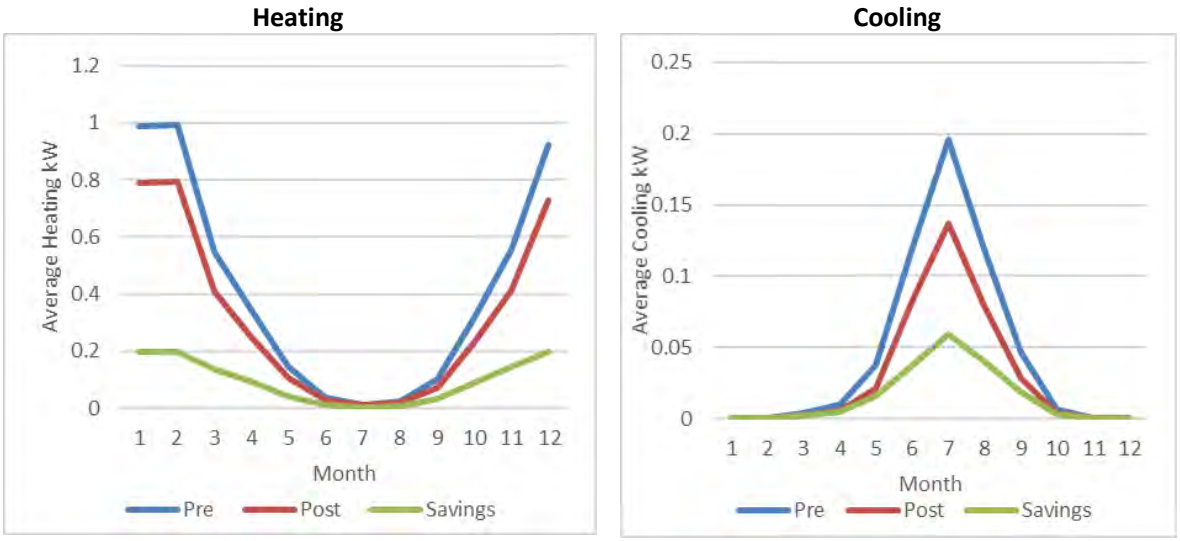
An examination of the heating and cooling load shapes and accompanying savings profile offers insight into how the CCHP impacted heating and cooling usage. Figure 21 shows the average winter and summer daily load shape and resulting CCHP savings profiles. In the winter, participants' CCHP electric energy savings were relatively consistent throughout the day. In the summer, the CCHP cooling savings were coincident with the cooling load periods of mid-to-late afternoons.

Figure 21. Participant Hourly Heating and Cooling Load and Resulting Savings



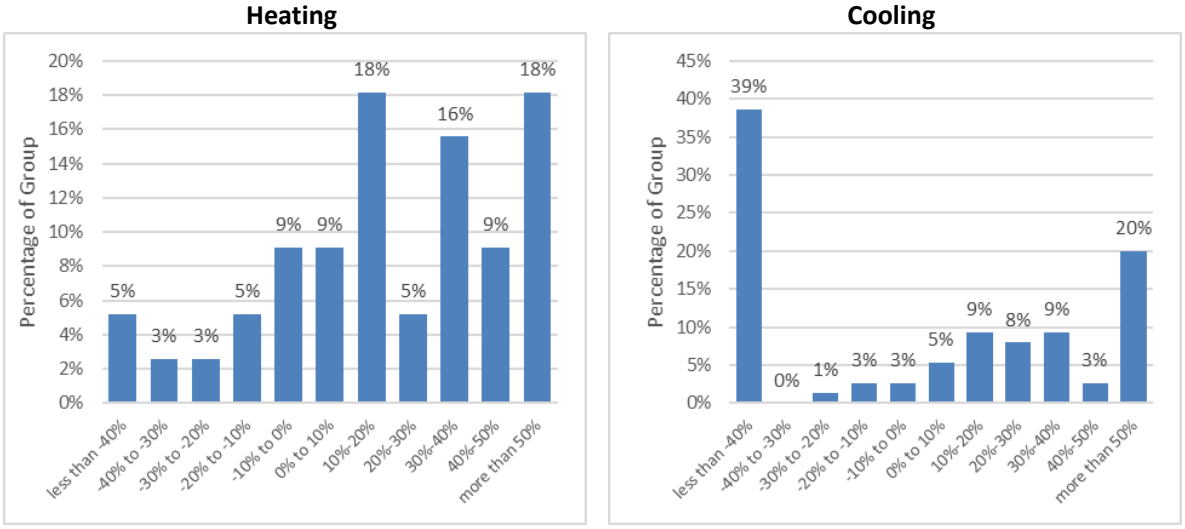
An examination of the average *monthly* load and savings profiles also showed that the savings were consistent with the monthly load shapes (Figure 22).

Figure 22. Monthly Heating and Cooling Load and Resulting Savings



The Evaluation team also explored the variability of savings across the tenant units by grouping the percentage of tenant units according to decile savings bins (incremental steps of 10% savings; see Figure 23). More than 40% of the Income Qualified Multifamily tenants saved over 30% of their pre-installation electric energy during the winter heating season, while the largest group of customers (18%) saved over 50%. On the summer cooling analysis, close to 40% of Income Qualified Multifamily customers had a net increase in summer electric use. These customers likely lacked any pre-installation cooling equipment (no room ACs) or were unlikely to have used their equipment. The second largest group of customers were also the highest saving group, with 20% of the tenants saving over 50% of their pre-installation summer cooling electricity usage.

Figure 23. Percentage Distribution of Annual Heating and Cooling Savings by Savings Bin



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Benchmarking of Results

The Evaluation team compiled results from three recent multifamily heat pump retrofit program evaluations in other regions to understand how the results compared to the Consumers Energy Income Qualified Multifamily initiative. A majority of the evaluations were focused on income-qualified properties. As shown by the summary benchmark data in Table 11, the Income Qualified Multifamily initiative findings are consistent with other multifamily income-qualified billing analysis results.

Table 11. Benchmarking of Multifamily Heat Pump Billing Analysis Results

Utility and Program	Percentage Savings	Home Type	Income	Analysis Type
Consumers Energy Income Qualified Multifamily initiative	**23.2%**	**Multifamily**	**IQ**	**Billing Analysis**
2020 Commonwealth Edison Multifamily Income-Qualified Heat Pump pilot (full report not yet public but summary report is here)	25%	Multifamily	IQ	Billing Analysis
2016 Efficiency Maine Low-Income Multifamily Weatherization program (report)	22.2%	Multifamily	IQ	Billing Analysis
2014 Connecticut Energy Efficiency Fund Home Energy Services (Income Eligible) (report available online)	11% [a]	Multifamily	IQ	Billing Analysis
2014 Energy Trust of Oregon Multifamily Ductless Retrofits (report available online)	15% [a]	Multifamily	Any	Billing Analysis
Puget Sound Energy Heat Pump Dealer Channel (not public)	18% [a]	Single Family	Any	Billing Analysis

[a] This represents the percentage of annual load, not the percentage of weather-sensitive load (which was not reported).

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Commercial and Industrial Cold-Climate Heat Pump Pilot Findings

Consumers Energy developed its Commercial and Industrial Cold Climate Heat Pump Pilot initiative in 2020 in response to the 2020 Consumers Energy Settlement Agreement with the Michigan Public Service Commission and other stakeholders. Beginning in early 2021, Consumers Energy launched the initiative targeting small commercial and industrial customers, defined as customers with facilities under 20,000 square feet. Initiative staff reached out to customers who did not have access to natural gas or were suspected to have propane heat. Staff then helped these customers choose a contractor to install a CCHP, addressed any questions the participants had throughout the installation process, and provided significant financial support to install new CCHPs; all but one customer had the entire cost fully covered.

For this research, the Evaluation team conducted in-depth telephone interviews with initiative participants to address several key research objectives:

- Explore key factors in customer decision-making regarding CCHP installations
- Explore customer experiences during the CCHP installation process
- Explore customer experiences using their CCHP
- Explore customer experiences with the initiative offering
- Identify opportunities to best support CCHP technology moving forward

In the fall of 2021, the Evaluation team conducted in-depth interviews with seven of the nine initiative participants, asking about heat pump technology awareness and motivations for participation, as well as participant experiences and satisfaction throughout the initiative process and with their new heat pump technology. During the winter of 2021/2022, the Evaluation team also metered the equipment to assess energy savings. Findings from this research are found in the 2021 Cold Climate Heat Pump Pilot Impact Evaluation Memo submitted as part of Consumers Energy's 2021 reconciliation. Metering for the 2022 cooling season is still in progress as of the writing of the report, and analysis and reporting will take place later in 2022.The remainder of this section presents findings from the participant interviews.

Participant Interviews Findings

In Fall 2021, the Evaluation team conducted in-depth interviews with seven Small C&I Initiative participants who were either the business owner or a key decision-maker related to the business. The subsections below describe how customers heard of and then decided to participate in the initiative offering, followed by installation experiences, heat pump use experiences, and overall initiative experiences and satisfaction. Additional details are available in the *C&I 2021 Cold Climate Heat Pump Pilot Customer Interview Results Presentation* submitted as part of Consumers Energy's 2021 reconciliation.

Decision-Making Processes

The Evaluation team asked participants about their awareness and understanding of heat pump technology, their plans to replace existing heating equipment, as well as their concerns, considerations, and motivations for installing the heat pumps.

Participants in the Small Commercial initiative were generally not familiar with heat pumps prior to being contacted by Consumers Energy staff. Over two-thirds of respondents (71%; n=5) were *not at all familiar* with heat pumps prior to the initiative. One respondent said they were *somewhat familiar* and had read some articles about heat pumps, but not enough to have purchased a heat pump without the support from the initiative. Another respondent said they were *very familiar* with the technology, but was under the impression that heat pumps were not suitable for Michigan winters.

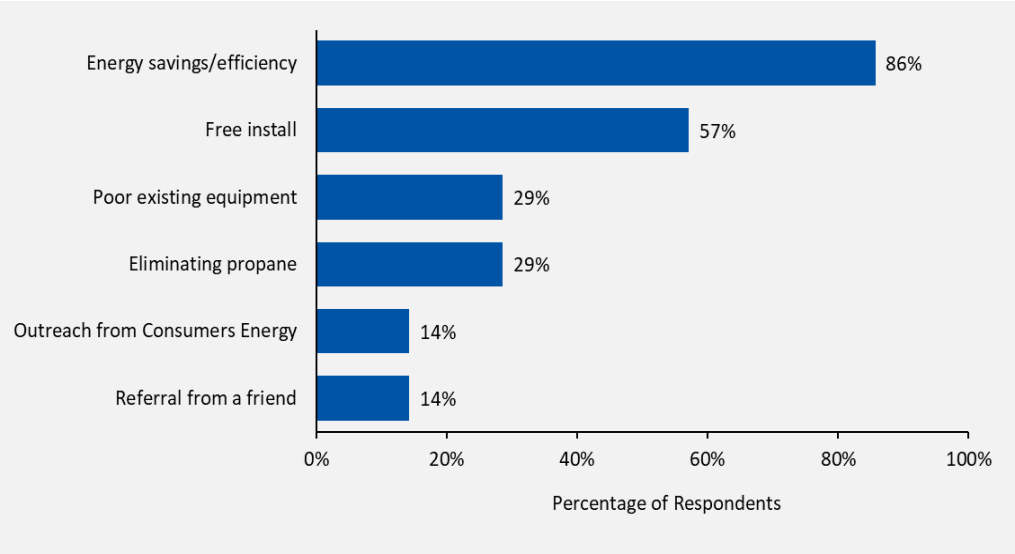
When asked about their existing heating and cooling equipment, all respondents reported having a propane furnace prior to installing their heat pumps, and 86% (n=6) had central AC. While four respondents had no immediate plans to replace their existing equipment, 43% (n=3) had planned to replace their heating equipment within the next one to three years, and all three would likely have replaced their furnace with a new propane furnace. This finding suggests that customers likely would not have considered a heat pump as an option if not for the initiative, despite some respondents reporting low satisfaction with their propane service.

When asked about their concerns and considerations when deciding to install a heat pump, respondents were primarily concerned about cost and technical considerations, while two respondents (29%) initially thought the offer was a scam: one said, “My main thing was, to be honest, I was scratching my head if it was too good to be true. I was suspicious; there are so many scams. My biggest concern [was that] I just wasn’t quite sure what was actually going on. It’s quite a good deal to get that kind of equipment.”

Respondents’ cost considerations included not knowing how much more money they would pay by switching to a heat pump, as well as how much lower their energy bill would be and how much less energy they would use. Three respondents also expressed concerns about how reliable the heat pumps would be during the winter. The following quote exemplifies this sentiment and demonstrates how this hesitancy is related to a lack of knowledge about CCHPs: “…Without knowing about the technology, we were a little concerned…about how well would the systems work in the really cold weather.”

When asked what motivated them to install their heat pump, respondents reported several motivations, mainly saving energy and the free installation, followed by the fact that the cost was largely if not completely covered by Consumers Energy (Figure 24).

Figure 24. Respondent Motivations to Install Heat Pumps



Source: Heat Pump Commercial Interview Guide Question C4. "What motivated you to agree to install the heat pump?" (n=7; multiple responses allowed)

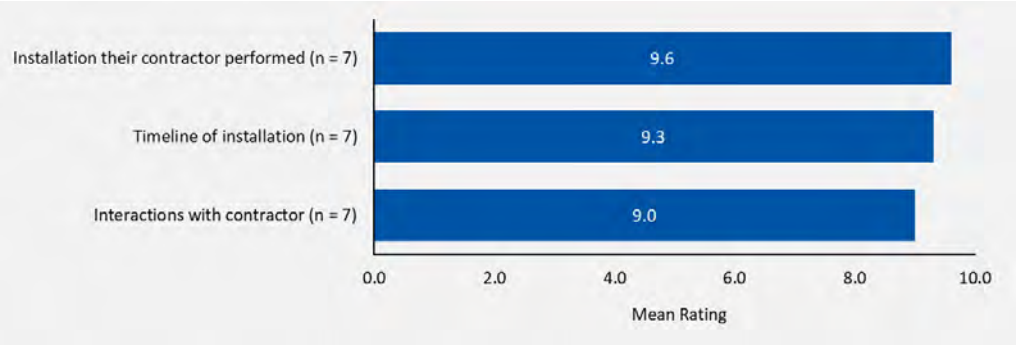
Installation Experiences

The Evaluation team also asked respondents about their experiences with finding a contractor and with having the heat pump installed. All respondents reported that it was easy to find a contractor, and none asked for multiple bids. About half of respondents (43%; n=3) preferred to use their own contractor and one respondent (14%) asked a friend who had also participated in the initiative for their contact. The other three respondents (43%) relied on contractor contacts provided by Consumers Energy: two chose a contractor they were familiar with from the list (and, as mentioned previously, Consumers Energy tailored this list to include trade partners they knew had experience with heat pumps). These findings indicate that the initiative resources for finding a contractor were effective.

Overall, respondents reported having a positive experience with their contractor, with 86% (n=6) saying they would use the same contractor again. All the respondents also reported that the contractors they worked with appeared to be knowledgeable about heat pumps, and 57% (n=4) said the contractor was *very knowledgeable*: "Extremely [knowledgeable] and very helpful and explained it all to me very well… They were fast, efficient, and did exactly what they were going to do in the time they said they were going to do it. They did a great job."

Average satisfaction with contractor interactions was a 9 on 10-point scale, where 1 meant *unacceptable* and 10 meant *outstanding* (as shown in Figure 25). Though respondents were generally satisfied with their contractors, two of the seven respondents (29%) expressed some dissatisfaction. One of these respondents specified that the contractor should have been more communicative about the project schedule and timeline but said they would still hire the contractor again because they would not know who else to hire. The other respondent was less satisfied with their interactions with the contractor and were not sure they would hire them again.

Figure 25. Installation Experiences Satisfaction Averages



Source: Heat Pump Commercial Interview Guide Questions G1a, G1b, and G1d. Please see *Appendix F* for specific question wording.

Respondents were also satisfied with the timeline of their installation. While about half of respondents (57%; n=4) reported some delay with their project timeline, it did not impact their overall satisfaction. However, some reported that if the installation had occurred during a time when they needed their heating or cooling, they would have been more dissatisfied. Heating or cooling needs were not pressing since these customers either had working equipment or their installation was completed in the shoulder season, as evident by the following statements:

- "It might have been different if we didn't have heat or air and every day was a struggle, but it was early spring… so it wasn't an issue, so we weren't pressed to hurry up and get this into service."
- "I'm glad they didn't do it in the winter, because then I would have been irritated [with the delayed project timeline]."

Most of the heat pump installations went smoothly, with respondents rating their satisfaction with the installation process as an average of 9.6 out of 10, as shown in Figure 25. When asked if there were any challenges with installing their heat pump, only two respondents reported some minor challenges related to the equipment not functioning properly at first and unforeseen installation issues. All respondents said that they received a new thermostat as part of their CCHP installation, and about half (43%; n=3) required new duct work. Slightly more than half of respondents (57%; n=4) reported that they have a back-up heating system in addition to the CCHP system. Of those four, two kept their old heating and cooling equipment, one just kept their old back-up heating, and one installed a new propane furnace as a back-up.

Experiences Using Heat Pumps

Due to the timing of this initiative and the research effort, respondents had primarily used their heat pump during the summer months and had used only the cooling function; however, some respondents (71%; n=5) reported that the heating function had come on during colder mornings in September or said they had been able to use the heat briefly in early spring. In general, respondents were very satisfied with their new heat pump and its operation, with an average satisfaction rating of 9.3 out of 10. While respondents were already generally satisfied with the equipment, a few customers noted being hesitant

to give the heat pump a higher rating until after using the heating function more consistently in colder weather. The Evaluation team conducted follow up interviews with Small Commercial initiative participants as part of on-site impact evaluations completed following the 2021/2022 winter heating season to assess participant experiences with the heat pumps in cold weather. [17]

Despite high satisfaction with heat pump performance, almost half of respondents (43%; n=3) reported some minor issues with their heat pumps, including not cooling down to the expected temperature and two issues with the installation that required a contractor to fix. The biggest challenge customers reported was needing to learn how to use their new smart thermostat; this finding was echoed in the winter heating impact analysis, which revealed that some customers would benefit from additional training or support to optimize heat pump controls and settings to maximize savings. These findings suggests that customers easily adapted to their new technology but could use some higher touch support during the first few weeks or months after installation to confirm that all the equipment is performing well and that the customer knows how to use the equipment properly.

Initiative Experiences and Satisfaction

When asked about their overall initiative experience, most respondents said they were *very satisfied* with their participation in the initiative. Most respondents (86%, n=6) had initially learned about the initiative offering from Consumers Energy staff and all seven reported that they had received excellent support throughout their participation. While respondent motivations for deciding to participate in the initiative included the fact that the equipment and installation were free, the support and persistence from Consumers Energy staff was also a motivating factor.

> "Just the willingness that they had to do this for just a small [facility] was huge […] People don't just give stuff away, and [a new heating system] was definitely something that was needed, and we would have had to purchase it in the future."
>
> -Respondent

Respondents' overall satisfaction with the pilot was an average of 9.9 out of 10, and 86% of respondents (n=6) *strongly agreed* that Consumers Energy made it easy to participate in the initiative. When asked if they were likely to recommend Consumers Energy to a friend or colleague if they had a choice in energy providers, most respondents (71%; n=5) said they were extremely likely to do so. The two respondents who gave lower ratings said that it was only because their utility is not something they really think or talk about. One satisfied respondent compared Consumers Energy to the utility that provides electricity at their home: "I've always had great service with Consumers [Energy]. I've had less outages and …anything I need for my business, I'm able to get immediate responses."

[17] TRC. 2022. C&I 2021 Cold Climate Heat Pump Pilot Impact Evaluation Memo.

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Appendix A. Survey and Interview Methodology and Details

This appendix provides survey and interview details and methodologies by initiative or stakeholder.

Contractor Interviews

Consumers Energy provided the Evaluation team with a sample of 177 contractors who had engaged with Consumers Energy HVAC energy waste reduction offerings at some point, but who had not participated in the CCHP Initiatives. The sample did not include any information regarding the number or type of projects completed by the contractor, so the Evaluation team was unable to stratify the sample in any meaningful way. As such, recruitment of contractors proceeded randomly until research quotas were satisfied. We interviewed a total of 11 contractors for this research.

Table A-1 includes contractors' company information such as type, number of projects per year, and products offered.

Table A-1. Interviewed Contractor List

Company Location	Customer Base	Number of Projects/Year	Average Heat Pump Installation/Year
Ada	Primarily residential, more high-end homes	~100	<5 ducted systems >20 mini-splits
Allen Park	Residential multifamily, some single family, very little commercial	1,000–1,500	75 since last fall
Allendale	Data not collected	Data not collected	Data not collected
Benzonia	90% to 95% residential, lots of big homes on shore of Lake Michigan used as seasonal residences; a little bit of multifamily, a little low income	200 installs	20–30
Dearborn Heights	Mostly residential, some multifamily	100	3 last year
Jackson	50% residential, 50% commercial	200–225	6–8 ducted systems >50 mini-splits
Livonia	Primarily (75% or more) income-qualified multifamily, with client that is the largest affordable housing provider in Michigan	5–10 projects per year 100–300 pieces of equipment	10–20 mini-splits per year (primarily server rooms and elevator machine rooms)
Okemos	60% residential and 40% commercial, lots in the city, also lots of dual-fuel applications with propane and lots of air-to-air and geothermal projects	~1,000	~100 in 2020, 80% air-to-air 24 mini-splits in the past year
Parma	Residential and some multifamily (very little commercial)	150–200 pieces of equipment	<10
Sparta	75% residential, commercial is mostly service maintenance, with a rare design/build	~100	12–15 per year for ASHPs and mini-splits.
Warren	50% residential and 50% commercial	200	<5

Distributor and Manufacturer Interviews

The Evaluation team interviewed five distributors and two manufacturers involved in the production and distribution of CCHPs (including mini-split heat pumps) in Michigan. We fielded the interviews via telephone, and each took 30 to 45 minutes to complete. The team recorded and transcribed each interview to assist with our analysis. To motivate manufacturers and distributors to participate, we offered a $75 incentive to each respondent in the form of an Amazon, Target, or Meijer gift card or a donation to a local United Way.

Sampling

For this effort, the Evaluation team specifically targeted manufacturers who have supplied equipment for Consumers Energy programs and associated distributors in Michigan that supply CCHPs produced by these manufacturers. The list of manufacturers and distributors interviewed is shown in Table A-2.

Table A-2. Interviewed Distributor and Manufacturer List

Company Type	Role of Interviewee	Primary Brands Offered	Primary Types Offered	States/Regions Served
Manufacturer	Manager, Utility & Efficiency Programs	(Confidential)	Mini-split	Central U.S.
Manufacturer	Regional Representative	(Confidential)	Mini-split	MI, OH, PA, WV
Distributor	President	Robur	Absorption	MI, OH, IN
Distributor	Director of HVAC Services	Mitsubishi, Rheem, Trane	Mini-split	MI, OH, Eastern U.S.
Distributor	Territory Manager	Trane, Mitsubishi	Mini-split, unitary	MI
Distributor	Regional Sales Manager	LG, Rheem, Bosch	Mini-split, unitary	MI, OH, IN, PA, WV
Distributor	Owner	Daikin, Amana	Mini-split, unitary	MI, WI, IL, IN, OH, PA

The team sampled distributors from a contact list provided by Consumers Energy staff as well as from internet searches for distributors associated with key manufacturers. Additionally, the Evaluation team asked for referrals for distributors during interviews with contractors. We targeted distributors such that representation across manufacturers was roughly equal (ensuring that interviewed distributors do not represent one manufacturer more than another).

Recruiting

The Evaluation team reached out to manufacturers and distributors by phone to schedule interviews. During phone recruitment, we explained the research and provided an Evaluation team contact person so the organization could reach out if they had additional questions or were interested in scheduling an interview. The team primarily used email to recruit referrals, which similarly included an explanation of the research and a request for scheduling an interview.

Profile of Distributors and Manufacturers

Table A-2 above shows respondent information including company type, the role of the interviewee at the company, primary brands offered, types of CCHPs offered, and regions served. Most interviewees represented mini-split CCHP technology and were responsible for operations in several states.

Residential Market Rate Participant Surveys

The Evaluation team sent a survey invitation to the census of 29 Residential Market Rate pilot participants in November 2021. The email survey invitation included a $15 incentive for taking the survey. The Evaluation team sent two reminder emails; after one week and after two weeks. Nine of the 29 participants completed the survey, for a 31% response rate: with such a small sample size, the results should be interpreted with caution and only viewed as directional indications (not intended to be analyzed with statistical confidence).

Income Qualified Multifamily Property Manager and Owner Interviews

The Evaluation team conducted in-depth telephone interviews with three site contacts (a construction manager, a resident manager, and an owner) in November 2021. Each interview lasted approximate 30 minutes. We targeted owners and managers of income-qualified multifamily properties who had participated in the Consumers Energy Income Qualified Multifamily initiative. Franklin Energy provided PMO contact information, including email address and phone numbers, for Evaluation team outreach and recruitment.

The Evaluation team initially distributed emails to six property site contacts and attempted phone recruitment for the seventh due to a missing email address. Though the team made three email attempts, the emails did not result in any successful recruitment for the interviews. The Evaluation team then pivoted to making recruitment calls from Monday through Friday, mid-morning to early evening, calling each number a maximum of five times.

With an interview target for a census (seven) of participating PMOs, the actual number of three interviewed PMOs was consistent with expectations, even with an increased incentive of $150 to make the interview more attractive for potential participants.

Income Qualified Single Family and Multifamily Participant Surveys

The Evaluation team collected feedback from 32 multifamily tenant surveys in November 2021. The email survey invitation included a $15 incentive for taking the online survey. We targeted tenants of income-qualified multifamily properties who had participated in the Consumers Energy heat pump offering. The Evaluation team did not have access to participating tenant contact information, so we attempted to identify tenants through two distinct efforts. First, the team relied on existing income-qualified tenant records to match CCHP properties based on physical address. Using this approach, the team identified 46 potential income-qualified multifamily tenants to recruit. Second, during the team's interviews with multifamily PMOs, we asked and all three PMOs if they were willing to distribute the survey recruitment email to their tenants. This second approach resulted in the potential for 90 additional tenant respondents, though the Evaluation team is unsure of the final count of emails distributed by the PMOs.

The Evaluation team solely relied on email distribution to recruit tenants for the online-only survey. Though the team made three email attempts for the address-matched income-qualified tenant group, the emails combined with the PMO email recruitment effort resulted in 32 successful recruitments for the surveys, for a response rate of 24% (32 of 136).

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Small Commercial Participant Interviews

The Evaluation team conducted in-depth telephone interviews with seven business owners and decision-makers in September and October 2021. Each interview lasted approximately 30 to 45 minutes and we offered respondents a $75 gift card for their time. We targeted owners and decision-makers of small commercial and industrial facilities (<20,000 square feet) who had participated in the Consumers Energy Small Commercial initiative offering. Consumers Energy provided these decision-makers' contact information, including email address and phone numbers, for Evaluation team outreach and recruitment. The interview guide was reviewed and approved by Consumers Energy staff to ensure that questions were consistent with their expectations and reflected the issues of interest to Consumers Energy.

The Evaluation team recruited customers via email and phone. Due to the small sample size of nine participants, we attempted to recruit the entire sample with a minimum goal of five completes. The Evaluation team was able to recruit seven of the nine participants, with a response rate of 78%. An eighth participant was interested in participating but their heat pump had not been installed yet, so they were not able to answer questions about the full experience. The ninth participant was unreachable after a total of five contact attempts via email and voicemail.

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Appendix B. Impact Analysis Methodology and Details

This appendix provides the methodology and details related to the Residential Market Rate pilot engineering analysis and the Income Qualified Multifamily initiative billing analysis.

Market Rate Engineering Methodology

The Evaluation team conducted an engineering analysis of the impacts from the Residential Market Rate pilot and relied on MEMD assumptions and information we had collected on customer data such as such as home vintage, presence of central cooling, installed system COP at 5°F, rated HSPF and SEER, tonnage, and other data. The Evaluation team relied on the MEMD weighting tool, which generates single measure outputs based on home vintage, climate zone, sizing, and efficiency levels.

The MEMD building simulation data provided end-use level consumption details broken out by the seven Michigan climate zones (Alpena, Detroit, Lansing, Muskegon, Saginaw, Sault Ste. Marie, and Traverse City) and three building vintages (old, average, and new). The Evaluation team used the MEMD building simulation end-use consumptions for ASHP heating, ASHP electric resistance back-up heating, and ASHP cooling to calculate pre– and post–CCHP equipment consumption on a per-ton basis. We then adjusted these end-use consumptions using COP from ASHP federal standard HSPF and SEER values to reflect site-specific equipment. We used several types of CCHP-collected site data in the analysis:

- Home vintage
- Presence of central AC
- Home heating fuel type
- Home heating equipment type
- Premise zip code
- CCHP details: quantity, COP at 5°F, HSPF, SEER, and tons

Since existing space heating equipment data collection was limited to fuel type, the team assumed that existing equipment represents federal standard equipment (in AFUE) and represents a 50/50 average of boilers and furnaces, if applicable. The Evaluation team created this split because the data field for system type collected was either “Furnace/Boiler” or “Resistance.” The difference in federal standard efficiency is minimal: 0.8 for furnaces and 0.82 for boilers. Therefore, the team used 0.81 AFUE.

We also assumed that existing central cooling equipment represents the federal standard SEER value. For homes without central cooling, we assumed that a portion of homes use room or window AC units to provide a portion of cooling, and we based this portion of homes on *2015 Residential Energy Consumption Survey*[18] data for the East North Central census division. The Evaluation team used data

[18] U.S. Energy Information Administration Residential Energy Consumption Survey 2015 Data Website: https://www.eia.gov/consumption/residential/data/2015/

from the Consumers Energy 2021 *Electric Energy Waste Reduction Potential Study*[19] to develop a ratio of room AC tonnage for single family homes when compared to a central system (since the room AC unit likely did not provide cooling load equivalent to the CCHP system). Like with central ACs, we assumed the room AC efficiency to represent the federal standard EER value.

Since no sizing information was collected on the sites about the existing HVAC systems, the Evaluation team assumed equivalent kBtu per hour heating or cooling tonnage as the CCHP, except for existing room AC sizing (for which we made an adjustment). Therefore, results only reflect offset heating and cooling load by the CCHP, and not total household heating and cooling load.

We used two data points to map MEMD 2019 data to the site-specific data: "Approximate House Age" and "Premise Zip." The household age was a one-to-one match with MEMD vintages, and therefore was a simple mapping lookup. The Evaluation team mapped the zip codes nearest to the available MEMD weather station based on distance and engineering judgment for weather impacts. With these two site-specific data points—vintage and zip code—we were able to map the MEMD 2019 building simulation consumptions to each specific site.

To adjust the MEMD 2019 ASHP end-use consumptions to reflect the existing equipment on a per ton basis, the team applied COP adjustments using the federal standard definitions outlined above. To adjust the MEMD 2019 ASHP end-use consumptions to reflect the CCHP equipment, we performed a more detailed analysis (as additional equipment data was available). Using typical meteorological year version 3 (TMY3) 8760 hourly data for each MEMD modeled reference city, we performed hourly bin analysis to determine hours based on temperature bins in 5°F buckets. Assuming the HSPF value reflected performance at 47°F, the team developed a linear relationship using the COP at 5°F system performance data. We capped this linear relationship during cold temperatures to not be less than 1 COP, representing 100% electric resistance performance. Using the hourly bin analysis data by 5°F buckets and assuming CCHP heating did not occur above 65°F, the Evaluation team developed a weighted average CCHP HSPF efficiency to represent annual heating performance of the CCHP specific to the unit installed. We then used the weighted average CCHP HSPF and SEER values to adjust MEMD 2019 ASHP end-use consumptions to reflect CCHP performance on a per-ton basis. In order to represent total heating and cooling load, we multiplied the CCHP installed tonnage by the pre/post heating and cooling loads per ton.

The Evaluation team relied on Consumers Energy 2021 residential natural gas and electric marginal rates (per kilowatt-hour and per therm), which include all surcharges for single-family customers. The team used previously developed load shapes to reflect equipment usage during peak and non-peak periods for the electric bill impacts. We created annual electric fuel costs by applying each specific equipment type's consumption load shape to the peak and off-peak rates. For fuel oil and propane costs, the

[19] 2021 Energy Waste Reduction Electric Potential Study Report: https://cadmus.sharepoint.com/sites/collaboration/6409-P01/ces/Shared%20Documents/Final%20Reports/2021/Electric%20Potential%20Study/2021%20Energy%20Waste%20Reduction%20Electric%20Potential%20Study%20Report%20FINAL%202021.06.10.pdf

Evaluation team used the latest Michigan monthly data from U.S. Department of Energy resources. These fuel costs utilized in the impact analysis are shown below in Table B-1.

Table B-1. Market Rate Fuel Costs Utilized in Impact Analysis

Fuel Type	Cost
AC_Central Loadshape - Electricity with Surcharge	$0.18
AC_WallWindow Loadshape - Electricity with Surcharge	$0.18
ASHP Loadshape - Electricity with Surcharge	$0.17
ZONAL_ER_HEAT Loadshape - Electricity with Surcharge	$0.16
AC Central Load Shape - Electricity with Surcharge	$0.18 per kWh / $52.48 per MMBtu
AC Wall Window Load Shape - Electricity with Surcharge	$0.18 per kWh / $52.19 per MMBtu
ASHP Load Shape - Electricity with Surcharge	$0.17 per kWh / $48.57 per MMBtu
Zonal Heat Load Shape - Electricity with Surcharge	$0.16 per kWh / $48.18 per MMBtu
Propane	$2.44 per gallon / $26.71 per MMBtu
Fuel Oil	$3.10 per gallon / $22.56 per MMBtu
Natural Gas	$7.91 per thousand cubic feet / $7.62 per MMBtu

Sources: U.S. Energy Information Administration. Accessed on January 14, 2022. Heating Oil and Propane Update https://eia.gov/petroleum/heatingoilpropane/#itn-tabs-1
Electric and natural gas rates used from Consumers Energy.

Multifamily Billing Analysis Methodology

To estimate electric energy usage changes within the Income Qualified Multifamily initiative projects, the Evaluation team designed and conducted a statistical billing analysis. The team relied on historical advanced metering infrastructure (AMI) interval data to estimate facility-wide and per-tenant-unit savings associated with CCHP installations using the Princeton Scorekeeping Method. The team incorporated TMY3 data to normalize usage and control for weather. We also included a nonparticipant comparison group, selected from other income-qualified electrically heated multifamily nonparticipants to control for the impacts of nonprogrammatic factors (such as changes in economic conditions including COVID-19–related behavior changes).

Data Sources

The Evaluation team requested and compiled participant and household data for the CCHP billing analysis from several sources:

- ***Heat pump initiative tracking data.*** The team received initiative tracking data from the implementation contractor to identify CCHP properties. These initiative tracking data included all participants from March 2020 to December 2020, including property name, participation dates, building square footage, and heat pump efficiency and capacity ratings. The tracking data did not include specific tenant unit addresses or the specific account information connected with each tenant.
- ***Multifamily composite database.*** The team developed a multifamily database to identify multifamily properties based on property size for prior 2020 evaluation research, which we used to identify all unique addresses (and all accounts associated with each property), including tenant units.

- ***Electric AMI data.*** Consumers Energy provided electric AMI data for all properties that had identifiable account data. This included meter read dates and times and all kilowatt-hour usage, by account, between June 2019 and September 2021.
- ***Michigan weather data.*** The team collected average hourly temperatures from June 2019 through September 2021 for four weather stations corresponding to the nearest monitoring station locations associated with CCHP participants. We matched hourly heating degree hours (HDHs) and cooling degree hours (CDHs) to AMI data read dates and times, and compiled hourly TMY3 15-year normal weather averages from 1991 through 2005 from the National Oceanic and Atmospheric Administration to assess energy usage under normal weather conditions.

Data Processing

The Evaluation team conducted several data processing steps to review, validate, and transform the raw AMI and tracking data into an analysis dataset:

- Imported and cleaned the tracking, AMI, and weather station datasets into Statistical Analysis System software
- Merged tracking and AMI datasets using account ID
- Filled in missing or zero AMI data readings with averages based on similar day-types or as the average of the previous and following hours
- Checked the hourly AMI histories for problems such as vacancies, outliers, and too many missing/interpolated readings
- Mapped each property to the nearest weather station using the property zip code
- Used hourly temperatures to determine variable base HDHs and CDHs for each station
- Merged the HDHs and CDHs onto the AMI and tracking data, using respective dates and times for each account
- Matched TMY3 HDHs and CDHs from the nearest station to weather-normalize the AMI data

Participant and Nonparticipant Groups

For the AMI analysis, the Evaluation team assigned properties into participant and nonparticipant groups. To be selected for the participant group, all multifamily heat pump properties had to have a continuous nine-month period of available usage data both before and after their participation in the pilot. The team used a rolling specification to assign pre- and post-periods, identifying a range of months around the installation period for each participant. Starting with a census of participants from the March through December 2020 period (initially seven properties), the Evaluation team identified a final participant group for analysis (after screening for participants who had at least nine months of pre-period and post-period billing data). We conducted account-level reviews of pre- and post-period usage for all individual participants to identify anomalies (periods of vacancies or other anomalies) that could bias the results. The team also applied additional screening criteria, described in detail in the *Data Screening and Model Attrition* section.

The team used a comparison group of nonparticipants to account for exogenous factors that may have occurred coincident with heat pump initiative activities. These factors can include macroeconomic effects, COVID-related behavior or occupancy changes, or other interactions that may have affected energy usage outside the heat pump influence. The Evaluation team identified comparison groups using customers who we had identified as living in income-qualified electrically heated multifamily properties. After creating the eligible group of nonparticipants, we further refined the nonparticipant group by matching each property to a participant property based on pre-installation usage. This assisted us in creating groups with baseline usage profiles as similar as possible to those of participants.

Disaggregation

Consumers Energy had the Evaluation team focus the heat pump analysis on electric-heated properties to create savings associated with reducing electric heating and cooling loads. Because of the focus on electric heating and cooling loads, the Evaluation team disaggregated the billing data to isolate the weather-sensitive electric heating and cooling usage from overall annual electric usage (which may include water heating, cooking, plug load, and lighting usage). First, we estimated weather-normalization models for each customer in the pre- and post-installation periods using actual observed weather data. Then we estimated the weather-sensitive components of electric usage using TMY3 data. Finally, we estimated the heating- and cooling-related components of usage.

Data Screening and Model Attrition

Data anomalies, outliers, missing data points, incomplete records, and other data issues all introduce potential bias into a billing analysis. The Evaluation team used several rules to flag and then remove accounts that failed to meet certain conditions:

- ***Must have sufficient pre- and post-installation billing data for analysis.*** All accounts had to contain a minimum of nine months of pre- and post-installation usage data.
- ***Must have a pre- and post-installation change within 70%.*** All accounts showing post-installation usage changes of up to 70% of pre-installation usage were retained in the analysis.
- Must not be an outlier or vacancy. The Evaluation team performed account-level reviews of pre- and post-installation period usage for all individual participants and removed anomalies (such as periods of vacancies) that could bias the savings results. We also removed units that participated in another energy-efficiency program from the analysis, as we could not determine which project created the observed savings.

The data screening resulted in a final analysis sample of three unique participant properties representing 77 tenant units. This corresponds to just under half (43%) of the original participating properties. As shown in Table B-2, the largest source of attrition for the billing analysis of participants originated from removing vacancies from the analysis, primarily because the billing data was only available for accounts that were active at the time of the request. Many of the accounts that were currently active did not have the necessary historical usage data at the apartment unit level to be included in the analysis. For the nonparticipant group, the single largest source of attrition resulted from units that did not show an electric heating signature.

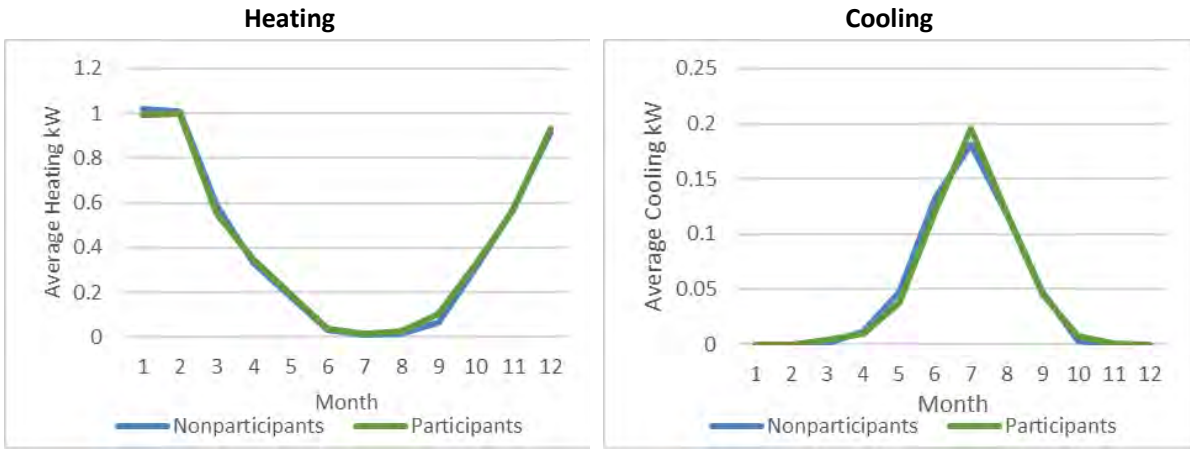
Table B-2. Income Qualified Multifamily Heat Pump Billing Analysis Summary Attrition

Screen	Participants	Nonparticipants
Initial Requested Sample	**97**	**2,329**
AMI Data Available	96	2,308
Sufficient Pre-Post Data	94	2,192
Removed Outliers/Vacancies	84	1,733
Matched Nonparticipant Property Type to Participant Property Type (such as removed high rise and mobile homes)	84	1,583
Determined that Dwelling Used Electric Heating	84	145
Passed Pre-Post Hourly PRISM Models/Hourly Prediction	84	132
Change within 70%	77	119
Matched Usage to Participants	77	112
Final	**77**	**112**

Baseline Electric Energy Use

Baseline multifamily building electric usage—the whole-building electric usage before installing energy-efficiency upgrades—is a critical input to whole-building energy savings estimation for electric-heated properties. The Evaluation team, using hourly PRISM (Princeton Scorekeeping Method) weather normalization and energy load disaggregation models, estimated the annual and monthly heating and cooling loads for the Income Qualified Multifamily participating tenant units. Additionally, estimating baseline heating and cooling energy usage across both participating and nonparticipating tenant units allows for isolating initiative-induced impacts specific to heat pump installation. This is important, as it accounts for non-programmatic influences on energy use, controlling for occupancy changes, behavior changes, changes attributable to COVID-19, and any other non-programmatic changes. A summary of the monthly average heating and cooling loads (in average kilowatts) across the participants and nonparticipant groups is shown in Figure B-1. There is little discernable difference—and, more importantly, no statistically significant difference—between participants' and nonparticipants' monthly heating and cooling loads.

Figure B-1. Baseline (Pre-Installation) Annual Heating and Cooling Load



The Evaluation team, with access to tenant apartment electric usage, estimated an average weather-normalized pre-installation baseline tenant unit usage of 3,860 kWh. Table B-3 shows the breakdown of the heating, cooling, and annual baseline pre-period annual weather-sensitive usage (per tenant apartment). As expected, given that multifamily tenant units in the CCHP were electrically heated, heating electric energy use is the predominant component (approximately 94%) of annual weather-sensitive use in these units.

Table B-3. Participant Tenant Unit Pre-Period Baseline Electric Weather-Normalized Per-Unit Usage

Usage Type	Weather-Sensitive Annual Usage (kWh)	Heating Usage (kWh)	Cooling Usage (kWh)
Billing Analysis	3,860	3,626	234

Source: Evaluation team AMI billing analysis.

Assess Change in Energy Use

As the final step in the analysis, the Evaluation team estimated real world changes to energy use between pre-and-post-installation usage patterns for participants and nonparticipants. Energy savings are the difference between participants' and nonparticipants' energy usage between the pre- and post-installation periods.

Engineering Calibration and Validation

The Evaluation team benchmarked the billing analysis findings relative to values produced from a simplified heat pump engineering model and the initiative-claimed savings (the initiative relied on current MEMD savings estimates). The goal of benchmarking was to help frame the billing analysis findings and understand how close the changes to energy usage tracked with alternative sources. The Evaluation team compiled initiative tracking claimed savings from eTracker and normalized the savings at the tenant apartment unit level by using the total number of installed heat pumps, the claimed savings, and the total number of apartment units. The team relied on the heating load requirement (3,626 kWh), assumed a CCHP COP of 2.75, and entered this data into a simple algorithm expressing continued baseboard heating, CCHP heating, and total heating demand based on several different displacement scenarios (Table B-4).

Table B-4. Cold-Climate Heat Pump Simplified Engineering Estimate

DHP Heating Load Displacement	Baseboard kWh	CCHP with COP of 2.75 (kWh)	Savings (kWh)	Total kWh
100%	-	1,319	2,307	3,626
75%	907	989	1,731	3,626
50%	1,813	659	1,154	3,626
36%	2,319	475	832	3,626

Bill Savings Estimation

To estimate the bill savings attributable to the CCHPs installed in the multifamily tenant units, the Evaluation team estimated the bill savings occurring during the time-differentiated bill periods across the year. According to residential rate data, peak period rates occur in summer months, from May 1 through September 30, during weekdays from 2 p.m. to 7 p.m. The Evaluation team then estimated the savings occurring during the peak and off-peak periods. Table B-5 shows a summary of the seasonal peak and off-peak rates and savings.

Table B-5. Cold-Climate Heat Pump Bill Savings Calculations

Residential Rate	Residential Billing Rate ($)	Income Qualified Multifamily CCHP Savings Occurring During Each Period (kWh)	Bill Savings ($)
Summer Peak	$0.213	6.1	$1.30
Off-Peak	$0.164	889.9	$145.94
Total Bill Savings			**$147.24**

Electric Savings: Engineering Comparison

The Evaluation team developed a simplified engineering estimate to compare how the evaluated electric savings compared with anticipated savings from a CCHP and added the initiative-claimed savings based on MEMD measures. Table B-6 shows a comparison of Income Qualified Multifamily initiative savings from the billing analysis sample, two engineering estimates based on two different displacement scenarios, and the initiative MEMD claimed savings estimate. The billing analysis estimate showed lower realized savings relative to the engineering estimate (assuming 50% of the electric baseboard heating was displaced by the CCHPs) and the MEMD estimate. In order for the engineering estimate to match the billing savings estimate of 832 kWh of heating load savings, the CCHPs would need to displace just over one-third (36%) of the heating load, which therefore assumes that the legacy baseboard heating systems still account for the majority of heating load for the apartments. The continued use of baseboard heat is consistent with feedback from the tenant survey, in which tenants reported continued use of baseboard heat as their primary heating source.

Table B-6. Annual Per–Tenant Unit Cold-Climate Heat Pump Electric Weather-Sensitive Savings Estimates Comparison

Source	Weather-Sensitive Usage (kWh) (A)	Weather-Sensitive Savings (kWh) (B)	Savings versus Weather-Sensitive Usage (%) (B / A)
Billing Analysis	3,860 (Annual)	896	23.2%
Billing Analysis	3,626 (Heating)	832	22.9%
Engineering @ 50% Displacement [a]	3,626 (Heating)	1,154	31.8%
Engineering @ 36% Displacement [a]	3,626 (Heating)	832	22.9%
MEMD/Pilot Claimed Savings [b]	3,860 (Annual)	1,474	38.2%

[a] This is an engineering estimate based on the heating season only and derived from AMI billing analysis.

[b] This represents annual weather-sensitive usage from the AMI billing analysis.

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Appendix C. Consumers Energy Heat Pump Market Rate Customer Survey

Objectives	Research Questions	Question Number
Assess customer awareness and motivations to install heat pumps	Were participants aware of heat pumps prior to participating in the offering? How do customers learn about heat pumps? What are participants' motivations for installing a heat pump? What are important decision factors for installing a heat pump? How much rebate is required to motivate participation?	Section B
Assess participant installation experience	How did participants experience the installation? Are there opportunities to improve the installation experience?	D1–D3
Document participant perceptions of heat pumps, energy or cost savings, comfort levels, and satisfaction	What are participants' experiences with heating/cooling comfort? How satisfied are participants with the heat pumps and the offering? How satisfied are participants with Consumers Energy?	D4–D12, B1, B2
	What non-energy benefits did the offering generate (such as reduced bill impacts, enhanced comfort levels, and improved operational issues)?	D11
Document participant usage behavior and home characteristics	How do respondents manage energy use at the thermostat?	Section C
	What are participants' home characteristics?	Section E

Survey Overview: The Evaluation team administered an online survey to residential customers who received a new heat pump. Then the team sent an email with a link to the survey, followed by reminder emails to encourage households to complete the survey withing the desired timeframe. In addition, the Evaluation team offered participants a $15 Meijer or Amazon.com gift card for completing the survey.

Target Audience: Census of Residential Market Rate pilot participants who installed a new heat pump as part of the Consumers Energy heat pump offering.

Survey Introduction and Purpose

Welcome, thank you for taking a few minutes to provide feedback about your cooling and heating equipment. Your feedback is very important to us and will help us improve rebates and incentives for new products that help customers save energy. This survey should take about 10 minutes. Your responses are confidential and will be used for research purposes only.

Be sure to enter your name and address at the end of the survey to receive your $15 Meijer or Amazon gift card as our thanks.

Click on the Next and Back buttons at the bottom of each page to navigate through the survey.

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A. *Screener*

A1. Our records indicate that you received a rebate for a heat pump installed in your home. Is this correct?
1. Yes
2. No **[TERMINATE]**
98. Don't know **[TERMINATE]**

A2. Approximately how long have you lived in your current home?
1. Less than one year
2. One to three years
3. Over three years

A3. **[If A2=1]** Were you living in your current home when the heat pump was installed?
1. Yes
2. No **[TERMINATE]**

TERMINATION MESSAGE: This survey is for Consumers Energy customers who received a rebate for a heat pump through the heat pump rebate program and who were living in the home when the heat pump was installed. Thank you for your interest in participating in this survey.

B. *Current Company Metrics and Awareness*

We'd like to ask some questions about your opinions toward Consumers Energy.

B1. How likely would you be to recommend Consumers Energy to a friend or family member if you had a choice in energy providers?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
○	○	○	○	○	○	○	○	○	○	○	○

B2. Please describe in detail why you gave that rating. _____

With these next questions, we would like to know more about your experience with heat pumps.

B3. Were you familiar with heat pumps before deciding to purchase and install the heat pump?
1. Yes
2. No
98. Don't know

B4. **[DISPLAY IF B3=1]** Prior to participating in this offer, had you ever had a contractor recommend a heat pump?
1. Yes, I had a contractor recommend a heat pump
2. No, a contractor has never recommended a heat pump to me

B5. Before you participated in this offer, were you aware that Consumers Energy offered rebates for heat pumps?

1. Yes, I was aware of heat pump rebates
2. No, I was unaware of heat pump rebates

B6. How did you first learn about the heat pump rebate? Please select only one response. **[RANDOMIZE 1–6]**

1. Contractor recommendation
2. Consumers Energy website
3. Consumers Energy flyer or other marketing material
4. Friend, family, neighbor, or colleague
5. Email from Consumers Energy
6. Online search
7. Other (please specify)

98. Don't know

B7. What were the main reason(s) you decided to install a heat pump in your home? (Select up to three) **[RANDOMIZE 1–9]**

1. To reduce energy bills in the winter months
2. To reduce energy bills in the summer months
3. To distribute heating and cooling more evenly throughout the home
4. To add heating and/or cooling for a new or renovated space in the home
5. To replace a broken heating or cooling system
6. To reduce reliance on natural gas or delivered fuels
7. To add cooling (where there was not previously a whole-home system)
8. To take advantage of heat pump incentives (from Consumers Energy and/or my contractor)
9. To take advantage of electricity produced at my home by renewable sources (such as solar or wind)
10. Something else (please describe)

B8. Please rate the importance of the following items on your decision to install a heat pump. **[RANDOMIZE ITEMS]**

Items	Not at All Important 1	2	3	4	5	6	7	8	9	Extremely Important 10	Don't know
a. The amount of rebate from Consumers Energy (up to $1,000)	○	○	○	○	○	○	○	○	○	○	○
b. Recommendation from a contractor	○	○	○	○	○	○	○	○	○	○	○
c. Possible energy savings over the previous heating/cooling system	○	○	○	○	○	○	○	○	○	○	○

B9. Would you have installed a heat pump if Consumers Energy had not offered a heat pump rebate?
1. Yes (I would have installed a heat pump without a rebate)
2. No
98. Don't know

B10. **[IF B9>1]** Would you have installed a heat pump if the rebate had been one-quarter of the value you received (up to $250)?
1. Yes (I would have installed the heat pump with a $250 rebate)
2. No
98. Don't know

B11. **[IF B9>1]** Would you have installed a heat pump if the rebate had been half as much as the amount you received (up to $500)?
1. Yes (I would have installed the heat pump with a $500 rebate)
2. No
98. Don't know

C. *Thermostat Use*

Next, we have a few questions about how you typically use your thermostat to manage the level of comfort in your home.

C1. What type of thermostat do you have in your home? (Select one.)
1. **Non-programmable** thermostat (set temperature manually and it did not change automatically)
2. **Programmable** thermostat with **set-backs programmed** (thermostat set to automatically change temperature at specific times)
3. **Programmable** thermostat—**not programmed** (thermostat has programming capability, but these were not used.)
4. **Basic networked or Wi-Fi–enabled** thermostat (had remote control, but not occupancy sensing or learning features)
5. **Smart learning** thermostat that includes advanced features such as occupancy sensing and schedule learning (examples include Nest, Ecobee, Honeywell Lyric, and Emerson Sensi)
98. Don't know

C2. Who in your household tends to monitor and adjust your thermostat?
1. I mostly monitor and adjust my home thermostat
2. Everyone in my household monitors and adjusts my home thermostat
3. Other members of my household typically monitor and adjust my home thermostat

C3. How did your household **most frequently** manage your thermostat to control the temperature in your home this summer? (Select one)
1. Keep it at a constant temperature
2. Manually adjust the temperature as needed
3. Create customized/programmed settings to automatically change temperatures at different times of the day
4. Allow the smart thermostat to manage the temperature by learning my preferences and/or detecting when home or away
5. Other (please describe)
98. Don't know

C4. Your heat pump offers the ability to use heating and cooling schedules. Did the installation technician setup your heat pump on a heating and cooling schedule?
1. Yes, the installer set up a heating and cooling schedule
2. No, the installer did not set up a heating and cooling schedule
98. Don't know

C5. **[IF C4=1]** Are you still using this heating and cooling schedule?
1. Yes, I have kept the heating and cooling schedule
2. No, I (or someone in my household) turned off the heating and cooling schedule
3. No, I (or someone in my household) changed the heating and cooling schedule to my own
98. Don't know

C6. Have you been provided with instructions on how to set up and control your heating and cooling schedule on your heat pump?
1. Yes, I received instructions
2. No, I did not receive instructions
98. Don't know

D. *Installation and Usage Experience*

Next, we would like to know about your experience with the heat pump.

D1. Our records indicate that the heat pump was installed in your home around **[INSTALLATION-COMPLETE DATE]**. Were you present during the installation of the heat pump?
1. Yes
2. No

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D2. Using a rating scale from 1 to 10, where 1 is *unacceptable* and 10 is *outstanding*, how would you rate each of the following installation experiences with the heat pump offering?

Question	Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know / NA
Scheduling a time for installation	O	O	O	O	O	O	O	O	O	O	O
Staying informed about the installation	O	O	O	O	O	O	O	O	O	O	O
[If D1=1] Overall installation time	O	O	O	O	O	O	O	O	O	O	O
[If D1=1] The professionalism of the installation technician	O	O	O	O	O	O	O	O	O	O	O
Education and instructions provided to you about heat pump usage	O	O	O	O	O	O	O	O	O	O	O
Follow-up from the installation technician or Consumers Energy	O	O	O	O	O	O	O	O	O	O	O

D3. **[IF ANY QUESTION IN D2=6 OR LOWER]** If there was something unsatisfactory about the heat pump installation, please describe in detail why you gave that rating.

_____

D4. In general, how did the heat pump affect your home comfort? (Select all that apply)

1. My home is **just as comfortable** as it was previously
2. My home is **more comfortable** than it usually was
3. My home is uncomfortably warm
4. My home is uncomfortably cold
5. My home is **too humid**
6. My home is **too dry**
7. My home was more evenly heated and/or cooled prior to the installation
8. Something else (please describe)

D5. **[IF D1=1 AND COMPLETE DATE IS PRIOR TO APRIL 1, 2021]** How would you rate the heating comfort level provided by the heat pump during winter months?

Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
O	O	O	O	O	O	O	O	O	O	O

[If D5<6] What concerns do you have about the heat pump's ability to heat to your comfort level?

_____

D6. How would you rate the cooling comfort level provided by the heat pump during summer months?

Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
○	○	○	○	○	○	○	○	○	○	○

[If D7<6] What concerns do you have about the heat pump's ability to cool to your comfort level?

_____

D7. Taking everything into consideration, how would you rate your overall experience with the heat pump so far?

Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
○	○	○	○	○	○	○	○	○	○	○

D8. Based on your experiences with the heat pump so far, how likely would you be to recommend it to a friend?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
○	○	○	○	○	○	○	○	○	○	○	○

D9. Based on your experience so far, do you have any recommendations to improve the heat pump rebate offer? _____

98. Don't know

D10. Since the heat pump was installed, have you seen a lower-than-expected energy bill?

1. Yes
2. No
3. Too soon to tell
98. Don't know

D11. In addition to energy savings, if any, are there additional benefits you have experienced or observed from the installation of a heat pump? (Select all that apply) **[RANDOMIZE]**

1. Increased comfort
2. Lower utility bills
3. Improved appearance of my home
4. Improved air quality
5. Improved heating and cooling distribution (across sections of my home)
6. Less maintenance required

7. Improved ability to manage heating/cooling on a schedule
8. Fewer illnesses for household members
9. Other (please specify)
10. Too soon to know **[EXCLUSIVE OF OTHER RESPONSES]**
11. No other benefits **[EXCLUSIVE OF OTHER RESPONSES]**

98. Don't know **[EXCLUSIVE OF OTHER RESPONSES]**

D12. **[If D12=1 AND D11<10]** Considering that the heat pump offering provided both saved energy and some additional benefits to your home, please indicate which was the most important to you:

1. The energy savings
2. The other benefits previously identified
3. The energy savings are equal to the other benefits

98. Don't know

E. *Demographics*

Finally, we have a few questions about your home.

E1. How many people live in your household on a regular basis, year-round?

1. 1
2. 2
3. 3
4. 4
5. 5
6. More than 5

99. Prefer not to answer

E2. Approximately how many square feet of living space does your home have? Do not include the basement unless it is a space that you consider lived in.

1. Under 1,000 square feet
2. 1,000 to less than 1,500 square feet
3. 1,500 to less than 2,000 square feet
4. 2,000 to less than 2,500 square feet
5. 2,500 to less than 3,000 square feet
6. 3,000 to less than 4,000 square feet
7. 4,000 or more square feet

98. Don't know

F. *Closing*

F1. On occasion, managers of the Consumers Energy programs may want to contact a customer to learn more about their participation experience. Please check here if you prefer not to be contacted by a program manager.
1. Do not contact me

F2. Do you have any recommendations for ways Consumers Energy can support you in helping you save energy?
1. Please describe_____

F3. To thank you for your time spent completing this survey, we would like to send you a $15 gift card to either Meijer or Amazon.com. Please choose which gift card you would like to receive.
1. $15 Meijer gift card
2. $15 Amazon.com gift card
3. Neither – I do not wish to receive a gift card

F4. **[IF F3=1 OR 2]** Please provide your name, address, and email to receive your gift card. This information will only be used to mail your gift card.
1. Name:_____
2. Address:_____
3. Address 2:_____
4. City:_____
5. State:_____
6. Zip:_____
7. Email**:** _____

Please click Next to submit the survey.

[END OF SURVEY MESSAGE] Those are all the questions we have at this time. Thank you for your participation in the Consumers Energy heat pump offer.

For more information on energy efficiency, here's where to find it:

- **Want Online Information about Our Other Energy-Efficiency Rebates and Programs?** For details of additional ways Consumers Energy may be able to help you make your home more energy efficient and help you manage your monthly energy bills, please visit us online at ConsumersEnergy.com/myhome.
- **Want to Speak to an Energy-Efficiency Advisor by Phone?** To talk to someone about additional rebates and programs, please contact one of our Energy Advisors at (888) 652-1237.

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Appendix D. Consumers Energy Heat Pump Property Owner and Manager Interview Guide

Research Questions

Objectives	Research Questions	Interview Section
Document participant installation experience	How well did the offering manage the user installation experience? Are there opportunities to improve the installation experience?	B1, B3
Document participant usage behavior and experience	How are tenants using and operating the heat pumps? Did customers retain secondary or supplemental heating equipment after the heat pump was installed?	B2, B4
Document awareness and perceptions of heat pumps	What is the current perception of heat pump technologies? Were participants aware of heat pumps prior to being approached by Consumers Energy or the contractor? What are the perceived energy benefits of heat pumps? What non-energy benefits did the offering generate (such as reduced bill impacts, enhanced comfort levels, or improved operational issues)?	C1–C4, E2–E5
Document participant decision-making around participating in the heat pump offering	What key factors affected participants' decisions to install a heat pump? What are the key barriers to adopting heat pumps?	D1–D4
Identify marketing and outreach best practices	How did the participant learn about the offering?	C3
	What are the most effective means of marketing heat pumps?	F1–F3
Assess satisfaction with the offering and with Consumers Energy	How satisfied are property owners and managers with the heat pump offering? How satisfied are tenants with the heat pumps and the offering? How satisfied are property owners and managers with Consumers Energy?	G1–G4

Target Audience: The target audience for these interviews was multifamily PMOs who participated in the CCHP initiatives. The Evaluation team attempted to interview a census of participating PMOs.

A. General Introduction

A1. To begin, please tell me about your multifamily properties.

1. How many unique multifamily properties do you own or manage?
2. How many of them are located in Michigan?
3. Do you own/manage only subsidized or income eligible housing or do you also own/manage market rate properties?

B. Installation and Usage Experience

B1. Please describe your experience, including any positive or negative elements, of the heat pump installation for each of the following installation components (please note if you are not aware of any of these elements):

1. Scheduling a time for the installation
2. Informing the tenants
3. Overall installation time
4. Professionalism of the installation technicians
5. Education and instructions provided to management about heat pump usage
6. Education and instructions provided to tenants about heat pump usage **[PROBE: WERE YOU INFORMED ABOUT PRIORITIZING HEAT PUMP USAGE OVER BASEBOARD HEATING?]**
7. Follow up

B2. Have you received any feedback from your tenants about the new heat pumps? **[PROBE: DO THE COMMENTS TEND TO BE POSITIVE, COMPLAINTS, OR QUESTIONS?]**

B3. Have you had any concerns or issues with the heat pumps installed in your property? **[PROBE: HAVE TENANTS COMPLAINED, DO MAINTENANCE STAFF HAVE ANY FEEDBACK ABOUT THEM?]**

B4. It is our understanding that the existing baseboard heating equipment was left in tenant apartments. Are you aware of whether tenants are continuing to use their baseboard heaters or if they rely mostly on the new heat pumps for heating?

1. Are you aware if the tenants received educational materials or training on the use of the heat pumps? **[PROBE: HAVE TENANTS SEEN THESE MATERIALS? HOW WERE THEY DISTRIBUTED? DO THEY FIND THE MATERIALS TO BE USEFUL?]**

C. Heat Pump Awareness and Perceptions

C1. Before participating in this heat pump offering, were you familiar with heat pumps?

C2. Prior to participating in this offering, had you ever had a contractor recommend heat pumps?

C3. Before you participated in this offering, were you aware that Consumers Energy offered rebates for heat pumps?

1. **[IF HEARD ABOUT OFFERING]** Where did you hear about the heat pump offering?
2. **[IF HEARD ABOUT OFFERING]** What were your immediate perceptions of the offering?

C4. Other than **[NAME OF PROPERTY IN THE HEAT PUMP OFFERING]**, do any of your properties currently have heat pumps installed for heating and cooling?

1. **[IF HAS HEAT PUMPS INSTALLED]** How many (if any) of the properties you own/manage use heat pumps? **[PROBE TO SEE IF THEY ARE IN MICHIGAN]**
2. For those properties, do residents typically retain secondary or supplemental heating equipment after the heat pump is installed? Please describe.

D. Motivators and Barriers

D1. What were the most important factors in your decision to participate in the heat pump offering? **[DO NOT READ OR PROMPT; SELECT ANY THAT ARE MENTIONED]**

1. Lower tenant utility costs
2. Lower owner utility costs
3. Improve the property appearance
4. Improve tenant comfort
5. Increase the property value
6. Replace old or broken equipment
7. Take advantage of low-cost/no-cost improvements
8. Reduce impact on the environment
9. Lower operating and maintenance costs
10. Improve property aesthetics
11. Improve health and safety
12. Satisfaction with previous Consumers Energy program experience
13. Turnkey and easy to participate
14. Other (Please specify)

98. Don't know

D2. Which of these factors was the most important to your decision? **[REPEAT THOSE MENTIONED IN PREVIOUS QUESTION TO ALLOW SELECTION FROM LIST]**

D3. What do you consider to be the primary barriers to adding heat pumps to other properties? **[DO NOT READ OR PROMPT; SELECT ANY THAT ARE MENTIONED]**

1. Overall upfront costs
2. Logistical effort required to deal with installation
3. Finding the right contractor
4. Getting management approval
5. Tenant disruption
6. Tenants' ability to use the equipment to reduce energy consumption
7. Other (Please specify)

98. Don't know

D4. Which of these factors is the most significant barrier to your decision? **[REPEAT THOSE MENTIONED IN PREVIOUS QUESTION TO ALLOW SELECTION FROM LIST]**

E. Savings and Benefits of Participation

E1. Do you or your tenants pay the electric utility bills?

E2. **[IF TENANTS PAY]** Have your tenants provided feedback about their bills since installation of the heat pumps? If so, please describe what this feedback has entailed.

E3. **[IF PROPERTY OWNER/MANAGER PAYS UTILITY BILLS]** Have you noticed any change in your utility bills since installation of the heat pumps? If so, please describe the change. **[PROBE: HAVE THERE BEEN ANY DIFFERENCES IN UTILITY BILL CHANGES BETWEEN WINTER HEATING AND SUMMER COOLING?]**

E4. In addition to energy savings, are there any other benefits that your property, your tenants, or property management have experienced from installing the heat pumps? **[DO NOT READ OR PROMPT; SELECT ANY THAT ARE MENTIONED]**

1. Lower maintenance costs
2. Improved operations
3. Increased property value
4. Decreased vacancy rates
5. Increased rental income
6. Increased net operating income
7. Increased tenant comfort
8. Decreased late or nonpayment of rent
9. Decreased tenant complaints
10. Improved property aesthetics
11. Health and safety improvements
12. Other (Please specify)
13. Too soon to tell
14. No other benefits

98. Don't know

E5. **[ASK IF E3=YES AND E4≠13, 14, OR 98]** Considering that the heat pump offering provided both energy savings and some other benefits to your property, please indicate which was the <u>most important</u> benefit:

1. The energy savings
2. The non-energy benefits (previously identified)
3. The energy savings benefits are equal to the non-energy benefits

98. Don't know

F. Outreach and Marketing

F1. What, in your opinion, could be done to increase the adoption of heat pumps in the multifamily market?

F2. What are the most effective ways to let other multifamily property owners and managers know about the benefits of heat pumps?

F3. What information would be helpful for other property managers and owners to become interested in heat pumps?

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G. Opinion of Heat Pump Offering and Consumers Energy

G1. Taking everything into consideration, how would you rate your overall experience with the multifamily heat pump offering, where 1 means *unacceptable* and 10 means *outstanding*?

Unacceptable 1	2	3	4	Average 5	6	7	8	9	Outstanding 10	Don't know
○	○	○	○	○	○	○	○	○	○	○

G2. Based on your experiences with the heat pump offering, how likely would you be to recommend the offering to a business colleague, where 1 means *extremely unlikely* and 10 means *extremely likely*?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
○	○	○	○	○	○	○	○	○	○	○	○

G3. Based on your experiences with the heat pump offering, how likely would you be to recommend Consumers Energy to a business colleague if you had a choice in energy providers, where 1 means *extremely unlikely* and 10 means *extremely likely*?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
○	○	○	○	○	○	○	○	○	○	○	○

G4. Based on your experience with the heat pump offering, how likely would you be to make similar improvements to some or all the properties you manage, where 1 means *extremely unlikely* and 10 means *extremely likely*?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
○	○	○	○	○	○	○	○	○	○	○	○

H. Wrap Up

H1. In what ways can Consumers Energy programs better help you manage your multifamily properties' energy use?

H2. Our research also includes a tenant survey to capture their experience and usage with the heat pumps, but we do not have tenant contact information to recruit them for this effort. Would you be interested in **[OPTION A]** securely sharing tenant emails with us so they can receive an email link to complete an online survey or **[OPTION B]** would you be willing to forward an email invitation to your tenants to complete the online survey? Tenants will receive a $15 gift card for their time. [**ENTER WILLINGNESS RESPONSE OPTION AND BE SURE TO REQUEST THE PMO EMAIL ADDRESS TO ENSURE EITHER OPTION CAN BE SHARED**]

Those are all the questions we have. Thank you very much for taking the time to assist us with this evaluation. Your contribution is a very important part of the process. We are planning to send you your choice of a $50 Amazon or Meijer card (if you choose Meijer, we will need your mailing address, as there is no e-card option). Please let us know your choice of card **[ENTER CARD CHOICE AND REQUEST EMAIL ADDRESS IF AMAZON OR MAILING ADDRESS IF MEIJER]**.

Look for your gift card in the mail in the next three weeks. If you have any questions about this survey or about your gift card, please call **[APEX STAFF]** at **[303-590-9888 Ext XXX]**. Thank you for your time.

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Appendix E. Consumers Energy Heat Pump Multifamily Tenant Survey Guide

Objectives	Research Questions	Question Number
Document participant awareness of heat pump	Are tenants aware of what a heat pump is? Were tenants aware of a heat pump installed for their apartment? Are tenants who were aware of the heat pump also aware that Consumers Energy funded it?	Section B
Document participant installation experience	How did the heat pump offering help Consumers Energy to manage the tenant installation experience? Are there opportunities to improve the installation experience?	D1–C3
Assess participant perceptions of heat pump impact on comfort levels and electricity bills	What perceptions do tenants have of heating and cooling comfort levels? What are the perceived energy benefits of heat pumps? What non-energy benefits did the offering generate (such as reduced bill impacts, enhanced comfort levels, and improved operational issues)?	C4–C11, D2–D4
Document participant usage behavior and experience	How are tenants using and operating the heat pumps? Are tenants continuing to use their baseboard heating?	C12–C18
Assess participant satisfaction with the offering and with Consumers Energy	How satisfied are tenants with the heat pumps offering? How satisfied are tenants with Consumers Energy?	E1–G3, A1, A2

Survey Overview: The Evaluation team administered a web-based survey with multifamily tenants who received a new heat pump. Then the team sent an email with a link to the survey to participants who could be matched to participating multifamily buildings and had an email address, followed by reminder emails to encourage households to complete the survey within the desired timeframe. In addition, the Evaluation team offered participants a $15 Meijer or Amazon.com gift card for completing the survey.

Target Audience: Census of individual tenant dwellings that could be matched to the multifamily building and had an email address. The Evaluation team had 75 emails associated with the multifamily properties by linking an income-qualified survey contact database with the Income Qualified Multifamily incentive properties. Assuming a 10% response rate, we hoped to receive approximately eight completed surveys.

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A. Current Company Metrics

First, we'd like to ask some questions about your opinions toward Consumers Energy.

Consumers Energy Count on Us®

A1. How likely would you be to recommend Consumers Energy to a friend or family member if you had a choice in energy providers?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
O	O	O	O	O	O	O	O	O	O	O	O

A2. Please describe in detail why you gave that rating. _____

B. Awareness

B1. Are you familiar with what a heat pump is?

1. Yes, I am familiar
2. No, I do not know what a heat pump is

[IF B1=2, PROVIDE EXPLANATION ABOUT HEAT PUMPS: HEAT PUMPS ARE EQUIPMENT THAT PROVIDES BOTH HEATING AND COOLING FOR HOMES.]

B2. Our records indicate that the apartment you currently occupy received a new heat pump. Are you aware of this?

1. Yes
2. No

B3. **[If B2=1]** Were you aware that Consumers Energy funded this project and made the heat pump technology available in your home?

1. Yes, I was aware of Consumers Energy involvement
2. No, I was unaware of Consumers Energy involvement

98. Don't know

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C. Installation and Usage Experience

Next, we would like to know about your experience with the heat pump.

[SHOW QUESTIONS D1 TO C3 IF COMPLETE DATE IS NOT EMPTY]

C1. Our records indicate that the heat pump was installed in your apartment around **[COMPLETE DATE]**. Were you present during the installation of the heat pump?

1. Yes, I was present during installation
2. No, I was not present during installation

C2. Using a rating scale from 1 to 10, where 1 is *unacceptable* and 10 is *outstanding*, how would you rate each of the following installation experiences with the heat pump offering?

Question	Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
Scheduling a time for installation	○	○	○	○	○	○	○	○	○	○	○
Staying informed about the installation	○	○	○	○	○	○	○	○	○	○	○
[IF C1=1] Overall installation time	○	○	○	○	○	○	○	○	○	○	○
[IF C1=1] The professionalism of the installation technician	○	○	○	○	○	○	○	○	○	○	○
Education and instructions provided about heat pump usage	○	○	○	○	○	○	○	○	○	○	○
Follow-up from the installation technician or Consumers Energy	○	○	○	○	○	○	○	○	○	○	○

C3. **[IF ANY QUESTION IN C2≥6]** If there was something unsatisfactory about the heat pump installation, please describe in detail why you gave that rating.

_____

C4. Approximately how long have you lived in your current apartment?

1. Less than six months
2. Between six months and one year
3. Over one year

C5. Were you living in your apartment last winter, before the heat pump was installed?

1. Yes
2. No

C6. **[IF C5=1]** How would you rate the heating comfort level provided by the heat pump during winter months?

Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
○	○	○	○	○	○	○	○	○	○	○

C7. **[IF C6<7]** What concerns do you have about the heat pump's ability to heat to your comfort level? _____

C8. Were you living in your apartment last summer, before the heat pump was installed?

1. Yes
2. No

C9. **[IF C8=1]** How would you rate the cooling comfort level provided by the heat pump during summer months?

Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
○	○	○	○	○	○	○	○	○	○	○

C10. **[IF C9<7]** What concerns do you have about the heat pump's ability to cool to your comfort level? _____

C11. In general, how did the heat pump affect your home comfort? (Select all that apply)

1. My home is **just as comfortable** as it was previously
2. My home is **more comfortable** than it usually was
3. My home is uncomfortably warm
4. My home is uncomfortably cold
5. My home is **too humid**
6. My home is **too dry**
7. My home was more evenly heated and/or cooled prior to the installation
8. Something else (please describe)

C12. Our records indicate that the existing baseboard heating equipment was left in all apartments where heat pumps were installed.
Which of the following best describes how you heated your apartment last winter?
[RANDOMIZE 1-3]

1. Mostly used baseboard heating
2. Relied evenly on the heat pump and baseboard heating
3. Mostly used the new heat pump

98. Don't know

C13. Your baseboard heating should have a thermostat that controls your home's heating.
What type of thermostat do you have in your home?

1. **Non-programmable** thermostat (set temperature manually and it did not change automatically)
2. **Programmable** thermostat with **set-backs programmed** (thermostat set to automatically change temperature at specific times)
3. **Programmable** thermostat—**not programmed** (thermostat has programming capability, but these were not used.)
4. **Basic networked or Wi-Fi–enabled** thermostat (had remote control, but not occupancy sensing or learning features)
5. **Smart learning** thermostat that includes advanced features such as occupancy sensing and schedule learning (examples include Nest, Ecobee, Honeywell Lyric, and Emerson Sensi)

98. Don't know

C14. Who in your household tends to monitor and adjust your thermostat associated with your baseboard heating?

1. I mostly monitor and adjust my home baseboard thermostat
2. Everyone in my household monitors and adjusts my home baseboard thermostat
3. Members of my household (other than me) typically monitor and adjust my home baseboard thermostat

C15. How did your household **most frequently** manage your baseboard thermostat to control the temperature in your home this summer?
1. Keep it at a constant temperature
2. Manually adjust the temperature as needed
3. Create customized/programmed settings to automatically change temperatures at different times of the day
4. Allow the smart thermostat to manage the temperature by learning my preferences and/or detecting when home or away
5. Other (please describe)
98. Don't know

C16. Your heat pump offers the ability to use heating and cooling schedules. Did the installation technician set up your heat pump on a heating and cooling schedule?
1. Yes, the installer set up a heating and cooling schedule
2. No, the installer did not set up a heating and cooling schedule
98. Don't know

C17. **[IF C16=1]** Are you still using this heating and cooling schedule?
1. Yes, I have kept the heating and cooling schedule
2. No, I (or someone in my household) turned off the heating and cooling schedule
3. No, I (or someone in my household) changed the heating and cooling schedule to my own
98. Don't know

C18. Have you been provided with instructions on how to set up and control your heating and cooling schedule on your heat pump?
1. Yes, I received instructions
2. No, I did not receive instructions
98. Don't know

D. Savings and Benefits of Participation

D1. How would you describe how your electric utility use is billed?
1. I receive a monthly electric utility bill directly from the utility for my usage
2. My landlord receives an electric utility bill for the whole building's usage
3. The electricity use for my unit is billed some other way (please describe)
4. I'm not sure how the electric utility use is billed

D2. **[IF E1=1]** Have you seen a lower-than-expected energy bill?
1. Yes
2. No
3. Too soon to tell
98. Don't know

D3. In addition to energy savings, if any, are there other benefits that you have experienced or observed from the installation of heat pumps? (Select all that apply) **[RANDOMIZE 1–8]**

1. Increased comfort
2. Lower utility bills
3. Decreased complaints about my apartment temperature
4. Improved air quality
5. Improved appearance of my apartment
6. Improved heating and cooling distribution (across sections of my home)
7. Fewer illnesses for household members
8. Improved ability to manage heating/cooling on a schedule
9. Other (Please specify)
10. Too soon to tell [EXCLUSIVE OF OTHER RESPONSES]
11. No other benefits [EXCLUSIVE OF OTHER RESPONSES]

98. Don't know [EXCLUSIVE OF OTHER RESPONSES]

D4. **[ASK IF D2=1 AND D10≠10, 11, OR 98]** Considering that the heat pump offering provided both saved energy and some additional benefits to your apartment, please indicate which was most important to you:

1. The energy savings
2. The other benefits previously identified
3. The energy savings are equal to the other benefits

98. Don't know

E. Opinion of Heat Pump Offering and Consumers Energy

E1. Taking everything into consideration, how would you rate your overall experience with the heat pump?

Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
○	○	○	○	○	○	○	○	○	○	○

E2. Based on your experiences with the heat pump, how likely would you be to recommend a heat pump to a friend?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already Did Recommend	Don't know
○	○	○	○	○	○	○	○	○	○	○	○

E3. Do you have any recommendations for ways Consumers Energy can further support you in saving energy?
   1. Please describe_____

F. Closing

F1. On occasion, managers of the Consumers Energy programs may want to contact a customer to learn more about their participation experience. **Please check here if you prefer not to be contacted by a program manager.**
   1. Do not contact me

F2. To thank you for your time spent completing this survey, we would like to send you a $15 gift card to either Meijer or Amazon.com. Please choose which gift card you would like to receive.
   1. $15 Meijer gift card
   2. $15 Amazon.com gift card
   3. Neither – I do not wish to receive a gift card

F3. **[ASK IF F2=1 OR 2]** Please provide your name, address, and email to receive your gift card. This information will only be used to mail your gift card.
   1. Name:_____
   2. Address:_____
   3. Address 2:_____
   4. City:_____
   5. State:_____
   6. Zip:_____
   7. Email**:** _____

Please click Next to submit the survey.

Those are all the questions we have at this time. Thank you for your participation in the Consumers Energy heat pump offer.

For more information on energy efficiency, here's where to find it:

- **Want Online Information about Our Other Energy-Efficiency Rebates and Programs?** For details of additional ways Consumers Energy may be able to help you make your home more energy efficient and help you manage your monthly energy bills, please visit us online at ConsumersEnergy.com/myhome.
- **Want to Speak to an Energy-Efficiency Advisor by Phone?** To talk to someone about additional rebates and programs, please contact one of our Energy Advisors at (888) 652-1237.

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Appendix F. Consumers Energy Heat Pump Commercial Interview Guide

Cold-Climate Heat Pump Participant Interview Research Objectives and Questions

Objectives	Research Questions	Interview Questions
Explore key factors in customer decision-making regarding heat pump installations	Were customers aware of heat pumps prior to the pilot outreach?	C1, C1a, C1b, C1c
	What were customers' perceptions of heat pumps prior to installation? What barriers did customers face when considering the installation of heat pumps?	C3
	What motivated customers to install heat pumps?	C5, C5a, C5b
	What technology would customers have installed without the initiative intervention and why?	C4, C4a
Explore customer experiences during the heat pump installation process	How did participants find their contractor who installed the equipment? How did participants perceive their contractors knowledge of heat pump technology and installation methods? How did participants perceive the length of time to purchase and install the heat pump and how long did that process take?	D1, D2, D4, D4a, D5
	What type of equipment did customers use prior to the heat pump? Did participants need to install new duct work, a new thermostat, and/or back-up systems for their heat pump?	D6, D7, D8, D9, D10
	Were participants satisfied with their contractors (including their interactions with their contractors and the contractors' performance), the installation process, and the timeline? Why or why not? Would they use the contractor again?	G1a, G1b, G1d, D3
Explore customer experiences using their heat pump	Does the heat pump provide the level of heating required for comfort and meeting customer needs?	E2, E2a
	Does the heat pump provide the level of cooling required for comfort and meeting customer needs?	E3, E3a
	Can customers operate the heat pump easily, including the remote controls? Do they need to change their habits in any way?	E1, E4, E4a, E5, E5a, E5b, E6
	How does the heat pump compare to prior equipment with regards to air quality?	E7, E7a
	How does the heat pump compare to prior equipment with regard to noise?	E8, E8a
	Are participants satisfied with their heat pump? Why or why not?	G1c
Explore customer experiences with the initiative offering	How did participants learn of the initiative opportunity?	C2
	Did participants interact with program staff? If so, what were their experiences?	F1, F1a, F1b
	Were participants satisfied with the pilot offering?	G1e
Identify opportunities to best support heat pump technology moving forward	Which aspects of the initiative offering were most helpful to customers (such as the staff support versus the financial incentive)?	F4
	What additional support, if any, did participants need to pursue the installation and use of their heat pump?	F2, F2a, F3, F3a, D4b

Survey Overview. The Evaluation team attempted to interview the full population of participating customers, with a goal to complete at least five interviews. The team included a $75 incentive to increase the likelihood of response. The Evaluation team sent advance emails to all respondents with available email addresses and followed up with phone calls as needed to schedule interviews. This email explained the research and provided a Consumers Energy and Evaluation team contact person if the respondent had additional questions or wanted to schedule an interview. For phone recruitment, the

team left a voicemail or receptionist message on the first attempt whenever possible, then used discretion to determine any additional messages left on subsequent attempts (with a maximum of five attempts to each contact).

A. Introduction

A1. First, can you tell about the work you do at **[BUSINESS NAME]**?

A2. And what is your role at the business? **[PROBE FOR ROLE AND RESPONSIBILITIES]**

B. Consumers Energy

Next, we'd like to ask you a few questions about your opinions toward Consumers Energy.

B1. How likely is it that you would recommend Consumers Energy to a friend or colleague if you had a choice in energy providers using a scale from 1 to 10, where 1 means *extremely unlikely* and 10 means *extremely likely*?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
○	○	○	○	○	○	○	○	○	○	○	○

B2. Please describe why you gave that rating.

B3. To what extent do you agree that Consumers Energy made it easy to participate in the Cold-Climate Heat Pump Initiatives, using a scale from 1 to 5, where 1 means *strongly disagree* and 5 means *strongly agree*?

Strongly disagree 1	2	3	4	Strongly agree 5
○	○	○	○	○

C. Decision-Making

Next, I'd like to ask some questions about your decision to install a heat pump.

C1. Prior to Consumers Energy contacting you about the heat pump offering, how familiar were you with heat pump technology to heat and cool your facility?

1. **[IF AWARE, PROBE]** What were your perceptions of heat pumps?
2. **[IF AWARE, PROBE]** Had you heard anything about their performance in colder climates?
3. **[IF KNOW ABOUT HEAT PUMP PERFORMANCE IN COLD CLIMATES]** Where did you hear about it?
4. **[IF AWARE, PROBE]** Had you heard anything about their performance in colder climates?

C2. How did you first learn of the opportunity to receive a heat pump through Consumers Energy?

C3. What key concerns or considerations did you have when deciding whether or not to install the heat pump?

C4. What motivated you to agree to install the heat pump?
1. Were there any other factors? **[PROBE FOR COST, ENERGY SAVINGS, ENERGY-EFFICIENCY, REBATE FROM CONSUMERS ENERGY]**

C5. Did you have plans to install new heating or cooling equipment if Consumers Energy hadn't reached out to you?
1. **[IF WOULD HAVE INSTALLED NEW HVAC EQUIPMENT]** When would you have installed this new equipment?
2. What steps would you have taken to decide what equipment to purchase?

D. Experience with Contractor Selection and Installation Process

The next set of questions are about your experiences finding a contractor and installing of your new heat pump.

D1. So, once you decided to participate in Consumers Energy's Cold-Climate Heat Pump offering, can you talk me through the steps you took to find and select a contractor to perform the work?

D2. Did you have any difficulties finding a contractor to perform the work?

D3. How knowledgeable were the contractors you worked with about heat pumps? What about the installation process? **[PROBE IF ANY DID NOT SEEM TO BE KNOWLEDGEABLE ABOUT THE EQUIPMENT, WHERE THEY WERE LACKING KNOWLEDGE]**

D4. Once you found a contractor, how long did the project take from start to finish (purchasing to installing)? Did this timeline meet your expectations?
1. **[IF TIME EXPECTATIONS NOT MET]** What were your expectations?
2. **[IF TIME EXPECTATIONS NOT MET]** Is there anything that could have been done differently? **[PROBE IF ANY PART OF THE PROCESS TOOK LONGER THAN EXPECTED]**

D5. If you had to do it over again, would you work with the same contractor?

D6. Prior to the installation, what type of heating equipment did you use? Did you use electric or natural gas or another type of fuel to heat the property?

D7. What type of cooling equipment did you use?

D8. Did your contractor need to install new duct work, a new thermostat, or other infrastructure as part of the heat pump installation?

D9. What did your contractor do with the old heating system? **[PROBE IF REMOVED, KEPT IN PLACE AS BACKUP, CAPPED]**

D10. Did you need to install a new back-up system along with the heat pump? **[PROBE FOR HEATING OR COOLING SYSTEMS]**

E. Experience Using the Heat Pump

Next, I'd like to ask some questions about your experiences using the heat pump itself.

E1. What have been your experiences with operating the equipment to date?

E2. Have you had a chance to use the heating function on the heat pump that was installed at your facility?
   1. **[IF USED HEATING]** What time of year did you use the heating function? Did you have any issues with the heat pump providing sufficient heat for your comfort and meeting your needs? **[PROBE FOR IF THEY EVER HAD ISSUES PROVIDING HEAT]**

E3. Have you used the cooling function?
   1. **[IF USED COOLING]** Did you have any issues with the heat pump providing sufficient cooling for comfort and meeting your needs?

E4. Does the heat pump require any new operating procedures that you needed to learn how to use?
   1. How did that go?

E5. Does the equipment rely on a remote control or app?
   1. Do you use that feature?
   2. How has that gone?

E6. Have you had to change your heating/cooling habits in any way to accommodate the new technology?

E7. Have you noticed any changes in air quality since the heat pump was installed? **[PROBE: DECREASED AIR PARTICLES, NOXIOUS GASES, DEBRIS]**
   1. **[IF YES]** How so?

E8. How does the sound of the new equipment compare to your old heating/cooling equipment?
   1. **[IF SOUND WORSE]** What have you done to deal with the noise, if anything?

F. Experience with Pilot Offering

Next, I have a few questions about your experiences with Consumers Energy in relation to this pilot and then we'll be almost done.

F1. Did you interact with Consumers Energy program staff at any point in the process?
   1. **[IF YES]** What did you discuss?
   2. Did you get your questions answered?

F2. What additional support, if any, did you need *when considering to purchase and install* your heat pump?
   1. Who did you talk to? What questions did you have?

F3. Did you require any additional support—other than what you received from Consumers Energy—during the *installation process*?
   1. What about when using the equipment?

F4. Thinking about all the aspects of the initiative, from the support you received in picking equipment or a contractor to the financial rebate for the project, what aspect was most helpful in your decision to pursue the heat pump installation?

G. Satisfaction

I'd like to wrap up the conversation by asking you to rate your satisfaction on a few different factors.

G1. Feel free to expand on any answers you provide. Each of these items will be on a 1 to 10 scale, where 1 means *unacceptable* and 10 means *outstanding*.

Question	Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know / NA
The installation your contractor performed	○	○	○	○	○	○	○	○	○	○	○
The time it took to receive and install your equipment	○	○	○	○	○	○	○	○	○	○	○
The performance of the heat pump equipment	○	○	○	○	○	○	○	○	○	○	○
The interactions you had with your contractor	○	○	○	○	○	○	○	○	○	○	○
The overall Consumers Energy offering	○	○	○	○	○	○	○	○	○	○	○

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H. Closing

As we wrap up, I want to provide an opportunity for you to share anything I might have missed with my questions.

H1. Do you have any other comments or information you think might be useful for me to know given what we have talked about today?

H2. These are all the questions I have for you today. It is likely that one of our colleagues will be following up with you in a few months to better understand the energy use of your new cold-climate heat pumps during the winter months, so look out for that email or call. As a thank you for your input, we'd like to send you a $75 gift card redeemable at many businesses, including Amazon, Target, and Kroger. This gift card is called a Tango card and would be sent to your email address within the next five to 10 business days. Alternatively, we can donate the $75 to your local United Way. Which would you prefer?

H3. **[IF TANGO]** Could you please provide your preferred email address to receive the Tango virtual gift card? **[REPEAT BACK EMAIL ADDRESS]**
You should expect to receive your virtual gift card within the next five to 10 business days. The gift card will be emailed directly from **Tango,** with a reference to "Thank you for your participation!" If you have any questions, or have not received your gift card by then, please contact me at **[contact information]**.

H4. [IF UNITED WAY] In whose name should we make the donation to United Way? [INCLUDE FIRST AND LAST NAMES, COMPANY NAME, OR ANONYMOUS]

And what zip code should we use to find your local United Way?

On behalf of Consumers Energy, I want to thank you for taking time to provide input, and have a great day. **[END CALL]**

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Appendix G. Consumers Energy Heat Pump Contractor Interview Guide

Introduction and Purpose

Thank you for taking the time to talk with us today. This interview is a discussion about air source cold climate heat pumps, your businesses experience with the technology, and to assess the current status of the technology in the market. The intended outcome of this discussion is to document the perception, concerns, opportunities, critical decision points, and key outcomes involved with heat pump sales and installations. Consumers Energy can use this documentation to guide future decision making around their energy efficiency programs. We are offering a $75 gift card that can be redeemed at your choice of Amazon or Meijer for those that complete the 30-45 minute interview. We have four main objectives for this interview:

- Identify current levels of awareness and perceptions of heat pump technologies.
- Identify the main barriers to installing heat pumps in Michigan and if the Michigan market is ready for widespread adoption of heat pump technology.
- Identify any marketing or outreach best practices
- Document awareness of available heat pump incentive offerings

We expect this interview to take around 30 minutes.

A. General Introduction

A1. To begin, tell me about your business.
   1. What types of customers do you typically serve? [Standard residential? Income qualified? Multi-family? Commercial? Something else?]
   2. How many projects do you typically complete in a given year?
   3. How many employees does your company have?

A2. What type of equipment do you typically install? [Furnaces? Boilers? Heat pumps? Something else?]

A3. Do you have any experience participating in utility energy efficiency programs?
   1. Which utilities? Which programs? How often?

B. Heat Pump Awareness and Perceptions

B1. Does your company sell and install heat pumps?

1. **[If installs heat pumps]** How many (if any) heat pump sales or installations have you/your company had in the past year (2020)?
2. For those installations, do residents typically retain secondary or supplemental heating equipment after the heat pump is installed? Please describe.
3. What heat pump brands do you carry and install?
   Have you received any manufacturer-specific certifications for installing those brands?
4. How does the average warranty of a CCHP compare to gas furnaces or boilers?
5. **[If does not install heat pumps]** Why don't you install heat pumps?

B2. Do you promote CCHPs to your customers?

1. Are there specific applications or customer types that make good candidates for heat pumps? (i.e. retrofit vs. new construction)
2. Which ones?
3. Why?
4. Are small businesses good candidates for heat pumps?
   Are the barriers to entry different than the residential homeowner?

B3. Generally, what are your perceptions of CCHPs?

1. Do you think that CCHPs are a viable option for widespread adoption in Michigan?
2. Do you think that CCHPs are capable of generating energy savings for end users?
3. What has led to those perceptions of the equipment?
4. What do you think is the value proposition for you to want to install heat pumps? Why would you not want to?
5. Do you know other contractors who install CCHPs? What are their perceptions of the technology?

B4. What are customer perceptions of heat pumps?

1. Do they typically have any awareness of the technology?
2. What do you think is the value proposition for customers to install a heat pump? What are their motivations? If needed: Why would they not want to?
3. Do customers ever request to have the equipment installed without being prompted by your company? How do you respond to that request?
4. Is customer interest in heat pumps increasing, decreasing, or staying about the same? What would you say is causing that change?

B5. To what extent does a negative experience with older heat pump technologies affect your opinion about heat pumps? What about customers experiences?

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C. Market Barriers and Regulatory Readiness

C1. **[If installs heat pumps]** How do procedures for a heat pump installation compare to installing other HVAC equipment in terms of:
1. Time required (actual installation time).
2. Sales process/discussions with customers.
3. Revenue/Profit Margin.
4. Equipment availability.
5. What factors can cause variations in these procedures? (e.g. conversion vs. replacing similar equipment).

C2. What would you say are the main barriers or challenges preventing more widespread heat pump adoption in Michigan? [Probe for: customer awareness, contractor perceptions, equipment availability, codes and standards, energy prices, finding good candidates, etc.]

C3. If demand for heat pumps increases, how well do you think the supply chain is prepared to meet that demand (increasing production) for cold climate heat pumps? Why?
1. Do you have any concerns about the availability or delivery timing of heat pump equipment for current or future projects? Why or why not?

D. Outreach and Marketing

D1. What can Consumers Energy do to help drive adoption of heat pumps in the market?

D2. Do you think that messaging is needed to educate people that CCHPs, or heat pumps in general, have improved?
1. **[IF YES]** What would effective messaging look like?

D3. **[If Promotes heat pumps]** When you have a good candidate for a heat pump, what information is most convincing for the customer to install a heat pump?

E. Wrap Up

E1. Before we wrap up, is there anything else you'd like us to know?

Those are all the questions we have for you. Thank you very much for taking the time to assist us with this evaluation. Your contribution is a very important part of the process. Do you mind if we follow-up with you by phone or e-mail later, if additional questions arise?

E2. To thank you for your time spent completing this survey, we would like to send you a $75 gift card to either Meijer or Amazon.com. Please choose which gift card you would like to receive.
1. $75 Meijer gift card
2. $75 Amazon.com gift card
3. Neither – I do not wish to receive a gift card

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E3. Please provide your name, address, and email to receive your gift card. This information will only be used to mail your gift card.

1. Name:_____
2. Address:_____
3. Address 2:_____
4. City:_____
5. State:_____
6. Zip:_____
7. Email**:** _____

You should receive your gift card within four weeks. If you have not received it by then, please contact (contact person at Cadmus).

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Appendix H. Consumers Energy Heat Pump Manufacturer and Distributor Interview Guide

Research Objectives and Questions

Research Objectives	Research Questions	Interview Questions
Confirm/document the supply chain for CCHPs in Michigan	Do CCHPs follow the typical supply chain structure (Manufacturer -> Distributor -> Contractor -> Customer)?	EE1, EE2
	Does the supply chain vary for small commercial, multifamily, and residential end uses?	EE1
Identify the barriers leading to extended timelines for CCHP installation	How long does it typically take from manufacturing to distribution? Distribution to contractors?	FF1
	What caused delays in the timeline in 2020? Have there been any changes to this timeline due to COVID-19? Were delays different across states? Did demand for CCHP in Michigan differ in 2020 compared to 2019?	FF1, FF2, GG2
	Are any delays expected to improve in 2021?	FF1
Identify sources of differences in CCHP installation costs across states	Are wholesale costs in Michigan comparable to other states?	FF3
	What factors drive pricing of CCHPs?	FF3
Explore the cause of low participation by trade allies	What have manufacturers and distributors done to promote heat pump technology?	GG5, GG6
	What feedback have contractors (distributors) offered to distributors (manufacturers) on perceptions of CCHP?	GG3, GG4
Identify any additional barriers and challenges delaying widespread adoption of CCHPs in Michigan, like training or education	What are the primary barriers or challenges faced by manufacturers / distributors in selling and distributing CCHP?	GG1, G1
Identify ways in which Consumers Energy can influence market adoption	How can utilities best support the adoption of CCHPs? Where is the correct place to offer an incentive (downstream, midstream, or upstream)?	II1
	Are there successful market influences in other states that could be promoted in Michigan?	HH1
	Are there technology advancements that Consumers Energy should be aware of?	HH2

A. Firmographics

First, I have just a couple questions about your organization and your role. Please note that I will keep your individual responses anonymous.

A1. What is your role in the company?

A2. What areas of the country does your company primarily serve?

A3. **[DISTRIBUTORS]** Do you serve as a distributor of heat pumps in states other than Michigan? **[PROBE FOR DETAIL]**

A4. **[MANUFACTURERS]** Do you work with particular states/regions or nationwide? **[PROBE FOR DETAIL]**

B. Supply Chain

Now I have some questions about the supply chain for the cold-climate air-source heat pump market. If possible, I would like you to focus your responses on the market in the state of Michigan.

B1. How does heat pump equipment typically get from the manufacturer to the end-use customer?
1. What are the key roles in the cold-climate heat pump market from production to installation (such as manufacturers, distributors, contractors, and electricians)?
2. Does the supply chain for cold-climate heat pumps differ from traditional air-source heat pumps? What about other types of mechanical equipment (such as furnaces, boilers, or water heaters)? If so, how?
3. Does the supply chain vary depending on the type of building where the unit will be installed (single family, multifamily, or small commercial building)?

B2. Are there particular distributors, manufacturers, or contractors you work with for cold-climate heat pumps in Michigan? **[PROBE FOR DETAIL]**

C. Timeline/Costs

Next, we would like to ask you some questions specifically surrounding production and distribution timelines and costs.

C1. On average, what would you say is the length of time it normally takes for a cold-climate heat pump to reach the distributor or contractor after an order is placed?
Does the timeframe in Michigan differ from other states?
1. **[MANUFACTURERS]** When fulfilling orders for cold-climate heat pumps, what specific manufacturing challenges, if any, have you experienced in the Michigan market? **[PROBE FOR DETAIL]**
2. How does this compare to other states?
3. Did production times change from 2019 to 2020? If so, how? What do you attribute this to?
4. What do you think production times will look like in 2021?
5. **[DISTRIBUTORS]** Have you experienced any issues with the availability of cold-climate heat pumps in Michigan? **[PROBE FOR DETAIL]**
6. How does this compare to other states?
7. Did availability change from 2019 to 2020? If so, how? What do you attribute this to?
8. What do you think availability will look like in 2021?
9. Does the timeline for cold-climate heat pumps vary by season? If so, how?

C2. **[DISTRIBUTOR]** Do you typically stock cold-climate heat pumps or do you place orders after a purchase is made?
1. How many units do you typically have on-hand? What types? Are NEEP specifications considered? What led to your decision to stock these units?
2. **[IF NOT]** What prevents you from stocking cold-climate heat pumps?

C3. Compared to other states, are cold-climate heat pumps in Michigan competitively priced?

1. Have costs been stable over time?
   [PROBE] Have costs differed from 2019 to 2020?
   [PROBE] Do you think that change is temporary?
2. **[MANUFACTURERS]** Has there been much variation in cost of parts and labor in the manufacturing of the cold-climate heat pumps?
3. **[DISTRIBUTORS]** Has there been much variation in cost based on availability of cold-climate heat pumps?

D. Demand/Adoption

I would now like to spend a few minutes talking about overall interest for cold-climate heat pumps in the market.

D1. Compared to other states, how much demand is there for cold-climate heat pumps in Michigan?

1. What do you see as the primary barriers or challenges that are restricting widespread adoption of heat pump technology in Michigan?
2. How do warranties for cold-climate heat pumps compare to warranties for other technologies (such as natural gas furnaces)?

D2. In 2020, did demand for cold-climate heat pumps in Michigan differ from 2019?

1. **[IF YES]** What do you think caused that change?
2. Do you think the change was temporary or will it be resolved?
3. Have there been any impacts on demand related to COVID-19, that you are aware of?
   [PROBE FOR DETAIL]

D3. **[MANUFACTURERS]** What feedback have you received from distributors in Michigan about heat pump technology adoption?

1. What about cold-climate heat pumps, specifically?
2. Is this different from other states?

D4. **[DISTRIBUTORS]** What feedback have you received from contractors in Michigan about heat pump technology?

1. Is this different from other states?

D5. Do you know of any promotions or trainings your organization does to increase awareness of cold-climate heat pumps among your customers in Michigan?

1. Does this differ from other states?
2. Is this different from other types of equipment?

D6. Specifically, what has your organization done to promote heat pump technology to distributors/contractors?

1. Have you offered trainings, informational pamphlets, sales/discounts, or something similar?

E. Solutions

In this final section, I'd like to shift gears a little to understand your thoughts on how Consumers Energy and other utilities could provide support to further the adoption of cold-climate heat pump technology.

E1. Is there anything you think utilities could do to improve the adoption of cold-climate heat pump technology in Michigan? **[PROBE FOR DETAIL; SOLUTIONS BEYOND INCREASING INCENTIVES]**
   1. In your opinion, where is the right place to offer an incentive to drive adoption of a newer product such as cold-climate heat pumps (downstream, midstream, or upstream)?
   2. Have you seen models for promoting the adoption of cold-climate heat pumps in other jurisdictions that Consumers Energy should consider?

E2. Are there any recent or upcoming advancements in heat pump technology that Consumers Energy should be aware of?

F. Closing

As we wrap up, I want to provide an opportunity for you to share anything I might have missed with my questions.

F1. Do you have any other comments or information you think might be useful for me to know given what we have talked about today?

F2. These are all the questions I have. As a thank you for your input, we'd like to send you a $75 gift card to Amazon, Target, or Meijer. Amazon and Target gift cards are virtual and would be sent to your email address within the next 5 to 10 business days. Meijer is offered as a physical gift card, which will be mailed to your preferred address. Alternatively, we can donate the $75 to your local United Way. Which would you prefer?
   1. Amazon
   2. Target
   3. Meijer
   4. Please donate to my local United Way

F3. **[IF G2=1 OR 2]** Could you please provide your preferred email address to receive the **[AMAZON OR TARGET]** virtual gift card?

F4. **[IF G2=3]** Let me ask the information we need to mail your gift card to the intended recipient—this could be you personally or anyone else of your choosing:
   1. First name of recipient:
   2. Last name of recipient:
   3. Could you please provide the street address we should use to send the gift card?

You should expect to receive your gift card by no later than **[DATE]**. If you have any questions, or have not received your gift card by **[DATE]**, please contact **[contact information]** and reference the Consumers Energy heat pump interview.

F5. **[IF G2=4]** In whose name should we make the donation to United Way? **[INCLUDE FIRST AND LAST NAMES OR COMPANY NAME]**

On behalf of Consumers Energy, I want to thank you for taking time to provide input, and have a great day. **[TERMINATE]**

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Full length article

Heating with justice: Barriers and solutions to a just energy transition in cold climates

Claire McKenna [a], Carina Gronlund [b], Parth Vaishnav [a,*]

[a] School for Environment and Sustainability, University of Michigan, Ann Arbor, MI, United States
[b] Institute for Social Research and School of Public Health, University of Michigan, Ann Arbor, MI, United States

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ABSTRACT

Residential heat pumps could reduce greenhouse gas emissions, but increase energy burdens, the proportion of income households spend on utility bills. We analyze utility bills, thermostat settings and energy burdens for a sample of 51 households in Michigan, half below median income. We recruit a contractor to conduct energy assessments of these households and provide them with energy retrofit recommendations, including estimated costs and savings. We find that low-income households choose similar temperature setpoints to higher-income households, but live in less efficient homes. Below-median income households, which today experience a median energy burden of 6 %, would see it rise to 10 % if they shifted to electric heat pumps from natural gas. Weatherization could offset this increase, bringing burdens down to pre-electrification levels. However, median payback is 24 years, making retrofits infeasible for the poorest. Our results are indicative of an energy poverty trap that could hinder an equitable energy transition.

Spotlights

- Converting fossil-fuel based home heating to electric could reduce pollution but make bills less affordable.
- Switching to electric heating results in low-to-moderate income households paying a high percentage of income on energy.
- Retrofitting homes could make electric heating more affordable but it is expensive and therefore infeasible.
- High-cost energy efficiency home retrofits could hinder an equitable energy transition.
- Future work will investigate homeowner attitudes regarding electrifying their homes and barriers to equitable transition.

1. Introduction

In recent years, US state policy (Climate Leadership and Community Protection Act 2020; An Act Creating 2022; Climate Commitment Act 2022)) has signaled a commitment to reducing greenhouse gas emissions by transitioning home heating from fossil fuels to electricity. U.S. federal policy has sought to use subsidies to lower the upfront cost of heat pump adoption (Inflation Reduction Act, H.R. 5376). Electrification has been projected to increase annual utility cost for households in more than half of US states (Vaishnav and Fatimah 2020; Deetjen et al., 2021), with the worst effects in cold climates (Walker et al., 2022). Rising energy costs could have a large impact on households across the income spectrum.

1.1. Literature review

Higher utility bills could increase the economic and physical hardships in households already experiencing energy insecurity. A quarter of American households spend a high proportion (>6 %) of their income on utilities, defined as energy burden (Drehobl et al., 2020). High energy burden is associated with poor health outcomes (Reames, 2016), and households with certain vulnerabilities, such as older adults, choose uncomfortable and sometimes unsafe indoor temperatures to reduce bills (Cong et al., 2022). Lewis et al. center deteriorated housing conditions concentrated in racially segregated neighborhoods in their discussion of energy insecurity, which encompasses financial, behavioral and physical hardships related to home energy use (Lewis et al., 2020).

Households with lower energy burdens are not entirely precluded from the effects of higher ongoing costs associated with heating electrification because these costs are associated with building

* Corresponding author at: 440 Church St, 2575 Dana Building, Ann Arbor, MI 48109.
E-mail address: parthtv@umich.edu (P. Vaishnav).

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characteristics that are prevalent across the US housing stock. Old homes heated by natural gas have been shown to result in the greatest operational costs for heating with a heat pump (Vaishnav and Fatimah, 2020). 64.5 million American homes use natural gas for heating and 57 % of them were built before energy codes were implemented in the US (U.S. Energy Information Administration, 2023). Knowledge of household demographics, housing characteristics, and occupant behavior are essential to understanding the barriers to equitable access to heat pumps and a just distribution of harms and benefits associated with policy that facilitates the clean heating transition.

Current research about residential energy equity includes only one or two of these critical components. Studies that quantify the link between racial disparities in energy use and housing quality (Goldstein et al., 2022; Bednar et al., 2017), and demonstrate that households of color are more likely to have trouble paying their bills (Graff et al., 2021) do not take into account behavior. Studies that evaluate specific retrofit opportunities and quantify their the savings potential by employing national scale modeling do not address behavior impacts associated with those changes (Bradshaw et al., 2014; Wilson et al., 2019). Likewise, studies that examine the economics of heat pump adoption for low income households, whether in observed system performance (Ceglia et al., 2022; Flower et al., 2020; Calver et al., 2022; Pastore et al., 2022; Liu et al., 2018) or simulations (Donaldson and Lord, 2018; Barrella et al., 2020; Liu et al., 2020; Abbasi et al., 2022; Savage et al., 2022) focus on housing and heat pump technology characteristics without an empirical analysis of occupant behavior and preferences for heating and cooling.

Several recent studies examining the energy savings potential of residential retrofits in the European context point to the importance of incorporating household behavior in home energy assessments (Palma et al., 2022; Barrella et al., 2020; Koasidis et al., 2022; Domínguez-Amarillo et al., 2020). The literature addressing the effect of energy consumption behavior on the cost effectiveness of energy retrofits in the US commonly uses economics theory and analysis. Gillingham and Palmer (2014) conducted a literature review of explanations for limited uptake of home energy efficiency including that flawed decision making could reduce the utility of energy efficiency to customers. Three studies followed that examined this question using home energy efficiency project data from the US Department of Energy Weatherization Assistance Program (WAP). Zivin and Novan (2016) measure the treatment effect of retrofits on energy use of 275 households and provide evidence that electricity savings due to WAP are overstated. Allcott and Greenstone (2017) and Fowlie, Greenstone and Wolfram (2018) use large samples of primary empirical data to estimate the benefits of providing energy efficiency services to low-income homes. Though these studies consider behavioral explanations for under performance of projects compared to engineering estimates, they do not provide detail on the housing conditions prior to intervention or the specific work performed. See Table C.7 for a comparison of this paper's contributions to those of the literature.

Other large empirical studies that address impacts of high utility costs on vulnerable households similarly do not provide data on the housing characteristics of the populations they examine (Cong et al., 2022; White and Sintov, 2020), and therefore do not address why these impacts occur. Although Booth and Choudhary (2013) estimate the rebound effect, identify specific upgrade parameters, and focus on public housing in their assessment of uncertainty in retrofit performance (Booth and Choudhary, 2013), they do not address the transition in heating technology. Recent research has signaled the potential for heat pumps to contribute to residential sector clean heating transition where countries push for climate action and fossil fuels remain the predominant fuel source (Fitó et al., 2021; Thomaßen et al., 2021; Besagni et al., 2020).

1.2. Research gaps

There remains a gap in quantifying the impacts of residential heating electrification across income and in examining interventions specific to both housing quality and energy consumption behavior. Previous studies that have taken this form to assess the reasons for disproportionate impacts of energy cost across income (Cong et al., 2022; Jones et al., 2023) only examine it in the context of air conditioning, not heating. To bridge this gap, this study aims to disentangle the sources of inequality embedded in the economic impact of heat pump adoption and assess fixes available for real homes. The present work has three main contributions. First, we provide evidence that energy burden impacts across income are associated with housing quality rather than behavior. Second, we compare economic impact of heating fuel transition across income groups. Third, we test the idea that there is a way to mitigate the utility cost premium for heat pumps.

We conduct a year-long field study of 51 homes in Southeast Michigan, during which we perform a comprehensive energy audit of each home to observe envelope and HVAC system characteristics, including thermal imaging to identify temperature gradients indicative of air leakage and poor insulation, and blower door testing to measure air infiltration rate, as well an examination of the on-label efficiency of all appliances. We gather metered daily gas and hourly electric consumption data over the study period and collect energy assessment contractor recommendations for energy efficiency retrofits for each home. Our approach to examining residential energy equity is novel because we compare results derived from observed data with simulations derived from statistical sampling of large public data sources (Wilson et al., 2022).

Following this introduction, we present the methods, then results, then we will discuss the findings and conclude. We present our findings in five parts. First, we examine the existing conditions of the homes in the study and compare them across income, including key housing characteristics and indoor temperature preferences. Next, we quantify the impact that replacing natural gas heating with heat pumps would have on household energy burden. We then examine the sensitivity of time of use utility rates on the annual energy bill impact of fuel switching. Following that, we quantify the cost savings potential of energy efficiency envelope improvements and compare it to the utility bill impact. Finally, we explore energy efficiency retrofit recommendations provided to participants during home energy audits and assess the feasibility of these improvements to mitigate the ongoing cost impact of heating electrification on the sample.

2. Methods

This study uses observed household energy use and indoor temperature data along with a reduced complexity air source heat pump coefficient-of-performance model to determine energy cost and energy burden impacts of switching to a heat pump. We gather energy retrofit recommendations and estimate upfront costs, energy cost savings, and payback from a contractor who conducted a detailed energy audit for each home. We then quantify annual utility bill impacts for fuel switching and energy retrofits using a building energy model that provides detailed sub-hourly simulations a large sample of archetypal homes that are representative of the study region and compare them to our findings for the sample.[1]

[1] See Data Availability statement for more information on how to access data that can be made available under the Institutional Review Board guidelines for human subjects research. See Supplemental Methods for additional detail on justification for model and calculation assumptions and Supplemental Figure, Tables, and Notes for detail on participant demographics, supporting findings, and literature review.

2.1. Participants

As described below, we recruited 51 participants from Wayne and Washtenaw Counties in Michigan, which encompass the Detroit and Ann Arbor metro areas. We chose Southeast Michigan for three factors that make this study applicable to global contexts including the Midwest, New England, and the Mountain West regions of the US; Northern Europe; and the United Kingdom: cold climate, predominance of natural gas for heating, and older homes.

Participant recruitment included three steps. First, we circulated an expression of interest form through local media, university email lists, and local environmental and energy justice community groups that drew more than 1300 responses. Second, we asked these respondents to complete a demographic survey to assess the presence of key factors associated with energy insecurity: race, income, disability, children, and health vulnerability (Drehobl et al., 2020; Reames, 2016; Hernández, 2016). We received 883 responses to the demographic questionnaire. Third, we identified a random sample stratified using survey answers to ensure representation across four key, binary, classes of vulnerability: has a disability, has at least one child at home, foregoes paying energy bills at least once a year, controls heating or cooling for a vulnerable occupant. These four classes correspond to 16 combinations, and we had respondents who corresponded to only 10 of them.

Next, we identified 418 survey respondents living in single family homes. We then classified the respondents into 10 categories representing the unique combinations of the key categories listed above. We calculated how many households we would need to invite to have an equal number across these categories and randomly selected that many households from each group. Where the quantity of respondents in a category was not great enough to provide an equal weighting, we invited all the respondents in the category. Ultimately, we compiled a list of 90 potential participants to whom we sent invites to join the study. Our recruitment rate was 58 %. Demographic questions and descriptive statistics can be found in Note D.3 and Table C.1. 90 respondents were asked to join the study. Demographic questions and descriptive statistics can be found in Note D.3 and Table C.1.

All households in the sample live in single family homes. 50 of the 51 households are homeowners; 1 is a renter. All homes use natural gas for heating with the exception of 1, which uses propane. The sample includes a diversity of housing vintage (i.e. common building practices) from every decade since 1900: 9 homes were built before 1940, 17 homes were built between 1940 and 1960, 12 built between 1961 and 1980, 6 built between 1981 and 2000, and 7 built after 2000.

The study sample is representative of the populations of the two counties of Southeast Michigan along two key characteristics. (1) Income: the median income (in 2022 dollars) is $57,223 for Wayne County and $84,245 for Washtenaw County (U.S. Census, 2024). The sample includes 11 households reported earning annual income <$25k, 18 earning $25–50k, 9 earning $50–75k and 13 earning >$75k. (2) Race: 54.6 % white, 38.3 % Black, and 7.1 % all other races in Wayne County and 73.9 % white, 12.4 % Black, and 13.7 % all other races in Washtenaw County (U.S. Census, 2024). The sample includes 29 % Black (n = 15), 45 % white (n = 23) and 25 % (n = 13) all other races, including one participant who prefers not to answer.

Households were provided $100 compensation.

2.2. Data collection

We obtained one year of utility data for each household, including hourly metered electricity use and daily metered gas use where available. We conducted one visit to each home, during which we installed a smart thermostat where the heating and cooling system could accommodate the product (Ecobee 3 lite) (n = 40). For homes that could not receive the smart thermostat, we set up a wi-fi connected thermo-hygrometer (Govee H5179). Both devices record data at 15-minute intervals. An accredited energy audit contractor accompanied the research team and performed an ASHRAE Level 2 energy audit at each home.

Participants provided income ranges, so we estimate energy burden based on the arithmetic midpoint, i.e., if a participant reports their income to $25k-50k, the energy cost burden for that household was calculated at the proportion of their actual annual utility bills to $37.5k. We did not apply an equivalence scale to energy expenditure and income because we observed occupancy in some homes to which the published equivalence scales would not readily apply, for example, households with adult children that may live at home for periods of time varying duration and frequency throughout the year. See Supplementary Methods for detail on energy burden calculation.

2.3. Housing quality analysis

To assess participant behavior, we estimate indoor temperature setpoints in two ways. First, we estimate the heating inflection temperature (HIT) (ambient temperature at which a household begins heating) for each home using a splitwise regression of metered daily gas use on hourly average ambient air temperature (obtained from NOAA Local Climatological Data (LCD) for the data collection period). Second, we evaluate the observed heating and cooling setpoints and the observed indoor temperature for the heating and cooling season for a subgroup that received a smart thermostat (n = 40). We calculate cooling and heating season means for setpoint temperature as well as the standard deviation for setpoint and indoor temperature using this interval data.

2.4. Heat pump cost analysis

Our energy cost analysis for switching to all-electric heat pumps from natural gas-based heating consists of three steps. See Appendix A for detailed calculation methodology and model specifications.

- *Heat load calculation. Existing furnace gas use.* To determine heating natural gas use, we first estimated the inflection point for temperature dependent gas use using a split-wise regression of heating degree hours (a measure of the intensity of the space heating needed for a given time and place) on hourly total gas use. We assumed that the slope of the piecewise linear function (found with the segmented() function in R) past this inflection point indicates heating related natural gas usage. From that, we derived the slope which is the natural gas usage per heating degree hour. We then obtained the amount of gas used during each hourly time step for heating by multiplying the slope by the difference between the outside ambient air temperature departure from the indoor heating setpoint gathered during the initial data collection period when the energy audit took place.

Deriving heat load. We multiplied the hourly gas use by the furnace efficiency to obtain the hourly heating load for each house. We obtained the hourly ambient temperatures for each home during the window of time the utility data was provided by the utility (e.g. 11/10/2020–11/11/2021) using the NOAA Local Climatological Data (LCD) Tool for the closest available weather station.

- *Heat pump model.* We calculated the heat pump hourly temperature-dependent coefficient of performance (COP) using the following equation:

$$COP_i' \times (1 - l(t_i)) = COP_i \; Tmin < t, \; i \in 8760$$

$$COP_i = 1 \; t < Tmin$$

Where:

i indexes hour;

COP' = manufacturer reported coefficient of performance using the efficiency curve (ambient temperature vs. COP) of the Mitsubishi M2i cold climate ASHP for heating;

$l()$ = defrost efficiency loss for give temperature, t (%);

t = **hourly dry bulb temperature (F)** using the NOAA LCD weather data for the same period for which had metered natural gas data for each home;

COP = observable coefficient of performance;

$T_{min} = 10°F$ reflecting ambient temperature change over point from heat pump to backup heating mode via electric resistance coil;

$<T_{min}$ **COP** $= 1$ reflecting the heating efficiency of an electric resistance coil used for backup to ensure that heating setpoints are met below the change over point.

We calculated percentage improvement in cooling energy by dividing the Mitsubishi H2i SEER rating (SEER = 17) by the on-label AC efficiency obtained from the energy audits for each home. This kind of high efficiency equipment comes with a first cost premium over a standard furnace replacement. It is therefore expensive for low- and middle-income households and is likely not affordable without a subsidy that covers most of the cost. Selecting this equipment is a conservative assumption. We then applied this factor to an average cooling energy percentage obtained from the Resstock End Use Savings Shapes (Wilson et al., 2022) to determine the annual energy cost savings.

- *Energy cost calculation.* We calculated the energy cost using a model we developed in R that takes in the hourly estimated electric and daily gas usage for the hypothetical heat pump scenario and calculates the total bill costs in the manner calculated by the utilities as published in the electricity and gas rate schedules ("DTE Electric Company Rate Book for Electric Service", 2023). For example, to calculate the annual electricity cost for each home, we apply the flat rate service charge per month, capacity and non-capacity energy charges assessed per kWh, as well as surcharges and credits. We completed this process for three electricity rates and two gas rates to test the sensitivity of our results to rates available to participants. See Figure B.7 for rate summary and Note D.5 for rate description. We do not include tariff changes from one year to the next because future rate changes are unpredictable and beyond the scope of the analysis. Changes in consumer behavior associated with changes in utility tariffs are also beyond the scope of the paper and therefore not included in the analysis. Additionally, incorporating behavior changes would not have a meaningful impact on the results because short term elasticities are low for electricity and natural gas in the US (U.S. Energy Information Administration, 2021).

2.5. Resstock

We analyzed the potential for energy efficiency to mitigate cost increase due to heat pumps by calculating energy costs derived from four modeled retrofit scenarios included in the NREL Resstock End Use Savings Shapes database (Wilson et al., 2021). We selected hourly load profiles available for a baseline case and three "upgrades" including full electrification with or without deep efficiency retrofits, and deep efficiency retrofits with no change to the HVAC systems. To these scenarios, we applied the utility rates for all sensitivity cases as described above. We then calculated the mean incremental annual energy costchange resulting from a series of these changes across a random sample of 400 homes in the database representative of Detroit, MI.

2.6. Retrofit cost analysis

The contractor recommended energy efficiency measures and provided first cost and utility cost savings estimates for the recommended work. We used the "Return on Investment and Rebate Report" prepared for each study participant to summarize the recommended energy efficiency upgrades to code the unique efficiency measures recommended across the sample.

The parameters we used for estimating the feasibility of retrofitting were economic payback in years for the package of all recommended retrofits (calculated as the first cost divided by the annual energy cost savings), the first cost of the total package, and the modeled utility cost savings for the individual measures. The values for these parameters were obtained from the retrofit reports provided to participants by the energy audit contractor. The payback parameter described above follows the US Department of Energy Methodology and Procedures for Life Cycle Cost Analysis (Code of Federal Regulations. 10 CFR Part 436 Subpart A). No discount rates are used, making this the best-case estimate of the payback period. Given our findings, the decision to use an undiscounted payback period is conservative: if a discount rate were applied, the payback period would be even longer, strengthening our argument that the retrofits are not attractive on the basis of utility bill savings. Additionally, we show the rates that participants were provided as part of their energy audit, so payback periods not inclusive of a discount rate are more representative of the data participants have to inform their decision making.

3. Results

We find that electrifying homes with heat pumps increases annual energy cost by 58 % on average (range: 11–182 %) when compared to natural gas heating and considering a flat electricity rate, higher than previous estimates. This change exacerbates already high energy burdens for low-and-moderate income (LMI) households. While we find energy retrofit opportunities that saved energy cost for every home, they came with substantial obstacles that could limit uptake. There is an average payback period of 24 years and homeowners can be left without sufficient information to act, even after a visit from a home energy auditor. Willand et al. (2020) identified this situation as the retrofit trap in their 2020 analysis of Australian home retrofit programs. It can be understood as a form of poverty trap, defined Azaiadis and Stachurski as a reinforcing mechanism that acts as barrier to adoption of techniques that can alleviate poverty (Azariadis and Stachurski, 2005). The clean energy transition is hindered by an energy poverty trap because the extensive retrofits needed to make electrification affordable are themselves too expensive for low-income households.

3.1. Housing quality vs. set-point choices

We estimate energy burden for each household by calculating the proportion of their annual combined electricity and gas cost (sourced from utility bills) to the self-reported income range. The 5 highest energy burdened households have rates ranging from 10 to 40 %. 32 % of homes have energy burdens greater than 6 %, which is considered a high energy burden and twice the national average (Drehobl et al., 2020). All these households have below-median incomes. 37 % are between 3 and 6 %. 31 % of homes have an energy burden below 3 %; all but one of these homes have incomes that exceed the local median (see Figure B.1). See Table C.1 for descriptive statistics on utility costs and energy burden. Table C.6 provides a list of self-identified household income ranges and a comparison to the area median income (AMI) by zip code.

Not all homes in our sample were of the same age and quality. The homes were on average 60 years old and built in an era during which Michigan did not have energy efficient building codes.[2] These codes were adopted for the first time 1977 when ASHRAE 90–1975 was adopted state-wide ("US Dept. of Energy Building Energy Codes Program", 2024). 13 homes (5 in the <$25k income group and 8 in the $25–50k group) had been retrofit by Habitat for Humanity of the Huron Valley (Habitat) resulting in higher quality for their age. Improvements had been made 1–10 years prior to participating in this study.

Homes retrofit by Habitat perform consistently better than market rate homes in the sample [Fig. 1]. To understand the impact of these

[2] They were adopted for the first time 1977 when ASHRAE 90-1975 was adopted state-wide. (US Dept. of Energy Building Energy Codes Program, www.energycodes.gov/status/states/michigan).

retrofits on overall home energy efficiency, we examine the difference between trends of annual energy use per unit floor area (or energy use intensity) and per occupant across income in market rate homes compared to the Habitat homes. When treating self-reported income categories as an ordered set (<$25k, $25–50k, $50–75k, and >$75k) in a least squares regression of energy use intensity (EUI) per occupant on income, we find a significant downward trend (p-value=0.048) for market-rate homes, indicating that low-income households either live in less energy efficient homes or there is significantly different behavior across income levels.

The latter explanation would suggest, for example, that lower-income households start to use heating at higher ambient temperatures and cooling at lower ambient temperatures. Cong et al. provide evidence to the contrary. They find that lower-income families wait for ambient temperatures to rise higher before turning on air conditioning compared to those with higher incomes (Cong et al., 2022). This would imply that low-income families use less energy, a seeming contradiction of our results. However, we believe that there is no contradiction, since the Cong et al. results are not directly comparable to ours for two reasons. First, we report energy use per square foot per occupant, which Cong et al. do not observe. Second, Cong et al. have studied air conditioning, whereas energy use in our sample is dominated by heating. Huang et al. (2023) do find evidence that low-income households start to heat earlier in the season and heat for more months of the year than higher-income households. However, these results are also not comparable to ours since there is no normalization by area or occupancy. We estimate the heating inflection temperature (HIT), or the outdoor temperature at which each household turns on the heat because in every case heating constitutes the highest proportional energy expenditure (>60 %). To estimate the HIT, we calculate a linear splitwise regression of metered daily gas use on ambient air temperature. We find no significant trend in HIT across income (see Figure B.2). Combined, our findings and those of Huang et al. (2023) suggest that behavior-driven energy use patterns are unlikely to explain the higher energy use of low-income homes.

Observed heating and cooling setpoints—read from participants' smart thermostats—likewise reveal that lower income households do not on average choose higher setpoints in winter or lower setpoints in summer [Fig. 2a]. We do observe greater variance in the set points that households in the lowest income group (<$25k) choose [Fig. 2b], as well as in the indoor temperatures that they experience [Fig. 2c]. This suggests that, even though they have higher energy use intensity, these households are actively trying to manage their energy use and comfort by manipulating their set points. This provides evidence that the higher EUI is in fact due to poorer building envelopes and not because lower-income households are choosing consistently different setpoint temperatures.

We look at housing characteristics to explore whether the homes occupied by low-income households are in fact less efficient. Blower door testing conducted at each home provides an empirical measure of efficiency by measuring air infiltration. Low infiltration signifies high efficiency. We find that the homes retrofit by Habitat have better performance than market-rate homes in the sample. The median measured air infiltration rate of Habitat homes is almost half that of their counterparts (4.2 ACH 50 and 7.7 ACH 50, respectively) with less variability (range: 2.9–5.9; IQR = 3.4–5.3 and range: 3.2–17.5; IQR = 5.8–10.9, respectively). Applying the same regression method described above, after excluding Habitat homes, we find a significant downward trend (p-value = 0.023) for market-rate homes, indicating that the lower-income homes are indeed less efficient (Figure B.3).

3.2. Energy burden

For the 51 houses in our sample, we calculate the electricity loads that would result from replacing natural gas furnaces with air source heat pumps for space heating (see Supplementary Methodology for more detail on reduced complexity model and load derivation) and apply the most prevalent gas and electric utility rates across the sample to determine the energy cost change associated with this replacement. We calculate change in annual energy bills and energy cost burden which refers the difference in energy expenditures and percentage of income spent on utilities, respectively, between the baseline scenario and the heat pump scenario. 41/51 households were on a standard time-invariant rate, which will be discontinued as of May 2023. 10 had elected different rate structures, which include time-of-use rates, interruptible cooling rates, and specialty rates designed for low-income households. We find that switching to a heat pump would increase annual utility bills for every household in the sample, and that the cost goes up by $1154 on average (see Table C.3).

Our results show variability in median cost change across income and a disproportionate concentration of high energy burden increase below median income (<$25k and $25–50k). The median cost increase for below median income households is $801 ($n = 28$), constituting a 37 % utility spending increase on average. There is a 49 % utility spending increase for above median income households on average ($n = 22$) [Fig. 3a-1]. Even though the median cost increase is nominally lower for

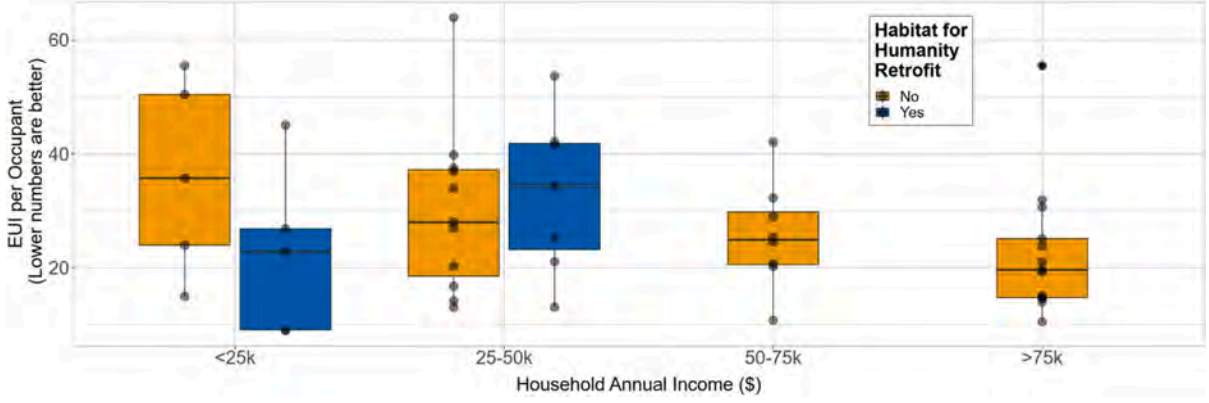

Fig. 1. Energy use intensity per occupancy by income group. Annual energy use per floor area divided by the number of occupants is shown here. The x-axis represents four income categories to which participants were assigned given the income range they provided. Each box plot shows the median (middle line), first and third quantiles (lower and upper box bounds), and minima and maxima (whiskers). The blue boxes represent homes that have been retrofit by habitat for humanity, which perform better than market rate homes in the sample (represented by oranges boxes) for homes earning less than $25k. Each dot represents one household. Using a non-linear least squares regression, we find a significant downward trend (p-value = 0.048) among market rate homes, indicating that those with lower incomes live in less efficient homes.

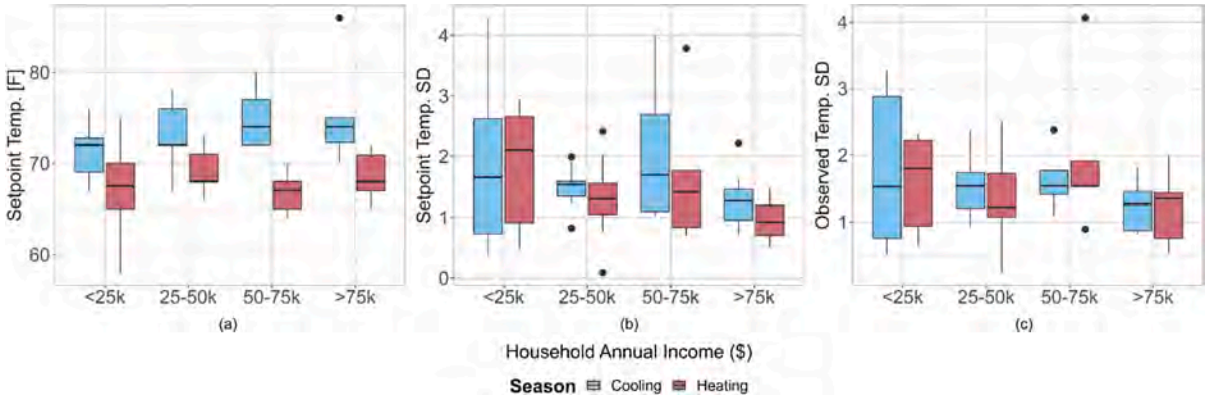

Fig. 2. a-b-c: Thermostat setpoint and observed indoor temperature by income. Observed heating and cooling setpoints (a), setpoint standard deviation (b), and indoor temperature standard deviation (c) on smart thermostats for each home.

below median income households, their energy burden increase is 4 times higher on average than those at or above median income [Fig. 3b-1]. Additionally, all households earning median income ($50–75k) and above (>$75k) - which currently have a median energy burden of 2.6 % – would experience a median change in energy burden of greater than 1 percentage point, indicating that energy burden could become a concern for households which are currently energy secure.

3.3. Time of use electricity rates

We examine the impact of two time-of-use rates available to all customers in the study region on the annual increased utility costs and energy burdens of the sample for a hypothetical conversion to heat humps. Switching to the standard time-of-use rate (DTE no. D1.11) ("DTE Electric Company Rate Book for Electric Service", 2023) reduces the mean cost increase for the sample by $120 per year from $1154 to $1034 (see Fig 3a-2) relative to a flat rate. Under this rate, the median

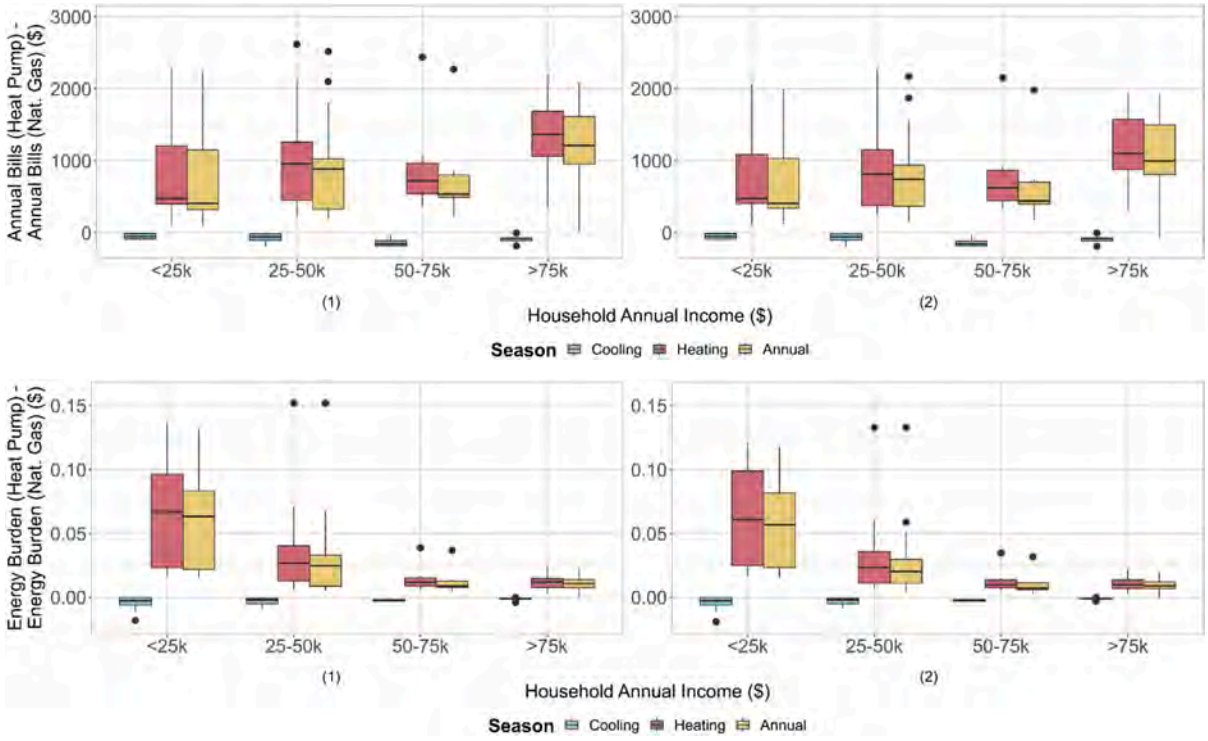

Fig. 3. a: Change in annual energy bills for switching to a heat pump from natural gas heating by income. The x-axis represents four income categories to which participants were assigned given the income range they provided. Dot represents outliers. Each box plot shows the median cost increase (middle line), first and third quantiles (lower and upper box bounds), and minima and maxima of change in utility cost change for (1) standard flat electricity rate and 2022 natural gas cost; (2) standard time-of-use electricity rate and 2022 natural gas cost.
b: Change in energy burden for switching to a heat pump from natural gas heating by income. The x-axis represents four income categories to which participants were assigned given the income range they provided. Dot represents outliers. Each box plot shows the median energy burden increase (middle line), first and third quantiles (lower and upper box bounds), and minima and maxima of change in energy burden change for (1) standard flat electricity rate and 2022 natural gas cost; (2) standard time-of-use electricity rate and 2022 natural gas cost.

utility cost change due to heat pumps is lower for every income category. The effect of this lower cost change is minimal for energy burden, reducing the rate by less than 1 percentage point for each category [Fig 3b-2].

By comparison, relative to a flat rate, the optional time-of-use rate (DTE no. D1.2) (DTE Electric Company Rate Book for Electric Service, 2023) would worsen the increase in annual utility cost for switching to a heat pump for all income groups. Switching to D1.2 increases the mean cost increase for the sample by $623 per year to $1777 (see Figure B.4). This rate nearly doubles the median energy burden changes for all income groups earning less than $75k (see Figure B.5). The D1.2 rate had a higher cost per kWh at peak times and a peak window two hours longer than the D1.11 rate. These rates impacted each household differently given the variety of occupants, schedules, housing vintage across the sample. For instance, those who saw the greatest cost increase with the standard time-of-use rate had the oldest, least efficient AC units in the sample and used their cooling systems during the peak window, whereas, in reality, the switch to a heat pump would include a new, more efficient AC.

While the gas commodity prices have risen dramatically from 2021 to 2023, the delivered price of natural gas for residential customers has in fact been modest and does not affect the results. See Figures B.4 and B.5 for a comparison of annual bill and energy burden changes with 2021 and 2023 gas rates. See Table C.2 for a detailed comparison of all of the electricity and gas rates available to DTE customers as of 2023 and their impact on baseline household energy use.

3.4. Energy retrofit model

Energy retrofits are a possible strategy to mitigate this increase in bills. Since we do not have empirical estimates of cost savings potential of envelope improvements to mitigate the cost increase of heating electrification, we first model the corresponding energy uses using the NREL ResStock End Use Savings Shapes (Wilson et al., 2022). We randomly sample 400 Michigan homes heated with natural gas from the database and examine four scenarios: baseline envelope with natural gas heating, envelope upgrade, heat pump upgrade, and combined heat pump and envelope upgrade. To then convert the energy uses to cost, we apply the electricity and gas rates experienced by 41/51 of our study participants to the hourly electricity and gas loads to estimate the relative cost impact of retrofits for the natural gas scenario and the heat pump scenario.

We find that transitioning to a heat pump without energy retrofits results in a mean utility cost increase of 26 % over the baseline. Adding a comprehensive envelope retrofit improvement mitigates this cost premium and drives utility costs back to what they were with natural gas heating with the existing envelope. Energy efficiency retrofits alone reduce bills by 11 % compared to the baseline condition [Fig. 4].

See Note D.1 for a comparison of the modeled results to the estimates calculated using observed data from the field study, including a breakdown of model findings by house vintage (Figure B.6).

3.5. Contractor retrofit recommendations

Our results suggest that, with energy retrofits, most homes would not experience an increase in utility bills relative to the status quo if they shifted to heat pumps. Based on REM/Rate (REM/Rate 2024), commonly used software, our contractor recommended a different combination of ten individual retrofit measures for the homes in our sample and these upgrades are expensive with long payback periods. The most commonly recommended measure is air sealing, an intervention in which joints are sealed to reduce air infiltration. We classify building envelope upgrades as simple if they can be completed by one contractor (e.g., spraying cellulose in the attic) and complex otherwise (e.g., foam injection into drywall). Upgrades to the HVAC system are in a separate category, as are upgrades to other appliances (e.g., fridges) (see Figure B.8). The median retrofit package costs are about 10 % of household income. ($3250 for <$25k; $4700 for $24–50k; $10,300 for $50–75k; $7000 for >$75k) (see Figure B.9). 14 households in the lowest three income groups are faced with total package costs of more than 20 % of their income. The median payback period across the sample is 24 years, with a large variance across the income groups (see Figure B.10).

Upfront cost and simple payback estimates for retrofits match previous studies. Fowlie et al. (2018) use empirical estimates for actual energy savings across the Michigan WAP and find internal rates of return (IRR) at −10.6 % (10 year), −2.3 % (16 year), and 0.21 % (20 year). We find even lower IRR for the recommended retrofits by the energy

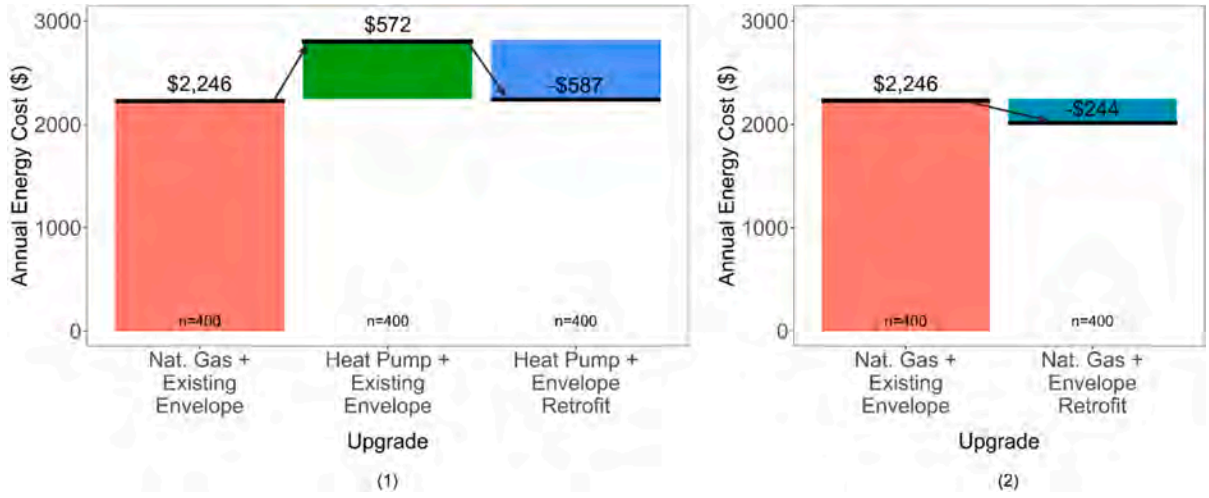

Fig. 4. Modeled mean annual energy cost impact of heating electrification and envelope improvements. (1) The baseline case (natural gas heating with existing envelope) represented in red is compared to two upgrades: heat pump with efficient envelope retrofit (green) and heat pump without envelope improvements (blue). (2) The baseline case (natural gas heating with existing envelope) represented in red is compared natural gas heating with efficient envelope retrofit (teal). Means represent 400 randomly sampled homes from the ResStock end use load profile database that use natural gas in Michigan. Using a Kruskall–Wallace test, we find a significant difference between the medians of the utility costs in each upgrade category (p-value < 0.01). We test the null hypothesis that the medians were the same using a pairwise with the Bonferroni adjustment and similarly find significant differences for each comparison.

assessment contractor: −16.1 % (10 year), −5.3 % (16 year), and 2.2 % (20 year). Less et al. (Less et al., 2021) estimate an archetypical retrofit package for a single family house that includes the most common retrofit recommendations in our sample (attic floor insulation, air sealing, foundation floor insulation) based on actual US construction costs at $7825 (see Note D.2 for measure cost calculation). The mean upgrade package cost estimated by the energy audit contractor in our sample is $7628 and the median is $5900 (see Figure B.9). Since the package described by Less et al. excludes system or appliance measures, we surmise that it is likely our contractor's costs are underestimates. Realized project costs could be higher, and payback periods longer.

There is no clear pattern about what measures are most cost-effective. The results show a large range of annual cost savings available from the recommended retrofit packages, with annual utility bill savings ranging from $26 to $730 [Fig. 5a]. We find that air sealing, which was recommended to all households, provides a payback range of 3.7 to 144 years [Fig. 5b] and attic insulation alone provides a payback range of 20 to 259 years (see Note D.2 for measure cost calculation). The high-end estimates that reflect payback periods much higher than seen in the literature are due a sample-specific scenario in which 25 % of the homes in the study received energy efficiency retrofits before the study period. For these homes, which were already high performing, the contractor recommended improvements to existing conditions (such as attic insulation and air sealing), which resulted in marginal energy savings and therefore long payback periods.

4. Discussion

We explored the drivers of energy inefficiency, explored the economic impact of replacing natural gas furnaces with heat pumps by income, assessed a range of energy retrofit measures that could support utility cost reduction in the 51 Michigan households we studied, and compared this impact to estimates from a national model. Heat pumps raise energy cost and energy burden disproportionately for low-income households. The median utility cost increase for switching to a heat pump is lowest for low-income households because they use the least amount of energy. This finding is suggestive of an efficiency paradox (Goldstein et al., 2022) where the lowest consuming households live in the least efficient homes, indicating that they are likely not using enough energy to meet their health, safety, and comfort needs. Yet, the increase in energy burden is disproportionately higher for low-income groups because even though their cost increase is nominally the smallest, it is a greater percentage of their annual income. Our results show that adopting heat pumps results in a fmedian energy burden increase of 75 % and 54 % for both income groups earning below AMI (<$25k and $25–50k, respectively). Given that households below median income have a 6 % median energy burden on their existing natural gas heating systems, such increases would severely worsen existing energy insecurity, for instance increasing risk of poor health (Reames et al., 2021) and coping behaviors like trading off paying utility for paying for rent or food (Hernández, 2016), or the underconsumption of energy in household who struggle to pay their bills (Meyer et al., 2018; Barrella et al., 2022; Faiella and Lavecchia, 2021; Antepara et al., 2020).

Policymakers should act to help lower the operating costs of heat pumps compared to natural gas for low-income households in cold climates. This can be done in three ways. First, government-sponsored initiatives to advance more efficient heat pump technology like the U.S. Department of Energy Residential Cold Climate Heat Pump Challenge are essential to improve energy bill affordability of fuel switching. More efficient heat pumps reduce the utility cost premium over natural gas furnaces.

Second, state regulators should exercise a more robust scrutiny of utility company returns and create more opportunities to improve customer outcomes in the rate making process. For example, the Michigan Public Service Commission recently ruled in a disputed rate case in the study region that resulted in allocations for energy retrofits in historically underserved areas due to intervening efforts from customer groups not typically represented in rate making like community

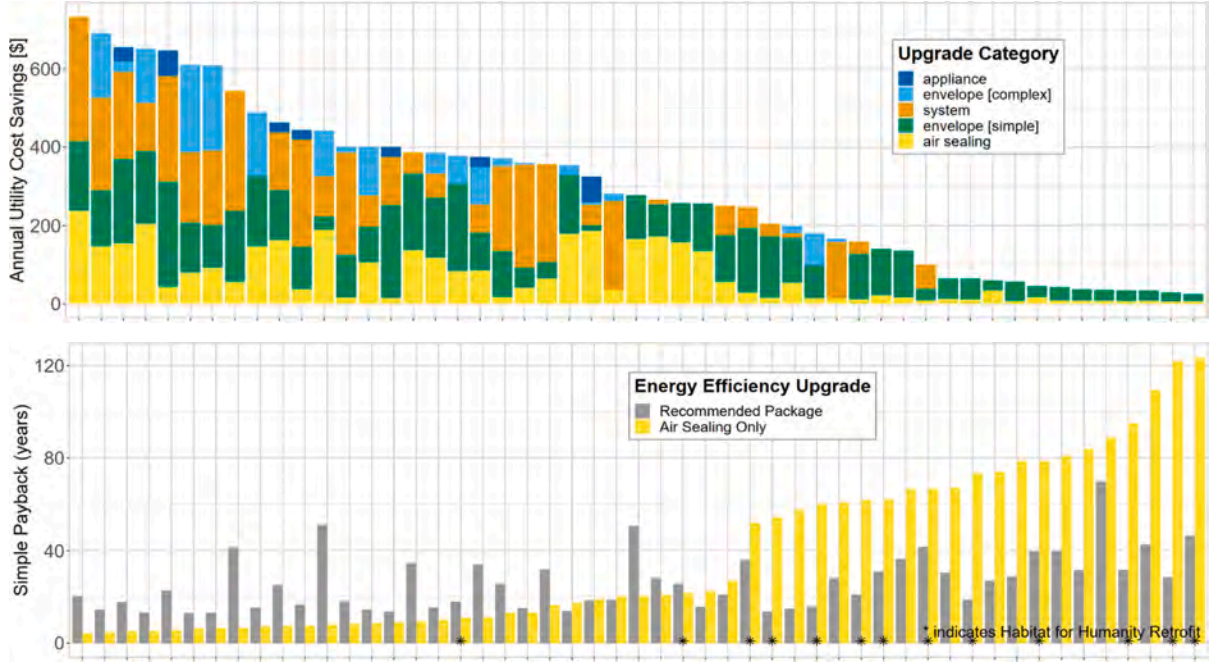

Fig. 5. a: Annual utility cost savings for retrofit packages by household. Colors represent categories we develop to indicate the relative cost and difficulty of adopting the recommendation. There is no clear pattern for which energy retrofits provide the best payback.
b: Simple payback for the recommended package and air sealing by household. Gray bars represent the payback for the full retrofit package recommended for each home. Corresponding yellow bars represent the air sealing payback period for that home. Star indicates houses that have been retrofit by habitat for humanity.

advocates and municipal governments (Hon et al., 2023). A high ratio of per-unit electricity to gas rates makes heat pumps less attractive than natural gas furnaces.

Third, states should consider implementing percentage of income payment plans (PIPP) that place a cap on energy expenditures relative to household income. These programs can be paired with federal- and state-funded retrofit programs to simultaneously improve the building stock and mitigate energy poverty. Capping household utility costs insulates low-income households from increase in bills.

Local factors exacerbate the economic penalty for household heating electrification described in this study and pose additional barriers to change not found in other regions. In our study sample, the average electricity cost is $0.18 per kWh and gas costs $0.8 per 100 cubic feet, or $0.03 per kWh. Per unit energy, electricity is therefore 5 times more expensive than gas, which is a large-enough difference that the higher efficiency of heat pumps is unable to compensate for it. (See Table C.4 for energy burden changes by income). Our results show that under these circumstances, energy cost increases for heating electrification could be disruptive even for households earning twice the median income.

Low-income households will need expanded and flexible financial assistance to retrofit their homes to prepare them for electrification. The subset (25 %) of homes that received deep energy retrofits prior to the data collection period had consistently more efficient air sealing and attic insulation than the market-rate homes. Retrofits to improve the performance of these characteristics were the most frequently recommended to study participants by the contractor, but we found they had a large range in payback period. There was no clear best choice investment that would provide either the greatest utility savings or the best payback, making it difficult for policymakers to make broadly-applicable recommendations for energy efficiency retrofits.

The group of very low earners (<$25k) with low energy burdens living in highly efficient homes were the same households that experienced the lowest energy burden increase due to heat pumps. This demonstrates the value of energy efficiency improvements in buffering households from the impact of utility cost rise due to electrification. However, the retrofits that provide the remedy are expensive. Our findings suggest that actual upfront costs for recommended retrofits in homes that have not been renovated far exceeded the $7700 cap for the Weatherization Assistance Program. Additionally, the payback periods in many cases were so high the projects would not qualify for the program, which requires a 1:1 saving-to-investment (SIR) ratio without consideration of discount rates. Current programs need to be expanded to cover the cost of expensive upgrades, and to be made available to more homes.

5. Conclusions

Policy action is needed to make heating electrification viable. The economics of electrification are adverse for the existing housing stock in cold climates. Our findings suggest that heat pumps are not a feasible economic alternative for households currently using natural gas, unless governments offset energy cost premiums through public funding. Some of the policy discussion around heat pumps does not acknowledge this (U.S. Department of Energy, 2023; Rewiring America, 2021; Fathollahzadeh et al., 2022). Such an investment can be justified on the basis of equity and by internalizing the social cost of carbon, current estimates of which are ~$180 per ton CO2 (U.S. Environmental Protection Agency, 2022; Rennert et al., 2022).

Coupling heating electrification with retrofits in existing homes with natural gas heating can limit utility cost increases and reduce a key barrier to heat pump adoption. At the same time, our study shows that even after a visit from a home energy auditor, homeowners can be left without sufficient information to act. The reports they are provided could be more useful in supporting investment decisions by providing a marginal abatement curve specific to each house, where the payback period of each measure is plotted against the cumulative cost of all the recommended measures. The homeowner can decide the most they are willing to spend, and the curve would show them all the fastest-payback measures that can be implemented for that amount.

The impact of rate structures should be analyzed based on empirical data from the rate base. Time-of-use rate design for electricity determines the cost increase for switching to heat pumps. We estimate that one rate (D1.11) reduced the increase in bills by 10 % compared to the flat rate (D1), while the other (D1.2) further elevated the average cost increase by 56 %. Modeled results using ResStock show the opposite, where the D1.11 rate is usually no worse than the flat rate (see Figure B.7 for utility rate comparison). Using empirical energy use data in utility rate design to understand how proposed rates affect households across the income spectrum and across housing quality given future adoption of heat pumps could help mitigate energy insecurity and promote greater access to heat pump adoption among natural gas users.

While our focus on Michigan allows us to understand the cost dynamics for electrification in a cold climate with high prevalence of natural gas use, limitations of our study include the small sample size and the limited regional scope. Additionally, we were unable to incorporate homeowner attitudes regarding converting their natural gas heating systems to electric heat pump systems. Future work will investigate these perceptions, examining the factors that influence decision making for residential electrification and further examining potential barriers to equitable adoption of heat pumps across income.

Ethics statement

The University of Michigan's Institutional Review Board reviewed and approved this research based on informed consent by study participants.

CRediT authorship contribution statement

Claire McKenna: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Project administration, Methodology, Investigation, Formal analysis, Data curation, Conceptualization, Funding acquisition. **Carina Gronlund:** Writing – review & editing, Supervision, Conceptualization, Methodology, Visualization, Formal analysis, Project administration. **Parth Vaishnav:** Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Project administration, Methodology, Investigation, Formal analysis, Data curation, Conceptualization, Supervision, Funding acquisition.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests:

Claire McKenna reports financial support was provided by U.S. Department of Energy and University of Michigan. Parth Vaishnav reports financial support was provided by University of Michigan.

Data availability

Model inputs and aggregated data that support the findings of this study are available from the corresponding author upon reasonable request. Demographic information for participants and raw data is not available in accordance with the informed consent agreement signed by study participants.

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Supplementary materials

Supplementary material associated with this article can be found, in the online version, at doi:10.1016/j.resconrec.2024.107699.

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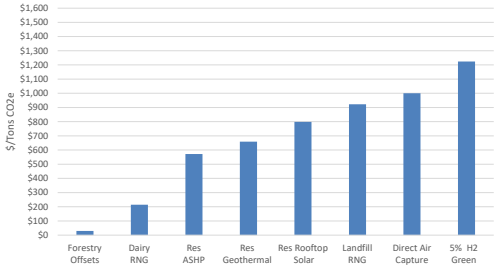
	Forestry Offsets	Dairy RNG	Res ASHP	Res Geothermal	Res Rooftop Solar	Landfill RNG	Direct Air Capture	5% H2 Green
$/Ton CO2e Abated	$30	$215	$572	$659	$798	$923	$1,000	$1,224

*Forestry offset ~ market rate
*Carbon capture, direct air capture based on literature as costs are not well understood in the industry
*Hybrid heating does not show a positive $/ton value
*Grey hydrogen does not show a positive $/ton value

Discount Rate	7.05%	
Inflation Rate	2.00%	
Base Year Data	2023	
Current Year	2024	
Delta	1	
Electric Rate residential (Dec 2024)	$0.1911	
Electric Rate C&I	$0.0849	
Average electric	$0.1433	
Gas Rate	$9.49	
Energy Loss	87	mmbtu/yr



*abatement cost methodology = For cost, use only cost needed to reduce the tonnage, do not include any BAU cost. Abatement is carbon footprint of fossil fuel less carbon footprint of clean fuel
*Emission are quanitified through a lifecycle approach
*"Marginal cost" represents a technology swap and therefore recognizing offset natural gas cost in economics - i.e. the cost of the technology itself incremental above natural gas
*"Annual cost" represents change in technology at existing asset end of life, not including offset cost for natural gas

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*Annual	Energy Usage	CI Score	Emissions (CO2e/yr)
Natural Gas (mmbtu)	87	79	7
Landfill RNG (mmbtu)	87	50	5
Electricity (KWh)	4,140,000,000		

	CE Load Serve - *As of 2021 IRP			Heat Pump	Marginal Abatement	Landfill Gas	Marginal Abatement
lbs/MWh	Grams / MJ	Tons/KWh					
1209							
1107							
1171							
1073	135	0.00049		2,016,275	-2,016,268	5	3
913	115	0.00041		1,716,216	-1,716,209	5	3
761	96	0.00035		1,431,004	-1,430,996	5	3
671	85	0.00030		1,261,260	-1,261,252	5	3
657	83	0.00030		1,234,930	-1,234,922	5	3
637	80	0.00029		1,197,925	-1,197,918	5	3
608	77	0.00028		1,143,311	-1,143,303	5	3
600	76	0.00027		1,126,810	-1,126,803	5	3
606	76	0.00028		1,139,684	-1,139,676	5	3
619	78	0.00028		1,163,176	-1,163,168	5	3
623	79	0.00028		1,171,013	-1,171,005	5	3
620	78	0.00028		1,164,829	-1,164,822	5	3
598	75	0.00027		1,123,089	-1,123,082	5	3
556	70	0.00025		1,044,099	-1,044,092	5	3
521	66	0.00024		979,336	-979,329	5	3
491	62	0.00022		923,482	-923,474	5	3
454	57	0.00021		853,701	-853,694	5	3
414	52	0.00019		777,342	-777,335	5	3
414	52	0.00019		777,342	-777,335	5	3
414	52	0.00019		777,342	-777,335	5	3
414	52	0.00019		777,342	-777,335	5	3
414	52	0.00019		777,342	-777,335	5	3
414	52	0.00019					
414	52	0.00019					
414	52	0.00019					

117 lbsCO2 / mmbtu = 1 / 2200 Ton / lbs = 0.05318182

1209 LBs / MWh = 453.59 grams / 1 LB = .000278 MWh / 1 MJ = 160.901074

117 lbsCO2 / mmbtu = 453.59 / 1 grams / Lb = 0.000948 mmbtu / MJ = 50.31039

117 lbsCO2 / mmbtu = 1Ton / 2200lbs = 0.05318182 = 0.003412 mmbtu / 1KWh

Natural Gas Fur .01443 tons/mmbtu >

AC .00049tons/KWh >

-300 / 1 gCO2e / MJ = 1 / 1000000 MT / g = 1 / 0.000948 MJ / mmbtu = -0.316455696 MT CO2e / mmbtu

0 / 1 gCO2e / MJ = 1 / 1000000 MT / g = 1 / 0.277778 MJ / KWh = 0.0000000 MT CO2e / KWh

10 / 1 gCO2e / MJ = 1 / 1000000 MT / g = 1 / 0.277778 MJ / KWh = 3.6E-05 MT CO2e / KWh

10 / 1 gCO2e / MJ = 1 / 1000000 MT / g = 1 / 0.000948 MJ / mmbtu = 0.010548523 MT CO2e / mmbtu = 5274.261603

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Asset Life	20																				
Energy Usage (mmbtu)	87																				
Total tons eliminated	7																				
RNG %	24%																				
RNG ($/mmbtu)	$65.00																				
RNG + full service	$74.49																				
Total Supply	79	gCO2e	1	MT	1	MJ	0.08333333	MT CO2e		87	7.2816541										
	1	MJ	1000000	g	0.000948	mmbtu		mmbtu													
										MCF	**Tons CO2e**										
Dairy RNG	-250	gCO2e	1	MT	1	MJ	-0.26371308	MT CO2e		21	-6										
	1	MJ	1000000	e	0.000948	mmbtu		mmbtu													
Natural Gas	79	gCO2e	1	MT	1	MJ	0.08333333	MT CO2e		66	6										
	1	MJ	1000000	g	0.000948	mmbtu		mmbtu													
Dairy RNG	$1,562																				
Natural Gas	$630																				
Total Costs	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Initial Investment	$0																				
Natural Gas		$643	$656	$669	$682	$696	$710	$724	$738	$753	$768	$784	$799	$815	$832	$848	$865	$882	$900	$918	$936
RNG		$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562
Total Cost		$2,205	$2,218	$2,231	$2,244	$2,258	$2,272	$2,286	$2,301	$2,315	$2,330	$2,346	$2,361	$2,377	$2,394	$2,410	$2,427	$2,445	$2,462	$2,480	$2,499
NPV of Total Costs	$24,372																				
NPV of RNG	$16,485																				
Displaced Natural gas		$203	$207	$211	$215	$220	$224	$229	$233	$238	$243	$247	$252	$257	$263	$268	$273	$279	$284	$290	$296
NPV of Total Costs	$2,491																				
Annual Tons of Abatement Reduced	7																				
Annual Cost	$2,073																				
$/mmbtu	$24																				
Marginal Annual Cost	$1,562																				
$/ton	$215																				

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Energy Usage (mmbtu)	87																					
Tons lifecycle (tons)	7																					
RNG %	100%																					
RNG ($/mmbtu)	$30.00	*obtained from peer producer collaboration																				
RNG + full service	$39.49																					
Total Supply	79	gCO2e	1	MT	1	MJ	0.08333333	MT CO2e		87	7											
	1	MJ	1000000	g	0.000948	mmbtu		mmbtu														
										MCF	Tons CO2e											
Landfill RNG	50	gCO2e	1	MT	1	MJ	0.05274262	MT CO2e		87	5											
	1	MJ	1000000	g	0.000948	mmbtu		mmbtu														
											3											
Landfill RNG	$3,451																					
Natural Gas	$829																					
Total Costs	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
Initial Investment	$0																					
Natural Gas																						
RNG		$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	
Total Cost		$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	
NPV of Total Costs	$36,414																					
Displaced Natural gas		$846	$863	$880	$898	$916	$934	$953	$972	$991	$1,011	$1,031	$1,052	$1,073	$1,094	$1,116	$1,138	$1,161	$1,184	$1,208	$1,232	
NPV of Total Costs	$10,377																					
Annual Tons of Abatement Reduced	3																					
Annual Cost	$2,467																					
$/mmbtu	$28																					
Marginal Annual Cost	$2,467																					
$/ton	$923																					

Electricity	117	gCO2e	1	MT	1	MJ	0.0004212	MT CO2e	
	1	MJ	1000000	g	0.277778	KWh		KWh	
	79	gCO2e	1	MT	1	MJ	0.08333333	MT CO2e	
	1	MJ	1000000	g	0.000948	mmbtu		mmbtu	
	79	gCO2e	1	MT	1	MJ	1	mmbtu	0.00833333
		MJ	1000000	g	0.000948	mmbtu	10	therms	

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Air Source Heat Pump

Life (Years)	15.00													
		1 kWh = 0.003412 MMBTU												
HSPF (10 energy star)	10=BTUs/WH													
BTU loss	87,379,849			79	gCO2e	1	MT	1	MJ	0.083333	MT CO2e		87	7
Kilowatt hours required	8,738			1	MJ	1000000	g	0.000948	mmbtu		mmbtu			
SEER (15 energy star)	15=output (btu)/input (wh)													
BTU gain	903,030													
Kilowatt hours required	60													

	Data	Source
CAPEX Replacement	$5,000	UofM heat pump study
Current Year Capex	$5,100	
Annual maintenance	$20	2023 EIA Study
Current Year maintenance	$20	
Heating energy required	8,738	KWh
Cooling energy required	60	KWh
Cost of energy	$1,681	
Total Annual O&M	$1,702	

Total Costs	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Initial Investment	$5,100															
O&M		$1,736	$1,770	$1,806	$1,842	$1,879	$1,916	$1,955	$1,994	$2,034	$2,074	$2,116	$2,158	$2,201	$2,245	$2,290
Rebate (30% up to $2000)		-$1,530														
Present Value of Costs	$5,100	$206	$1,770	$1,806	$1,842	$1,879	$1,916	$1,955	$1,994	$2,034	$2,074	$2,116	$2,158	$2,201	$2,245	$2,290
NPV of Total Costs	$21,393															
	37.39	3.819614	3.87557	3.954211	4.070275	4.105342	4.077983	4.028059	4.011404	4.024544	4.11325	4.281116	4.418748	4.537448	4.685744	4.848019
Annual Tons CO2 Reduced	4.12															
Annual Cost	$2,356															
$/mmbtu	$26.69															
Marginal Annual Cost	$2,356															
$/Ton Abated	$572															

2.215081
2.852757
3.45888
3.819614
3.87557
3.954211
4.070275
4.105342
4.077983
4.028059
4.011404
4.024544
4.11325
4.281116
4.418748
4.537448
4.685744
4.848019
4.848019
4.848019
4.848019
4.848019

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Lifetime	20																				
Energy Usage (mmbtu)	87	mmbtu	1	KWh	1	MWh	26	MWh	0.18	$	1000	KWh	$ 4,609.72								
Energy Usage (MWh)	26		0.003412	mmbtu	1000	KWh				KWh	1	MWh									
Energy Usage (KWh)	25,610																				
Tons lifecycle (tons)	7												1664.621981								
LCOE ($/MWh)	$142.00	https://www.energy.gov/eere/solar/solar-photovoltaic-systen								$	1	Mwh	$0.142								
										Mwh	1000	KWh									
Total Supply	79	gCO2e	1	MT	1	MJ	0.08333333	MT CO2e	87	7											
	1	MJ	1000000	u	0.000948	mmbtu		mmbtu													
Cost	$5,811																				
Total Costs	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Initial Investment	$0																				
Solar		$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811
NPV of Total Costs	$61,321																				
Annual Tons of Abatement Reduced	7																				
Annual Cost	$5,811																				
$/mmbtu	$67																				
Marginal Annual Cost	$5,811																				
$/ton	$798																				

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Geothermal Herat Pump

Life (Years)	25.00	
HSPF (13 energy star)	13=BTUs/WH	
BTU loss	87,379,849	4.248
Kilowatt hours required	6,722	
SEER (25 energy star)	25=output (btu)/input (wh)	
BTU gain	903,030	
Kilowatt hours required	36	

	Data	**Source**
CAPEX Replacement	$19,650	2023 EIA Study
Current Year Capex	$20,043	
Annual maintenance	$75	
Current Year maintenance	$77	
Heating energy required	6,722	
Cooling energy required	36	
Cost of energy	$1,291	
Total Annual O&M	$1,368	

Total Costs	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Initial Investment	$20,043																									
O&M		$1,395	$1,423	$1,452	$1,481	$1,510	$1,540	$1,571	$1,603	$1,635	$1,667	$1,701	$1,735	$1,770	$1,805	$1,841	$1,878	$1,915	$1,954	$1,993	$2,033	$2,073	$2,115	$2,157	$2,200	$2,244
IRA (30% ITC)	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241
Present Value of Costs	$20,043	$1,155	$1,183	$1,211	$1,240	$1,270	$1,300	$1,331	$1,362	$1,394	$1,427	$1,460	$1,494	$1,529	$1,564	$1,600	$1,637	$1,675	$1,713	$1,752	$1,792	$1,833	$1,874	$1,917	$1,960	$2,004
NPV of Total Costs	$36,627																									
Annual Tons of Abatement Reduced	55.60	4.441269	4.484246	4.544648	4.633794	4.660728	4.639715	4.601369	4.588577	4.59867	4.666802	4.795736	4.901447	4.992618	5.106519	5.231158	5.231158	5.231158	5.231158	5.231158	5.231158	5.231158	5.231158	5.231158	5.231158	5.231158
	4.79																									
Annual Cost	$3,157																									
$/mmbtu	$35.76																									
Marginal Annual Cost	$3,157																									
$/Ton Abated	$659																									

3.20887
3.698652
4.164198
4.441269
4.484246
4.544648
4.633794
4.660728
4.639715
4.601369
4.588577
4.59867
4.666802
4.795736
4.901447
4.992618
5.106519
5.231158
5.231158
5.231158
5.231158
5.231158

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Electric resistance

Life (Years)	15.00						
		1 kWh = 0.003412 MMBTU					
BTU loss	87,379,849	btu	1	mmbtu	1	kwh	25609.57
Efficiency	100%						
Kilowatt hours required	25,610		1000000	btu	0.003412	mmbtu	

	Data	Source
CAPEX Replacement	$1,190	2023 EIA Study
Current Year Capex	$1,214	
Annual maintenance	$0	2023 EIA Study
Current Year maintenance	$0	
Heating energy required	25,610	KWh
Cooling energy required	0	KWh
Cost of energy	$4,894	
Total Annual O&M	$4,894	

Total Costs	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Initial Investment	$1,214															
O&M		$4,992	$5,092	$5,194	$5,297	$5,403	$5,511	$5,622	$5,734	$5,849	$5,966	$6,085	$6,207	$6,331	$6,458	$6,587
Present Value of Costs	$1,214	$4,663	$4,443	$4,234	$4,034	$3,844	$3,662	$3,489	$3,325	$3,168	$3,019	$2,876	$2,740	$2,611	$2,488	$2,371
NPV of Total Costs	$52,180															
Displaced Natural gas	$0	$846	$863	$880	$898	$916	$934	$953	$972	$991	$1,011	$1,031	$1,052	$1,073	$1,094	$1,116
NPV of Displaced NG Costs	$8,636															
Tons of Abatement Reduced		4.26393	4.26393	4.26393	4.26393	4.26393	4.26393	4.26393	4.26393	4.26393	4.26393	4.26393	4.26393	4.26393	4.26393	4.26393
Annual Cost	$5,747															
$/mmbtu	$65.77															
Marginal Annual Cost	$4,796															
$/Ton Abated	$1,125															

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**All values based on ICRI study*

HHV_H2	0.1342286	mmbtu Kg H2		61,013	btu pound	2.2	pounds Kg	1 1000000	mmbtu btu	
Total throughput	200,000,000	mmbtu								
Blend (%)	5.00%									
Energy requirement / yr (mmbtu)	10,000,000	mmbtu								
H2 Production Required	0.134	mmbtu Kg H2								
Kg / yr	74,499,771	Kg H2								
Kg / day	204,109	Kg H2								
Electrolyser										
Stack Efficiency	55	kWh/kg								
Input Power	467,750	kW								
Capex Rate	1,872	$/Kw								
Capital Cost	875,627,449									
Water										
Input power	756	Kw								
Usage	3,147	tons/hour								
Capex Rate	4,583	$/Kw								
Capital Cost	3,464,748									
Compression										
Input Power	1,340	Kw								
Capex Rate	13,328	$/Kw								
Capital Cost	17,859,520									
Balance of Plant										
Input Power	2,913	kW								
Capex Rate	16,821	$/Kw								
Capital Cost	49,000,000									
Additional Capital	44,000,000									
Total Capital	989,951,717									
Solar Cost of Energy	50	$/MWh								
Total input power requird	473	Mw								
Capacity Factor	20%									
Capacity Required	2,364	Mw								
MWh required per year	20,706,831	MWh								

Total Costs	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Initial Investment	$989,951,717																				
O&M		$1,035,341,565	$1,056,048,396	$1,077,169,364	$1,098,712,752	$1,120,687,007	$1,143,100,747	$1,165,962,762	$1,189,282,017	$1,213,067,657	$1,237,329,011	$1,262,075,591	$1,287,317,103	$1,313,063,445	$1,339,324,713	$1,366,111,208	$1,393,433,432	$1,421,302,101	$1,449,728,143	$1,478,722,705	$1,508,297,160
IRA (($3/KG)		-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314
Total Cost	$989,951,717	$811,842,251	$832,549,083	$853,670,051	$875,213,438	$897,187,693	$919,601,433	$942,463,448	$965,782,703	$989,568,344	$1,013,829,697	$1,038,576,277	$1,063,817,789	$1,089,564,131	$1,115,825,400	$1,142,611,894	$1,169,934,118	$1,197,802,787	$1,226,228,829	$1,255,223,392	$1,284,797,846
NPV of Total Costs	$10,587,355,580																				
Displaced Natural Gas		$96,798,000	$98,733,960	$100,708,639	$102,722,812	$104,777,268	$106,872,814	$109,010,270	$111,190,475	$113,414,285	$115,682,570	$117,996,222	$120,356,146	$122,763,269	$125,218,535	$127,722,905	$130,277,363	$132,882,911	$135,540,569	$138,251,380	$141,016,408
NPV of Total Costs	$1,187,594,852																				
Energy (mmbtu)		10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000
Hydrogen (Kg)		74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771
Abatement		727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848
Annual Cost	$1,003,258,469																				
$/kg	$13.47																				
$/mmbtu	$100.33																				
Marginal Annual Cost	$890,721,907																				
$/Ton Abated	$1,224																				

10	eCO2e	1	MT	1	MJ	0.010548523	MT CO2e	105.485	
1	MJ	1000000	g	0.000948	mmbtu		mmbtu		
79	gCO2e	1	MT	1	MJ	0.083333333	MT CO2e	833,333	
1	MJ	1000000	g	0.000948	mmbtu		mmbtu		
								727,848	

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**All values based on LCRI study*

HHV_H2	0.1342286	mmbtu / Kg H2		61,013	btu / pound	2.2	pounds / Kg	1 / 1000000	mmbtu / btu

Total throughput	200,000,000	mmbtu
Blend (%)	5.00%	
Energy requirement / yr (mmbtu)	10,000,000	mmbtu
H2 Production Required	0.134	mmbtu / Kg H2
Kg / yr	74,499,771	Kg H2
Kg / day	204,109	Kg H2
Electrolyzer		
Stack Efficiency	55	kWh/kg
Input Power	467,750	kW
Capex Rate	1,872	$/Kw
Capital Cost	875,627,449	
Water		
Input power	756	Kw
Usage	3,147	tons/hour
Capex Rate	4,583	$/Kw
Capital Cost	3,464,748	
Compression		
Input Power	1,340	Kw
Capex Rate	13,328	$/Kw
Capital Cost	17,859,520	
Balance of Plant		
Input Power	2,913	kW
Capex Rate	16,821	$/Kw
Capital Cost	49,000,000	
Additional Capital	44,000,000	
Total Capital	945,951,717	

Total Costs	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Initial Investment	$945,951,717																				
O&M		$791,415,092	$807,243,394	$823,388,262	$839,856,027	$856,653,148	$873,786,211	$891,261,935	$909,087,174	$927,268,917	$945,814,296	$964,730,582	$984,025,193	$1,003,705,697	$1,023,779,811	$1,044,255,407	$1,065,140,515	$1,086,443,326	$1,108,172,192	$1,130,335,636	$1,152,942,349
Total Cost	$945,951,717	$791,415,092	$807,243,394	$823,388,262	$839,856,027	$856,653,148	$873,786,211	$891,261,935	$909,087,174	$927,268,917	$945,814,296	$964,730,582	$984,025,193	$1,003,705,697	$1,023,779,811	$1,044,255,407	$1,065,140,515	$1,086,443,326	$1,108,172,192	$1,130,335,636	$1,152,942,349
NPV of Total Costs	$9,953,910,806																				
Displaced Natural Gas		$96,798,000	$98,733,960	$100,708,639	$102,722,812	$104,777,268	$106,872,814	$109,010,270	$111,190,475	$113,414,285	$115,682,570	$117,996,222	$120,356,146	$122,763,269	$125,218,535	$127,722,905	$130,277,363	$132,882,911	$135,540,569	$138,251,380	$141,016,408
NPV of Total Costs	$1,187,594,852																				
Energy (mmbtu)		10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000
Hydrogen (Kg)		74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771
Abatement		527.426	527.426	527.426	527.426	527.426	527.426	527.426	527.426	527.426	527.426	527.426	527.426	527.426	527.426	527.426	527.426	527.426	527.426	527.426	527.426
Annual Cost	$943,233,203																				
$/kg	$12.66																				
$/mmbtu	$94.32																				
Marainal Annual Cost	$830,696,642																				
$/Ton Abated	$1,575																				

	10	gCO2e	1	MT	1	MJ	0.010548523	MT CO2e	105,485
	1	MJ	1000000	g	0.000948	mmbtu		mmbtu	
	50	gCO2e	1	MT	1	MJ	0.052742616	MT CO2e	527,426
	1	MJ	1000000	g	0.000948	mmbtu		mmbtu	
									421,941

CE Load Serve - *As of 2021 IRP*					
lbs/MWh	Grams / MJ	Tons/KWh	H2 Blend	Natural Gas	
1209					
1107					
1171					
1073	135	0.00049	#REF!	527,426	#REF!
913	115	0.00041	#REF!	527,426	#REF!
761	96	0.00035	#REF!	527,426	#REF!
671	85	0.00030	#REF!	527,426	#REF!
657	83	0.00030	#REF!	527,426	#REF!
637	80	0.00029	#REF!	527,426	#REF!
608	77	0.00028	#REF!	527,426	#REF!
600	76	0.00027	#REF!	527,426	#REF!
606	76	0.00028	#REF!	527,426	#REF!
619	78	0.00028	#REF!	527,426	#REF!
623	79	0.00028	#REF!	527,426	#REF!
620	78	0.00028	#REF!	527,426	#REF!
598	75	0.00027	#REF!	527,426	#REF!
556	70	0.00025	#REF!	527,426	#REF!
521	66	0.00024	#REF!	527,426	#REF!
491	62	0.00022	#REF!	527,426	#REF!
454	57	0.00021	#REF!	527,426	#REF!
414	52	0.00019	#REF!	527,426	#REF!
414	52	0.00019	#REF!	527,426	#REF!
414	52	0.00019	#REF!	527,426	#REF!
414	52	0.00019	#REF!	527,426	#REF!
414	52	0.00019	#REF!	527,426	#REF!
414	52	0.00019	#REF!	527,426	#REF!
414	52	0.00019	#REF!	527,426	#REF!
414	52	0.00019	#REF!	527,426	#REF!

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Hybrid Heat Pump				
Life (Years)	20.00			
	Percent of time used			
Furnace	41.67%	Every month temp is below 45 degrees		
Heat Pump	58.33%	Every month average temp is above 45 degrees		
		Furnace	**Heat Pump**	
BTU loss	87,379,849	42%	58%	
BTU gain	903,030	0%	100%	
Total Energy Loss	88,282,879			
Furnace				
Energy required (btu)	36,699,537			
Efficiency	95%			
mmbtu Required	39			
Heat Pump				
Energy Required (btu)	50,680,313	50.680313	2.6911246	
HSPF	8.5			
Kilowatt hours required	5,962			
SEER (15 energy star)	15=output (btu)/input (wh)			
SEER	15			
BTU gain	903,030			
Kilowatt hours required	60			
	Data	**Source**		
Heat Pump Capex	$6,940	https://www.fixr.com/costs/hybrid-heat-pump		
AC Capex	$3,750			
Current Year Capex	$10,904			
Annual maintenance	$40	2023 EIA Study		
Current Year maintenance	$41			
Cost of energy	$1,518			
Total Annual O&M	$1,558			

Total Costs	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Initial Investment	$10,904																				
O&M		$1,589	$1,621	$1,654	$1,687	$1,721	$1,755	$1,790	$1,826	$1,862	$1,900	$1,938	$1,976	$2,016	$2,056	$2,097	$2,139	$2,182	$2,226	$2,270	$2,316
Rebate (30% up to $2000)		-$900																			
Present Value of Costs	$10,904	$644	$1,415	$1,348	$1,284	$1,224	$1,166	$1,111	$1,059	$1,009	$961	$916	$873	$831	$792	$755	$719	$685	$653	$622	$593
NPV of Total Costs	$29,564																				
Displaced Natural gas	$0	$846	$863	$880	$898	$916	$934	$953	$972	$991	$1,011	$1,031	$1,052	$1,073	$1,094	$1,116	$1,138	$1,161	$1,184	$1,208	$1,232
NPV of Displaced NG Costs	$10,377																				
Tons of Abatement Reduced		2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47
Annual Cost	$2,802																				
$/mmbtu	$31.73																				
Marginal Annual Cost	$1,818																				
$/Ton Abated	$736																				

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Energy Star Formulas

COP — The COP is a measure of the amount of power input to a system compared to the amount of power output by that system. The COP is therefore a measurement of efficiency; the higher the number, the more efficient the system is. The COP is dimensionless because the input power and output power are measured in Watt. The COP is also an instantaneous measurement in that the units are power which can be measured at one point in time.

$$COP = \frac{\text{useful output}}{\text{energy input}} \quad \text{(Eq 1)}$$

SEER — the SEER is the ratio of output cooline enerev (in BTU) to electrical input enerev (in Watt-hour). However the SEER is a representative measurement of how the system behaves over a season where the outdoor temperature varies

$$SEER = \frac{\text{output cooling energy in BTU over a season}}{\text{input electrical energy in Wh during the same season}} \quad \text{(Eq 2)}$$

EER — How do you convert SEER to EER?
Typical EER for residential central cooling units = 0.875 × SEER. SEER is a higher value than EER for the same equipment.

COP — HSPF 10 = 2.93 COP

10	HSPF		3.6	COP	12.28668942
2.93	COP				

HSPF — Like SEER, this is a measurement of the efficiency of a system and the units are the same (BTU/h divided by Watt). However, this measures the efficiency of the system in heating mode, not cooling mode. Therefore it applies only to heat pumps or reversible air conditioning units and not to units that only cool a space.

The HSPF's formula:

$$\text{HSPF (heating seasonal performance factor)} = \frac{\text{The heating output in the (coldest) region}}{\text{Total electric use for the same region}}$$

KW/Ton — The efficiencies of large industrial air conditioner systems, especially chillers, are given in kW/ton to specify the amount of electrical power that is required for a certain power of cooling. In this case, a smaller value represents a more efficient system.

$$COP = \frac{\text{power output in } \$ \text{ (or BTU)}}{\text{power input in } \$ \text{ (or kW-hr)}} \quad \text{(Eq 3)}$$

80% annual fuel utilization efficiency (AFUE) furnace (the current federal minimum efficiency standard)5
90% AFUE furnace (the most common high-efficiency furnace and the ENERGY STAR® level for the North)
97% AFUE furnace (the ENERGY STAR Most Efficient level)
Geothermal Energy star DGX - EER 16, COP 3.6
8.2 heating seasonal performance factor (HSPF) heat pump (current federal standard for split systems)
8.5 HSPF heat pump (the ENERGY STAR level)6
10.3 HSPF heat pump (the ENERGY STAR Most Efficient level)7
A cold-climate electric heat pump. This is a very preliminary analysis based on one field test that found a seasonal 2.8 coefficient of performance (COP) in Connecticut. More products and data are needed.

Other Reference Data

Furnace reference data	https://www.goshaw.com/electric-furnaces/
Electric furnace Cost	https://homeguides.sfgate.com/much-electric-furnace-cost-102516.html#:~:text=Run%20in%20panel%20N2435,78%20per,N241%2C788%20using%20an%20electric%20furnace.
AC and Heat Pump model data sheets	https://www.energystar.gov/products/most_efficient/central_air_conditioners_and_air_source_heat_pumps
Residential energy calculator	http://www.energyhost.com/ResidentialEnergyCalculator/
Energy use to CO2e calculator	https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator

Formulas

Conductive Required Heating Energy	mmbtu/day	(Area*degree days*24 hours*U Value)/1000000
Infiltration Required Heating Energy	mmbtu/day	(Space vol*Delta Temp*air changes/hr*heat factor* 24 hours)/1000000 The air infiltration heat loss is uncontrolled heat loss through joints in the construction and cracks around doors and windows. This figure is affected by wind and pressure differentials between the outside and interior of the home which causes air to move inside the home, thereby producing heat loss as that air escapes the room. The heat capacity of air at sea level is, on average, 0.018 Btu per cu. ft. per degree F.

Model Assumptions

Mock home size (SF) (50'x31')	1707.5	https://fred.stlouisfed.org/series/MEDSOLFEI19020
Flint/Saginaw/Midland	1500	
Lansing	1660	
Grand Rapids	1966	
Jackson	1704	
Contributing insulation surfaces	Exterior walls; attic; single floor	
R-Values	Energy Star	https://www.lm.com/en/homeowner-insulation/homeowner-faq/what-r-value-do-i-need-/

	R-Value	Weight Average R-Value	Surface Area
Walls	15	4.1	1280
Attic	45	16.4	1707.5
Floors	25	9.1	1707.5
Weighted Average Home R-Value/Total Area		29.5	4695
U-Value		0.034	

Home volume	Cubic feet	13660	
Heat capacity factor	BTU/cubic foot	0.018	The heat capacity of air at sea level is, on average, 0.018 Btu per cu. ft. per degree F
Air Change	Cubic feet/hr	1.5	

Weather Assumptions

Climate Zone 4 & 5		https://inspectapedia.com/heat/Heating-Cooling-Climate-Zone-BTU-Requirements.php#HeatingBTUs
Heating Base Temp		68
Cooling Base Temp		72
Average Temps		https://en.climate-data.org/north-america/united-states-of-america/michigan/detroit-330/

Heating Degree Days	Days/month	Average Temp (Detroit)	Heating Degree Days	Cooling Degree Days
January Average Temp	31	24.4	1351.6	0
February Average Temp	28	26.1	1172.2	0
March Average Temp	31	35	1023	0
April Average Temp	30	47.6	612	0
May Average Temp	31	59.9	251.1	0
June Average Temp	30	69.9	0	0
July Average Temp	31	74	0	62
August Average Temp	31	72.2	0	9.3
Sept Average Temp	30	65.8	66	0
October Average Temp	31	53.3	455.7	0
November Average Temp	30	41.3	801	0
December Average Temp	31	30.4	1165.6	0

Energy Loss ~ Residential

Heating Energy Loss		Cooling Energy Loss	
Conductive Energy Loss (mmbtu)	Infiltration (mmbtu)	Conductive Energy Gain (mmbtu)	Infiltration Gain (mmbtu)
5.154	11.96	0.000	0.00
4.474	10.38	0.000	0.00
3.301	9.06	0.000	0.00
2.334	5.42	0.000	0.00
0.958	2.22	0.000	0.00
0.000	0.00	0.000	0.00
0.000	0.00	0.236	0.55
0.000	0.00	0.035	0.08
0.252	0.58	0.000	0.00
1.738	4.03	0.000	0.00
3.055	7.09	0.000	0.00
4.446	10.32	0.000	0.00
26	61	0.3	0.6
Total loss (mmbtu)	87.38	Total gain (mmbtu)	0.9

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Full length article

Heating with justice: Barriers and solutions to a just energy transition in cold climates

Claire McKenna [a], Carina Gronlund [b], Parth Vaishnav [a,*]

[a] School for Environment and Sustainability, University of Michigan, Ann Arbor, MI, United States
[b] Institute for Social Research and School of Public Health, University of Michigan, Ann Arbor, MI, United States

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ABSTRACT

Residential heat pumps could reduce greenhouse gas emissions, but increase energy burdens, the proportion of income households spend on utility bills. We analyze utility bills, thermostat settings and energy burdens for a sample of 51 households in Michigan, half below median income. We recruit a contractor to conduct energy assessments of these households and provide them with energy retrofit recommendations, including estimated costs and savings. We find that low-income households choose similar temperature setpoints to higher-income households, but live in less efficient homes. Below-median income households, which today experience a median energy burden of 6 %, would see it rise to 10 % if they shifted to electric heat pumps from natural gas. Weatherization could offset this increase, bringing burdens down to pre-electrification levels. However, median payback is 24 years, making retrofits infeasible for the poorest. Our results are indicative of an energy poverty trap that could hinder an equitable energy transition.

Spotlights

- Converting fossil-fuel based home heating to electric could reduce pollution but make bills less affordable.
- Switching to electric heating results in low-to-moderate income households paying a high percentage of income on energy.
- Retrofitting homes could make electric heating more affordable but it is expensive and therefore infeasible.
- High-cost energy efficiency home retrofits could hinder an equitable energy transition.
- Future work will investigate homeowner attitudes regarding electrifying their homes and barriers to equitable transition.

1. Introduction

In recent years, US state policy (Climate Leadership and Community Protection Act 2020; An Act Creating 2022; Climate Commitment Act 2022)) has signaled a commitment to reducing greenhouse gas emissions by transitioning home heating from fossil fuels to electricity. U.S. federal policy has sought to use subsidies to lower the upfront cost of heat pump adoption (Inflation Reduction Act, H.R. 5376). Electrification has been projected to increase annual utility cost for households in more than half of US states (Vaishnav and Fatimah 2020; Deetjen et al., 2021), with the worst effects in cold climates (Walker et al., 2022). Rising energy costs could have a large impact on households across the income spectrum.

1.1. Literature review

Higher utility bills could increase the economic and physical hardships in households already experiencing energy insecurity. A quarter of American households spend a high proportion (>6 %) of their income on utilities, defined as energy burden (Drehobl et al., 2020). High energy burden is associated with poor health outcomes (Reames, 2016), and households with certain vulnerabilities, such as older adults, choose uncomfortable and sometimes unsafe indoor temperatures to reduce bills (Cong et al., 2022). Lewis et al. center deteriorated housing conditions concentrated in racially segregated neighborhoods in their discussion of energy insecurity, which encompasses financial, behavioral and physical hardships related to home energy use (Lewis et al., 2020).

Households with lower energy burdens are not entirely precluded from the effects of higher ongoing costs associated with heating electrification because these costs are associated with building

* Corresponding author at: 440 Church St, 2575 Dana Building, Ann Arbor, MI 48109.
E-mail address: parthtv@umich.edu (P. Vaishnav).

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characteristics that are prevalent across the US housing stock. Old homes heated by natural gas have been shown to result in the greatest operational costs for heating with a heat pump (Vaishnav and Fatimah, 2020). 64.5 million American homes use natural gas for heating and 57 % of them were built before energy codes were implemented in the US (U.S. Energy Information Administration, 2023). Knowledge of household demographics, housing characteristics, and occupant behavior are essential to understanding the barriers to equitable access to heat pumps and a just distribution of harms and benefits associated with policy that facilitates the clean heating transition.

Current research about residential energy equity includes only one or two of these critical components. Studies that quantify the link between racial disparities in energy use and housing quality (Goldstein et al., 2022; Bednar et al., 2017), and demonstrate that households of color are more likely to have trouble paying their bills (Graff et al., 2021) do not take into account behavior. Studies that evaluate specific retrofit opportunities and quantify their the savings potential by employing national scale modeling do not address behavior impacts associated with those changes (Bradshaw et al., 2014; Wilson et al., 2019). Likewise, studies that examine the economics of heat pump adoption for low income households, whether in observed system performance (Ceglia et al., 2022; Flower et al., 2020; Calver et al., 2022; Pastore et al., 2022; Liu et al., 2018) or simulations (Donaldson and Lord, 2018; Barrella et al., 2020; Liu et al., 2020; Abbasi et al., 2022; Savage et al., 2022) focus on housing and heat pump technology characteristics without an empirical analysis of occupant behavior and preferences for heating and cooling.

Several recent studies examining the energy savings potential of residential retrofits in the European context point to the importance of incorporating household behavior in home energy assessments (Palma et al., 2022; Barrella et al., 2020; Koasidis et al., 2022; Domínguez-Amarillo et al., 2020). The literature addressing the effect of energy consumption behavior on the cost effectiveness of energy retrofits in the US commonly uses economics theory and analysis. Gillingham and Palmer (2014) conducted a literature review of explanations for limited uptake of home energy efficiency including that flawed decision making could reduce the utility of energy efficiency to customers. Three studies followed that examined this question using home energy efficiency project data from the US Department of Energy Weatherization Assistance Program (WAP). Zivin and Novan (2016) measure the treatment effect of retrofits on energy use of 275 households and provide evidence that electricity savings due to WAP are overstated. Allcott and Greenstone (2017) and Fowlie, Greenstone and Wolfram (2018) use large samples of primary empirical data to estimate the benefits of providing energy efficiency services to low-income homes. Though these studies consider behavioral explanations for under performance of projects compared to engineering estimates, they do not provide detail on the housing conditions prior to intervention or the specific work performed. See Table C.7 for a comparison of this paper's contributions to those of the literature.

Other large empirical studies that address impacts of high utility costs on vulnerable households similarly do not provide data on the housing characteristics of the populations they examine (Cong et al., 2022; White and Sintov, 2020), and therefore do not address why these impacts occur. Although Booth and Choudhary (2013) estimate the rebound effect, identify specific upgrade parameters, and focus on public housing in their assessment of uncertainty in retrofit performance (Booth and Choudhary, 2013), they do not address the transition in heating technology. Recent research has signaled the potential for heat pumps to contribute to residential sector clean heating transition where countries push for climate action and fossil fuels remain the predominant fuel source (Fitó et al., 2021; Thomaßen et al., 2021; Besagni et al., 2020).

1.2. Research gaps

There remains a gap in quantifying the impacts of residential heating electrification across income and in examining interventions specific to both housing quality and energy consumption behavior. Previous studies that have taken this form to assess the reasons for disproportionate impacts of energy cost across income (Cong et al., 2022; Jones et al., 2023) only examine it in the context of air conditioning, not heating. To bridge this gap, this study aims to disentangle the sources of inequality embedded in the economic impact of heat pump adoption and assess fixes available for real homes. The present work has three main contributions. First, we provide evidence that energy burden impacts across income are associated with housing quality rather than behavior. Second, we compare economic impact of heating fuel transition across income groups. Third, we test the idea that there is a way to mitigate the utility cost premium for heat pumps.

We conduct a year-long field study of 51 homes in Southeast Michigan, during which we perform a comprehensive energy audit of each home to observe envelope and HVAC system characteristics, including thermal imaging to identify temperature gradients indicative of air leakage and poor insulation, and blower door testing to measure air infiltration rate, as well an examination of the on-label efficiency of all appliances. We gather metered daily gas and hourly electric consumption data over the study period and collect energy assessment contractor recommendations for energy efficiency retrofits for each home. Our approach to examining residential energy equity is novel because we compare results derived from observed data with simulations derived from statistical sampling of large public data sources (Wilson et al., 2022).

Following this introduction, we present the methods, then results, then we will discuss the findings and conclude. We present our findings in five parts. First, we examine the existing conditions of the homes in the study and compare them across income, including key housing characteristics and indoor temperature preferences. Next, we quantify the impact that replacing natural gas heating with heat pumps would have on household energy burden. We then examine the sensitivity of time of use utility rates on the annual energy bill impact of fuel switching. Following that, we quantify the cost savings potential of energy efficiency envelope improvements and compare it to the utility bill impact. Finally, we explore energy efficiency retrofit recommendations provided to participants during home energy audits and assess the feasibility of these improvements to mitigate the ongoing cost impact of heating electrification on the sample.

2. Methods

This study uses observed household energy use and indoor temperature data along with a reduced complexity air source heat pump coefficient-of-performance model to determine energy cost and energy burden impacts of switching to a heat pump. We gather energy retrofit recommendations and estimate upfront costs, energy cost savings, and payback from a contractor who conducted a detailed energy audit for each home. We then quantify annual utility bill impacts for fuel switching and energy retrofits using a building energy model that provides detailed sub-hourly simulations a large sample of archetypal homes that are representative of the study region and compare them to our findings for the sample.[1]

[1] See Data Availability statement for more information on how to access data that can be made available under the Institutional Review Board guidelines for human subjects research. See Supplemental Methods for additional detail on justification for model and calculation assumptions and Supplemental Figure, Tables, and Notes for detail on participant demographics, supporting findings, and literature review.

2.1. Participants

As described below, we recruited 51 participants from Wayne and Washtenaw Counties in Michigan, which encompass the Detroit and Ann Arbor metro areas. We chose Southeast Michigan for three factors that make this study applicable to global contexts including the Midwest, New England, and the Mountain West regions of the US; Northern Europe; and the United Kingdom: cold climate, predominance of natural gas for heating, and older homes.

Participant recruitment included three steps. First, we circulated an expression of interest form through local media, university email lists, and local environmental and energy justice community groups that drew more than 1300 responses. Second, we asked these respondents to complete a demographic survey to assess the presence of key factors associated with energy insecurity: race, income, disability, children, and health vulnerability (Drehobl et al., 2020; Reames, 2016; Hernández, 2016). We received 883 responses to the demographic questionnaire. Third, we identified a random sample stratified using survey answers to ensure representation across four key, binary, classes of vulnerability: has a disability, has at least one child at home, foregoes paying energy bills at least once a year, controls heating or cooling for a vulnerable occupant. These four classes correspond to 16 combinations, and we had respondents who corresponded to only 10 of them.

Next, we identified 418 survey respondents living in single family homes. We then classified the respondents into 10 categories representing the unique combinations of the key categories listed above. We calculated how many households we would need to invite to have an equal number across these categories and randomly selected that many households from each group. Where the quantity of respondents in a category was not great enough to provide an equal weighting, we invited all the respondents in the category. Ultimately, we compiled a list of 90 potential participants to whom we sent invites to join the study. Our recruitment rate was 58 %. Demographic questions and descriptive statistics can be found in Note D.3 and Table C.1. 90 respondents were asked to join the study. Demographic questions and descriptive statistics can be found in Note D.3 and Table C.1.

All households in the sample live in single family homes. 50 of the 51 households are homeowners; 1 is a renter. All homes use natural gas for heating with the exception of 1, which uses propane. The sample includes a diversity of housing vintage (i.e. common building practices) from every decade since 1900: 9 homes were built before 1940, 17 homes were built between 1940 and 1960, 12 built between 1961 and 1980, 6 built between 1981 and 2000, and 7 built after 2000.

The study sample is representative of the populations of the two counties of Southeast Michigan along two key characteristics. (1) Income: the median income (in 2022 dollars) is $57,223 for Wayne County and $84,245 for Washtenaw County (U.S. Census, 2024). The sample includes 11 households reported earning annual income <$25k, 18 earning $25–50k, 9 earning $50–75k and 13 earning >$75k. (2) Race: 54.6 % white, 38.3 % Black, and 7.1 % all other races in Wayne County and 73.9 % white, 12.4 % Black, and 13.7 % all other races in Washtenaw County (U.S. Census, 2024). The sample includes 29 % Black (n = 15), 45 % white (n = 23) and 25 % (n = 13) all other races, including one participant who prefers not to answer.

Households were provided $100 compensation.

2.2. Data collection

We obtained one year of utility data for each household, including hourly metered electricity use and daily metered gas use where available. We conducted one visit to each home, during which we installed a smart thermostat where the heating and cooling system could accommodate the product (Ecobee 3 lite) (n = 40). For homes that could not receive the smart thermostat, we set up a wi-fi connected thermo-hygrometer (Govee H5179). Both devices record data at 15-minute intervals. An accredited energy audit contractor accompanied the research team and performed an ASHRAE Level 2 energy audit at each home.

Participants provided income ranges, so we estimate energy burden based on the arithmetic midpoint, i.e., if a participant reports their income to $25k-50k, the energy cost burden for that household was calculated at the proportion of their actual annual utility bills to $37.5k. We did not apply an equivalence scale to energy expenditure and income because we observed occupancy in some homes to which the published equivalence scales would not readily apply, for example, households with adult children that may live at home for periods of time varying duration and frequency throughout the year. See Supplementary Methods for detail on energy burden calculation.

2.3. Housing quality analysis

To assess participant behavior, we estimate indoor temperature setpoints in two ways. First, we estimate the heating inflection temperature (HIT) (ambient temperature at which a household begins heating) for each home using a splitwise regression of metered daily gas use on hourly average ambient air temperature (obtained from NOAA Local Climatological Data (LCD) for the data collection period). Second, we evaluate the observed heating and cooling setpoints and the observed indoor temperature for the heating and cooling season for a subgroup that received a smart thermostat (n = 40). We calculate cooling and heating season means for setpoint temperature as well as the standard deviation for setpoint and indoor temperature using this interval data.

2.4. Heat pump cost analysis

Our energy cost analysis for switching to all-electric heat pumps from natural gas-based heating consists of three steps. See Appendix A for detailed calculation methodology and model specifications.

- *Heat load calculation. Existing furnace gas use.* To determine heating natural gas use, we first estimated the inflection point for temperature dependent gas use using a split-wise regression of heating degree hours (a measure of the intensity of the space heating needed for a given time and place) on hourly total gas use. We assumed that the slope of the piecewise linear function (found with the segmented() function in R) past this inflection point indicates heating related natural gas usage. From that, we derived the slope which is the natural gas usage per heating degree hour. We then obtained the amount of gas used during each hourly time step for heating by multiplying the slope by the difference between the outside ambient air temperature departure from the indoor heating setpoint gathered during the initial data collection period when the energy audit took place.

Deriving heat load. We multiplied the hourly gas use by the furnace efficiency to obtain the hourly heating load for each house. We obtained the hourly ambient temperatures for each home during the window of time the utility data was provided by the utility (e.g. 11/10/2020–11/11/2021) using the NOAA Local Climatological Data (LCD) Tool for the closest available weather station.

- *Heat pump model.* We calculated the heat pump hourly temperature-dependent coefficient of performance (COP) using the following equation:

$$COP_i' \times (1 - l(t_i)) = COP_i \; Tmin < t, \; i \in 8760$$

$$COP_i = 1 \; t < Tmin$$

Where:

i indexes hour;

COP' = manufacturer reported coefficient of performance using the efficiency curve (ambient temperature vs. COP) of the Mitsubishi M2i cold climate ASHP for heating;

$l()$ = defrost efficiency loss for give temperature, t (%);

t = **hourly dry bulb temperature (F)** using the NOAA LCD weather data for the same period for which had metered natural gas data for each home;

COP = observable coefficient of performance;

$T_{min} = 10°F$ reflecting ambient temperature change over point from heat pump to backup heating mode via electric resistance coil;

$<T_{min}$ **COP** $= 1$ reflecting the heating efficiency of an electric resistance coil used for backup to ensure that heating setpoints are met below the change over point.

We calculated percentage improvement in cooling energy by dividing the Mitsubishi H2i SEER rating (SEER = 17) by the on-label AC efficiency obtained from the energy audits for each home. This kind of high efficiency equipment comes with a first cost premium over a standard furnace replacement. It is therefore expensive for low- and middle-income households and is likely not affordable without a subsidy that covers most of the cost. Selecting this equipment is a conservative assumption. We then applied this factor to an average cooling energy percentage obtained from the Resstock End Use Savings Shapes (Wilson et al., 2022) to determine the annual energy cost savings.

- *Energy cost calculation.* We calculated the energy cost using a model we developed in R that takes in the hourly estimated electric and daily gas usage for the hypothetical heat pump scenario and calculates the total bill costs in the manner calculated by the utilities as published in the electricity and gas rate schedules ("DTE Electric Company Rate Book for Electric Service", 2023). For example, to calculate the annual electricity cost for each home, we apply the flat rate service charge per month, capacity and non-capacity energy charges assessed per kWh, as well as surcharges and credits. We completed this process for three electricity rates and two gas rates to test the sensitivity of our results to rates available to participants. See Figure B.7 for rate summary and Note D.5 for rate description. We do not include tariff changes from one year to the next because future rate changes are unpredictable and beyond the scope of the analysis. Changes in consumer behavior associated with changes in utility tariffs are also beyond the scope of the paper and therefore not included in the analysis. Additionally, incorporating behavior changes would not have a meaningful impact on the results because short term elasticities are low for electricity and natural gas in the US (U.S. Energy Information Administration, 2021).

2.5. Resstock

We analyzed the potential for energy efficiency to mitigate cost increase due to heat pumps by calculating energy costs derived from four modeled retrofit scenarios included in the NREL Resstock End Use Savings Shapes database (Wilson et al., 2021). We selected hourly load profiles available for a baseline case and three "upgrades" including full electrification with or without deep efficiency retrofits, and deep efficiency retrofits with no change to the HVAC systems. To these scenarios, we applied the utility rates for all sensitivity cases as described above. We then calculated the mean incremental annual energy costchange resulting from a series of these changes across a random sample of 400 homes in the database representative of Detroit, MI.

2.6. Retrofit cost analysis

The contractor recommended energy efficiency measures and provided first cost and utility cost savings estimates for the recommended work. We used the "Return on Investment and Rebate Report" prepared for each study participant to summarize the recommended energy efficiency upgrades to code the unique efficiency measures recommended across the sample.

The parameters we used for estimating the feasibility of retrofitting were economic payback in years for the package of all recommended retrofits (calculated as the first cost divided by the annual energy cost savings), the first cost of the total package, and the modeled utility cost savings for the individual measures. The values for these parameters were obtained from the retrofit reports provided to participants by the energy audit contractor. The payback parameter described above follows the US Department of Energy Methodology and Procedures for Life Cycle Cost Analysis (Code of Federal Regulations. 10 CFR Part 436 Subpart A). No discount rates are used, making this the best-case estimate of the payback period. Given our findings, the decision to use an undiscounted payback period is conservative: if a discount rate were applied, the payback period would be even longer, strengthening our argument that the retrofits are not attractive on the basis of utility bill savings. Additionally, we show the rates that participants were provided as part of their energy audit, so payback periods not inclusive of a discount rate are more representative of the data participants have to inform their decision making.

3. Results

We find that electrifying homes with heat pumps increases annual energy cost by 58 % on average (range: 11–182 %) when compared to natural gas heating and considering a flat electricity rate, higher than previous estimates. This change exacerbates already high energy burdens for low-and-moderate income (LMI) households. While we find energy retrofit opportunities that saved energy cost for every home, they came with substantial obstacles that could limit uptake. There is an average payback period of 24 years and homeowners can be left without sufficient information to act, even after a visit from a home energy auditor. Willand et al. (2020) identified this situation as the retrofit trap in their 2020 analysis of Australian home retrofit programs. It can be understood as a form of poverty trap, defined Azaiadis and Stachurski as a reinforcing mechanism that acts as barrier to adoption of techniques that can alleviate poverty (Azariadis and Stachurski, 2005). The clean energy transition is hindered by an energy poverty trap because the extensive retrofits needed to make electrification affordable are themselves too expensive for low-income households.

3.1. Housing quality vs. set-point choices

We estimate energy burden for each household by calculating the proportion of their annual combined electricity and gas cost (sourced from utility bills) to the self-reported income range. The 5 highest energy burdened households have rates ranging from 10 to 40 %. 32 % of homes have energy burdens greater than 6 %, which is considered a high energy burden and twice the national average (Drehobl et al., 2020). All these households have below-median incomes. 37 % are between 3 and 6 %. 31 % of homes have an energy burden below 3 %; all but one of these homes have incomes that exceed the local median (see Figure B.1). See Table C.1 for descriptive statistics on utility costs and energy burden. Table C.6 provides a list of self-identified household income ranges and a comparison to the area median income (AMI) by zip code.

Not all homes in our sample were of the same age and quality. The homes were on average 60 years old and built in an era during which Michigan did not have energy efficient building codes.[2] These codes were adopted for the first time 1977 when ASHRAE 90–1975 was adopted state-wide ("US Dept. of Energy Building Energy Codes Program", 2024). 13 homes (5 in the <$25k income group and 8 in the $25–50k group) had been retrofit by Habitat for Humanity of the Huron Valley (Habitat) resulting in higher quality for their age. Improvements had been made 1–10 years prior to participating in this study.

Homes retrofit by Habitat perform consistently better than market rate homes in the sample [Fig. 1]. To understand the impact of these

[2] They were adopted for the first time 1977 when ASHRAE 90-1975 was adopted state-wide. (US Dept. of Energy Building Energy Codes Program, www.energycodes.gov/status/states/michigan).

retrofits on overall home energy efficiency, we examine the difference between trends of annual energy use per unit floor area (or energy use intensity) and per occupant across income in market rate homes compared to the Habitat homes. When treating self-reported income categories as an ordered set (<$25k, $25–50k, $50–75k, and >$75k) in a least squares regression of energy use intensity (EUI) per occupant on income, we find a significant downward trend (p-value=0.048) for market-rate homes, indicating that low-income households either live in less energy efficient homes or there is significantly different behavior across income levels.

The latter explanation would suggest, for example, that lower-income households start to use heating at higher ambient temperatures and cooling at lower ambient temperatures. Cong et al. provide evidence to the contrary. They find that lower-income families wait for ambient temperatures to rise higher before turning on air conditioning compared to those with higher incomes (Cong et al., 2022). This would imply that low-income families use less energy, a seeming contradiction of our results. However, we believe that there is no contradiction, since the Cong et al. results are not directly comparable to ours for two reasons. First, we report energy use per square foot per occupant, which Cong et al. do not observe. Second, Cong et al. have studied air conditioning, whereas energy use in our sample is dominated by heating. Huang et al. (2023) do find evidence that low-income households start to heat earlier in the season and heat for more months of the year than higher-income households. However, these results are also not comparable to ours since there is no normalization by area or occupancy. We estimate the heating inflection temperature (HIT), or the outdoor temperature at which each household turns on the heat because in every case heating constitutes the highest proportional energy expenditure (>60 %). To estimate the HIT, we calculate a linear splitwise regression of metered daily gas use on ambient air temperature. We find no significant trend in HIT across income (see Figure B.2). Combined, our findings and those of Huang et al. (2023) suggest that behavior-driven energy use patterns are unlikely to explain the higher energy use of low-income homes.

Observed heating and cooling setpoints—read from participants' smart thermostats—likewise reveal that lower income households do not on average choose higher setpoints in winter or lower setpoints in summer [Fig. 2a]. We do observe greater variance in the set points that households in the lowest income group (<$25k) choose [Fig. 2b], as well as in the indoor temperatures that they experience [Fig. 2c]. This suggests that, even though they have higher energy use intensity, these households are actively trying to manage their energy use and comfort by manipulating their set points. This provides evidence that the higher EUI is in fact due to poorer building envelopes and not because lower-income households are choosing consistently different setpoint temperatures.

We look at housing characteristics to explore whether the homes occupied by low-income households are in fact less efficient. Blower door testing conducted at each home provides an empirical measure of efficiency by measuring air infiltration. Low infiltration signifies high efficiency. We find that the homes retrofit by Habitat have better performance than market-rate homes in the sample. The median measured air infiltration rate of Habitat homes is almost half that of their counterparts (4.2 ACH 50 and 7.7 ACH 50, respectively) with less variability (range: 2.9–5.9; IQR = 3.4–5.3 and range: 3.2–17.5; IQR = 5.8–10.9, respectively). Applying the same regression method described above, after excluding Habitat homes, we find a significant downward trend (p-value = 0.023) for market-rate homes, indicating that the lower-income homes are indeed less efficient (Figure B.3).

3.2. Energy burden

For the 51 houses in our sample, we calculate the electricity loads that would result from replacing natural gas furnaces with air source heat pumps for space heating (see Supplementary Methodology for more detail on reduced complexity model and load derivation) and apply the most prevalent gas and electric utility rates across the sample to determine the energy cost change associated with this replacement. We calculate change in annual energy bills and energy cost burden which refers the difference in energy expenditures and percentage of income spent on utilities, respectively, between the baseline scenario and the heat pump scenario. 41/51 households were on a standard time-invariant rate, which will be discontinued as of May 2023. 10 had elected different rate structures, which include time-of-use rates, interruptible cooling rates, and specialty rates designed for low-income households. We find that switching to a heat pump would increase annual utility bills for every household in the sample, and that the cost goes up by $1154 on average (see Table C.3).

Our results show variability in median cost change across income and a disproportionate concentration of high energy burden increase below median income (<$25k and $25–50k). The median cost increase for below median income households is $801 ($n = 28$), constituting a 37 % utility spending increase on average. There is a 49 % utility spending increase for above median income households on average ($n = 22$) [Fig. 3a-1]. Even though the median cost increase is nominally lower for

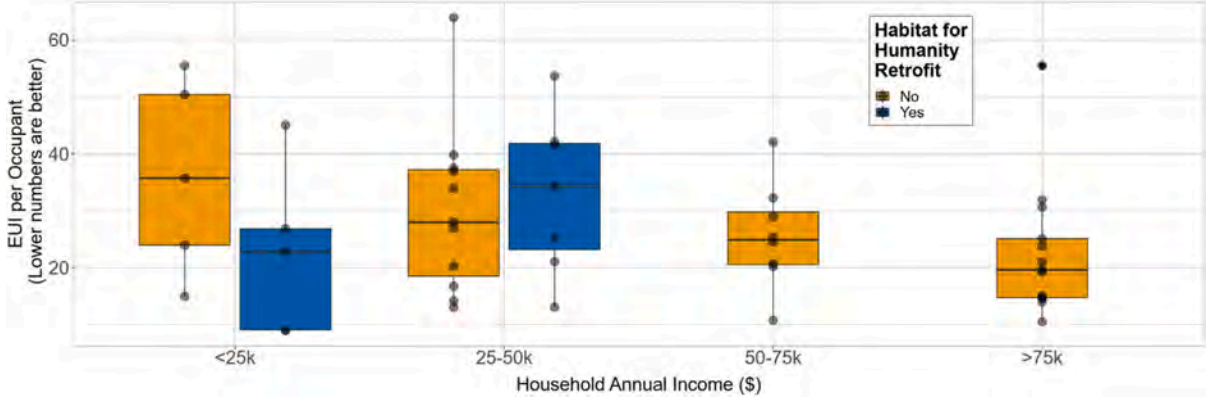

Fig. 1. Energy use intensity per occupancy by income group. Annual energy use per floor area divided by the number of occupants is shown here. The x-axis represents four income categories to which participants were assigned given the income range they provided. Each box plot shows the median (middle line), first and third quantiles (lower and upper box bounds), and minima and maxima (whiskers). The blue boxes represent homes that have been retrofit by habitat for humanity, which perform better than market rate homes in the sample (represented by oranges boxes) for homes earning less than $25k. Each dot represents one household. Using a non-linear least squares regression, we find a significant downward trend (p-value = 0.048) among market rate homes, indicating that those with lower incomes live in less efficient homes.

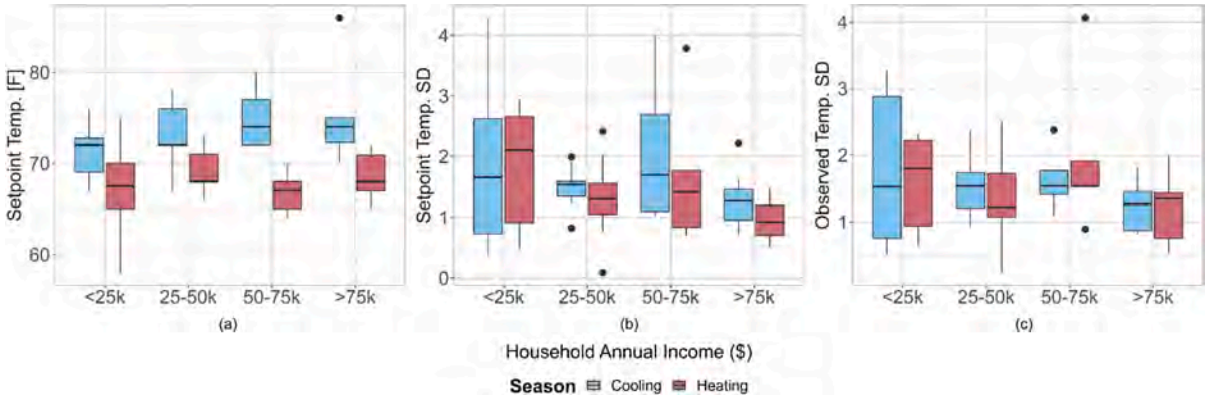

Fig. 2. a-b-c: Thermostat setpoint and observed indoor temperature by income. Observed heating and cooling setpoints (a), setpoint standard deviation (b), and indoor temperature standard deviation (c) on smart thermostats for each home.

below median income households, their energy burden increase is 4 times higher on average than those at or above median income [Fig. 3b-1]. Additionally, all households earning median income ($50–75k) and above (>$75k) - which currently have a median energy burden of 2.6 % – would experience a median change in energy burden of greater than 1 percentage point, indicating that energy burden could become a concern for households which are currently energy secure.

3.3. Time of use electricity rates

We examine the impact of two time-of-use rates available to all customers in the study region on the annual increased utility costs and energy burdens of the sample for a hypothetical conversion to heat humps. Switching to the standard time-of-use rate (DTE no. D1.11) ("DTE Electric Company Rate Book for Electric Service", 2023) reduces the mean cost increase for the sample by $120 per year from $1154 to $1034 (see Fig 3a-2) relative to a flat rate. Under this rate, the median

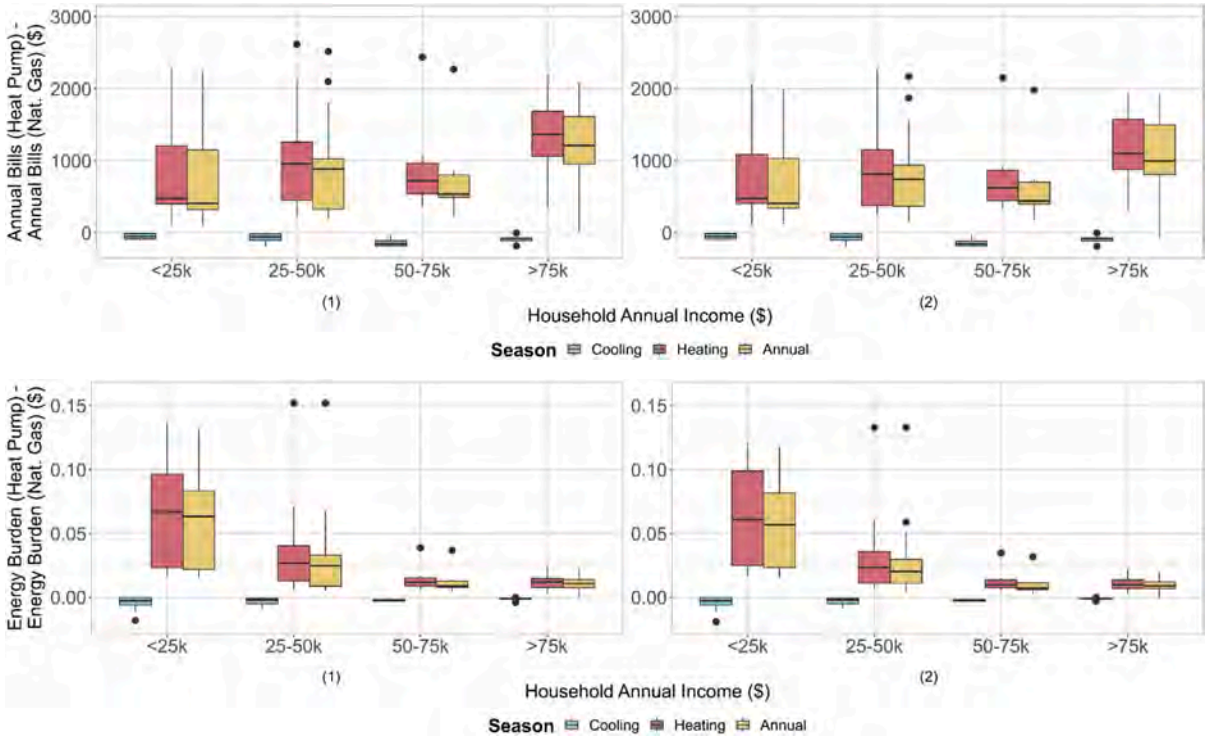

Fig. 3. a: Change in annual energy bills for switching to a heat pump from natural gas heating by income. The x-axis represents four income categories to which participants were assigned given the income range they provided. Dot represents outliers. Each box plot shows the median cost increase (middle line), first and third quantiles (lower and upper box bounds), and minima and maxima of change in utility cost change for (1) standard flat electricity rate and 2022 natural gas cost; (2) standard time-of-use electricity rate and 2022 natural gas cost.
b: Change in energy burden for switching to a heat pump from natural gas heating by income. The x-axis represents four income categories to which participants were assigned given the income range they provided. Dot represents outliers. Each box plot shows the median energy burden increase (middle line), first and third quantiles (lower and upper box bounds), and minima and maxima of change in energy burden change for (1) standard flat electricity rate and 2022 natural gas cost; (2) standard time-of-use electricity rate and 2022 natural gas cost.

utility cost change due to heat pumps is lower for every income category. The effect of this lower cost change is minimal for energy burden, reducing the rate by less than 1 percentage point for each category [Fig 3b-2].

By comparison, relative to a flat rate, the optional time-of-use rate (DTE no. D1.2) (DTE Electric Company Rate Book for Electric Service, 2023) would worsen the increase in annual utility cost for switching to a heat pump for all income groups. Switching to D1.2 increases the mean cost increase for the sample by $623 per year to $1777 (see Figure B.4). This rate nearly doubles the median energy burden changes for all income groups earning less than $75k (see Figure B.5). The D1.2 rate had a higher cost per kWh at peak times and a peak window two hours longer than the D1.11 rate. These rates impacted each household differently given the variety of occupants, schedules, housing vintage across the sample. For instance, those who saw the greatest cost increase with the standard time-of-use rate had the oldest, least efficient AC units in the sample and used their cooling systems during the peak window, whereas, in reality, the switch to a heat pump would include a new, more efficient AC.

While the gas commodity prices have risen dramatically from 2021 to 2023, the delivered price of natural gas for residential customers has in fact been modest and does not affect the results. See Figures B.4 and B.5 for a comparison of annual bill and energy burden changes with 2021 and 2023 gas rates. See Table C.2 for a detailed comparison of all of the electricity and gas rates available to DTE customers as of 2023 and their impact on baseline household energy use.

3.4. Energy retrofit model

Energy retrofits are a possible strategy to mitigate this increase in bills. Since we do not have empirical estimates of cost savings potential of envelope improvements to mitigate the cost increase of heating electrification, we first model the corresponding energy uses using the NREL ResStock End Use Savings Shapes (Wilson et al., 2022). We randomly sample 400 Michigan homes heated with natural gas from the database and examine four scenarios: baseline envelope with natural gas heating, envelope upgrade, heat pump upgrade, and combined heat pump and envelope upgrade. To then convert the energy uses to cost, we apply the electricity and gas rates experienced by 41/51 of our study participants to the hourly electricity and gas loads to estimate the relative cost impact of retrofits for the natural gas scenario and the heat pump scenario.

We find that transitioning to a heat pump without energy retrofits results in a mean utility cost increase of 26 % over the baseline. Adding a comprehensive envelope retrofit improvement mitigates this cost premium and drives utility costs back to what they were with natural gas heating with the existing envelope. Energy efficiency retrofits alone reduce bills by 11 % compared to the baseline condition [Fig. 4].

See Note D.1 for a comparison of the modeled results to the estimates calculated using observed data from the field study, including a breakdown of model findings by house vintage (Figure B.6).

3.5. Contractor retrofit recommendations

Our results suggest that, with energy retrofits, most homes would not experience an increase in utility bills relative to the status quo if they shifted to heat pumps. Based on REM/Rate (REM/Rate 2024), commonly used software, our contractor recommended a different combination of ten individual retrofit measures for the homes in our sample and these upgrades are expensive with long payback periods. The most commonly recommended measure is air sealing, an intervention in which joints are sealed to reduce air infiltration. We classify building envelope upgrades as simple if they can be completed by one contractor (e.g., spraying cellulose in the attic) and complex otherwise (e.g., foam injection into drywall). Upgrades to the HVAC system are in a separate category, as are upgrades to other appliances (e.g., fridges) (see Figure B.8). The median retrofit package costs are about 10 % of household income. ($3250 for <$25k; $4700 for $24–50k; $10,300 for $50–75k; $7000 for >$75k) (see Figure B.9). 14 households in the lowest three income groups are faced with total package costs of more than 20 % of their income. The median payback period across the sample is 24 years, with a large variance across the income groups (see Figure B.10).

Upfront cost and simple payback estimates for retrofits match previous studies. Fowlie et al. (2018) use empirical estimates for actual energy savings across the Michigan WAP and find internal rates of return (IRR) at −10.6 % (10 year), −2.3 % (16 year), and 0.21 % (20 year). We find even lower IRR for the recommended retrofits by the energy

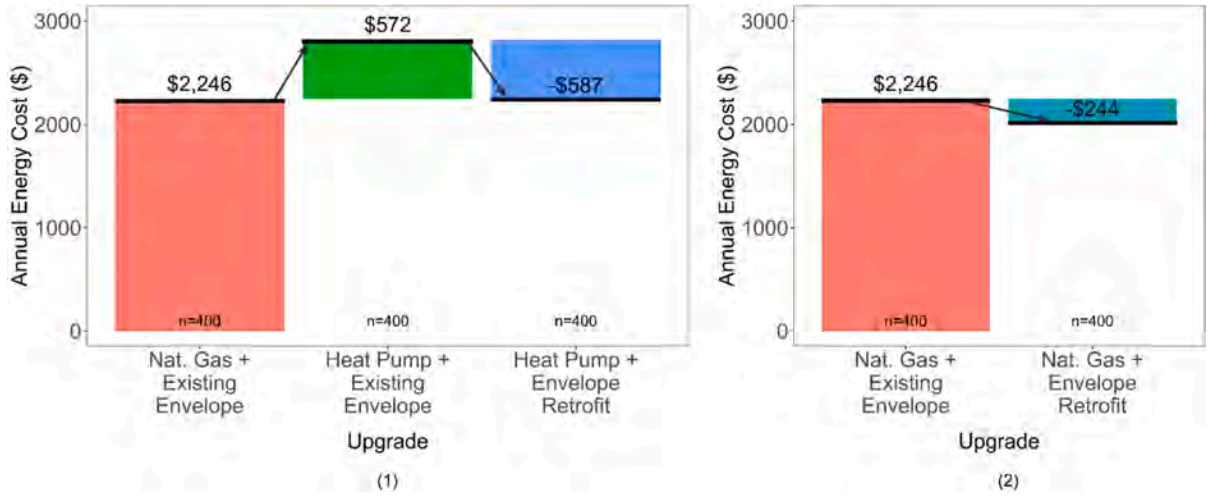

Fig. 4. Modeled mean annual energy cost impact of heating electrification and envelope improvements. (1) The baseline case (natural gas heating with existing envelope) represented in red is compared to two upgrades: heat pump with efficient envelope retrofit (green) and heat pump without envelope improvements (blue). (2) The baseline case (natural gas heating with existing envelope) represented in red is compared natural gas heating with efficient envelope retrofit (teal). Means represent 400 randomly sampled homes from the ResStock end use load profile database that use natural gas in Michigan. Using a Kruskall–Wallace test, we find a significant difference between the medians of the utility costs in each upgrade category (p-value < 0.01). We test the null hypothesis that the medians were the same using a pairwise with the Bonferroni adjustment and similarly find significant differences for each comparison.

assessment contractor: −16.1 % (10 year), −5.3 % (16 year), and 2.2 % (20 year). Less et al. (Less et al., 2021) estimate an archetypical retrofit package for a single family house that includes the most common retrofit recommendations in our sample (attic floor insulation, air sealing, foundation floor insulation) based on actual US construction costs at $7825 (see Note D.2 for measure cost calculation). The mean upgrade package cost estimated by the energy audit contractor in our sample is $7628 and the median is $5900 (see Figure B.9). Since the package described by Less et al. excludes system or appliance measures, we surmise that it is likely our contractor's costs are underestimates. Realized project costs could be higher, and payback periods longer.

There is no clear pattern about what measures are most cost-effective. The results show a large range of annual cost savings available from the recommended retrofit packages, with annual utility bill savings ranging from $26 to $730 [Fig. 5a]. We find that air sealing, which was recommended to all households, provides a payback range of 3.7 to 144 years [Fig. 5b] and attic insulation alone provides a payback range of 20 to 259 years (see Note D.2 for measure cost calculation). The high-end estimates that reflect payback periods much higher than seen in the literature are due a sample-specific scenario in which 25 % of the homes in the study received energy efficiency retrofits before the study period. For these homes, which were already high performing, the contractor recommended improvements to existing conditions (such as attic insulation and air sealing), which resulted in marginal energy savings and therefore long payback periods.

4. Discussion

We explored the drivers of energy inefficiency, explored the economic impact of replacing natural gas furnaces with heat pumps by income, assessed a range of energy retrofit measures that could support utility cost reduction in the 51 Michigan households we studied, and compared this impact to estimates from a national model. Heat pumps raise energy cost and energy burden disproportionately for low-income households. The median utility cost increase for switching to a heat pump is lowest for low-income households because they use the least amount of energy. This finding is suggestive of an efficiency paradox (Goldstein et al., 2022) where the lowest consuming households live in the least efficient homes, indicating that they are likely not using enough energy to meet their health, safety, and comfort needs. Yet, the increase in energy burden is disproportionately higher for low-income groups because even though their cost increase is nominally the smallest, it is a greater percentage of their annual income. Our results show that adopting heat pumps results in a fmedian energy burden increase of 75 % and 54 % for both income groups earning below AMI (<$25k and $25–50k, respectively). Given that households below median income have a 6 % median energy burden on their existing natural gas heating systems, such increases would severely worsen existing energy insecurity, for instance increasing risk of poor health (Reames et al., 2021) and coping behaviors like trading off paying utility for paying for rent or food (Hernández, 2016), or the underconsumption of energy in household who struggle to pay their bills (Meyer et al., 2018; Barrella et al., 2022; Faiella and Lavecchia, 2021; Antepara et al., 2020).

Policymakers should act to help lower the operating costs of heat pumps compared to natural gas for low-income households in cold climates. This can be done in three ways. First, government-sponsored initiatives to advance more efficient heat pump technology like the U.S. Department of Energy Residential Cold Climate Heat Pump Challenge are essential to improve energy bill affordability of fuel switching. More efficient heat pumps reduce the utility cost premium over natural gas furnaces.

Second, state regulators should exercise a more robust scrutiny of utility company returns and create more opportunities to improve customer outcomes in the rate making process. For example, the Michigan Public Service Commission recently ruled in a disputed rate case in the study region that resulted in allocations for energy retrofits in historically underserved areas due to intervening efforts from customer groups not typically represented in rate making like community

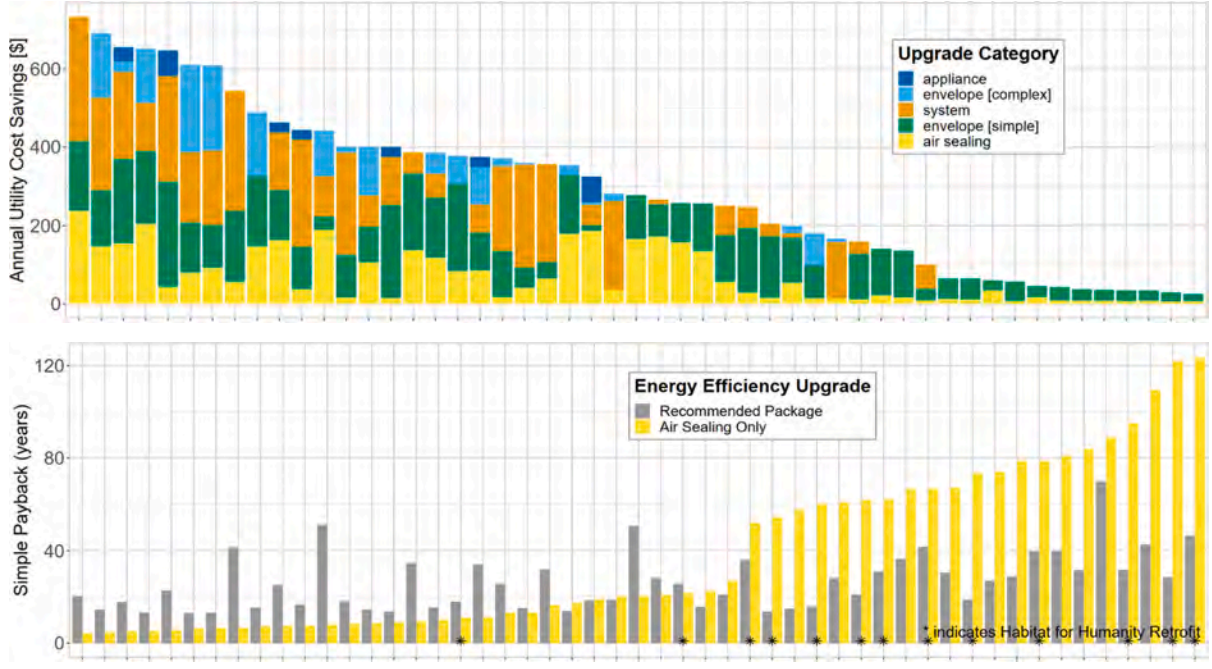

Fig. 5. a: Annual utility cost savings for retrofit packages by household. Colors represent categories we develop to indicate the relative cost and difficulty of adopting the recommendation. There is no clear pattern for which energy retrofits provide the best payback.
b: Simple payback for the recommended package and air sealing by household. Gray bars represent the payback for the full retrofit package recommended for each home. Corresponding yellow bars represent the air sealing payback period for that home. Star indicates houses that have been retrofit by habitat for humanity.

advocates and municipal governments (Hon et al., 2023). A high ratio of per-unit electricity to gas rates makes heat pumps less attractive than natural gas furnaces.

Third, states should consider implementing percentage of income payment plans (PIPP) that place a cap on energy expenditures relative to household income. These programs can be paired with federal- and state-funded retrofit programs to simultaneously improve the building stock and mitigate energy poverty. Capping household utility costs insulates low-income households from increase in bills.

Local factors exacerbate the economic penalty for household heating electrification described in this study and pose additional barriers to change not found in other regions. In our study sample, the average electricity cost is $0.18 per kWh and gas costs $0.8 per 100 cubic feet, or $0.03 per kWh. Per unit energy, electricity is therefore 5 times more expensive than gas, which is a large-enough difference that the higher efficiency of heat pumps is unable to compensate for it. (See Table C.4 for energy burden changes by income). Our results show that under these circumstances, energy cost increases for heating electrification could be disruptive even for households earning twice the median income.

Low-income households will need expanded and flexible financial assistance to retrofit their homes to prepare them for electrification. The subset (25 %) of homes that received deep energy retrofits prior to the data collection period had consistently more efficient air sealing and attic insulation than the market-rate homes. Retrofits to improve the performance of these characteristics were the most frequently recommended to study participants by the contractor, but we found they had a large range in payback period. There was no clear best choice investment that would provide either the greatest utility savings or the best payback, making it difficult for policymakers to make broadly-applicable recommendations for energy efficiency retrofits.

The group of very low earners (<$25k) with low energy burdens living in highly efficient homes were the same households that experienced the lowest energy burden increase due to heat pumps. This demonstrates the value of energy efficiency improvements in buffering households from the impact of utility cost rise due to electrification. However, the retrofits that provide the remedy are expensive. Our findings suggest that actual upfront costs for recommended retrofits in homes that have not been renovated far exceeded the $7700 cap for the Weatherization Assistance Program. Additionally, the payback periods in many cases were so high the projects would not qualify for the program, which requires a 1:1 saving-to-investment (SIR) ratio without consideration of discount rates. Current programs need to be expanded to cover the cost of expensive upgrades, and to be made available to more homes.

5. Conclusions

Policy action is needed to make heating electrification viable. The economics of electrification are adverse for the existing housing stock in cold climates. Our findings suggest that heat pumps are not a feasible economic alternative for households currently using natural gas, unless governments offset energy cost premiums through public funding. Some of the policy discussion around heat pumps does not acknowledge this (U.S. Department of Energy, 2023; Rewiring America, 2021; Fathollahzadeh et al., 2022). Such an investment can be justified on the basis of equity and by internalizing the social cost of carbon, current estimates of which are ~$180 per ton CO2 (U.S. Environmental Protection Agency, 2022; Rennert et al., 2022).

Coupling heating electrification with retrofits in existing homes with natural gas heating can limit utility cost increases and reduce a key barrier to heat pump adoption. At the same time, our study shows that even after a visit from a home energy auditor, homeowners can be left without sufficient information to act. The reports they are provided could be more useful in supporting investment decisions by providing a marginal abatement curve specific to each house, where the payback period of each measure is plotted against the cumulative cost of all the recommended measures. The homeowner can decide the most they are willing to spend, and the curve would show them all the fastest-payback measures that can be implemented for that amount.

The impact of rate structures should be analyzed based on empirical data from the rate base. Time-of-use rate design for electricity determines the cost increase for switching to heat pumps. We estimate that one rate (D1.11) reduced the increase in bills by 10 % compared to the flat rate (D1), while the other (D1.2) further elevated the average cost increase by 56 %. Modeled results using ResStock show the opposite, where the D1.11 rate is usually no worse than the flat rate (see Figure B.7 for utility rate comparison). Using empirical energy use data in utility rate design to understand how proposed rates affect households across the income spectrum and across housing quality given future adoption of heat pumps could help mitigate energy insecurity and promote greater access to heat pump adoption among natural gas users.

While our focus on Michigan allows us to understand the cost dynamics for electrification in a cold climate with high prevalence of natural gas use, limitations of our study include the small sample size and the limited regional scope. Additionally, we were unable to incorporate homeowner attitudes regarding converting their natural gas heating systems to electric heat pump systems. Future work will investigate these perceptions, examining the factors that influence decision making for residential electrification and further examining potential barriers to equitable adoption of heat pumps across income.

Ethics statement

The University of Michigan's Institutional Review Board reviewed and approved this research based on informed consent by study participants.

CRediT authorship contribution statement

Claire McKenna: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Project administration, Methodology, Investigation, Formal analysis, Data curation, Conceptualization, Funding acquisition. **Carina Gronlund:** Writing – review & editing, Supervision, Conceptualization, Methodology, Visualization, Formal analysis, Project administration. **Parth Vaishnav:** Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Project administration, Methodology, Investigation, Formal analysis, Data curation, Conceptualization, Supervision, Funding acquisition.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests:

Claire McKenna reports financial support was provided by U.S. Department of Energy and University of Michigan. Parth Vaishnav reports financial support was provided by University of Michigan.

Data availability

Model inputs and aggregated data that support the findings of this study are available from the corresponding author upon reasonable request. Demographic information for participants and raw data is not available in accordance with the informed consent agreement signed by study participants.

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Supplementary materials

Supplementary material associated with this article can be found, in the online version, at doi:10.1016/j.resconrec.2024.107699.

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Review

Direct air capture (DAC) vs. Direct ocean capture (DOC)–A perspective on scale-up demonstrations and environmental relevance to sustain decarbonization

Omnya Al Yafiee [a,b], Fatima Mumtaz [a,b,*], Priyanka Kumari [a,b], Georgios N. Karanikolos [c,d], Alessandro Decarlis [e,f], Ludovic F. Dumée [a,b,*]

[a] Khalifa University, Department of Chemical and Petrochemical Engineering, Sas Al Nakhl Campus, Abu Dhabi, United Arab Emirates
[b] Research and Innovation Center On 2D Nanomaterials (RIC2D), Khalifa University, Sas Al Nakhl Campus, Abu Dhabi, United Arab Emirates
[c] Department of Chemical Engineering, University of Patras, 26504 Patras, Greece
[d] Institute of Chemical Engineering Sciences, Foundation for Research and Technology-Hellas (FORTH/ICE-HT), 26504 Patras, Greece
[e] Research and Innovation Center On CO_2 and Hydrogen (RICH), Khalifa University, Arzanah Precinct, Abu Dhabi, United Arab Emirates
[f] Khalifa University, Department of Geosciences, Sas Al Nakhl Campus, Abu Dhabi, United Arab Emirates

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ABSTRACT

As the atmospheric concentration of CO_2 steadily increases and the world grapples with the pressing challenges of global warming, international research communities are actively exploring inventive technologies to combat the adverse effects of elevated CO_2 levels. An important challenge in this context is to extract CO_2 directly from the atmosphere. Consequently, capturing the last from seawater is crucial due to its impact on the delicate balance of marine ecosystems and the potential consequences for global climate regulation. While DAC and DOC show potential towards combating climate change, challenges including high operational costs and the need for further technological advancements persist. This paper critically discusses the status, challenges, and scalability of DAC and DOC at pilot or industrial scale. Key challenges include capital and operational costs, energy demands, and integrating green energy sources to reduce environmental impact. The review emphasizes on techno-economical benchmarking analyses to evaluate feasibility for large-scale deployment and their effectiveness in mitigating CO_2 emissions and acting as tools towards delocalized CO_2 production.

1. Introduction

As defined within the Paris agreements and the Global Climate Actions, announced at the COP28 conference hosted by the United Nations in 2023, global temperature rise should not exceed 1.5 °C compared to pre-industrial temperatures to limit the impact of climate change [1]. Human dependence on fossil fuels is still dominant and the transition to green energy production or decarbonization solutions ongoing [2]. In order to mitigate past and current emissions, the capture over 10 gigatons of greenhouse gases, primarily carbon dioxide (CO_2) annually from the air by 2050 to remain below this 1.5 °C threshold [3]. Negative emissions are essential alongside point source capture because they offer a means to actively remove carbon dioxide from the atmosphere, helping to offset emissions that are difficult to eliminate entirely. Direct Air Capture (DAC) and Direct Ocean Capture (DOC) play crucial roles within the broader spectrum of negative emissions technologies, complementing approaches such as afforestation, Bioenergy with Carbon Capture and Storage (BECCS), and Ocean Alkalinity Enhancement (OAE) [8,9]. While point source capture targets specific emission points, DAC and DOC provide additional avenues for carbon removal on a larger scale, contributing to overall efforts to combat climate change. Integrating these various technologies allows for a more comprehensive approach to achieving negative emissions goals and mitigating the impacts of carbon dioxide accumulation in the atmosphere [9].

Direct Air Capture (DAC) is a set of technologies that involves extracting CO_2 directly from the atmosphere [4]. DAC has been demonstrated at laboratory scale and pre-industrial scale and typically employs absorption- or adsorption-based processes to strip CO_2 molecules from the atmosphere. Once captured, the CO_2 must be either utilized for industrial processes, stored in tanks/reservoirs underground, or

* Corresponding authors at: Khalifa University, Department of Chemical and Petrochemical Engineering, Sas Al Nakhl Campus, Abu Dhabi, United Arab Emirates.
E-mail addresses: fatima.mumtaz@ku.ac.ae (F. Mumtaz), ludovic.dumee@ku.ac.ae (L.F. Dumée).

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converted into valuable products [5]. The increased global interest in DAC technologies has been encouraged through various new tax credits and policies worldwide, and a total of 18 DAC plants capturing more than 0.01 Million tons of CO_2 each year are as of 2023 operating globally [6]. Although a promising effort, these plants have an average capacity of 10,000 tCO_2 captured/year, only representing less than 0.1 % of the target CO_2 capture capacity required by 2050 to quench temperature increase [6]. DAC unfortunately remains financially prohibitive with current costs (2023) on the order of US$ 600 to 1,000/ton of CO_2 captured depending on the technology used, plant configuration, and the domestic cost of energy [7]. DAC technologies and efficiency must be improved to reach a target of $\leq$ US$ 100/ton to support market acceptance and field deployment [6].

Another route to capture CO_2 from environmental ecosystems is to strip CO_2 from the oceans [8]. Direct Ocean Capture (DOC) involves the removal of CO_2 from saline water and can be deployed either offshore or on the coastline [8]. The oceans absorb about 27 % of the total atmospheric CO_2 emissions yearly and maintain an equilibrium with that present in the atmosphere by naturally converting CO_2 to bicarbonate and carbonate ions. However, the increases in atmospheric CO_2 concentration is leading to increasingly steady acidification of all fresh and salty water bodies [9]. While the concentration of CO_2 in the atmosphere increased from ~345 ppm in 1985 to ~415 ppm in 2020 (recorded in Hawaii) [10], the pH of seawater has decreased over the same period from 8.15 in 1985 to 8.05 in 2020 (recorded in Hawaii) [11]. DOC application as a tool for carbon capture may therefore also support environmental efforts to reverse the ocean acidification process in high-risk niches and limit the impact on coral and fish communities. Many of such species are particularly sensitive to changes in pH, and further major shifts would directly affect the stability of the shells and exoskeletons of such micro-organisms [12].

Both DAC and DOC are supported by ongoing research and development, and their effectiveness, feasibility, and potential risks are subjects of scientific investigation and ethical considerations. Review papers and studies about DAC technologies used by the industry, along with future potential, life cycle assessments and the economic viability of their global application [13] have been developed whole DAC's techno-economic impact and scaling-up issues were explored providing a novel overview for its commercialization [14] in another assessment. A high-level discussion of the current DAC status and pillars of technology, as well as upcoming new projects, was introduced also [15], while current DAC plants were reviewed and compared techno-economically to evaluate future implementation between 2020 and 2050, and break-even point in terms of deployment compared to point source carbon capture systems [16]. A recent review focused on the prominent industrial DAC developers such as Climeworks plants in Hinwil and Hellisheidi and their carbon capture methodologies for cost-efficiency in CO2 capture per metric ton. Elaborate cost assessments on the selection of energy operations and the requisite process energy demands were presented. Verification of net negative emissions following carbon footprint reduction in operational plants, coupled with proposals to mitigate current DAC expenses was discussed, while highlighting the future strategies promoting a composite approach comprising private investments, governmental initiatives, corporate pledges to achieve net zero emissions, and backing from oil enterprises to enhance worldwide carbon capture capacity [17]. Another work presented mostly the LCAs of DAC processes and drawing from the outcomes of a LCA, the paper delved into the CO2 capture and mitigation capabilities of the DAC-U system, particularly emphasizing its applicability in household settings, while also scrutinizing its acceptance potential in Japan [18]. Very limited analysis have been performed on scalable DOC solutions, with only a focus on electrochemical ocean capture and electrochemical hydrogen looping (EHL) capturing efficiency [19].

In this review paper, the status of DAC and DOC particularly developed at pilot or full industrial scale is presented and critically discussed. Key challenges related to the pillars of CO_2 capture include the capital and operational costs, the energy demand, and the ability to integrate green energy sources to reduce the environmental footprint of the technologies. The focus of the review lies primarily on assessing the scalability and maturity of the technologies and establishing critical comparisons. Technological and economical benchmarking analyses are performed to evaluate the feasibility of large-scale deployment and the relevance to mitigate CO_2 emissions. A pertinent comparison between both DAC and DOC, from a deployment and scalability point of view, is also made to support an assessment of the technologies maturity and likely impact to mitigate emissions or support local production of CO_2.

2. DAC scaled-up technologies

DAC was first introduced by Klaus Lackner, a chemical engineer at Arizona State University, in 1999 [17]. DAC facilities, either permanent or mobile, are becoming increasingly popular as ways to tackle global warming and innovative solutions evaluating the performance of different sorbents/materials, processes, and designs are currently being developed [6]. As of 2023, 18 DAC plants, having a capacity of at least 1 ton CO_2 captured/year, are operational worldwide. The locations of these plants based on publically available information, are presented in Fig. 1. The majority of these sites are located in either North America or Europe.

The objective of this section is to discuss the technical and commercial maturity of commercial DAC systems. Scaled-up technologies, which have been commercialized and adopted by DAC companies will be discussed and critically assesed in terms of performance and energy requirements, as well as based on life cycle and techno-economic assessments.

2.1. Climeworks, Switzerland

Climeworks is a Swiss company, founded in 2009, that specializes in DAC technology [18]. Climeworks built in 2017 the world's first commercial DAC plant, named Capricorn, in Hinwil, Switzerland with 18 CO_2 collectors and a capturing capacity > 100 tons of CO_2/year [19]. Also in 2017, the Arctic fox facility was launched by Climeworks, combining DAC with underground CO_2 storage with a capturing capacity of up to 50 tons of CO_2/year [20]. Based on the previous plant outcomes, Climeworks was able to move into large-scale DAC by launching the Orca plant in 2021 which consists of 8 collectors, the current largest and first operational plant located in Hellisheidi, Iceland with a capturing capacity of 4,000 tons of CO_2/year [21] (Table 1, Entry 1). As an expansion of Orca, Climeworks is currently constructing the largest DAC and storage plant (Mammoth plant) in Hellisheidi, which will be designed to capture up to 36,000 tons of CO_2 annually and is planned to be operational by the middle of 2025 [22].

Climworks' technology is based on packed-bed amine functionalized adsorbents, through a cyclic process called temperature-vacuum swing adsorption (TVSA), wherby capture is performed at atmospheric conditions while regeneration is achieved at 100 °C under vacuum [23]. As depicted in Fig. 2a, ambient air flows into the collector, passing through the adsorbent to capture CO2 until it reaches maximum capacity. Once this capacity is reached, the inlet airflow is halted to initiate the desorption process. In order to desorb CO_2, heat must be delivered to the CO_2 collector at 100 °C leading to CO_2 being released from the adsorbent, with a negative vacuum pressure used as driving force [23]. Water vapour present in the captured gas stream is removed by passing a condenser prior to a separator to produce > 99.9 % pure stream of CO_2 at a pressure slightly over 1 atm and ambient temperature. A typical cycle for the batch process takes 4–6 h [24] to be completed with the majority of the duty cycle assisted by geothermal energy, as for the Artic fox and Orca plants, or from waste heat, for the Capricorn plant.

Climeworks suggests six different types of adsorbent materials for industrial applications including amine on silica, amine on alumina, amine on cellulose, two carbonate on silica-based adsorbents, and

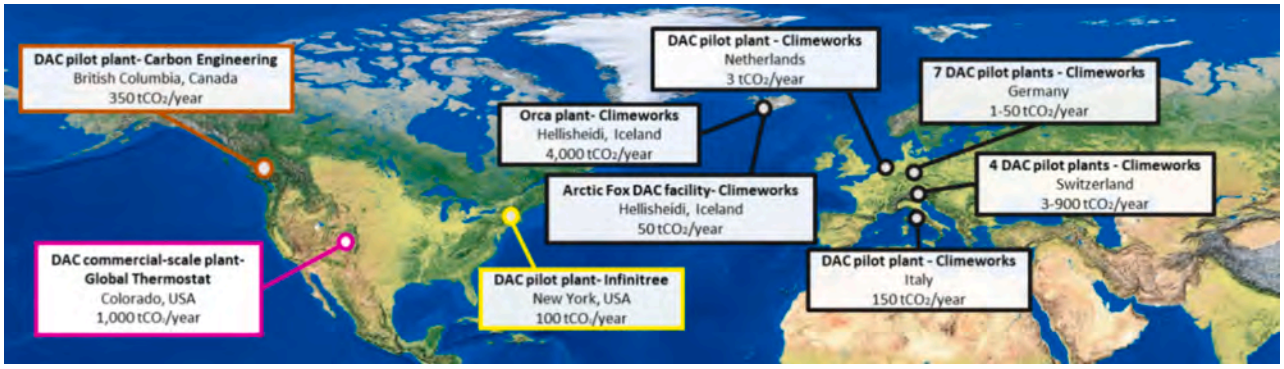

Fig. 1. Map of operational DAC plants worldwide with disclosed locations. 15 of the plants owned and managed by Climeworks are distributed around Europe. Two DAC plants are in USA; one belongs to Infinitree and the other to Global Thermostat. One DAC pilot plant in Canada owned by Carbon Engineering.

anionic resin, although specific detailed specifications are not publicly disclosed [24]. For the six adsorbents considered, the carbon footprint varies between 10 and 46 g of CO_2 emitted per 1 kg of CO_2 captured (Fig. 3(a). The production phase of the adsorbent contributes 60–91 % to the total carbon footprint of the adsorbent, which is greater than the end-of-life contribution. Fig. 3a shows that amine-functionalized alumina, potassium carbonate on silica, and potassium carbonate on activated carbon have the lowest carbon footprint. As a result of the considerable uncertainty associated with the life-cycle inventories (LCIs) of the adsorbents at the onset of their development, differences in their carbon footprints are considered minor [24]. However, Climeworks uses currently the following 2 amine functionalized chemisorbents in its processes: *(1)* SI-AEATPMS ([N-(2-aminoethyl)-3-aminopropyl]trimethoxysilane (AEATPMS) grafted on silica gel) and *(2)* APDES-NFC-FD (3-aminopropylmethyldiethoxysilane (APDES) on Nano fibrillated cellulose (NFC)) [25]. The latter is the one used in the Orca plant [25]. Other life cycle assessment (LCA) done on several DAC adsorbents showed that the production of 1 kg of SI-AEATPMS has the lowest carbon footprint equal to 4.12 kg CO_2/ kg adsorbent produced, thus the lowest environmental impact [26]. However, for the cradle-to-gate system, APDES-NFC-FD was the only one in the study that achieved an overall negative CO_2 emissions factor of − 116 kg CO_2 emitted/ton CO_2 captured [26]. In the 2nd place, SI-AEATPMS achieved an emissions factor of 625 kg CO_2 emitted/ton of CO_2 captured [26].

The two DAC plants in Hellisheidi and Hinwil were found to capture 93.1 v/v % and 85.4 v/v % of inlet atmospheric CO_2, respectively. The pilot in Hinwil, connected to a local waste incineration plant to utilize waste heat as a source of power, was used as a demonstration, to enable the development of 8-collector DAC, while the Orca plant in 2021 is located in Hellisheidi, Iceland, with a maximum capture capacity of 4,000 tons of CO_2/year [18]. Each collector in Orca is able to capture approximately 500 tons of CO_2/year. The capturing capacity of one collector is equivalent to about 20,000 trees' annual capacity. The Orca plant uses geothermal energy as a thermal energy source [27]. It requires 200–300 kWh/ton of CO_2 captured primarily consumed by the fans and control systems as well as an additional 1,500–2,000 kWh of thermal energy supply per ton of CO_2 captured for the regeneration of the adsorbent [15].

A LCA on DAC using Climeworks' technology stated it would require 3,683 DAC plants with an annual capacity of 100 ktons of CO_2 per plant to capture 1 % of the global annual CO_2 emissions equivalent in 2019 without any material or energy constraints [24]. Corresponding demand for materials (except adsorbent) and energy have low shares (below 0.1 %) of their global. The LCA is utilizing data from the plants in Hinwil and Hellisheidi, Switzerland, and considers the TVSA-based DAC system. Using an energy source with the least possible carbon footprint would enhance the benefit of DAC in climate change mitigation, in addition to the type of adsorbent as discussed before, as well as plant construction. At Hellisheidi, the DAC uses geothermal energy, while at Hinwil, it uses municipal waste incineration as a source of energy. In a worst-case scenario without metal recycling, the construction of a DAC plant with a capacity of 4,000 tons of CO_2 captured per year would emit only 15 g of CO_2 per kilogram of CO_2 captured (Fig. 3(b). In a best-case scenario with metal recycling, the carbon footprint of construction for a DAC application would be reduced to 6 g of CO_2 per kilogram of CO_2 captured. According to the future scenario in 2030, a large-scale DAC will require an additional 1.31 % of total electricity generation [24]. Global electricity generation will need to increase by 0.12 % to accommodate CO_2 storage in geological formations. The area required for 3,683 DAC plants on a large scale would be about 29 km^2 (~6% of the land area in the UAE is dedicated to agriculture, 490 km^2 [28]) and an additional 445 km^2 if wind energy was used as a source of electricity [24].

2.2. Carbon Engineering, Canada

Carbon Engineering (CE) is a Canadian company that has focused on developing and commercializing DAC technology since 2009 to remove CO_2 from the atmosphere based on an aqueous solvent–based DAC system [29] (Table 1, Entry 2). Using a continuous process of aqueous KOH sorbent coupled with calcium caustic recovery, CO_2 is being captured using CE's DAC technology. After many years of testing and research, CE launched its first pilot plant in British Columbia, Canada, with a capturing capacity of 350 metric tons CO_2/ year from the air in 2015. It was operating till 2020 and used for testing and research for further development toward commercial-scale processes [30]. CE's Innovation Centre was constructed in 2021, making it the world's biggest specialized DAC research and development facility. CE finalized the engineering design for the first large-scale commercial facility in 2022, utilizing data from the pilot plant and R&D facility [30]. Carbon Engineering is building currently the largest DAC facility, called the "STRATOS" facility, with a capturing capacity of half a million tons of CO_2 annually with the potential for scale-up to 1 million tons [31] (Table 1, Entry 3). It is expected that this plant will be operational by mid 2025 in Texas, USA.

The design ensures the continuous process operation by letting the air pass through the potassium hydroxide solution in the air contactor, then the CO_2-rich solvent is routed to further treatments to release CO_2 and regenerate the solvent (Fig. 2(c)) [32]. The process includes two connected chemical loops, and the first loop ensures the capturing of CO_2 from the atmosphere by reacting it with an aqueous solution with ionic concentrations of ~1.0 M OH^-, 0.5 M $(CO_3)^{2-}$, and 2.0 M K^+. In the second loop, $(CO_3)^2$ is precipitated by reaction with Ca^{2+} to form $CaCO_3$ while the Ca^{2+} is replenished by the dissolution of $Ca(OH)_2$. The $CaCO_3$ is calcined to liberate CO_2 producing CaO, which is slaked to produce $Ca(OH)_2$ [32]. Natural gas supplies the energy requirement for

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Table 1
Details of some DAC operational projects and future plans disclosed by major companies in the field.

Entry	Facility	Company	Location	DAC type	Temp of Adsorption (°C)	Temp of Desorption (°C)	Energy demand		Energy supply	CO_2 purity	Cost	Capture capacity	Ref.
							Electricity kWh/ton CO_2 captured	Thermal kWh/ ton CO_2 captured	By	%	US$/ton CO_2 captured	ton CO_2 / year	
1	Orca plant	Climeworks-(Operating)	Hellisheidi, Iceland	Adsorption (amine-based adsorbents)	Ambient	100	200–300 [15]	1,500–2,000 [15]	Geothermal Energy [24]	99.9	600 [6]	4,000	[24]
2	Pilot plant	Carbon Engineering-(Operating)	British Columbia, Canada	Absorption (KOH solution)	Ambient	900	–	–	Natural gas	97.1	–	350	[6]
3	"STRATOS" plant	Carbon Engineering-(Under construction)	Texas, USA	Absorption-(KOH)	Ambient	900	–	2,450 (expected)	Natural gas	97.1	94–232 (expected)	1 Million	[32]
4	Pilot-scale demonstration	Airthena-(nonoperational)	–	Adsorption-(MOF)	Ambient	80	2.28 per module	–	Photovoltaic	70–80	102	2 [119]	[45]
5	Commercial-scale DAC plant	Global Thermostat (Operating)	Colorado	Adsorption (amine-polymer-adsorbents)	Ambient	85–95	150–260	1,170–1,410	Steam	>98.5	< 150 (expected to reach)	> 1,000	[15]

regeneration. This technology can capture up to 73 % of CO_2 in atmospheric air [27].

Alkaline earth metal and alkali metal oxides and hydroxides (e.g., calcium oxide, sodium hydroxide, calcium hydroxide) have been investigated for DAC processes for their efficient and rapid CO_2 capture, but despite that, their development has been under questioning due to their high regeneration costs [33]. They are characterized by a superior affinity for CO_2 and could be regenerated by a reversible chemical carbonation reaction during the adsorption–desorption cycle of CO_2. Since KOH solution have strong alkalinity and offer fast reaction rates even with ultra-diluted CO_2, they have been investigated as sorbents for DAC processes [34]. KOH reacts with CO_2 to produce K_2CO_3, the last will react with CO_2 again to produce $KHCO_3$ which is soluble in water. Although the process performance is good, the energy requirements for regeneration remain significant. In order to regenerate the sorbent, CaO is added in water to form $Ca(OH)_2$, then the latter reacts with the salt resulted from the CO_2 and the alkali solvent reaction to form 2 products: $CaCO_3$ and the alkali solvent. Then, calcination of $CaCO_3$ is required to release pure CO_2 which needs a high operating temperature (≈900 °C), so a high energy consumption occurs, approximated to 180 kJ/mol CO_2 [35]. These methods have several disadvantages as well, such as solvent losses and salt impurities that lead to a loss of sorption capacity occurring during the calcium looping, as presented in Fig. 2c [32].

Natural gas is used to provide the heat demand that is more than 2,000 kWh/ton of CO_2 captured. It has been recorded that using natural gas, Carbon engineering DAC can emit 0.5 ton CO_2 / ton captured [15]. It might be possible to use carbon–neutral renewable synthetic natural gas (RE-SNG), but generating hydrogen from synthetic natural gas (SNG) would require approximately 4400 kWh [15]. As a result of high SNG production costs, there will be an increase in overall energy demand as well as production costs. It has been suggested in newer studies that a sustainable and affordable system should be completely electrified. For example, a fully electrified system requires 1,500 kWh of electricity for both power and heating per ton of CO_2 captured at 150 bar [15].

An LCA was performed on Carbon Engineering's technology and aimed at the capture and storage of 1 ton of CO_2, indicating that a total of 0.58 tons of CO_2 was emitted by the system [36]. This is considered relatively high due to the amount of heat required for CO_2 recovery from the sorbent. The use of a low-carbon energy supply (~70 g CO_2 emitted/kWh) can decrease the amount of CO_2 emitted to 0.26 tons /ton captured [36]. Regarding the utilization of a sorbent like KOH, it is important to extend its lifetime and limit environmental impact. In order to capture 1 gigaton per year the DAC units will occupy an area of at least 400 km^2, in addition to the area needed for DAC supply chains and the power supplied by photovoltaics, which is estimated to be 11,500 km^2 [36].

2.3. CSIRO, Australia

CSIRO stands for the Commonwealth Scientific and Industrial Research Organization. It is Australia's national science agency and one of the largest and most diverse scientific research organizations in the world. CSIRO was founded in 1916 and is an independent Australian government agency responsible for scientific research across various fields, including agriculture, health, energy, environment, and information technology [37]. CSIRO worked on different DAC projects, most of which are still in the early research stages. These projects are based on several capturing technologies including liquid absorbents (ACOHA and ENCORE projects), solid/liquid absorbents (Carbon Assist Project), and solid adsorbents (Airthena project, Fig. 2b).

In 2018, the CSIRO team initially examined the viability of utilizing amine liquid capture technology for DAC [38]. This investigation expanded on earlier laboratory studies and demonstrations of the technology's effectiveness in treating flue gas. The outcome of this research was the creation of the Ambient CO_2 Harvester (ACOHA) [39]. The captured CO_2 can be utilized as raw material in industries such as

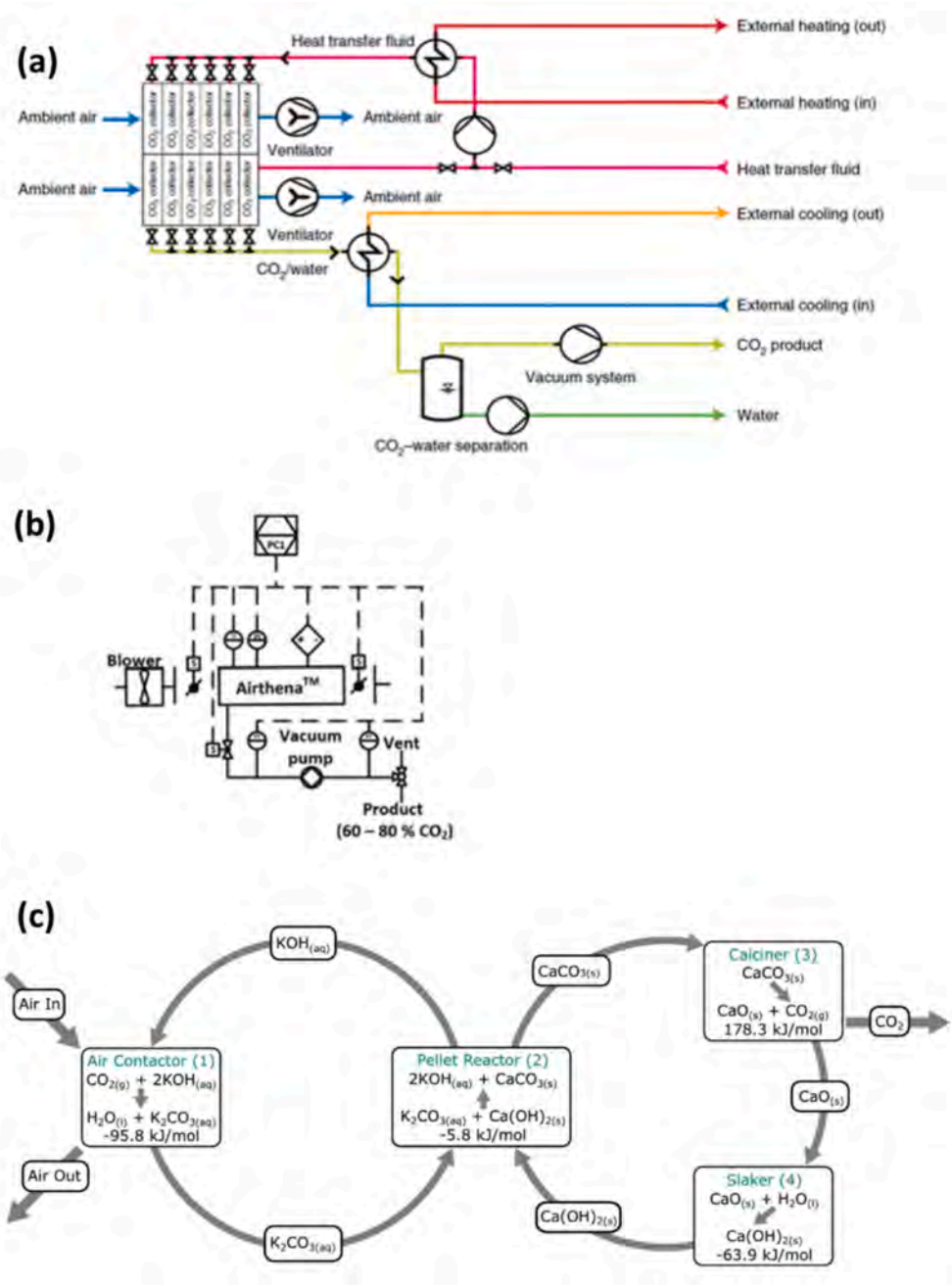

Fig. 2. (a) DAC process by Climeworks: Flow diagram of the DAC with 12 CO_2 collectors via temperature–vacuum swing adsorption [24], (b) Airthena-CSIRO Single DAC module [45]. (c) Carbon direct air capturing by KOH solution and calcium loop [32].

beverages, greenhouses, and fuel synthesis, or it can be stored. The ACOHA technology is adaptable for deployment at various scales [38]. The key strengths of ACOHA lie in its foundation on commercially available technologies, its potential to reduce costs through innovative processes and equipment, and its ability to quickly scale up for a significant impact on climate change mitigation [39]. The project's primary focus is on advancing DAC through liquid absorption technology, by incorporating innovative research in three critical areas: the formulation, investigation, and selection of liquid absorbents, the design and development of a cost-friendly absorber, and the process of solvent regeneration [40]. As also other efforts of CSIRO in DAC by absorption field, ENCORE project was also initiated with a partnership with Rolls Royce Plc [41]. The ENCORE project originated from the DAC solution developed by CSIRO, which is currently being utilized on a laboratory scale in Australia. The adsorbent is based on amino acid salts, for the purpose of capturing CO_2 from the surrounding air. The first phase of ENCORE is done including the study and design of the pilot plant demonstration by November 2021 [40]. The 2nd phase is to be implemented in the UK in 2024 [38]. Pilot plant constructed in phase 2 is planned to have a capturing capacity of 100 tons of CO_2 annually [40]. The carbon footprint of ENCORE system is expected to be ~0.12 ton CO_2 emitted per ton captured [40].

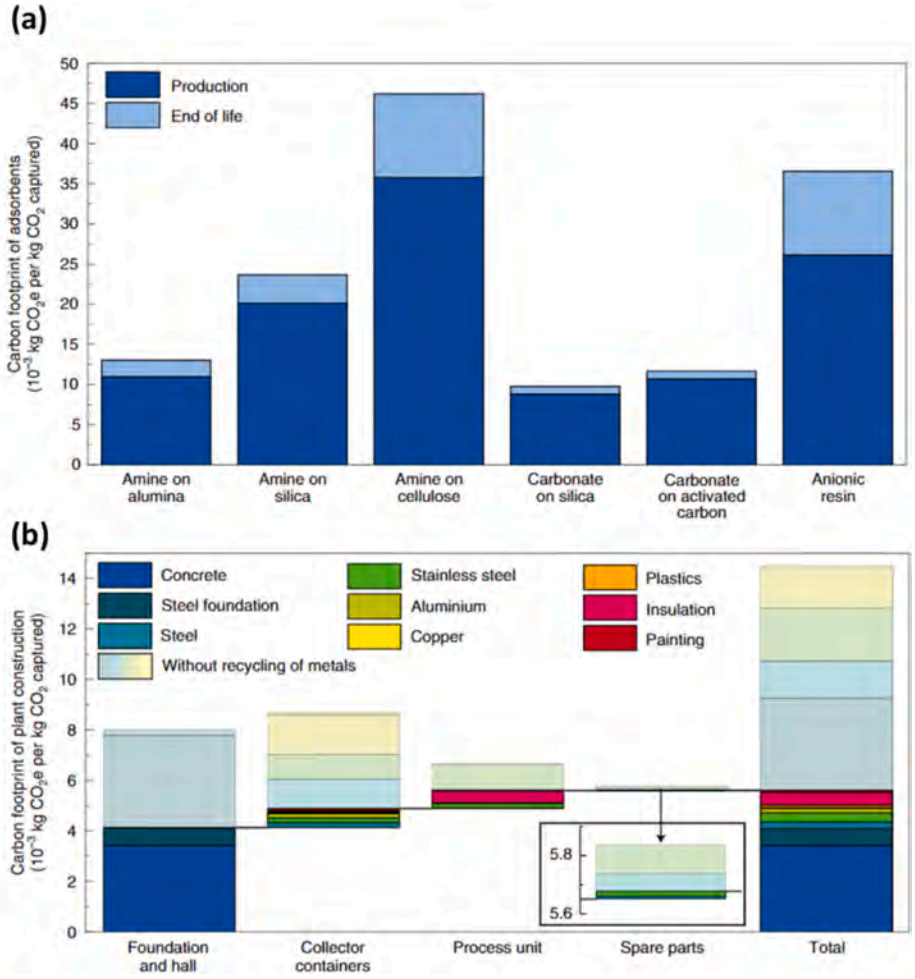

Fig. 3. (a) Carbon footprint of the 6 adsorbents suggested by Climeworks in their production phase and their end-life. (b) Carbon footprint analysis for Climeworks DAC plant construction with capacity of 4 kton/year CO_2 captured [24].

On the other hand, CarbonAssist employs an innovative sorbent material, comprising 30 wt% solid and 70 wt% liquid amine solvents, known for its remarkable selectivity in capturing CO_2 directly from air [42]. This material surpasses existing industry standards in terms of energy and heat consumption, cost-effectiveness, and efficiency. Encased within a two-part unit, the chemical system can be easily manufactured on a commercial scale. The sorbent operational lifespan ranges from 2 to 5 years, contingent on the specific application [42]. The research team is in the final stages of preparing a pilot plant in South Australia. The pilot plant is expected to have the capacity to extract 90 tons CO_2 /year, and efforts are underway to develop a larger second unit that can capture 365 tons CO_2 /year [38].

Airthena technology was announced in 2020 as an important breakthrough for CSIRO's procession in DAC (Fig. 2b) [43]. An adsorbent-based DAC system based on metal–organic framework (MOF) polymer nanocomposite was developed by CSIRO. The Airthena system is capable of producing 140 g of CO_2/ day with very low energy consumption (1.6 kWh/kg-CO_2 captured per module) during regeneration [44]. Two tons of CO_2 annually can be captured from the atmosphere using one module, which can be used for small-scale applications such as beverage carbonation and industrial cleaning [45]. Airthena is the only CSIRO's system with declared technical details and studied, thus it will be analyzed further in the coming paragraphs (Table 1, Entry 4).

There are 3 to 5 modules in the single Airthena's DAC demonstrator that process atmospheric air as a feedstock. With negligible back pressure, CO_2 is selectively stripped from the feed at a flow rate of 50 m^3/h per module. The blower, the adsorption chamber, and the vacuum pump make up a single module, as shown in Fig. 2b. The adsorption chamber includes the core of Airthena technology: a MOF/polymer nanocomposite and substrate configuration that adsorbs and desorbs CO_2. In a spiral configuration, thin layers of the MOF/polymer nanocomposite are coated onto long resistive heating sheets that are being incorporated in each adsorption chamber. A simple, energy-efficient, and low-cost technology called resistive heating is used in the regeneration phase [45].

For continuous operation of the Airthena's DAC process, Fig. 2b presents a simplified Process and Instrumentation Diagram. A parallel configuration is used for the three adsorption chambers. Hence, a smooth interchange of the adsorption and desorption phases is possible. TVSA is adopted as the adsorption-regeneration cycle [45] operating at 3 phases. The first phase is the absorption phase (1 h), where the fans allow air to flow into the chamber to capture CO_2. Subsequently, the regeneration phase (30 min) starts, and it is composed of 3 steps: In the evacuation step (15 min), the vacuum pump is activated to remove any remaining air within the module. In the desorption step (10 min), the vacuum pump is turned off, and the heaters are turned on. Within 10 min, the temperature is increased up to 80 °C to release CO_2 from the adsorbent. Then, in the collection step (5 min), the heaters are turned

off, and the vacuum pump is turned on to collect CO_2, which reaches 80 % purity. The adsorption-regeneration cycle is repeated after the collection step. When the collection step is over, a pause step occurs during which the operational module waits for other module to complete its cycle.

A pilot scale study on the Airthena demonstrator with 3 modules stated that each module has an average capacity of 3 g CO_2 per cycle, and the entire demonstrator can capture a total of 8 kg CO_2 over 2680 cycles [45]. It was also revealed that the composite adsorbent performed very well with no obvious loss in capacity or stability. The produced CO_2 has a purity of 70–80 % over the 2680 cycles. An optimum desorption temperature of 80 °C was observed. The demonstrator needed a supply of 1.6 kWh/ kg of CO_2 captured for adsorbent regeneration per module and a total energy requirement of 2.28 kWh/kg of CO_2 captured per module. Airthena modules are highly stable in ambient air, can be placed in remote locations, and have low energy consumption, which can be met entirely by renewable energy. Solar photovoltaics showed the lowest cost of electricity to run the process (102 US$/ton of CO_2 captured). The cost can be decreased more if a source of waste heat is available to 46 US$/ton of CO_2 captured [45]. For upgrading the purity, additional energy costs must be considered. MOF-based adsorbents offer high affinity to water molecules adsorption, requiring water stripping or dehumidifier units to increase the outlet purity.

2.4. Global Thermostat, USA

Global Thermostat is a company that specializes on CO_2 removal technologies, particularly DAC, and it was founded in 2010. Global Thermostat has operated a pilot and commercial demonstration plant at SRI International in Menlo Park, California, since 2010 [15] (Table 1, Entry 5).

The company provides DAC technology with a similar concept to Climeworks' DAC via adsorption but using amino-polymer-based adsorbent [15]. In the modular units, CO_2 regeneration occurs at 85–95 °C and happens in less than 100 s [6]. The outlet purity of CO_2 is $>$ 98.5 %. Sub-atmospheric pressure saturated steam is utilized to supply the required heat with 50 % heat recovery [15]. To decrease the final system costs, Global Thermostat designed a high-efficiency system and developed its amino-polymer-based adsorbent to reduce the full cycle time to less than 30 min. At the end of 2022, Global Thermostat started operating its first commercial-scale DAC plant with a capturing capacity $>$ 1,000 tons a year in Colorado [46]. The electricity demand is 150–260 kWh per ton CO_2 captured and heat demand is 1170–1410 kWh/ton CO_2 captured [15]. In this plant, Global Thermostat stated that the cost of CO_2 capturing will be targeted to achieve less than 150 US $/ton [15].

2.5. Other DAC systems

In addition to the described systems, other companies have been developing in this field with their technologies. As there is no publicly available information regarding the technical and financial aspects of these systems or their pilot-scale demonstration, this review will nominate some representative technologies among them with a brief description for each.

Skytree, founded in 2008 as a spin-out of the European Space Agency and based in the Netherlands [15], commercializes electrostatic absorption technology and moisturizing desorption technology (80–90 °C) for capturing CO_2. The key principle behind electrostatic absorption technology involves the use of electrically charged surfaces or fields to attract and capture particles, then, the desorption happens by moisturising of CO_2-rich sorbent. Ion-exchange resin serves as a pivotal component in this technology [15]. Thin resin sheets are initially exposed to the surrounding air, ensuring unimpeded airflow through the material. Once the loading process concludes, the sheets are transitioned into a sealed system. Within this closed environment, air is extracted, and moisture is introduced. Subsequently, the resin, upon contact with water, desorbs CO_2. Skytree's carbon capture system launched for indoor farming at Growy vertical farms in the Netherlands in 2022 is the company's first On-site Carbon Capture [47].

Infinitree is a carbon capture company located in New York that uses an ion exchange adsorbent to directly capture CO_2 from air [15]. It adopts the same working principle of Skytree, the moisture swing adsorption. It has an operating pilot plant in New York with a capturing capacity of 100 ton CO_2/year [6].

Soletair Power, headquartered in Lappeenranta, Finland, has been diligently working and developing the integration of DAC in buildings since its launch in 2016 [48]. Integrating this technology reduces buildings' emissions by up to 50 %, supports employee wellbeing, and provides a non-fossil resource that can be reused in a variety of ways [48]. Currently, they offer three types of DAC units, which are: (1) Outdoor CO_2 capture unit [capacity of up to 1,000 tons/year] (2) Building HVAC integrated CO_2 capture unit [capacity of up to 20 tons/year per] (3) Indoor CO_2 filtering and purifier unit [48]. A TVSA process and amine-functionalized adsorbent are utilized by Soletair Power within its carbon capture systems [48]. In 2018, they commissioned a demonstration facility [49]. DAC along with an electrolyzer for hydrogen production were utilized to provide the feedstock for a hydrocarbon production reactor. A total of 6.2 kg of wax and oil were produced each day during the 300 h that the pilot plant was operating [49].

Verdox, established in late 2019, is in the process of bringing its electroswing adsorption (ESA) platform technology to the commercial market. Originally conceived at MIT, this technology is designed for extracting carbon dioxide from both industrial emissions and the atmosphere. The company asserts that this approach leads to a 70 % reduction in energy consumption compared to conventional methods via absorption and adsorption [50]. Verdox has developed a prototype for DAC that utilizes electrochemical cells. In this ESA process, the cells are charged to capture CO_2 and subsequently discharged to produce a purified CO_2 stream for storage or utilization. The prototype incorporates quinone electrodes, which exhibit a strong attraction to CO_2 molecules when negatively charged but do not retain this affinity when the charge is deactivated [13]. In laboratory experiments, it has been demonstrated that the system can endure a minimum of 7,000 cycles of charging and discharging, experiencing a 30 % decrease in efficiency over that duration [51]. While a comprehensive techno-economic analysis has not been published yet, it has been estimated that the combined capital and operating costs for capturing one ton of CO_2 range from 50 to US$ 100 [51].

2.6. DAC commercial systems comparison and discussion on scale-up

Based on the regeneration temperature required, DAC technologies are categorized as either low-temperature solid sorbent systems, or high-temperature aqueous solution systems [10]. The processes based on DAC by adsorption are mainly categorized as low-temperature solid sorbent systems because the temperatures needed to regenerate these adsorbents are generally lower than the temperatures needed to regenerate liquid absorbents [10]. However, the reversibility of adsorption or absorption processes is influenced by factors such as the nature of the materials involved, the specific interactions at play, and the overall thermodynamics of the processes.

2.6.1. Low-temperature solid adsorbents

Technologies in this group involve an adsorption chamber containing the solid sorbent, where cyclic adsorption and desorption operation is performed. Physisorption technologies demand lower energy for sorbent regeneration than chemisorption-based ones since the CO_2 capture is done by only weak van der Waals forces. Nevertheless, adsorbents like zeolites and MOFs necessitate the removal of water before CO_2 separation/capture due to their low selectivity of CO_2 to water

vapour making them more suitable for dry conditions. Interestingly, this aligns with the advantage of cold climates for physisorption DAC technologies [52].

External and internal diffusion resistance play a crucial role in determining the effectiveness of adsorption. Because adsorption is an exothermic process, it is generally advisable to use an adsorbent with high thermal conductivity [13]. This quality facilitates heat transfer leading to minimizing the risk of thermal degradation. In scenarios where CO_2 concentration in streams is low, the heat transmission to the system through adsorption tends to be slow. Typically physical interactions are involved, such as van der Waals forces or weak chemical bonds. While these interactions may be weaker than the chemical bonds occuring in the absorption process, they can still be effective for capturing gases [1,2]. For instance, adsorbents, such as Metal-Organic Frameworks (MOF-177 and MOF-74), Zeolite 13X and 5A, activated carbon, and carbon nanotubes (CNTs), have microporous structure with high surface areas and tuneable pore sizes, therefore, are specifically designed to utilize on van der Waals forces to effectively adsorb CO2 at low concentrations [3]. While these interactions may be weaker than the chemical bonds occuring in the absorption process, they can still be effective for capturing gases [53,54]. In adsorption, CO_2 molecules adhere to the surface of a solid material. Thus, the capacity may be limited by the available surface area on the adsorbent. Subsequently, increasing the capacity of adsorption-based DAC plants may be also limited by land use. Adsorption also often has various constraints that affect its productivity, including low CO_2 selectivity and lower removal efficiency when compared to alternative technologies such as absorption processes. The removal efficiency of CO_2 by low-temperature DAC systems is controlled by the emissions resulting from operating the system which is mainly dominated by the source of energy, found to be ranging from approximately 8 % to approximately 95 % [55]. It's important to note that Climeworks produces the highest purity CO_2 of ~99.9 % because of adding subsequent units to condense the water content captured during the process.

Concerning low-temperature DAC systems, the primary contributor to the overall energy requirement is the heat consumed during the desorption phase [56]. The necessary regeneration temperatures typically range from 80 to 120 °C, significantly lower than those in the high-temperature DAC processes, at around 800 °C for KOH regeneration [13]. Consequently, low and medium thermal sources like geothermal, solar, and waste steam heat can be employed for adsorbent regeneration. Electricity is predominantly utilized for CO_2 compression, airflow through the porous structure, and for operating the vacuum pump to eliminate products and waste during the de-airing and desorption. Generally, the thermal energy required falls within the range of 4–7.5 GJ/ton CO_2 captured, while electricity consumption hovers around 200 to 700 kWh/ton CO_2 captured [56].

Implementing heat recovery systems to capture and reuse the heat generated during the adsorption process is of major importance as this can significantly reduce the overall energy consumption. Integrating renewable energy sources, such as solar or wind power, to supply energy for the adsorption process is also important as this can help reduce the reliance on non-renewable energy and lower the carbon footprint [11]. Investigating advanced regeneration techniques, such as microwave or radiofrequency heating, to achieve faster and more energy-efficient desorption also deserves attention.

2.6.2. *High-temperature liquid absorbents*

According to Carbon Engineering, KOH-based DAC can capture ¾ of CO_2 in the inlet air [43]. However, after considering the carbon emitted by the use of natural gas to provide the energy requirements of the system, the capturing capacity turrns to be less. With identical electricity supply conditions, low temperature DAC (LT-DAC) exhibited a greater carbon removal efficiency compared to high temperature DAC (HT-DAC), falling within the range of 45 % to 70 % [56]. Generally, DAC systems utilizing robust hydroxide sorbents demonstrate lower efficiencies in comparison to adsorbent-based DAC systems. This difference is attributed to the elevated temperature (800–900 °C) needed in the former to release CO_2.

During HT-DAC process operation, the solvent's regeneration process imposes the highest burden on the system's energy requirements. Using CE's technology as the typical process of this type, the calcination of $CaCO_3$ constitutes the most significant portion of the heat demand, specifically 5.25 GJ/ton of CO_2. Additionally, ~360 kWh/ton of CO_2 is needed for CO_2 compression, a cryogenic air separation unit for O_2 production, and to power the fans and pumps [56]. Among these, CO_2 compression is the most energy-consuming, accounting for almost 37 %, followed by 22 % for the air contactor and 22 % for oxygen production. Generally, for typical HT-DAC systems, the heat demand ranges from 5 to 9 GJ/ton of CO_2, and electricity demands range from 350 to 770 kWh/ton of CO_2 [56].

The high-temperature requirements of the HT-DAC systems limit the flexibility of renewable energy utilization. An ideal scenario for HT-DAC would be to run on low-carbon fuels, like biomethane or electrolytic hydrogen from renewable sources. There is potential for HT-DAC to transition to fully electric operation in the future, but at the moment this is only feasible on a small scale [4]. The commercial-scale HT-DAC system is designed to use natural gas as a source of heat and capture CO_2 produced by gas combustion, eliminating the need for additional capture equipment [4]. As a result, HT-DAC's emissions are significantly reduced while carbon is still removed. Nevertheless, in the future, if renewable energy sources can be used to provide high-temperature heat, carbon emissions could be further reduced, maximizing revenue opportunities [4]. Fast-tracking the commercial availability of large-scale electric calcination technology is considered a top necessity in order to facilitate HT-DAC plants running exclusively on renewable energy.

In the case of HT-DAC systems, a LCA studied three scenarios formulated by altering both the heat demand and the sources of electricity [57]. Findings revealed that in the baseline scenario, a carbon removal efficiency of 62 % could be achieved when the electricity demand was fulfilled by a natural gas combined cycle power plant. In the best and worst-case scenarios, where solar photovoltaic (PV) and the average coal-fired power plant in the USA were used as electricity sources, the carbon removal efficiencies were determined to be 93 % and 10 %, respectively [57].

2.6.3. *Cross-technology limitations, energy, and cost analysis*

In this section, low-temperature scaled-up DAC systems are compared first. While Global Thermostat shows a lower demand than Climeworks in terms of total energy requirements, the Airthena technology has not been tested yet for large scale or being scaled up as opposed to Global thermostat and Climeworks technologies which have been studied extensively at large pilot level. Airthena systems however require a lower temperature (80 °C) compared to the rest, likely to reduce at scale the process energy consumption, and Climeworks requires the highest temperature (100 °C). Based on the produced CO_2 purity, the Airthena system provides purity (70–80 %) less than the other two companies, so additional treatment will be required. The highest purity (99.9 %), which is provided by Climeworks, eliminates the necessity for further treatment and thus additional costs. Climeworks, also, achieves a very high capturing efficiency of 90 %, which none of the technologies can provide, according to recent literature. Based on the previous discussion and available information, it can be concluded the the Climeworks system is the most mature LT-DAC system for commercial scale. The cost imposed by this technology can be a challenge, but Climeworks predicts that by 2030 carbon removal costs will be below US$ 250/ton [58].

Climeworks is the only LT-DAC–based company with available disclosed information, so many LCAs and techno-economic assessments were done on their technology thus it will be further compared with CE's technology (HT-DAC). Based on total energy demand, CE's system requires a higher demand than Climeworks, and this is justified by the very

high regeneration temperature (800–900 °C) required to regenerate the KOH solution and the need for other further treatment units in the CE system e.g. slacker. The current cost of CE's technology is not disclosed, nevertheless, their expected cost to be reached by 2025 is 94–232 US $/ton CO_2 captured. Yet, the purity provided by CE (97.1 %) is still lower than Climeworks however it is still high and does not need further treatment. According to the land use, the 'ORCA' plant by Climeworks, with a capacity of 4,000 metric tons per year, has a size of 798.9 m^2 [6]. The 'STRATOS' plant by CE, with a capacity of 1 million tons/year, has an estimated area of 200,000 m^2 [6]. In general, the indirect land occupation related to the supply chain for HT-DAC systems is about four times greater than that of the LT-DAC systems, specifically the temperature swing-based ones. This difference is primarily attributed to the manufacturing and end-of-life stages of DAC units and adsorbents [36]. By levelising the annual plants' capacities per area, it is noticed that both plants are capable of capturing annually 5 tons of CO_2 /m^2. Carbon capture and regeneration units are separate in HT-DAC systems, which enable continuous carbon absorption and regeneration. In contrast, LT-DAC technology combines adsorption and desorption in one unit. This limits each step's operating time. There may be an increase in the cost of time management and storing of renewable energy heat, as a result of this [15]. A techno-economic assessment used CE as a base case for HT-DAC with an electrified system and Climeworks' technology as a base case for LT-DAC [15]. Electrified systems for DAC use electricity to power the capture process. The levilesed costs of HT and LT in 2020 are 878 US$/ton CO_2 captured and 788 US$/ton CO_2 captured, respectively [15]. The electricity demand of HT-DAC and LT-DAC are 1,535 and 250 kWh/ton CO_2 captured, respectively. LT requires an additional low-temperature heat demand of 1,750 kWh/ton CO_2 [15]. The costs of HT/LT are expected to decrease by 2050 as follows: 2030 (378/338 US $/ton CO_2), 2040 (265/237 US$/ton CO_2), and 2050 (222/199 US$/ton CO_2) [15].

From a carbon footprint viewpoint, for the capture and storage of 1 ton of CO_2 via HT-DAC and LT-DAC, 0.58 and 0.30 tons of CO_2 will be emitted into the atmosphere, respectively [36]. The primary factor influencing life-cycle greenhouse gas emissions in the process is the need for process heat to extract CO_2 from the sorbent [36]. The carbon footprint for DAC systems can be minimized by the use of low-carbon energy sources or better energy integration configurations, as discussed in the previous section for each case. Since HT-DAC systems require the highest energy for regeneration they impose the highest carbon footprint.

Water demand in the DAC system can also play a role in the sustainability of the related technologies. The amount of water evaporated, during the DAC process at high-temperature with aqueous solutions, may vary from 0 to 50 tons/ton CO_2 captured [15]. This evaporation is contingent to factors such as the temperature and humidity of the surrounding air, as well as the salt concentration of the solution. The regeneration process in HT-DAC involves several processes that impose elevated temperatures, which can lead to water evaporation and loss; Keeping a constant amount of water in the alkali solution is important to control the absorbtion kintics. For instance, Carbon Engineering's new design requires 4.7 tons of water/ton CO_2 captured at ambient conditions of 64 % RH and 20 °C [15]. Climeworks can however capture 0.8–2 ton of water/ton of CO_2 captured [15]. LT DAC systems may therefore become a net near-deionised water producer to sustain other processes, representing an added value to the process.

CO_2 low concentrations in the air is the most challenging obstacle to DAC economic feasibility. This is why very highly selective materials are required to be applied in DAC applications. Nevertheless, the contaminants in air and compositions can vary from day to day and from location to location. The low concentration of CO_2 in the air allows other gases present to compete with CO_2 on active sites of the capturing sorbent. The most important contaminant that could affect the capturing process is humidity. The water vapor content can decrease the capturing capacity of CO_2 for most DAC systems based on physisorption materials, such as MOFs and Zeolites, due to competitive adsorption. However, this can be easily solved by introducing a condenser before the capturing chamber to dehumidify the inlet air, as done in Climeworks technology.

After extracting CO_2 from the atmosphere, there are multiple options for its utilization. It can either be stored underground for long-term removal or employed directly for various purposes, such as beverage carbonation, fertilization in greenhouses, or as a refrigerant. Additionally, CO_2 can be used indirectly as a feedstock for processes that generate chemicals, fuels, and building materials. Among the 18 DAC plants currently operational globally, only two are storing CO_2 in a specifically designated storage site, which are Orca and Arctic fox ClimeWorks' plants [4]. The remaining 16 plants are capturing CO_2 for immediate use in nearby industrial facilities. CO_2 has several storage options, including geological storage in deep saline aquifers, depleted oil and gas fields, and other rock formations. The expenses and time required to establish CO_2 storage facilities vary based on the location and are influenced by factors such as the availability of subsurface data and reservoir properties. The costs associated with CO_2 storage can be relatively low. For instance, more than half of onshore storage in the United States is projected to be accessible at a cost below US$ 10/ton of CO_2, and approximately half of its offshore storage is projected to be available at costs below US$ 35/ton of CO_2 [4].

2.6.4. Emerging technologies for DAC

There are several emerging DAC solutions that have been either proposed theoretically or else demonstrated at low technology readiness levels (1–3). These strategies include (i) membrane separation, as well as (ii) a hybrid process involving absorption and electrodialysis and will be presented in this section.

Membranes are amongst the most efficient methods of capturing CO_2 from flue gas-type effluents since they are relatively inexpensive, simpler to install and operate, and leave a smaller ecological footprint than sorption processes. To maximize membrane permeance for CO_2 capture from air, however, the materials selected should be fine-tuned with extremely CO_2-philic compounds, while the thickness of the selective layer of the membrane should be reduced to a nanoscale level to support fast transfer and extreme selectivity. However, to date, CO_2 separation with membranes is not yet commercially available on a large scale and still needs additional improvements to be used at very low solute concentrations of CO_2 in air and to be economically feasible. CO_2 gas separation from other gases is mainly accomplished using glassy or rubbery polymeric membranes. The main objective is to overcome and solve the trade-off between existing polymer permeability and selectivity [59]. As the main application of membrane gas separation, most polymers have been examined for removing CO_2 from methane [60]. As a starting initiative for using membranes in DAC, some studies investigated such polymer membranes in CO_2/N_2 mixtures. The performance of glassy polymers in separating CO_2, depending on their physicochemical properties, was promising. Glassy polymers studied, such as Poly(1-trimethylsilyl-1-propyne) (PTMSP), Polymers of intrinsic microporosity (PIMs), Poly(ether-Sulfone) (PES) are highly reproducible and have acceptable mechanical properties. However, their performance was significantly reduced as a result of physical or chemical attacks [60]. On the other hand, rubbery polymers could be considered a better choice for CO_2 capturing in DAC, since rubbery polymers, such as Polydimethylsiloxane (PDMS) & PEBAX, are not susceptible to physical aging as glassy ones. Table 3 compares gas separation of CO_2 in CO_2/N_2 gas mixture through membranes made of glassy and rubbery polymers, and new porous carbon-zeolite mixed-matrix membrane. For DAC application, selectivity less than 40–50 cannot be acceptable neither efficient because of the low concentration of carbon dioxide in the atmosphere. PEBAX, as seen in Table 2, is suggested as a promising and scalable material for membrane design for DAC. A simulated multistage membrane process, using ASPEN PLUS, was used to evaluate the potential of using membranes for DAC, specifically an ultra-thin free-standing siloxane nanomembrane and the energy requirements [61].

Table 2
Comparison of CO_2 separation performance in dry simulated air by different membranes.

Polymer/ membrane material	Details	Conditions (T/ P)	CO_2 permeance/ permeability	Selectivity (CO_2/ N_2)	Ref.
PEBAX MH1657 (60 % PEO,40 % PA6)	Thermoplastic polyether-block-amides Used in thin film composition membrane (TCM)	25 °C 2 bar	128 ± 17 Barrer	64	[120]
PDMS (polydimethylsiloxane)	Rubbery polymer Used in (TCM)	25 °C 2 bar	3,395 ±55 Barrer	11	[120]
PTMSP	Glassy polymer	25 °C	29,000 Barrer	10.7	[60]
PIM-1	Glassy polymer	30 °C 0.2 bar	2,300 Barrer	25	[121]
SABO −34 (30 %wt loading)	Porous carbon-zeolite mixed-matrix membrane	35 °C 1 bar	2,615 Barrer	31	[122]

The outlet concentration of the retentate gas was desired to be equal to 300 ppm. To model the separation, 4 membrane stages were considered. It was concluded that it is possible to achieve the target CO_2 concentration with membrane separation that has a CO_2 selectivity as low as 30. However, other gases also permeate faster in systems with low selectivity, leading to a rapid increase in CO_2 concentrations in the retentate streams. Therefore, the lower selectivity membrane should have a smaller area than a high selectivity one. As a result, the membrane should not release retentate gas with more than 300 ppm of CO_2. With highly CO_2 selective membranes, CO_2 emissions and pumps energy consumption are relatively low. The higher the selectivity, the higher the CO_2 concentration in the product gas, the larger membrane area needed, and the lower the energy required.

A combination of absorption and electrodialysis process was first proposed ~two decades ago in Germany. The method devised involve the intake of air, wherein the CO_2 present in the air is absorbed using a NaOH solution [62]. The CO_2 is then released in a nearly pure form by acidifying the product Na_2CO_3 with H_2SO_4. Subsequent steps involve the restoration of NaOH and sulfuric acid through an electrochemically driven membrane process (electrodialysis). Notably, the process exclusively relies on electricity, without the need for thermal energy. In 2009, the process underwent a redesign for continuous operation, eliminating the utilization of H_2SO_4 [62]. The essential acidification of the Na_2CO_3 solution was carried out directly in an electrodialysis cell. Despite these advancements, there has been no commercial application of the process.

Achieving efficient separation with membranes for DAC requires addressing several factors due to the low concentration of CO_2 in the feed; however, elevated pressure is not necessary for this process. The lower the concentration, the higher the selectivity needed. To maximize membrane permeance for CO_2 capture from air, the materials should be fine-tuned with highly CO_2 −philic compounds. Additionally, the selective layer of the membrane should be reduced to nanoscale thickness to support fast transfer and extreme selectivity. Surface functionalization of membranes using materials such as Polyethyleneimine, graphene oxide (GO), and zeolites can enhance CO_2 selectivity (>40). Moreover, directing air onto the membranes using a compressor can help achieve the necessary separation efficiency. For instance, a study simulated a multistage membrane process using ASPEN PLUS to evaluate the potential of organic-polymer membranes for DAC, specifically ultra-thin freestanding siloxane nanomembranes (34 nm thick), and their energy requirements [4]. The inlet pressure was set to atmospheric pressure, and the permeate pressure was set at 5 kPa. By using four stages of membrane separation in series with a CO_2 selectivity of 50, it was possible to achieve up to a 66 % CO_2 concentration in the product gas under ambient pressure conditions. This validates that high pressure is not required to achieve efficient separation using membrane-DAC.

2.6.5. *DAC scale-up, potential, and challenges*

The greenhouse gas (GHG) emissions of DAC configurations are significantly influenced by the source of energy supplied for heat and electricity during the CO_2 capture process. Waste heat is particularly environmentally advantageous as a heat source. The GHG intensity of the electricity mix on the grid is a critical factor for DAC configurations connected to the grid, and its impact varies by country. Countries that combine the use of waste heat with mixes of low GHG-intensive electricity demonstrate the lowest GHG emissions. For instance, Norway and Iceland achieved GHG removal efficiencies of 97 % and 94 %, respectively, obtained by an LCA study using the Climeworks DAC system as a base case [55]. In contrast, countries heavily reliant on fossil fuels for electricity, like Greece, experience high GHG emissions, almost reaching net-positive GHG emissions at 0.91-ton CO_2/ ton CO_2 captured for grid-coupled DACs [55]. Autonomous system designs emerge as a promising alternative, showing GHG removal efficiencies ranging from 79 % to 91 % [55], particularly in locations with ample solar irradiation, eliminating the need for fossil fuel-based grid electricity and heat consumption. The findings suggest that by employing geothermal energy as a heat source along with a predominantly renewable electricity mix, the efficiency of carbon removal can reach 93 % [56]. Under optimal conditions utilizing waste heat and low-carbon electricity, the carbon removal efficiency can almost reach 97 %. However, this figure can drop significantly to as low as 8 % when the grid electricity is predominantly sourced from fossil power [56].

The cost of and potential of DAC for countries and companies to implement remain crucial interrogations. By 2050, DAC should be able to remove gigaton-scale CO_2 for US$ 100/ton or less [6]. It may be economically viable to perform DAC is the price for the capture of a ton approaches US$ 100. As of now, DAC removal costs are between US$ 200 to 600/ton, which is far from the goal. Nevertheless, DAC cost will for sure vary from region to region. Demonstrations of DAC technology have already taken place in Europe and North America. These regions are deemed suitable for hosting additional DAC facilities due to their accumulated experience and the potential for co-locating with existing industrial centres, as well as established infrastructure for transporting and storing CO_2. Other regions that exhibit cost competitiveness for deploying DAC include those with exceptionally high renewable energy potential, such as North Africa and the Middle East. Additionally, regions with low natural gas prices, such as the Middle East and Russia, and those with a strong interest in CO_2 utilization, such as Japan, are considered viable for DAC deployment. At a regional level, it is anticipated that lower CAPEX for DAC will be in North Africa, China, Russia, and the Middle East, than in Europe and US due to cost-effective materials and manufacturing [4]. Regions abundant in gas resources, such as the Russia and the Middle East, are expected to have lower gas prices compared to Europe and the United States. Simultaneously, CO_2 prices are projected to be higher in Europe, the United States, and Japan ($\leq$USD US$ 250/ton CO_2) than in the aforementioned regions [4]. These factors collectively contribute to a regional decline in the cost of carbon captured via DAC by 31–43 % from 2020 to 2030 and by 10–24 % from 2030 to 2050 [4].

For DAC to be used to combat climate change by capturing CO_2, the scaling up of the process should be extensively studied and further developed. Below are some considerations and approaches involved in scaling up DAC [6,22]. The first one is technological advancement. Scaling up DAC requires the development and deployment of more

efficient and cost-effective technologies. A reduction in operational costs can be achieved by advancing and optimizing CO_2 sorbents, optimizing air contactors, and regeneration units. The recent focus has been on modular units and passive air contactors [6]. As for DAC equipment, improvements in its manufacturing and/or creation can lower the costs. As for the sorbents, after many cycles of loading and unloading, they deteriorate. Over time, this process reduces the sorbent's quality, which ultimately compromises carbon capture's efficiency and capacity. Hence, it is imperative to develop higher-capacity sorbents utilizing readily available materials such as biochar and silica [15]. Additionally, there is a need to discover more energy-efficient metal oxide adsorbents [15]. Addressing energy demands is another critical aspect, as the technology is currently hindered by high energy requirements. Implementing moisture swing techniques can potentially reduce the energy required for regeneration, while electro-swing processes may eliminate the need for thermal energy altogether [6]. Furthermore, utilizing low-cost, renewable power sources, such as recycling waste heat, to operate DAC plants has the potential to further reduce operational costs. Another approach to cost reduction involves the mass production of DAC units, prioritizing an increase in the quantity of units rather than their individual size [6]. By applying the principles of learning by doing in the mass production of DAC, it is anticipated that costs will decrease significantly and swiftly. Another important aspects to consider is the absence of governmental backing and policy support that pose a challenge to the widespread adoption of DAC on a large scale [14]. Political endorsement is undeniably a crucial element in enabling DAC technology, particularly in driving down its cost to below US$ 100 per ton. Initial investments and the establishment of supportive policy frameworks are essential for the successful implementation of mass production and deployment of additional DAC facilities. The last area to consider is integration with carbon management. Scaling up DAC should be accompanied by robust carbon management strategies. This involves developing infrastructure for CO_2 storage or identifying viable utilization options such as carbon–neutral fuels or materials production.

Other routes to mitigate CO_2 in environmental ecosystems should also be equally investigated and one of such, relying on stripping CO_2 from the oceans, referred to as Direct Ocean Capture (DOC), will be presented in the next section.

3. Direct ocean capture commercial pilot systems

Oceans are essential to the global carbon cycle due to their vast carbon storage capacity, of approximating 38,000 gigatons [63], which is significantly greater than either the 700 gigatons capacity of the atmosphere or the 2,000 gigatons capacity of the terrestrial biosphere [64]. Additionally, oceans absorb ~2 gigatons of CO_2 annually, over two orders of magnitude greater than the amount in the atmosphere [65,66]. A new statistic depicted that ocean annual CO_2 sink during 2012–2021 was 26 % of total CO_2 emissions [67]. Ocean acidification is also a major concern for marine scientists since affecting marine wildlife. Marine calcifiers are particularly at risk as they make calcareous structures that are vulnerable to ocean acidification. Acidified seawater (at CO_2 levels from 1,000 μatm to 1,500 μatm measured for southern oceanwater) can dissolve $CaCO_3$ minerals and hinder calcification, causing increased fragility of calcareous structures [68,69].

Tactics to capture CO_2 from oceanwater rely on converting dissolved inorganic carbon from carbonates and bicarbonates into molecular CO_2, which may then be stripped at sub-atmospheric pressure [70]. The efficiency of DOC processes is influenced by the concentrations of dissolved CO_2, CO_3^{2-} and HCO_3^-, as well as the native ocean acidity. Since the solubility of CO_2 is greater at lower temperatures at high-latitudes, the oceanic CO_2 uptake therefore varies depending on the global ocean location, representing a significant factor when designing effective CO_2 capture strategy [71,72].

This section will discuss the potential of DOC technologies as well as current design attempts of pilot-scale DOC systems for CO_2 removal. Besides, critical analysis related to technical considerations, and a techno-economic discussion on the challenges faced towards scale-up will be presented.

3.1. Electrochemical pH swing DOC systems

The electrochemical pH swing process involves regulating the production of protons (H^+) and hydroxide (OH^-) by applying a gradient of potential between the anode and cathode. This transition from an alkaline to an acidic pH aid in the trapping and subsequent release of CO_2. By adjusting the potential difference, the local pH of the cathodic and anodic compartments can be modified in two ways i.e. a high pH environment is created at the cathode to capture CO_2 as HCO_3^- or CO_3^{-2}, while a low pH environment is established at the anode to release free CO_2 [31]. The electrochemical process can produce pure CO_2 that can be directly utilized for the production of high-value chemicals and fuels. The treated water, following CO_2 release, is subjected to a pH increase to counteract acidification and facilitate atmospheric CO_2 absorption prior to its release into the ocean. Such a process holds significant potential for various industrial and commercial applications. The resulting CO_2 purity and the pH adjustments to the treated water are important factors in ensuring the efficient utilization of the process [31,73]. Electrochemical capture encompasses several techniques, including but not limited to organic redox, pH-swing (utilizing methodologies such as bipolar membrane electrodialysis, electrolysis, capacitive deionization, H^+ (de) intercalation, and proton-coupled electron transfer (PCET) of organic molecules), and high-temperature molten carbonate cells. Hybrid methods involve combining electrochemical CO_2 capture and conversion approaches with battery systems [74].

At present, four primary forms of electrochemically mediated pH swing processes were employed for DOC, including Bipolar-Membrane Electrodialysis (BMPED), Electrochemical Cation-Exchange (ECE) process, Electrochemical Hydrogen Looping (EHL), and asymmetric Cl-mediated electrochemical process. In the following section, the efficacy of these techniques will be discussed in terms of energy requirements and CO_2 capture efficiency [75–79].

3.1.1. BMPED cell

BMPED provides more efficient energy means for capture and release of CO_2 from oceanwater dissolved inorganic carbon (DIC) using renewable electricity, making it a potentially valuable tool in the fight against climate change [75] (Table 3, Entry 1). In a BMPED cell, a voltage is applied across the cell whereby seawater is dissociated while BMPED membrane stack, made of ion-selective bipolar membranes only enable H^+ to and OH^- ions to counter-diffuse. The increase in concentration of H^+ ions led to a pH shift in the carbonate buffer and alter the dissolved inorganic carbon concentration within the oceanwater, resulting in the conversion of HCO_3^- and CO_3^{2-} into dissolved CO_2. The subsequent vacuum stripping of CO_2 produces pure CO_2 gas, while the acidified CO_2-free oceanwater undergoes alkalization to restore its initial state before being released back into the ocean [75]. Utilizing a thermodynamic model that considers the speciation of DIC in ocean water, an analysis was conducted to examine its precipitation. In this model, four types of equilibrium reactions were included, namely gas–liquid, acid-base, complexation, and precipitation reactions. The simulation revealed that DIC is extracted from the oceanwater when pH values becomes less than 4, specifically, at a pH of ~5 % of DIC is converted to dissolved CO_2 [31].

The feasibility of the in situ BPMED to mineralize oceanic DIC into carbonate minerals via alkalization route was introduced [80] (Table 3, Entry 2). Purpose of in situ alkalization was to minimize the electrical energy consumption of the process. To begin, Visual MINTEQ 3.1 was utilized to simulate the alkaline pH range that would optimize carbon capture and determine the minimum electrical energy needed for the pH-swing process. Then, a six-compartment cell equipped with a single BPM was fabricated to demonstrate the impact of pH on both carbonate

Table 3
Details of DOC type, CO2 capture capacity and capture cost of DOC lab-scale prototypes available.

Entry	Facility	Company/ Location	DOC Technology	Operational Parameters						CO_2 Capture efficiency (%)	Cost US $/ton CO_2 captured	Ref.
				Temperature (°C)	pH	Current Density mA/cm^2	Energy Consumption kWh/ton CO_2	Time (h)	Water Flow rate (mL/ min)			
1	Lab Scale Prototype	Delft University, Netherlands	*In Situ* BMPED Alkalization	Ambient	3–9.7	5	798	0.5	68	60	–	[80]
2	Lab Scale Prototype	Palo Alto Research Center (PARC), USA	BPMED	Ambient	5	0.98	1,386	0.5	3,000	59	–	[81]
3	Lab Scale Prototype	Pasadena, California	BPMED	Ambient	4.7	3.3	980	1	30	71	80 approx.	[76]
4	Lab Scale Prototype	Washington, United States	ECE	Ambient	5.5	7	2,000	0.5	460	–	–	[78]
5	Lab Scale Prototype	Washington, US	EHL	Ambient	5.5	8	660	–	40	95	–	[99]
6	Lab Scale Prototype	MIT, Cambridge	Cl-mediated ED	Ambient	6	100	699	10	1.04	87	156	[77]
7	Lab Scale Prototype	Shenzhen, China	Steel Slag Mineralization	30	4.5	100	127	–	–	90	10.4	[89]

mineralization and membrane fouling. CO_2 capture experiments were conducted using both synthetic oceanwater and real seawater from the Wadden Sea in the Netherlands. Finally, the proposed concept was validated by using an upscaled BPMED cell that contained 10 bipolar-cation exchange membrane (BPM-CEM) cell pairs. These findings provide valuable insights for the industrialization of seawater carbon capture through mineralization. At constant current density of 5 mA/cm^2, oceanwater flow rate of 68 mL/min, 60 % of DIC from real oceanwater and 58 % from synthetic oceanwater was extracted in 0.5 h without adding any additional chemicals as shown in Table 2, Entry 1. At optimized current density and flow rate, total energy consumption for the in situ pH-swing of ca. pH 3.2–9.75 was 325 kJ/mol $CaCO_3$ for DIC capture from real oceanwater. Theoretically, at a mild-pH swing, the thermodynamic energy required to capture $CaCO_3$ though in situ mineralization is ~35 kJ/mol $CaCO_3$ which is less than 10 % of that experimentally achieved. However, the irreversible BPM-overpotential account for more than 55 % of the required electrical energy [80].

A nine-cell pH-swing BMPED system was built to extract CO_2 from

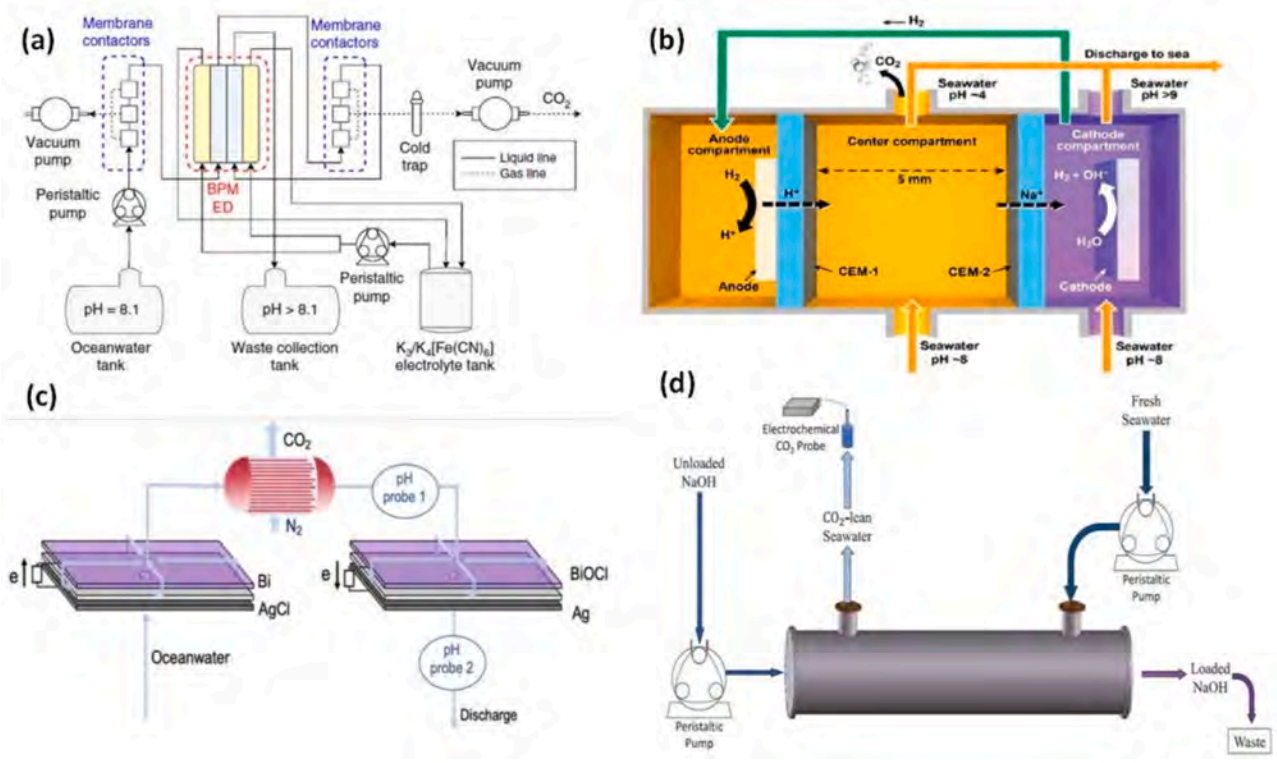

Fig. 4. The experimental flow diagram of the lab-scale electrochemical DOC systems: (a) BMPED cell [76], (b) EHL flow cell [99], (c) asymmetric Cl-mediated cell [77], and (d) HFMC cell [86].

oceanwater. Each cell consisted of a basified solution compartment, a bipolar membrane (BMP), an acidified solution compartment, and an anion exchange membrane [81] (Table 3, Entry 3). A cation exchange membrane was used at both ends of the membrane stack to separate it from the electrode compartment (titanium with an iridium-ruthenium based coating). The rate of CO_2 gas extraction was increased as the pH of the acid solution dropped until a steady-state equilibrium was reached. To compare energy efficiency of system, CO_2 extraction was measured at different oceanwater flow rates at a normalized current of less than 1 mA/cm^2. A prototype cell displayed 59 % extraction of CO_2 in 30 min at an electrical energy expenditure of 242 kJ/mol CO_2, at oceanwater flow rate 3.1 L/min, at pH 5 as given in the Table 2, Entry 2. CO_2 removal efficiency was further increased to 68 % by increasing the flow rate to 6 L/min and lowering pH to 3.7 value, with a small increase in the energy to 285 kJ/ mol (CO_2) [81]. The energy consumption estimates given here may not however account for the energy required to pump the oceanwater solution through the system or to vacuum strip CO_2 from acidified oceanwater which could require for extra 10–15 % gross energy.

In order to improve the energy efficiency for CO_2 extraction and conversion, one additional set of membranes was incorporated into BMPED system (as depicted in Fig. 4(a)) for removal of input gases from oceanwater such as O_2 and N_2 [76]. This BPMED cell was comprised two oceanwater compartments partitioned by a bipolar membrane (BPM), two reversible redox-couple compartments, each delimited from the oceanwater compartment by a cation exchange membrane (CEM) and two electrodes for electrochemical reactions. By using two sets of membrane contractors, the BMPED system displayed 88 kJ/mol less energy consumption as compared to BMPED system using single set of membrane contractor. The BPMED device demonstrated high efficacy in removing CO_2 from oceanwater with a capture capacity of 71 % for an electrical energy consumption of 155 kJ/mol CO_2, oceanwater flow rate of 37 mL/min, a pH value of 4.7 for the acidified stream, and a total voltage of approximately 1 V in 1 h, as displayed in Table 2, Entry 3. Furthermore, the designed BMPED unit was coupled with another CO_2 reduction cell (CO_2R) to convert CO_2 into other fuels and chemicals. CO_2R cell converted CO_2 into ethanol, propanol, and carbon monoxide (CO) at Faradaic efficiency (FE) of 73 % and 95 % at 58 mA/cm^2 using Cu and Ag electrocatalysts respectively. By contrast, energy required for conversion of CO_2 into fuels is higher, for example to conversion of CO_2 into methane requires 13.9 kWh/kg of CO_2, whereas, CO_2 extraction from oceanwater requires 0.98 kWh/kg of CO_2 which would be small fraction of capture and conversion energy combined [76].

Captura, a spinoff of the California Institute of Technology, has launched the first DOC pilot plant off the coast of Newport Beach, CA in 2021 [82]. The plant can capture 100 tons of CO_2/year using a system based on the electrodialysis process that uses renewable energy to split water molecules into an acid and a base. The captured CO_2 is stored for further utilization, while the decarbonized water is returned to the ocean, where it interacts with the atmosphere to draw down an equivalent quantity of CO_2. The Captura's process is poised to make a significant impact on the fight against climate change by utilizing the ocean's natural ability to capture CO_2 from the atmosphere.

3.1.2. Electrochemical cation exchange cell

The Electrochemical Cation Exchange (ECE) cell, developed by the Naval Research Laboratory, is a sophisticated technology capable of extracting CO_2 and H_2 from oceanwater in a single process [78] (Table 3, Entry 4). The ECE cell was composed of four configuration modules, among which configuration of first three modules was based on commercially available electro-deionization cells. Fourth module was customized to reduce energy efficiency required for lowering oceanwater pH below 6. ECE includes a center compartment, electrode compartments for reversing polarities, and two cation-permeable membranes which separate the three compartments. A lab-scale prototype of the ECE system was created, which was then integrated into a portable skid. Alongside the ECE system, the skid also housed a reverse osmosis (RO) unit, power supply, pumps, membrane contactor CO_2 gas recovery system, hydrogen gas vacuum tower, and gas analyzer. The outcome was the creation of a comprehensive CO_2 and H_2 capturing system. pH of the seawater was changed by an applied current through E-CEM electrodes and the change was monitored by a standard combination electrode. Other components of the system (RO, E-CEM, well pump, vacuum towers, vacuum pumps, solenoid valves, and power supply) were controlled as an integrated unit. In order to remove CO_2 gas from seawater, commercial poly(ethylene) hollow fiber membranes contactors were used. A standard hydrogen gas vacuum tower simultaneously processed the water from the acting cathode compartment of the module as it released H_2 gas, which was qualitatively measured using a standard Honeywell gas analyzer as was the CO_2. CO_2 capture costs, and operational parameters for ECE cell are given in the Table 2, Entry 4. The pH of the oceanwater was adjusted based on the applied current to the ECE system, and it was reduced from 8.1 to less than 6 within just 20 min. The added configuration improved the pH lowering performance of the ECE system by 65 % that was a positive point in CO_2 capturing efficiency in shorter time duration. Natural Key West oceanwater with CO_2 concentration of 100 mg/L was used to calculate CO_2 capture efficiency. According to reports, when the pH level of ocean water drops to 6 or lower, the carbonate and bicarbonate present in it react to form CO_2 gas [83]. This process implies that at an operating current density of 7.0 mA/m^2, an ocean water flow rate of 460 mL/min, and a pH level of 5.5, the theoretical value for CO_2 capture is 0.0023 mol CO_2/L. It is expected that experimental H_2 and CO_2 capture will be performed in future with similar energy efficiency as that of commercial electrolysis given the faster polarity reversal of ECE system [78].

3.1.3. EHL cell

EHL systems are superior to BPMED and ECE DOC ones with respect to the fact that they require lower voltage and leading to greater efficiency for capturing CO_2 from ocean water (Table 3, Entry 5). For instance, at 10 mA/cm^2 current density, BPMED operates at 1.9 V and ECE operates at 1.73 V, whereas EHL operates at 0.48 V [79]. In EHL system, oxidation of hydrogen takes place at anode and the oxidized H^+ are transported though the proton exchange membrane to the center compartment where protons react with CO_3^{2-} and HCO^{3-} to produce acidified seawater and release CO_2 gas for storage. Seawater is then neutralized in the central compartment where hydrogen evolution results in the formation of NaOH at the cathode, thus basifying the solution. The flow diagram of lab-scale EHL system is shown in the Fig. 4(b) and operational parameters and capture costs are given in Table 2, Entry 5. Lab-scale designed EHL unit demonstrated 91 % CO_2 removal from oceanwater at a current density of 8 mA/cm^2, oceanwater flowrate of 40 mL/min, at pH 5.5, with record low electrical energy of 104 kJ/mol CO_2. The EHL flow cell demonstrates a major 56 % reduction in electric energy usage compared to the BMPED system, with a total consumption of 660 kWh/ton of CO_2. Additionally, the mild operating conditions and low operating voltages make the EHL system a potentially ideal candidate for scaling up protocols in DOC pilot plants [79].

Although EHL has a high CO_2 removal efficiency and requires less energy for commercial DOC purposes, there are still certain challenges to overcome, for instance, extra steps are required for the pretreatment of ocean water before pumping into system to prevent or reduce biofouling. These extra steps increase the complexity of the process and ultimately increase the overall cost of the system. For this purpose, integration of electrochemical oceanwater splitting device (EOSD) into global coastal economy would be helpful [84]. The integrated device would split oceanwater using O_2 and CO_2 from air by combining electrochemical and chemical reactions. Water electrolysis generates an alkaline electrolyte and concurrently capture CO_2 may hence reduce the amount of Ca^{2+} and Mg^{2+} ions present in solution due to their precipitation as carbonates. The EHL process was reported to yield 4.17 g of corallite, for a capture of 0.48 g of CO_2, and a production of 111.11 g of

H_2 using 7.446 kWh of electricity with only 0.051 kWh of electricity per liter of oceanwater input [84].

3.1.4. Chlorine-Mediated electrodialysis cell

Despite its high efficiency, the cost of membranes used in BPMED may hinder the commercialization of the process [85] (Table 3, Entry 6). In order to overcome this challenge, a solely electrochemical pH modulation process obtained with an asymmetric chlorine-mediated electrochemical system was implemented to reduce costs associated with using BPMs in electrochemical systems [77]. Besides being a membrane-free system with lower capital costs and lower energy requirements, the system was more simple to deploy than BPMED and offered very much reduced risks of leaking any redox complexes into ocean [77]. Bismuth and silver electrodes were employed to capture and release chloride ions by faradaic reactions and a chlorine-mediated pH swing was achieved through different reaction stoichiometry between the two electrodes, to effectively remove CO_2 from oceanwater. A schematic illustration of the system is shown in the Fig. 4(c), whereby within the Bi/AgCl feed cell, one electrode releases H^+ for acidification of oceanwater, while the counter electrode releases Cl^- to ensure charge balance. In the BiOCl/Ag cell, molecular CO_2 is captured using a hollow fiber membrane contractor, before being returned to the ocean following the reverse reaction and oceanwater alkalization. The new pH swing system displayed 87 % removal efficiency of CO_2 from oceanwater at, oceanwater flow rate 1.04 mL/min, pH value 6, operation time of 10 h, with energy consumption of 122 kJ/mol as depicted in Table 2, Entry 6 [77].

3.1.5. Hollow fiber membrane contactors (HFMCs)

A solution to lower the expenses incurred from electrochemical DOC procedures is implementing passive membrane-based contactors. HFMCs utilizing passive membrane technology have already been optimized for carbon capture systems following combustion. Consequently, they hold great potential as a viable option for DOC as well. In a recent work, a novel method utilizing HFMC for DOC was introduced in a multifaceted approach [86]. Fig. 4(d) depicts the lab-scale experimental setup for HFMC. NaOH was selected as the solvent due to its quick CO_2 absorption and proven track record in DAC systems. HFMCs employ gas-permeable membranes that are impermeable to liquids, necessitating the use of NaOH to drive dissolved CO_2 through the membrane from ocean water to the solvent side in a counterflow direction. A combination of experimental works and computational modeling as well as and techno-economic assessment were developed to analyze the efficiency of CO_2 capture from ocean water in both pilot and commercial systems. Instant sea Synthetic Sea Salt was used for experiments, and CO_2 concentration was reached 0.39 mol/L in solvent at ambient temperature, solvent flowrate of 200 mL/min, oceanwater flowrate of 200–1,200 mL/min, 16–20 h. HFMCs are a suitable option for large-scale gas exchange processes with slow kinetics as they provide a large contact surface area per unit volume for efficient gas exchange between two fluids. However, the investigation of common challenges associated with HFMCs for DOC purpose remains critical to reduce further costs as well as pressure drop and membrane fouling occurring during the process, prior to scaling up.

3.2. Carbonate mineralization DOC systems

Oceanwater is an excellent source of Ca^{2+} and Mg^{2+} ions that can react with CO_2 to form carbonate precipitates, which greatly aids in achieving CO_2 fixation [87]. To enhance the CO_2 capture capacity of oceanwater, it is recommended to utilize waste materials that are rich in Ca and Mg [67]. One such material is steel slag, which is cost-effective and contains up to 58 % of CaO and 10 % of MgO [88] (Table 3, Entry 7). With 0.4 % CaO, the solubility of CO_2 in oceanwater can reach up to 80 % at 25 °C and 0.3 MPa. A recent research paper has reported that, under ambient temperature and 0.3 MPa pressure, the concentration of carbonate precipitation in oceanwater increases by 115 % when the steel slag concentration is increased by 1 % [89]. The capture of CO_2 from ocean water utilizing steel slag involves three distinct stages, namely, aqueous CO_2 dissolution, Ca leaching, and $CaCO_3$ precipitation via the reaction between steel slag ions and dissolved CO_2. As solubility of CO_2 increases, the precipitation of $CaCO_3$ also increases resulting in an overall increase in CO_2 solubility in oceanwater. For CO_2 absorption, online chromatographic absorber was functioned at 1 atm pressure, 30 °C temperature and gas flow rate of 2,805 ton/h. Details of operational parameters and capture costs are displayed in Table 2, Entry 7. The steel slag to gas ratio was varied and when the optimal liquid–gas ratio was 250–280, 90 % CO_2 absorption was observed. Experimental procedure validity was also verified with simulations by Aspen Plus that further supported CO_2 capture and storage from oceanwater using steel slag with approximate absorption of 128 kg CO_2/ton of steel slag. Another study has reported use of cement kiln dust (CKD) (composed of 46.4 % Ca and 1.3 % Mg respectively) industrial by-product for CO_2 storage in the form of carbonates [90]. In this study, oceanwater was used as solvent to leach out Ca, precipitation of $CaCO_3$ and CO_2 storage from CKD. Concentration of eluted Ca was comparable with other methods of leaching, except some methods using HCl, NH_4Cl, and trisodium citrate solvents. Using oceanwater as solvent, in the absence of other chemicals, at pH value 12.5, solid/liquid ratio of 1/50, 3.35 kg Ca/L of CKD, 185 kg CO_2/ton of CKD and 615 kg $CaCO_3$/ton of CKD were obtained that was very significant value from CO_2 capture point of view. Amount of CO_2 captured in this study was higher than steel slag waste using 2 M HCl as solvent (128 kg CO_2/ton of steel slag). The results explain the potential deployment of this study for DOC purpose in future. Steel slag contains hazardous elements such as chromium (Cr) and arsenic (As), which may dissolve in water. The alkaline nature of steel slag can contribute to an increase in pH levels when dissolved in water, which is a critical factor to consider before disposing of it in the ocean. Before using CDK for CO_2 capture, it is therefore important to consider the sulphates, silicates and hydroxide content associated to hardness of the water.

3.3. DOC commercial plants prospects and plans

DOC operating principle lies towards shifting CO_2 bicarbonate–carbonate equilibrium into gaseous CO_2 or solid carbonate to achieve CO_2 capture [91]. The electrochemical and carbonate mineralization DOC systems have demonstrated high potential at the laboratory scale, yet the challenge of upscaling these systems remain a crucial hurdle. At present, the feasibility of electrochemical DOC systems operating at a commercially relevant scale remains unproven. Critical challenges include achieving a balance of the gas–liquid interfaces, which must be scaled up from a few cm^2 to hundreds of m^2, to be relevant for DOC operations [92]. Notwithstanding, the rapid evolution of scaling technology in this area is expected to result in large-scale production of these systems within the next decade. In view of this, a discussion on prospects for commercial DOC systems is done below in terms of performance, energy requirements and capture costs.

Captura, California (Pasadena), USA, using Caltech Laboratories, proposed a HFMC electrolysis DOC system to capture CO_2 from oceanwater. Low-cost hollow fibers (~US$ 20–50/m^2) similar to the ones used for water filtration will be incorporated with polydimethylsiloxane modifications on outer layers for selective striping of CO_2 from oceanwater [93]. The DOC process will only use renewable energy without addition of other chemical and without byproducts production. Based on the ED concept used for pilot plant system, Captura's another DOC pilot plant has been successfully scaled-up in the Pasadena lab and moved it to AltaSea at the Port of Los Angeles in 2023 to start ocean water trials [82]. The company used a continuous flow of oceanwater to measure system performance and make necessary improvements. The scale-up DOC system captures 100 tons CO_2/year.

Equinor, Stavanger, Norway, a multinational energy company, has partnered with Captura to develop industrial-scale solutions to remove

CO_2 from the ocean [94]. The partnership will start with a pilot plant in Norway that can capture up to 1,000 metric tons of CO_2 annually. The pilot plant will be based at Equinor's Karsto natural gas processing facility on the west coast of Norway. It will follow a 1 ton/year system that commenced operations at Newport Beach, California in August 2022, and a 100 ton/year system that was recently installed at the Port of Los Angeles. The captured CO_2 will then be used for commissioning the Northern Lights facilities, which is the world's first open-source CO_2 transport and storage infrastructure. The pilot project will draw seawater and remove a measurable stream of CO_2 from it. The feasibility and design of the pilot project is already underway, with installation planned for the fall of 2024. The success of the pilot project can potentially lead to the development of large-scale commercial plants in key regions around the world [94].

Caltech is developing an offshore system based on electrodialysis concept to extract CO_2 from oceanwater [95]. To reduce system associated cost and processed water volume, project will be aimed to validate high current density, low power electrodialyzer stack and membrane contactors to facilitate CO_2 capture. The proposed system will provide a viable pathway to capture CO_2 at the cost of $<$ 100 USD/ton CO_2 and could be scaled up to multi-gigaton CO_2/year.

MIT has proposed battery-like electro-swing DOC system [96]. With its battery-like composition of electrochemical cells, this cutting-edge technology effectively releases CO_2 Ocean water, enhances the water's alkalinity, and returns the treated water back to the ocean. Its innovative design is set to revolutionize the way we tackle ocean acidification, and this system could be a significant step towards a more sustainable future. The proposed system boasts several noteworthy advantages. First and foremost, it obviates the need for expensive membranes or supplementary chemicals. Secondly, its ease of deployment renders it practical. Thirdly, it is free from byproducts. Additionally, the proposed innovative electrode configurations are highly effective at reducing transport and electrical resistance levels in the context of large water volumes. This system is characterized by low energetics, facilitated by renewable solar or wind resources, and can be installed on platforms or cargo ships.

The Swiss Federal Laboratories for Materials Science and Technology (EMPA), Switzerland, have proposed electrodialysis concept to capture 2.4 ton of CO_2/h. This project involves the development of "Ocean Floating Islands" that would operate via electrodialysis, a process powered by solar energy for the simultaneous production of H_2 and extraction of CO_2 from oceanwater [70]. The proposed installation can be mounted on a fixed-hull ship, and would consist of 70 clusters, each with photovoltaic (PV) islands of 100 nm diameter. The total surface area covered by the PV islands would be 550,000 m^2, with the entire installation occupying a surface area of approximately 1 km^2. The PV islands will provide electrical power to the desalination and electrolysis cells for H_2 production, the electrochemical cells for CO_2 extraction, the catalytic reactors for methanol production and separation, storage batteries, a methanol storage tank, and other installed accessories. With a total incoming solar power of 120 MW and 20 % efficient PV modules, the system could produce an average of 24 MW_{el} of electrical power. At oceanwater flow of 41,000 ton/h, ED cells which consume 5.1 MW_{el}, could extract the dissolved CO_2 with 59 % efficiency, yielding 2.4 ton/h CO_2. Economically, a much larger electrodialysis flow (41,000 ton/h) would require a novel, highly cost-efficient method. It should be noted that a similar oceanwater flow rate is pretreated in the RO desalination plant using sand filtration with periodic backwashing [70]. Furthermore, the capital costs for oceanwater pretreatment equipment and floating island structures are highly uncertain.

The energy and environmental research center (EERC), nonprofit division of the University of North Dakota, located in Grand Forks, North Dakota, United States) has proposed DOC technology based on cyclic precipitation of carbonates from oceanwater in a process called hydrolytic softening [97]. This innovative process bears similarities to conventional water treatment methods. Essentially, the water is softened through the precipitation of dissolved inorganic carbon (DIC) as calcium carbonate via the use of hydrated lime. Hydrolytic softening presents a promising solution for the decomposition of calcium carbonate, allowing for the release of CO_2 gas that can be utilized for sequestration or industrial purposes. Furthermore, this process regenerates the lime for repeated usage, making it a sustainable and cost-effective approach for DOC. In comparison to other methods that rely on membrane electrodialysis, the proposed process can significantly reduce energy input costs by up to 77 %.

The Institute for Carbon Management at University of California, Los Angeles has proposed an innovative and scalable process design for DOC [98]. This new process involves a single-step electrolytic precipitation of carbonates. In this perspective, oceanwater (as an electrolyte) is pumped through electrolytic flow reactors, and dissolved CO_2 in oceanwater and atmosphere is combined with Ca^{2+} and Mg^{2+} species in an aqueous reaction medium. This innovative mineralization technology is notable for several significant advantages over other biotic or abiotic methods. Most notably, it efficiently eliminates the thermodynamic and kinetic challenges associated with carbonate precipitation by directly and in situ electrochemically converting dissolved inorganic carbon (DIC) into carbonate minerals. Furthermore, this process is significantly more time-efficient than natural rock-based mineralization techniques, which can require years to complete. Additionally, this method can be successfully applied across a broad range of CO_2 concentrations and temperatures, from ambient levels to 100 vol% CO_2 and from ambient to around 90 °C, without incurring any additional costs. Lastly, as a result of the electrochemical dissociation of ocean water, solvents are not required to stimulate CO_2 adsorption for ocean carbon management.

The deployment of DOC storage facilities may occur onshore, offshore, or mobile platforms. Onshore DOC operations are positioned along coastlines to capitalize on their adjacency to both the ocean and land. Offshore facilities are situated in the open ocean, with the captured CO_2 being conveyed to storage facilities located beneath the seabed, such as saline aquifers or depleted oil and gas reservoirs. In Norway, there are currently two prominent CO_2 storage facilities operational, namely Sleipner and Snøhvit, both situated in the Norwegian Sector of the North Sea. The Sleipner field, managed by the Norwegian energy company Equinor, has been engaged in the separation and re-injection of CO_2 as part of a carbon capture and storage (CCS) initiative since 1996. This initiative involves capturing nearly one million metric tons of CO_2 annually from the natural gas extracted at the field, and subsequently re-injecting it into the Utsira Formation–a deep saline aquifer located beneath the North Sea [6,7]. Captura seeks to establish partnerships with experienced carbon sequestration firms such as the Northern Lights project to facilitate the geological storage of captured CO_2. This process entails underground storage of CO2 in a supercritical liquid state, within depleted oil and gas formations or geologic saline aquifers. Stringently selected sequestration sites will ensure containment of CO_2, with the responsibility for monitoring and verification resting with the sequestration company [8]. Equinor and Captura will work together on different versions of Captura's technology for carbon capture and storage. They will start by building a 1,000 tons/y onshore pilot plant at Equinor's Kårstø natural gas processing facility in Norway. The plant will remove CO_2 from seawater and support the Northern Lights project, which aims to be the world's first open-source CO_2 transport and storage infrastructure [9].

3.4. Techno-economic assessment of DOC processes

For determining the feasibility of any DOC process for scaling up to large capture facility, techno-economic assessment (TEA) plays crucial role. Spatial or economic considerations may limit the scalability of certain technologies. For electrochemical DOC cell, the total cost can be broken down into four sectors; equipment cost and power cost for capture and release of CO_2 and ED, respectively. However, the contributions of the capture process, both for equipment and operation, are almost negligible compared with the costs for ED. This section will discuss the

main costs associated to CO_2 capture using these hybrid ED processes in terms of operating conditions and energy requirements [99].

3.4.1. BMPED cell

The BPMED cell involves two types of cells, incorporated into the CO_2 recovery cell and the alkali regeneration cell. Both cells are sandwiched between a BPM and a CEM. CEMs are polymeric membranes containing negative functional groups used to attract cations, while BPMs are composed of two types of ion-exchange membranes, a CEM and an AEM stacked together, to prevent ion leakage. AEMs are membranes with fixed positively charged chemical groups connected to the main polymer chains of the membrane [99].

An analysis was conducted on the total operational and equipment cost of BMPED cell that recovers CO_2 from bicarbonate solutions [100]. A 10-stack cell BMPED unit was used, with a stainless steel (SUS) electrode as the anode, platinum-coated titanium (Pt/Ti) cathode, commercial-grade BMP, and CEM. This unit was operated at a current density of 96 A/m^2 and a feed flow rate of 1.2 L/min, resulting in 30 % CO_2 recovery from bicarbonate solutions. The system was designed to treat 300 metric tons/h of CO_2 emission, which is equivalent to the amount emitted by a 400 MW coal-fired power plant. Assuming a unit cost for electricity at US$ 0.12, a minimum cost of US$ 180/ton CO_2 was achieved. The cost of electricity accounts for approximately 60 % of the total cost, while the cost of membranes accounts for 30 % of the total cost. To scale up the process, it was assumed that if the electric power price is reduced to US$ 0.06/kW h, the membrane costs are reduced by 1/10, and the current density is increased to 90 %, the minimum cost could be reduced to approximately US$ 70, which is competitive with the conventional amine chemical absorption process. The lifetime of the membranes can also be extended to reduce the total cost further (5 years for the base case). A group has reported a method for capturing CO_2 from bicarbonate solution using Neosepta BPM membrane with a thickness of 0.2 nm. This method can regenerate the captured CO_2 at the cost of US$ 38.07/ton CO_2, based on 2020 prices. During operation, the system consumes energy as low as 50 kJ/mol CO_2 and has a current efficiency of 91.2 % [101].

It is important to note that the CO_2 can be easily trapped in the membrane stack of BMPED, causing a “hot spot” that may damage the membrane surface and reduce its lifespan. To address this problem, a high-pressure BMPED stack was developed to eliminate CO_2 gas bubbles during the DOC process [81]. By increasing the pressure from 1.5 atm to 6 atm, the electrochemical energy was reduced from 471 kJ/mol CO_2 to 333 kJ/mol-CO_2. This high-pressure stack prevented the occurrence of “hot spots” and reduced energy consumption during the experimental process. The performance of the BPMED-based in situ mineralization method is also hindered by inorganic fouling in the alkaline pH range ($pH \geq 9$) when using real oceanwater as feed. However, it is believed that mineral scaling will not occur in the acidic channels due to their low pH ($pH \leq 4$). A report suggests that acid is the most effective choice for removing scale from the membrane, surpassing sparging O_2 and CO_2 [102]. To optimize BMED performance, it is advised to decrease the resistances of the AEM and CEM, as well as create thinner channels for the acid, base, and feed compartments [103]. Performance tradeoff curves can be used for BMPED to make comprehensive comparisons between different BMED operations and systems. It can also help in cost optimization if a cost model is provided. The performance tradeoff curve shows that the development of high-performance bipolar membranes can improve the overall performance of BMED to a moderate degree because multiple components govern the performance of a BMED process. For BMPED, higher temperature could improve the reaction rate, however, the thermal stability of the ion exchange membranes poses a limitation on high temperature processes. For instance, the commercial BMP cannot withstand temperatures higher than 40–60 °C for a long duration. Moreover, CO_2 solubility decreases at higher temperatures (up to 100 °C). This means that operating at high temperature is not yet practical.

3.4.2. ECE, EHL and Cl-mediated EC cells

From an economic point of view, CO_2 capture is only viable if the energy consumption of the capture is < 66 kJ/mol CO_2, whereas, electrochemical processes often have energy consumption greater than 300 kJ/mol CO_2 [74]. In terms of energy consumption, among the electrochemical DOC systems, EHL is more cost-effective approach for scale up design [37]. For example, BPMED consumes approximately 1400 kWh/ton CO_2 of electric energy, while ECE uses around 20,000 kWh/ton CO_2. Cl-mediated EC consumes about 699 kWh/ton CO_2, whereas EHL flow cell requires roughly 660 kWh/ton CO_2. While using acidified simulated seawater at pH ~4.7, a BPMED cell consumed ~155 kJ/mol CO_2 (~900 kWh/ton), which is approximately 1.5 times higher than that of the EHL flow cell [76]. Other than energy consumption, oxygen evolution reactions at BPMED and ECE require costly IrO_2 catalysts which hinder the potential for large-scale deployment when compared with electrolysis for hydrogen production. In contrast, EHL system utilizes oceanwater as electrolyte instead of chemical-based electrolytes. For highly efficient system for large-scale deployment, periodic cleaning and softening of oceanwater before injecting into EHL flow cell is perquisite for avoiding scale and $Mg(OH)_2$ and $Ca(OH)_2$ deposition at electrodes.

Compared to other electrochemical systems, the recently introduced Cl-mediated electrochemical DOC system costs US$ 56/ton CO_2 and is considered cheapest among all mentioned electrochemical systems so far [29]. This cost does not include the electrode replacement cost that also tends to be lower since only two electrodes are involved, while no membrane or redox couples are involved which demands more frequent replacement than the installed Bi/AgCl electrodes. Overall estimated cost for such electrochemical system is US$ 100/ton CO_2. By adding the cost of other systems such as oceanwater pumping, intake filtration, and CO_2 separation, the total process cost could reach up to US$ 2,000/ton CO_2 [76]. For deployment of electrochemical DOC systems at larger scale, future efforts are required to reduce pumping and degassing costs.

3.4.3. HFMC cells

A preliminary TEA was performed to determine the feasibility of scaling up of HFMCs-based DOC system to large DOC facility. Estimated capital and operating costs for a direct ocean capture HFMC plant that captures 980,000 ton/year of CO_2 was US$ 9,565 [86]. Cost analysis revealed that current DOC system is 16 times more expensive than DAC benchmarks due to the very low CO_2 removal rates. Main reason for low flux rate of CO_2 is the low concentrations of CO_2 in oceanwater. For this study, synthetic seawater with a CO_2 concentration of 110 ppm was used, which is significantly lower than the atmospheric CO_2 concentration of approximately 416 ppm recorded in 2019. Flux can be increased by optimizing different variables such as flow rate, temperature, membrane thickness, however these options are not sufficient to make a cost-effective DOC system. To increase CO_2 flux, one cost-effective option is to reduce the pH of oceanwater because reducing pH will release gaseous CO_2 and increase CO_2 flux. In doing so, the membrane cost will increase twice for lowering pH to one whole number that will account for the extra cost of locally treating oceanwater pH. Nevertheless, even after adding additional membrane cost, if oceanwater pH can be lowered from 8 to 5, the cost of the system can be reduced from US$ 9,565 to US$ 290/ton CO_2 value respectively. In this cost range (~US$ 300), this DOC technology may become competitive with state-of-the-art DAC system [86].

3.4.4. Additives-based mineralization approaches

Considering additives-based DOC processes, mineralization of oceanwater using steel slag worked at low energy consumption of 127 kWh/ton CO_2 which was calculated according to the mass of flue gas, and the total system cost coming from pumps, crusher, mixer and separator was estimated to be US$ 10.4/ton CO_2 [41]. CKD industrial waste and oceanwater as solvent was used in another DOC process. However, the cost per ton of captured CO_2 was not calculated. Nevertheless, it was suggested that a cement manufacturing plant or paper

mill that emits a large amount of CO_2 and uses $CaCO_3$ as a raw material present in close vicinity to the ocean would be very beneficial for this technology to be scaled up in more economic and eco-friendly way [42]. To further reduce the cost of DOC scaled up designs, they should be integrated with onshore desalination plants to take advantage of the installed water-handling facilities. The captured CO_2 can be injected directly from platforms into sub-surface geologic structures for long term sequestration or used as a feedstock for fuels or for commodity and specialty chemicals production.

The maritime transport cost is another factor in mineralization approach. It has been estimated that it might take 100 ships yearly to achieve a net carbon removal of approximately 1Gt of CO_2, with an energy consumption of 99.5 MJ/ton [67]. Recently, researchers advocated a sewage-delivered ocean alkalinity enhancement (SDOAE) approach to reduce transport costs [104]. Approximately 1,000 km^3 of wastewater (sewage) is generated and discharged worldwide annually. Sewage contains high concentration of organic acids which reduces the pH of sewage. Therefore, SDOAE approach can be used to transport strong alkalis, avoiding a significant amount of secondary precipitation (i.e., $CaCO_3$), that can further reduce the overall cost of DOC process [104]. The pH of seawater is typically not conducive to dissolving olivine and $CaCO_3$, but their dissolution can be facilitated by the SDOAE approach. This process increases the alkalinity of the water, which can be carried offshore by river plumes and ocean currents. Therefore, ocean alkalinity enhancement and carbon dioxide removal can be implemented on a large scale.

Mitigating membrane fouling and electrode poisoning in direct ocean capture (DOC) technologies involves several strategies. For membrane fouling, pre-treatment of seawater using filtration, chemical treatment, and UV light is essential, along with anti-fouling membranes enhanced through surface modification and hydrophilic properties. Operational strategies such as optimizing flow rate, backwashing, chemical cleaning, and controlling biofouling with biocides and coatings also play crucial roles [4]. To combat electrode poisoning, selecting resistant or alloyed materials, surface modification with protective coatings and catalyst layers, and operational strategies such as potential control, periodic regeneration, and proper electrolyte flow are effective [5]. Additionally, electrolyte management through regular purification and additives can prevent contaminants from affecting electrodes. Implementing these approaches improves the efficiency and longevity of DOC systems, promoting sustainable carbon capture from ocean water [4,5].

4. Comparison between DAC and DOC technologies

Direct Air Capture (DAC) is also attracting increased attention and financial investment from notable figures like Bill Gates and Elon Musk [105]. Compared to DAC, DOC is an even less explored territory. However, Equatic, Captura, and other companies are working to demonstrate the concept's feasibility with support from the Chan Zuckerberg Initiative, Gates Foundation, oil and gas companies, and the Advanced Research Projects Agency-Energy (ARPA-E). In this section, a comparison between DAC and DOC will be presented in terms of process design and energy demand, capture cost, land use and location, scalability, and potential for intensification.

4.1. Process design and energy demand

Conventional DAC technologies have traditionally relied on thermal amine-based scrubbing methods typically used to separate CO_2 from natural gas and hydrogen [106]. This method employs a chemical wet process, whereby liquid sorbents capture CO_2 and then release it through a temperature (100 °C–150 °C) or pressure (up to 10 kPa) swing (TS or PS) process. In DAC pilot and commercial plants, adsorptive solids or basic aqueous solutions are mostly used to capture CO_2 from atmosphere that requires relatively smaller footprint and could be powered by renewable energy such as solar, wind, and geothermal sources [24,32,45]. While this method has been tested on a large scale for CO_2 capture from industrial power plants and is a reliable technology, it has some weaknesses that remain as a challenging task for commercial application [107,108]. Firstly, the amine-scrubbing method is widely used for point source carbon capture, which still are attributed to 60 % of annual CO_2 emissions. Capturing carbon emissions from point sources involves an estimated thermal energy requirement of about 3.2–4.0 GJ/ton of CO_2 captured. This is equivalent to 89–112 million TJ of annual energy consumption, which accounts for about 13–17 % of the world's energy consumption [109,110]. However, using thermochemical-based capture in highly diluted CO_2 concentrations (0.04 % CO_2) requires more energy with a total 4.8–10.2 GJ of thermal energy per ton of CO_2 captured, which is not practically feasible [111]. Energy requirement is further increased for solvent DAC technology which is equivalent to either 8.81 GJ natural gas or 5.25 GJ natural gas coupled with 366 kWh of electricity. DAC can be considered as a "refinery for the sky" when it comes to energy. In the United States, refineries consume approximately about 880 TWh of energy per year. Assuming the same amount of energy is utilized for DAC and that each DAC facility requires about 300 MW of consistent energy to capture 1 $MtCO_2$/year, the same quantity of energy could be used to capture 370 $MtCO_2$/year. These figures demonstrate the possibility and difficulty of deploying DAC on an industrial scale from an energy perspective [112].

The energy efficiencies of thermodynamic-driven capture systems are subpar, typically ranging from 10 to 15 % due to inherent limitations within the system such as, high regeneration cost, degradation of adsorbents at higher temperatures as well as poor recyclability of adsorbent. Secondly, considering Gibbs free energy, regeneration process to spontaneously release CO_2 followed by the capture process requires entropic contribution by increasing temperature to compensate enthalpic contribution. Higher temperature for CO_2 release could also lead to sorbent degradation, resulting in slower CO_2 adsorption rates and low CO_2 capture efficiency [113]. However, high-grade (900 °C) heat demand of aqueous solution-based DAC could limit the options for heat source and increase the cost [15]. This scenario is expected to require more energy to capture and release CO_2 from these diluted sources and may impede the continued use of wet scrubbing in CO_2 capture systems. Furthermore, the widespread use of this method has been impeded by high-temperature/pressure that require significant costs to separate CO_2, as well as environmental issues associated with the use of corrosive amine derivatives as CO_2 sorbents [114].

For DOC, electrochemically-mediated carbon capture (EMCC) has been extensively studied as a viable alternative to amine-scrubbing carbon capture systems [111]. The primary distinction between EMCC and amine-scrubbing processes is that the entire capture and release processes are regulated by applying a bias or potential to an electrochemical device, instead of a TS/PS swing. Using the ED concept, in terms of energy utilization, DOC is considered favorable over DAC with a total usage of 1.3 kWh/kg (1,179kWh/ton) of CO_2 as compared to 1.54 to 2.45 kWh/kg (1,396.7 to 2,222.15 kWh/ton) in the case of DAC. Ideally, EMCC devices can combine with renewable energy to generate power for CO_2 capture. The modularity and portability features of ECCs facilitate direct air capture from any location, thereby effectively balancing the emissions and advancing the cause of carbon neutrality.

4.2. Cost, land use and geographical locality

Despite possessing the capability to capture high amounts of carbon, DAC technology remains prohibitively expensive and has yet to meet the necessary efficiency standards required to tackle the global carbon capture challenge. Particularly, at low atmospheric CO_2 concentrations of approximately 420 ppm, DAC implication would be more challenging and expensive with highest estimated cost to be between ~US$ 500 to 600/ton CO_2 which limits its prevalent implementation [115]. At these very low CO_2 concentrations, solvents or sorbents with strong binding

capabilities are required. As CO_2 binding capability is faster with strong base, therefore, for absorption, a chosen solvent should be a strong base. This binding demands a chemical shift process, which in turn requires more energy. Similarly, for adsorption, to saturate solid sorbent, a driving force is needed for regeneration and without that driving force more energy is needed to release the CO_2 from the sorbent. In doing so, larger surface area and efficient solid or liquid sorbent would be required which is the second largest factor after electricity in the capital cost of a DAC plant [116]. Carbon Engineering's sodium hydroxide-based operating plant places costs within the range USDUS$ 94–232/ton CO_2 [117]. The capital cost of constructing the Climeworks' Hinwil DAC system, which captures 900 ton CO_2/year was US$ 3–4 million which is the largest influencer of the levelized capture price of US$ 500–600 /ton of CO_2 [112].

To date, most prominent DOC approaches use electrochemical water-splitting to partition seawater into acidic and basic streams and then capturing of CO_2 from the acidic stream [76,80,81] (Fig. 4). For stand-alone ED-based DOC plant, estimated cost is 1,870to 2,50 US$/kg CO_2 which is 2 times more than Climeworks cost of DAC [24]. DOC cost could be reduced to 500US$/ton CO_2 if a desalination plant is located in close vicinity by utilizing infrastructure, but, that will reduce the CO_2 capture capacity to less than 100 kton/year of CO_2 [72]. Recent research has demonstrated use of fixed bed of sodium carbonate capsules for DOC purpose. Estimated cost of the designed DOC system was US$ 8,977.34/ton CO_2 which is not economically competitive compared to the DAC industrial target cost of 500 to 600 US$/ton [115].

In terms of geographical locality, DAC is not limited to locations with large, stationary CO_2 sources. In principle, it can be applied anywhere, although it would be ideal to have both an energy source and a CO_2 storage site nearby. This has several advantages: small-scale industries can continue to operate without the need for process modifications, CO_2-producing facilities that are located far away do not require extensive CO_2 transport infrastructure, DAC facilities can be co-located with renewable energy generation facilities to reduce transmission losses, and/or with CO_2 storage facilities to minimize transport costs and infrastructure. The location should also consider the land utilized, permeability of land, nearby air and noise pollution, and the discharge into local waterways. Whereas, designing a DOC system could be economical and smaller in size than a DAC system since it needs to process much less fluid volume, while DOC operating plants could be installed offshore and above CO_2 reservoirs under the seafloor that would not require valuable land space as well as reduce the cost of CO_2 transportation.

4.3. Scalability and intensification strategies

The primary industrial developers of DAC today are Carbon Engineering (Canada) and Climeworks (Switzerland). According to the IEA, as of 2022 there are 19 operational DAC plants worldwide with the potential to capture up to 0.01 $MtCO_2$/year [112,118]. Carbon Engineering is the first commercial entity to pursue solvent DAC technology. They use a potassium hydroxide solvent-based approach to their DAC technology coupled with a calcium caustic recovery loop. Carbon Engineering is currently building the largest DAC facility, called "STRATOS", with a capturing capacity of half a million of CO_2 annually and potential for scale-up to 1 million. It is expected that this plant will be operational by mid-2025 in Texas, USA. Climeworks is currently constructing the largest DAC and storage plant (Mammoth plant) in Hellisheidi, which will be designed to capture up to 36,000 tons of CO_2 annually and is planned to be operational by the middle of 2025 [22].

For DOC, there are no industrial plant operating yet, however, Captura, has launched the first DOC pilot plant off the coast of Newport Beach, CA in 2021 which is capable of capturing 100 tons of CO_2 per year using a system based on electrodialysis [82]. Although EMCC technology is technically underdeveloped, it does offer several potential benefits. These include safe operation in conditions of low pressure and ambient temperature, the ability to scale up the electrochemical device, and higher efficiency when compared to the thermochemical amine scrubbing method [83]. Particularly, EMCC technology can capture CO_2 emissions from small sources, including agriculture, forests, oceans, transportation, and residential areas where traditional methods are not feasible due to energy consumption and size. As this DOC application is still in its early stages of development, further research advances for practical demonstration are critical.

DOC stands to gain significant advantages from DAC. Firstly, DAC research frequently yields insights into materials, processes, and engineering that could be adapted to enhance the efficiency and effectiveness of DOC systems. DAC projects provide valuable lessons in scaling up carbon capture technologies, offering a roadmap for DOC initiatives to navigate challenges associated with large-scale deployment more effectively. Successful DAC projects can influence policy frameworks and attract increased funding for carbon capture efforts, benefiting both DAC and DOC initiatives. Lastly, as DAC gains acceptance, it has the potential to positively shape public perceptions of carbon capture technologies, including DOC, by highlighting their feasibility and benefits. Overall, fostering collaboration and knowledge exchange between the DAC and DOC communities holds promise for accelerating progress towards robust carbon capture solutions.

5. Conclusions and prospects for DAC and DOC

The application of both Direct Air Capture (DAC) and Direct Ocean Capture (DOC) for decarbonization strategies depends on a variety of factors including efficiency, scalability, environmental impact, and economic feasibility. Although DAC technologies offer versatile solutions to combat climate change, they face major challenges with respect to the energy consumption, cost-effectiveness, and scalability. LCA and TEA for DAC have so far relied on data from pilot or lab-scale processes, which are not representative of commercial-scale processes. Establishing scaling laws for emerging materials or technologies is necessary to accurately extrapolate LCA data to larger scales and evaluate the true potential to either combat climate change or support decentralized CO_2 production.

To improve the performance of DOC technologies, it is likely that the development of novel solvents and adsorbent materials with enhanced capture capacity, selectivity, and lower regeneration costs, will be required. The emergence of membranes as alternative capture solutions is also unclear given the lack of datasets and the experimental challenges to develop ultra-selective materials in such dilute conditions. In addition, the effectiveness of heat exchangers and auxiliary facilities is also currently limited while conducting optimization of networking processes, is of major importance to improve efficiency. At present most technologies developed are not mature enough to support large scale deployment and that the future of DAC, and current projects being developed and implemented. Given that no large-scale plants on the tens of megaton of CO2 captured per year are planned at present, and since the deployment of any large-scale plants may take at minima 5–10 years from the design phase to the full commissioning, the direct impact of DAC on climate mitigation also does not will not likely benefit the current climate actions over the next 10–15 years, unless supported by massive public investment.

Alternatively, DOC technologies have been shown to leverage the natural carbon cycle and can potentially mitigate ocean acidification while providing a source of sequestered carbon. Nevertheless, DOC technologies are currently much less mature than DAC ones, and equally face challenges, particularly related to the potential impacts on marine ecosystems and the scalability of the technology. Performing thorough techno-economic analysis and LCA is crucial to optimize CO_2 reductions, including as an example mangrove restoration. The potential of DOC to however help balance pH changes at large scale may represent a route to limit the degradation of extremely pH-dependent ecosystems, such as coral reefs. However, the scalability of the technology and need to pump

and dose extremely large amounts of seawater appears as a major bottleneck to the technology scale-up. Electrochemical ocean capture has improved CO_2 capture potential but scaling and efficiency improvements require further research particularly due to biofouling of exchangers during capture. The impact of DOC operations on biodiversity is also unclear and studies to address them both locally and at scale must be performed. Exploring the capture of CO_2 at different depths of the water column, particularly in anoxic conditions where lower biological matter concentrations may be present compared to surface waters.

The current climate actions require technologies and both technical and governmental choices able to lead to major abatement of carbon emissions. The implementation of both DAC and DOC is context dependent, including local environmental conditions, available resources, and the primary goals of the carbon capture project. In the broader context, although both DAC and DOC represent significant advancements in carbon capture technology and have potential, they are currently not sufficiently mature and continued research and development is needed. The implementation of DAC and DOC however as a mean to produce CO_2 locally for industrial applications appears much more realistic leading to a net-zero CO2 balance. The use of DAC and DOC may reduce the footprint of long-range CO2 transfer and act as a secondary mitigation pathway. Their integration into broader climate mitigation strategies may not represent a major outcome over the medium term but their implementation for decentralized CO_2 carbonates production may however find on the long-term, markets ready to invest.

Future work in the field of DAC and DOC could involve several avenues for further exploration and development. One promising direction is the optimization of both technologies for enhanced efficiency and cost-effectiveness, perhaps through the refinement of capture materials or process engineering techniques. Additionally, research efforts could focus on scaling up these technologies from pilot to industrial levels, addressing challenges related to infrastructure, energy requirements, and environmental impacts along the way. Collaboration between academia, industry, and policymakers could facilitate the implementation of large-scale DAC and DOC projects, while interdisciplinary studies could explore novel integration strategies with other carbon capture and renewable energy technologies. Furthermore, there is a need for continued monitoring and assessment of the environmental and socio-economic implications of widespread DAC and DOC deployment to ensure their long-term sustainability and effectiveness in combating climate change.

CRediT authorship contribution statement

Omnya Al Yafiee: Writing – original draft, Formal analysis, Data curation. **Fatima Mumtaz:** Writing – original draft, Formal analysis, Data curation. **Priyanka Kumari:** Writing – review & editing, Supervision, Formal analysis. **Georgios N. Karanikolos:** Writing – review & editing, Supervision. **Alessandro Decarlis:** Writing – review & editing, Data curation. **Ludovic F. Dumée:** Writing – review & editing, Supervision, Methodology, Data curation, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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Updated Buildings Sector Appliance and Equipment Costs and Efficiencies

March 2023

Independent Statistics and Analysis
U.S. Energy Information Administration

www.eia.gov
U.S. Department of Energy
Washington, DC 20585

The U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy (DOE), prepared this report. By law, our data, analyses, and forecasts are independent of approval by any other officer or employee of the U.S. Government. The views in this report do not represent those of DOE or any other federal agencies.

March 2023

Updated Buildings Sector Appliance and Equipment Costs and Efficiencies

Energy used in the residential and commercial sectors provides a wide range of services, including heating, cooling, lighting, refrigeration, cooking, and numerous other end uses. The U.S. Energy Information Administration (EIA) conducts two buildings-sector surveys—the *Residential Energy Consumption Survey* (RECS) and the *Commercial Buildings Energy Consumption Survey* (CBECS)—that provide information on the equipment stock and energy consumption within existing buildings. However, these surveys do not directly gather other information that we need to project future energy consumption, such as equipment cost information or nameplate efficiency ratings.

The Residential Demand Module (RDM) and the Commercial Demand Module (CDM) of the National Energy Modeling System (NEMS) use equipment cost and performance technology menus that represent competing options for most of the major end uses. The contracted reports in Appendixes A–D provide the information basis on which these menus can be built, focusing on cost and efficiency characterizations across equipment and fuel types. Previous editions of the *Annual Energy Outlook* (AEO) used similar contracted reports.

Multiple equipment classes and types are represented in these menus so that the projected equipment stock can change over time in response to fuel prices and other factors that affect equipment choice, such as appliance standards. The equipment menus interact with other NEMS parameters to determine market shares, equipment efficiency levels, cost estimates, and equipment interactions,[1] and they are used to translate service demand into energy demand.

Appendixes A and B constitute one set of reports that characterizes most major residential equipment and commercial heating, cooling, and water heating equipment. Appendix A is used in developing Reference case projections, while Appendix B is used in developing advanced technology cases.[2] These assumptions will be developed and implemented during the AEO2024 cycle.

Appendixes C and D constitute another set of reports that characterizes residential and commercial lighting, as well as commercial ventilation and refrigeration equipment. Appendix C is used in developing the Reference case, while Appendix D is used in developing advanced technology cases. These assumptions were developed and implemented during the AEO2023 cycle.

When referencing the contracted reports in Appendixes A, B, C, and D, you should cite them as reports by Guidehouse and Leidos, prepared for the U.S. Energy Information Administration.

[1] Examples of equipment interactions are solar water heaters that supplement traditional water heaters, clothes washers that reduce the need for clothes drying, and water heaters that provide dishwashers and clothes washers with heated water.

[2] In addition to the Reference case, we also develop sensitivities to explore different assumptions for the cost and performance of future technologies. For the more optimistic cases, some equipment achieves lower life-cycle costs through improved efficiency or lower upfront costs, or both. The contracted reports provide a base case and an advanced case for modeling the AEO Reference case along with the more optimistic cases. We use the advanced case assumptions to develop side cases for AEO reports that include such analyses.

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APPENDIX A

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EIA - Technology Forecast Updates – Residential and Commercial Building Technologies – Reference Case

Presented to:

U.S. Energy Information Administration

Prepared by:

Guidehouse
1676 International Drive
McLean, VA 22102

And

Leidos
11951 Freedom Drive
Reston, VA 20190

March 3, 2023

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Objective

The objective of this study is to develop baseline and projected performance/cost characteristics for residential and commercial end-use equipment.

- Installed base in 2012 and 2018 (for commercial products) or 2015 and 2020 (for residential products) and current market (2022)
  - Review literature, standards, installed base, contractor, and manufacturer information
  - Provide a relative comparison and characterization of the cost/efficiency of a generic product
- Forecast of technology improvements that are projected to be available through 2050
  - Review trends in standards, product enhancements, and Research and Development (R&D)
  - Project impact of product improvements and enhancement to technology

The performance/cost characterization of end-use equipment developed in this study will assist EIA in projecting national primary energy consumption.

Methodology

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Input from industry stakeholders, including government, R&D organizations, and manufacturers, was used to project product enhancements concerning equipment performance and cost attributes.

- Technology forecasting involves many uncertainties.
- Technology developments impact performance and cost forecasts.
- Varied sources ensure a balanced view of technology progress and the probable timing of commercial availability.
- Only currently published efficiency standards and regulations are considered when predicting technology developments; unpublished future regulatory action is not predicted.
- All costs are shown in 2022 dollars (2022$).
- Ranges, when given, represent the span of typical values for a given parameter (e.g., installed cost for equipment meeting the federal standard) not the highest and lowest available on the market.

Definitions

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The following tables represent the current and projected efficiencies for residential and commercial building equipment ranging from the installed base in 2012 and 2018 (for commercial products) or 2015 and 2020 (for residential products) to the highest efficiency equipment that is expected to be commercially available by 2050, assuming incremental adoption. Below are definitions for the terms used in characterizing the status of each technology.

- Installed Base: Efficiency values are for those units installed and "in use" in that year. Cost values are for the typical new unit sold in that year.
- Current Standard: The minimum efficiency (or maximum energy use) that is required (allowed) by current U.S. Department of Energy (DOE) standards, when applicable.
- ENERGY STAR: The minimum efficiency that is required (or maximum energy use allowed) to meet the ENERGY STAR criteria, when applicable. The performance data that are presented are representative of certified products that just meet current ENERGY STAR specifications.
- Typical: Efficiency and cost values are for the average, or "typical," product being sold in the particular timeframe. This may represent either the shipments-weighted average product performance or the most common product on the market.
- High: Efficiency and cost values are for the product with the highest efficiency available in the particular timeframe.

Market Transformation

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The market for the reviewed products has changed since this analysis was previously conducted.[1] These changes are noted and reflected in the efficiency and cost characteristics.

- In some categories the typical new product purchased today is more efficient than the average product in the installed base in 2012 (commercial) or 2015 (residential):
  - Residential sector: boilers, central air conditioners, room air conditioners, gas-fired furnaces (North), gas-fired furnaces (Rest of Country), oil-fired furnaces, electric resistance furnaces, heat pump water heaters, gas-fired instantaneous water heaters, natural gas cooktops, natural gas ovens, refrigerator-freezers, freezers, clothes dryers, clothes washers, and dishwashers
  - Commercial sector: gas-fired furnaces, oil-fired boilers, commercial rooftop heat pumps, commercial ground-source heat pumps, gas-fired instantaneous water heater, natural gas and electric ranges, griddles, and ovens
- More stringent Federal standards have taken effect for the following products:
  - Gas-fired and oil-fired boilers in 2021
  - Rooftop air conditioners and rooftop heat pumps in 2018
- Federal standards are slated to take effect in the coming years for the following products:
  - Central air conditioners, residential air-source heat pumps, gas-fired furnaces, oil-fired furnaces, gas-fired boilers, oil-fired boilers, rooftop air conditioners, and rooftop heat pumps in 2023
  - Portable air conditioners in 2025
- ENERGY STAR continues to raise the bar with revised criteria for:
  - Central air conditioners, residential air-source heat pumps, rooftop air conditioners, rooftop heat pumps, residential water heaters, and dishwashers in 2023

Note: The previous analysis is available in the EIA Technology Forecast Updates (2018) report.

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Residential Space Heating and Cooling

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Residential Gas-Fired Furnaces (North)

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DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR (North) V. 4.1	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)[1]	80	80	80	80	80	80	80	80	80	80	80	80
AFUE (%)	80	80	80	90	95	99	95	99	95	99	95	99
Electric Consumption (kWh/y)[2]	374	374	386	636	631	725	631	725	631	725	631	725
Average Life (y)[3]	17	17	17	17	17	17	17	17	17	17	17	17
	26	26	26	26	26	26	26	26	26	26	26	26
Retail Equipment Cost (2022$)	1,300	1,300	1,080	1,200	1,220	1,390	1,220	1,390	1,220	1,390	1,220	1,390
Total Installed Cost (2022$)	2,880	2,880	3,690	4,130	4,150	4,320	4,150	4,320	4,150	4,320	4,150	4,320
Annual Maintenance Cost (2022$)	60	60	120	130	130	130	130	130	130	130	130	130

1. Typical input capacity is represented in terms of thousand British thermal units (kBtu) per hour (i.e., kBtu/h).
2. Electric consumption, represented in terms of kilowatt hours per year (kWh/y), accounts for the electricity consumption of components such as the furnace fan, draft inducer, and the ignitor. In some high efficiency products, this component also includes auxiliary equipment, such as condensate pumps and heat tape.
3. In the Residential Furnaces EERE 2022 Notice of Proposed Rulemaking (NOPR) Technical Support Document (TSD), an average lifetime of 22.5 years is calculated for gas-fired furnaces (North). Lifetime range was calculated using the Weibull Distribution in the Residential Furnaces EERE 2022 NOPR.

Note:
Models on the market can be either weatherized or non-weatherized. The majority (74%) are non-weatherized, and the values in the table use only non-weatherized data.
Electric consumption and cost values for 2022 and beyond are for a national sample and use the Residential Furnaces EERE 2022 NOPR Life-Cycle-Cost (LCC) spreadsheet.
Electric consumption and costs for the 2030, 2040, and 2050 high values are estimated based on the maximum-efficiency level analyzed in Residential Furnaces EERE 2022 NOPR, which is 98% annual fuel utilization efficiency (AFUE).
The current standard went into effect in November 2015.
ENERGY STAR V. 4.1 went into effect in February 2013.
The range for average life represents the span of typical values.

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Residential Gas-Fired Furnaces (Rest of Country)

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DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR (ROC) V. 4.1	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	80	80	80	80	80	80	80	80	80	80	80	80
AFUE (%)	80	80	80	90	90	99	95	99	95	99	95	99
Electric Consumption (kWh/y)[1]	279	279	386	636	636	725	631	725	631	725	631	725
Average Life (y)[2]	16	16	16	16	16	16	16	16	16	16	16	16
	25	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)	1,260	1,260	1,080	1,200	1,200	1,390	1,220	1,390	1,220	1,390	1,220	1,390
Total Installed Cost (2022$)	2,380	2,380	3,690	4,130	4,130	4,320	4,150	4,320	4,150	4,320	4,150	4,320
Annual Maintenance Cost (2022$)	40	40	120	130	130	130	130	130	130	130	130	130

1. Electric consumption accounts for the electricity consumption of components such as the furnace fan, draft inducer, and the ignitor. In some high efficiency products, this component also includes auxiliary equipment, such as condensate pumps and heat tape.
2. In the Residential Furnaces EERE 2022 NOPR, an average lifetime of 21.5 years is calculated for gas-fired furnaces (Rest of Country). Lifetime range was calculated using the Weibull Distribution in the Residential Furnaces EERE 2022 NOPR.

Note:
Models on the market can be either weatherized or non-weatherized. The majority (74%) are non-weatherized, and the values in the table use only non-weatherized data.
Electric consumption and cost values for 2022 and beyond are for a national sample and use the Residential Furnaces EERE 2022 NOPR LCC spreadsheet.
Electric consumption and costs for the 2030, 2040, and 2050 high values are estimated based on the maximum-efficiency level analyzed in Residential Furnaces EERE 2022 NOPR, which is 98% AFUE.
The current standard went into effect in November 2015.
ENERGY STAR V. 4.1 went into effect in February 2013.
The range for average life represents the span of typical values.

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Residential Gas-Fired Furnaces

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- Current Federal standards for non-weatherized gas furnaces:
  - AFUE ≥ 80%
- ENERGY STAR V. 4.1 criteria for gas furnaces:
  - South: AFUE ≥ 90%
  - North: AFUE ≥ 95%
  - Furnaces must be equipped with electronically commutated fan motor and have less than or equal to 2.0% air leakage
- Most efficient unit currently available: 99.0% AFUE. The current market is nearly evenly split between non-condensing units (AFUE≤82%) and condensing units (AFUE≥90%).
- The maximum AFUE for non-condensing gas furnaces is 82%; above this level, the potential for exhaust gas condensation increases. This condensate is corrosive and requires cost restrictive corrosion resistant venting.
- High-efficiency condensing furnaces typically have high-grade stainless steel (AL 29-4C) heat exchangers.
- Many condensing furnaces are available as direct vent and sealed combustion systems, which do not use room air for combustion, but instead draw combustion air directly from outdoors.
- Depending on the location of the home, piping materials in use, and other considerations, condensing furnaces may need an acid neutralizer and/or lift pump for the condensate.
- Furnaces may contain permanent split capacitor (PSC) fan motors or electronically commutated motors (ECMs). The type of motor affects the electrical consumption of the furnace as well as the seasonal energy efficiency ratio (SEER) / energy efficiency ratio (EER) of the associated air conditioner.
  - The 2016 Energy Conservation Standards for Residential Furnace Fans Final Rule requires that all furnaces use ECM fans.
  - Most non-weatherized gas furnaces employ ECMs and can fully modulate rather than cycling on and off. Because they modulate, there is an increase in total fan-on time.

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Residential Gas-Fired Furnaces

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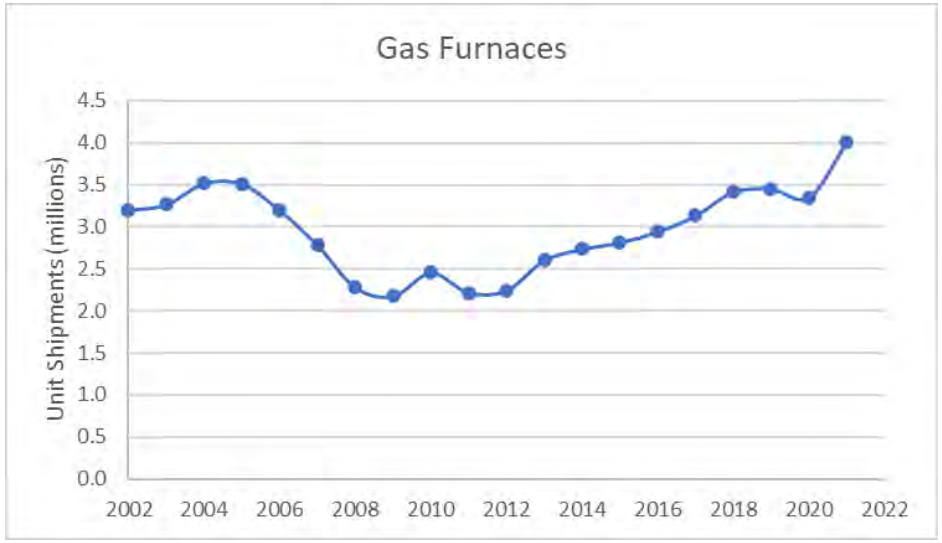
Annual shipments reached 3.5 million units in 2005 and then declined each year until 2009, leveling off at about 2.25 million units. Since 2012, shipments have increased steadily and reached a peak of 4.0 million units in 2021.



Source: *Air-Conditioning, Heating, and Refrigeration Institute (AHRI)*

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DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.1	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	105	105	105	105	105	105	105	105	105	105	105	105
AFUE (%)	83	83	83	85	85	97	85	97	85	97	85	97
Electric Consumption (kWh/y)[1]	477	477	477	466	466	410	466	410	466	410	466	410
Average Life (y)[2]	20	20	20	20	20	20	20	20	20	20	20	20
	33	33	33	33	33	33	33	33	33	33	33	33
Retail Equipment Cost (2022$)	2,620	2,620	2,620	2,650	2,650	3,170	2,650	3,170	2,650	3,170	2,650	3,170
	3,450	3,450	3,450	3,490	3,490	4,090	3,490	4,090	3,490	4,090	3,490	4,090
Total Installed Cost (2022$)	3,250	3,250	3,250	3,480	3,480	5,140	3,480	5,140	3,480	5,140	3,480	5,140
	6,520	6,520	6,520	6,820	6,820	10,110	6,820	10,110	6,820	10,110	6,820	10,110
Annual Maintenance Cost (2022$)	80	80	80	80	80	240	80	240	80	240	80	240

1. Electric consumption accounts for the electricity consumption of components such as the furnace fan, draft inducer, and the ignitor. In some high efficiency products, this component also includes auxiliary equipment, such as condensate pumps and heat tape.
2. Lifetime range was calculated using the Weibull Distribution in Residential Furnaces EERE 2011.

Note:
The current standard went into effect in May 2013.
ENERGY STAR V. 4.1 went into effect in February 2013.
Ranges represent the span of typical values for a given parameter.

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Residential Oil-Fired Furnaces

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- Current Federal standards:
  - AFUE ≥ 83%
  - ≤ 11 watts of electrical power when in standby and off modes (non-weatherized models only)
- ENERGY STAR V. 4.1 criteria: AFUE ≥ 85%
- Since the latent heat content of oil is lower than that for either propane or natural gas, oil-fired appliances can typically operate at a higher AFUE rating than comparable gas-fired appliances before condensation issues arise.
- Most efficient unit currently available: 96.7% AFUE – condensing units with tiny market share (<1%), due to market acceptance issues.
- Condensate from condensing oil furnaces is typically even more corrosive than that of gas-fired systems due to the higher sulfur content in fuel oil. Hence, condensing oil furnaces also likely require the use of an acid neutralizer.
- Oil-fired furnaces, like gas-fired furnaces, achieve condensing conditions through the use of a secondary heat exchanger. Typically, these secondary heat exchangers use a high-grade stainless steel (AL 29-4C).
- Sooting is an issue for all oil-fired appliances, but secondary heat exchangers, with their narrow passages, are even more prone to be plugged by soot. Because of this, condensing oil furnaces typically require frequent cleaning and maintenance.

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Residential Oil-Fired Furnaces

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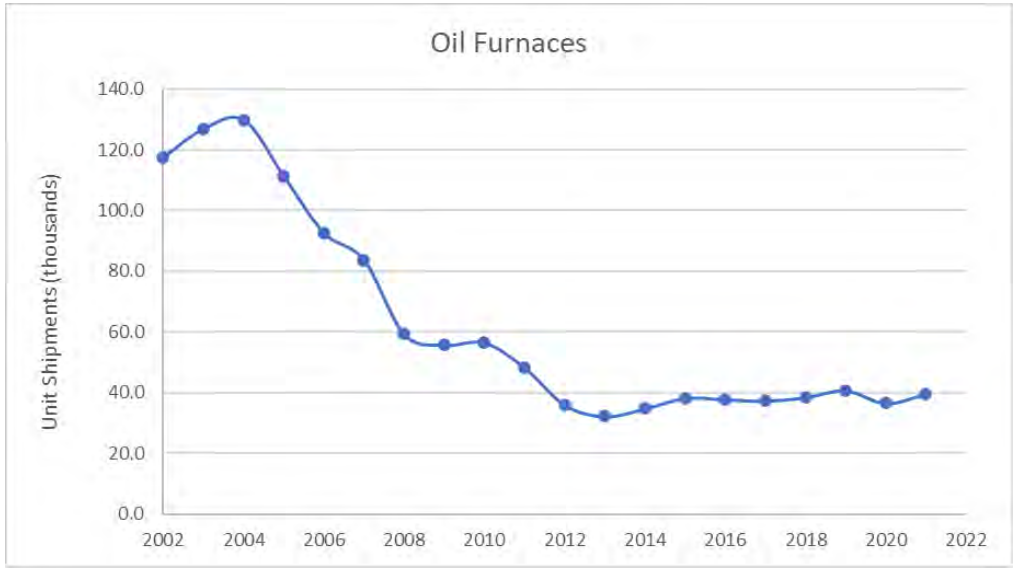
Annual shipments declined rapidly after 2004, likely due, at least in part, to an increase in fuel oil prices, which more than tripled from 2002 to 2008. Since 2012 shipments have largely leveled off.



Source: *AHRI*

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Residential Gas-Fired Boilers

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DATA	2015	2020[1]	2022				2030[2]		2040[2]		2050[2]	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.0	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	100	100	100	100	100	100	100	100	100	100	100	100
AFUE (%)	82	95	84	95	90	96	95	96	95	96	95	96
Electric Consumption (kWh/y)[3]	197	506	282	506	527	502	506	502	506	502	506	502
Average Life (y)	20	20	20	20	20	20	20	20	20	20	20	20
	30	30	30	30	30	30	30	30	30	30	30	30
Retail Equipment Cost (2022$)	2,540	2,890	1,820	2,890	2,440	3,670	2,890	3,670	2,890	3,670	2,890	3,670
Total Installed Cost (2022$)	7,760	5,940	8,700	5,940	6,700	6,710	5,940	6,710	5,940	6,710	5,940	6,710
Annual Maintenance Cost (2022$)[4]	110	160	150	160	160	160	160	160	160	160	160	160

1. The 2020 AFUE is estimated based on EERE 2022 preliminary analysis, which estimates that gas-fired boilers with the highest market share in 2020 have an AFUE of 95%.
2. The 2030, 2040, 2050 projections are estimated based on the EERE 2022 preliminary analysis, which notes that majority of the market is expected to be condensing, if new standards are not implemented. The EERE 2022 preliminary analysis estimates a minimum efficiency of 95% AFUE for condensing units.
3. Electric Consumption accounts for the electricity consumption of auxiliary electrical components including circulating pump, the boiler pump (condensing boilers only), the draft inducer (if present), and the ignitor. It also accounts for the electricity consumption of auxiliary equipment such as a condensate pump and heat tape, which are sometimes installed with higher efficiency boilers. Additionally, it accounts for the additional cooling load due to heat loss from the boiler and water heater as a result of water heating during the cooling season.
4. Maintenance cost is the routine annual cost to the consumer of general maintenance for product operation. Maintenance cost is higher for condensing boilers for the inspection of condensate system and replacement of condensate neutralizer filter.

Note:
The current standard went into effect in January 2021.
ENERGY STAR V. 3.0 went into effect in December 2013.
Water boilers considered. Steam boilers also exist but make up a small percentage of the market.
The range for average life represents the span of typical values.

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Residential Gas-Fired Boilers

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- Federal standard for gas-fired hot-water boilers (more common than steam):
  - AFUE ≥ 84%
  - Standard went into effect on January 21, 2021
- ENERGY STAR criteria: AFUE ≥ 90%
- Most efficient gas-fired boiler available: 96.4% AFUE
- Gas-fired boilers have lost market share to furnaces and heat pumps over the past 30 years.
- U.S. gas hot water boiler sales are split approximately 60/40 between condensing and non-condensing.[1] Condensing boilers typically have heat exchangers made of stainless steel, and non-condensing boilers typically have heat exchangers made of cast iron.
- Typically, condensing boilers are low-mass in construction with modulating burners, variable-speed inducer fan systems or sealed powered direct-vent combustion, multiple sensor technologies, and electronic ignition and control.
- Due to incentives and market pressure, the U.S. boiler industry has been shifting towards also providing condensing boilers. Most of these boilers are private-labeled products sourced from Europe, where the hydronic market is much bigger and condensing appliances are much more common and/or required by law.
- Most value-added components for condensing boilers are sourced abroad, even when the condensing boiler is assembled in North America (e.g., heat exchanger, gas valve, burner, sensors, and/or controls).

Source: EERE 2022 Preliminary Analysis TSD, Chapter 3

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Residential Gas-Fired Boilers

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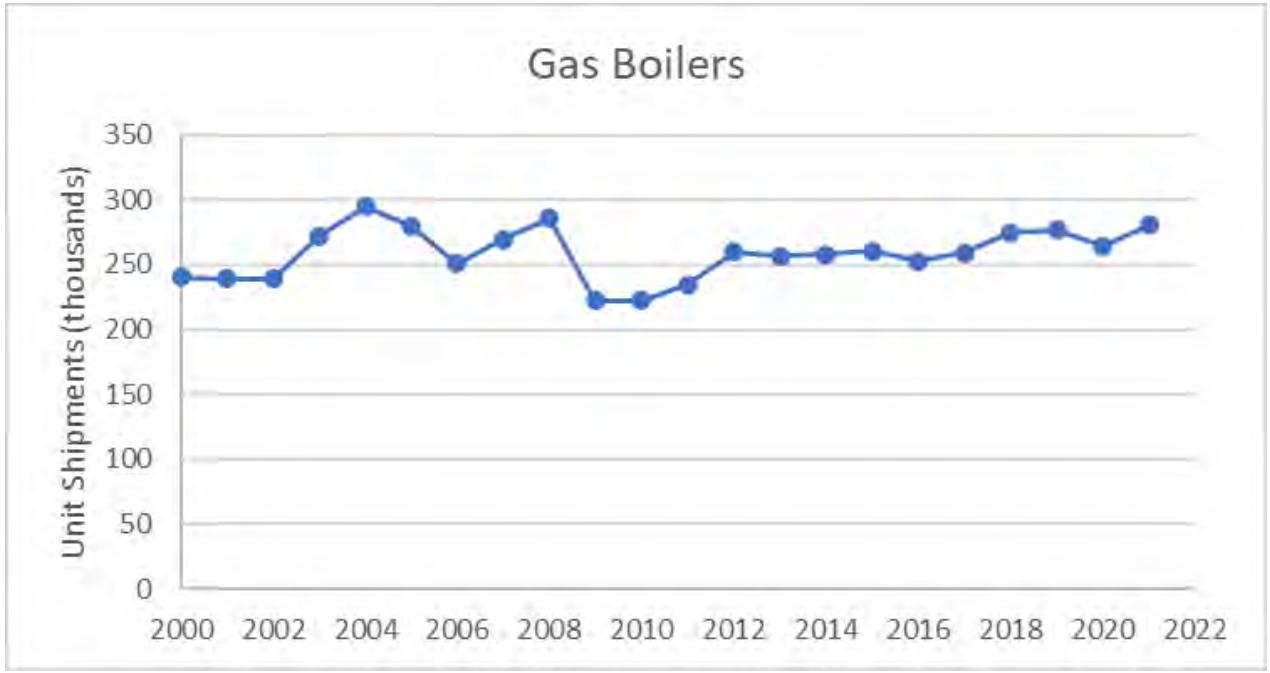
Annual shipments had a significant decrease following the 2009 financial crisis and a steady recovery in the years since.



Source: *Boilers EERE 2022 Preliminary Analysis*

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Residential Oil-Fired Boilers

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DATA	2015	2020[1]	2022				2030[2]		2040[2]		2050[2]	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.0	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	140	140	140	140	140	140	140	140	140	140	140	140
AFUE (%)	84	86	86	86	87	88	86	88	86	88	86	88
Electric Consumption (kWh/y)[3]	230	310	310	310	307	305	310	305	310	305	310	305
Average Life (y)[4]	18	18	18	18	18	18	18	18	18	18	18	18
	28	28	28	28	28	28	28	28	28	28	28	28
Retail Equipment Cost (2022$)	4,850	3,590	3,590	3,590	3,680	3,770	3,590	3,770	3,590	3,770	3,590	3,770
Total Installed Cost (2022$)	9,800	5,510	5,510	5,510	5,600	5,690	5,510	5,690	5,510	5,690	5,510	5,690
Annual Maintenance Cost (2022$)[4]	160	170	170	170	170	170	170	170	170	170	170	170

1. The 2020 AFUE is estimated based on EERE 2022 preliminary analysis, which estimates that oil-fired boilers with the highest market share in 2020 have an AFUE of 86%.
2. The 2030, 2040, 2050 projections are estimated based on the EERE 2022 preliminary analysis, which notes that majority of the market is expected to be at 86% AFUE, if new standards are not implemented.
3. Electric Consumption accounts for the electricity consumption of auxiliary electrical components including circulating pump, the ignitor, condensate pump, and heat tape, which are sometimes installed with higher efficiency boilers. Additionally, it accounts for the additional cooling load due to heat loss from the boiler and water heater as a result of water heating during the cooling season.
4. Maintenance cost is the routine annual cost to the consumer of general maintenance for product operation.

Note:
The current standard went into effect in January 2021.
ENERGY STAR V. 3.0 went into effect in December 2013.
Water boilers considered. Steam boilers also exist but make up a small percentage of the market.
The range for average life represents the span of typical values.

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Residential Oil-Fired Boilers

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- Federal standard for oil-fired hot-water boilers (more common than steam):
  - AFUE ≥ 86%
  - Standard went into effect on January 21, 2021
- ENERGY STAR criteria: AFUE ≥ 87%
- Most efficient oil-fired boiler available: 88% AFUE
- Since the latent heat content of oil is lower than that for either propane or natural gas, oil-fired appliances can typically operate at a higher AFUE rating than comparable gas-fired appliances before condensation issues arise.
- Oil boilers have heat exchangers made of cast iron or steel.
- No condensing oil-fired boilers currently exist in the U.S. market. The high sulfur content in fuel-oil causes heat exchanger fouling if the flue gases from an oil-fired boiler were to condense. As a result, condensing oil-fired boilers would require more frequent maintenance and repair, if installed.

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Residential Oil-Fired Boilers

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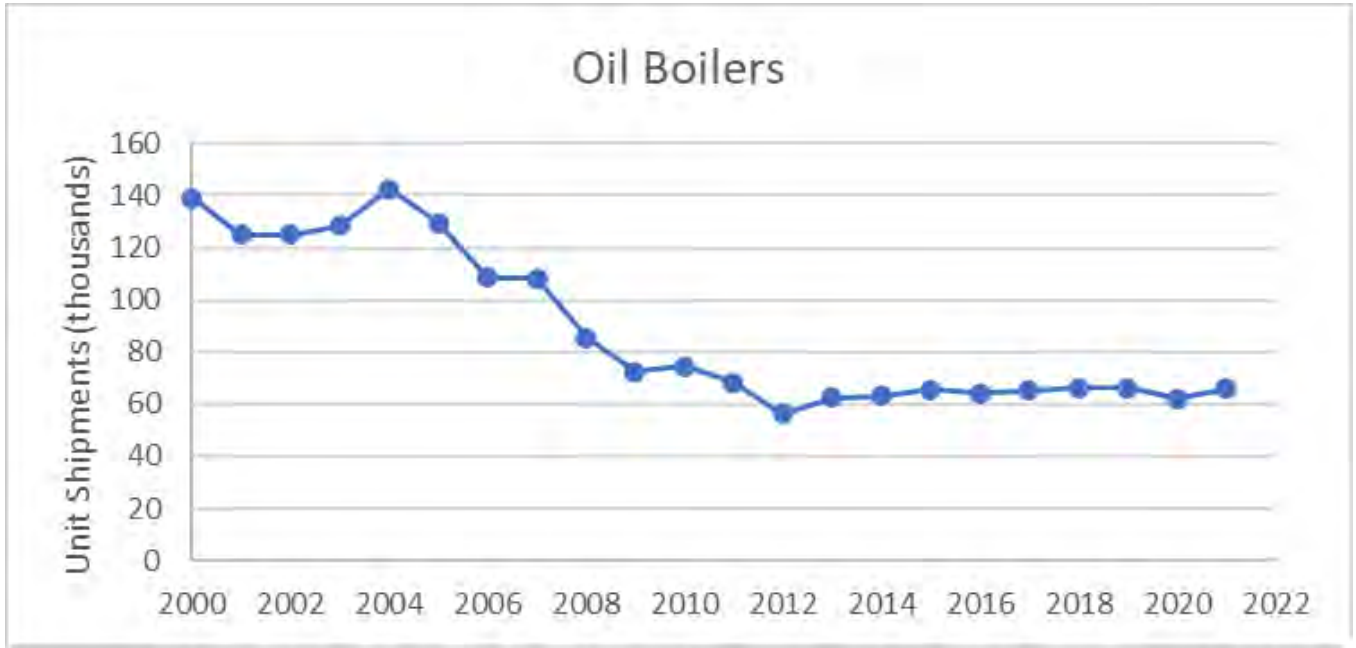
Annual shipments declined rapidly after 2004, likely due, at least in part, to an increase in fuel oil prices, which more than tripled from 2002 to 2008. Since 2012 shipments have largely leveled off.



Source: *Boilers EERE 2022 Preliminary Analysis*

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Residential Electric Resistance Furnaces

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DATA	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	Typical	Typical	Typical
Typical Input Capacity (kBtu/h)	68	68	68	68	68	68	68
AFUE (%)	98	98	100	100	100	100	100
Average Life (y)	15	15	15	15	15	15	15
	30	30	30	30	30	30	30
Retail Equipment Cost (2022$)[1]	760	760	950	950	950	950	950
Total Installed Cost (2022$)[1]	1,290	1,290	1,480	1,480	1.480	1,480	1,480
Annual Maintenance Cost (2022$)[1]	50	50	50	50	50	50	50

1. Costs for a 100% AFUE unit are assumed to be equal to the costs of a 98% AFUE unit.

Note:
The current standard went into effect in January 1992.
The range for average life represents the span of typical values.

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Residential Electric Resistance Furnaces

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- Federal standards for electric furnaces:
  - AFUE ≥ 78%
  - Standby and off mode power consumption ≤ 10 watts
- According to preliminary Residential Energy Consumption Survey (RECS) data released May 2022, electric central warm-air furnaces are the main source of space heating in approximately 17.5 million U.S. homes or about 14%.
- Electric furnaces range in capacity from 10 to 25 kW (34 to 85 kBtu/h), with 20 kW (68 kBtu/h) being the typical for units on the market.
- Electric resistance furnaces are considered near 100% efficient because there is no flue heat loss, and any jacket losses are contained within the home.
  - ASHRAE Standard 103, the test method for furnaces incorporated by reference into the federal test procedure, specifies that for electric furnaces AFUE = 100 – 1.7 x jacket losses. Jacket losses can be determined either through testing or assumed to be 1%. Thus, the minimum AFUE of electric furnaces is 98.3%.

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Residential Electric Resistance Unit Heaters

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DATA	2015	2020	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical	Typical	Typical
Typical Capacity (kBtu/h)	3.5	3.5	5.1	5.1	5.1	5.1
Efficiency (%)	100	100	100	100	100	100
Average Life (y)[1]	15	15	15	15	15	15
	30	30	30	30	30	30
Retail Equipment Cost (2022$)[2]	90	90	85	85	85	85
	240	240	340	340	340	340
Total Installed Cost (2022$)[3]	150	150	390	390	390	390
	320	320	1,190	1,190	1,190	1,190
Annual Maintenance Cost (2022$)[4]	-	-	-	-	-	-

1. Assumes similar lifetime to Electric Furnaces on the basis that both products have heating elements that burn out and lead to product failure.
2. The lower bound of the equipment costs represents the average retail price listed at the typical capacity for electric baseboard heaters through a retailer website. The upper bound represents the average retail price for compact recessed electric wall heaters at the same capacity.
3. Range represents the estimated minimum and maximum installation costs.
4. Maintenance costs are negligible.

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Residential Electric Resistance Unit Heaters

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- Electric resistance unit heaters include electric wall and baseboard heaters. Plug-in space heaters are not included.
- There are currently no federal efficiency requirements for electric resistance unit heaters.
- According to preliminary RECS data released May 2022, electric resistance unit heaters are the main source of space heating in approximately 8.25 million U.S. homes or about 7%.
- Electric heaters range in capacity from 500 to 2,500 watts (1.7 to 8.5 kBtu/h), with 1,500 watts (5.1 kBtu/h) being the most typical for units on the market.
- Electric resistance heating is considered 100% energy efficient; all incoming electric energy is converted to heat.

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Residential Central Air Conditioners – North (Not Hot-Dry or Hot-Humid)

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DATA	2015	2020	2022				2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.0	High	New Standard	ENERGY STAR V. 6.1	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
SEER[1]	12.5	13.9	13.0	14.1	15.0	17.0	14.1	16.0	17.0	14.4	17.0	14.4	17.0	14.4	17.0
SEER2[2]	11.9	13.2	NA	13.4	NA	16.2	13.4	15.2	16.2	13.7	16.2	13.7	16.2	13.7	16.2
Average Life (y)	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)	2,410	2,670	2,580	2,700	3,110	3,950	2,680	3,750	3,950	2,760	3,950	2,760	3,950	2,760	3,950
Total Installed Cost (2022$)	4,000	4,300	5,250	5,320	5,520	5,980	5,310	5,880	5,980	5,350	5,980	5,350	5,980	5,350	5,980
Annual Maintenance Cost (2022$)[3]	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150

1. Values shown are for split-system units in the 36 kBtu/h (3-ton) size class. Costs and efficiency levels are for "coil-only" systems, meaning they do not include a blower. Note blower-coil systems were analyzed for residential air-source heat pumps, which is why the "High" SEER levels are higher for heat pumps than for air conditioners.
2. In 2023, new energy conservation standards for Residential Central Air Conditioners and Heat Pumps took effect. The new standards specify a different metric for central air conditioners (SEER2). SEER to SEER2 conversions were determined using the RESNET website.
3. Annual maintenance include preventative maintenance and services provided by HVAC professionals for maintaining product operation. Examples include, calibrate and level thermostat, clean filters, clean indoor and condenser coil, flush/treat condensate drain with anti-algae, inspect condenser coil, monitor operating pressure of refrigerant, inspect fan blade, etc.

Note:
The previous standard went into effect in January 2015. The current standard went into effect in January 2023.
ENERGY STAR V. 5.0 went into effect in September 2015. ENERGY STAR V. 6.1 went into effect in January 2023.
Ranges represent the span of typical values for a given parameter.

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Residential Central Air Conditioners – South (Hot-Dry and Hot-Humid)

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DATA	2015	2020	2022				2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.0	High	New Standard	ENERGY STAR V. 6.1	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
SEER[1]	13.0	14.4	14.0	14.6	15.0	17.0	15.1	16.0	17.0	15.1	17.0	15.1	17.0	15.1	17.0
SEER2[2]	12.4	13.7	NA	13.9	NA	16.2	14.3	15.2	16.2	14.3	16.2	14.3	16.2	14.3	16.2
Average Life (y)	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)	2,410	2,760	2,680	2,850	3,110	3,950	3,110	3,750	3,950	3,190	3,950	3,190	3,950	3,190	3,950
Total Installed Cost (2022$)	4,000	4,390	5,310	5,390	5,520	5,980	5,520	5,880	5,980	5,570	5,980	5,570	5,980	5,570	5,980
Annual Maintenance Cost (2022$)	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150

1. Values shown are for split-system units in the 36 kBtu/h (3-ton) size class. Costs and efficiency levels are for "coil-only" systems, meaning they do not include a blower. Note blower-coil systems were analyzed for residential air-source heat pumps, which is why the "High" SEER levels are higher for heat pumps than for air conditioners.
2. In 2023, new energy conservation standards for Residential Central Air Conditioners and Heat Pumps took effect. The new standards specify a different metric for central air conditioners (SEER2). SEER to SEER2 conversions were determined using the RESNET website.
3. Annual maintenance include preventative maintenance and services provided by HVAC professionals for maintaining product operation. Examples include, calibrate and level thermostat, clean filters, clean indoor and condenser coil, flush/treat condensate drain with anti-algae, inspect condenser coil, monitor operating pressure of refrigerant, inspect fan blade, etc.

Note:
The previous standard went into effect in January 2015. The current standard went into effect in January 2023.
ENERGY STAR V. 5.0 went into effect in September 2015. ENERGY STAR V. 6.1 went into effect in January 2023.
Ranges represent the span of typical values for a given parameter.

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- The previous standards took effect in 2015; amended standards for all product classes went into effect in January 2023.
  - Amended standards are based on new metrics (SEER2, EER2).
  - SEER2 values are generally expected to be lower than SEER because a higher external static pressure is required during testing, which reduces measured performance.
- Systems installed in the Southwest (CA, AZ, NM, and NV) must also meet an EER standard that varies by cooling capacity and system configuration.

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Residential Central Air Conditioners

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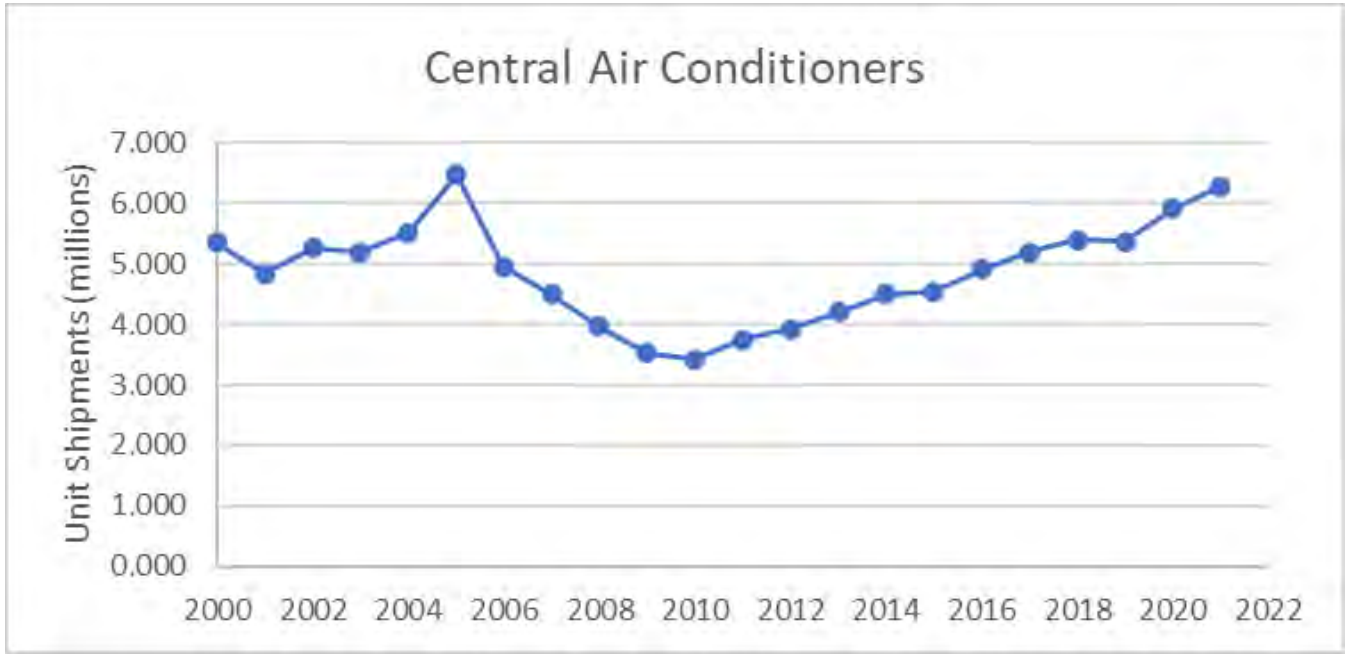
Annual shipments spiked at 6.5 million units in 2005 at the peak of the housing boom and just before more stringent Federal standards took effect in 2006. Annual shipments have been steadily increasing since 2010 and have almost reached the previous high in 2021.



Source: *AHRI*

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Residential Room Air Conditioners

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DATA	2015	2020	2022				2030[2]		2040[2]		2050[2]	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.2	High[1]	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	10	10	10	10	10	10	10	10	10	10	10.0	10.0
CEER (Btu/Wh)	10.9	10.9	10.9	12.0	12.0	15.7	12.0	15.7	12.0	15.7	12.0	15.7
Average Life (y)	6	6	6	6	6	6	6	6	6	6	6	6
	13	13	13	13	13	13	13	13	13	13	13	13
Retail Equipment Cost (2022$)	560	330	330	340	340	450	340	450	340	450	340	450
	710	480	480	480	480	590	480	590	480	590	480	590
Total Installed Cost (2022$)	640	490	490	490	490	600	490	600	490	600	490	600
	830	630	630	640	640	750	640	750	640	750	640	750
Annual Maintenance Cost (2022$)[3]	0	0	0	0	0	0	0	0	0	0	0	0

1. RAC EERE 2022 NOPR has analysis for combined energy efficiency ratio (CEER) of 16 Btu/Wh, which represents variable speed room air conditioners. However, maximum CEER identified in DOE's Compliance Certification Database (CCD) in August 2022 was 15.7 Btu/Wh. Accordingly, the high CEER is estimated to be 15.7 for 2022 and beyond. Cost values for a representative unit with a CEER of 16 Btu/Wh were used.
2. The 2030, 2040, 2050 projections are estimated based on RAC EERE 2022 NOPR, which notes that in the absence of no new standards, room air conditioners with a CEER of 12 Btu/Wh are expected to have the maximum market share.
3. Maintenance costs are negligible per RAC EERE 2011 and RAC EERE 2022 NOPR.

Note:
All values are for the most common product class, Product Class 3 (without reverse cycle, with louvered sides, and 8,000 to 13,999 Btu/h).
The current standard went into effect in June 2014.
ENERGY STAR V. 4.2 went into effect in October 2015.
Ranges represent the span of typical values for a given parameter (for example, installed cost for equipment meeting the federal standard) not the highest and lowest available on the market.

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Residential Room Air Conditioners

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- Analyzed the most common type of room air conditioners: louvered sides (window air conditioners) without reverse cycle and having cooling capacity of 8,000–13,999 Btu/h (DOE Product Class 3).
- Federal standards for Product Class 3:
  - CEER ≥ 10.9 (beginning June 1, 2014)
- CEER incorporates energy use in cooling mode and standby and off modes.
- ENERGY STAR V. 4.2 criteria for Product Class 3:
  - CEER ≥ 12.0 (effective October 26, 2015)
- Efficiency improvements in room air conditioners are attained by:
  - Higher efficiency compressor and fan motors (including variable speed motors), and
  - An increased heat transfer area in the evaporator and condenser using larger heat exchangers, finer fin spacing, micro-channel heat exchangers, and similar design options.

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Residential Room Air Conditioners

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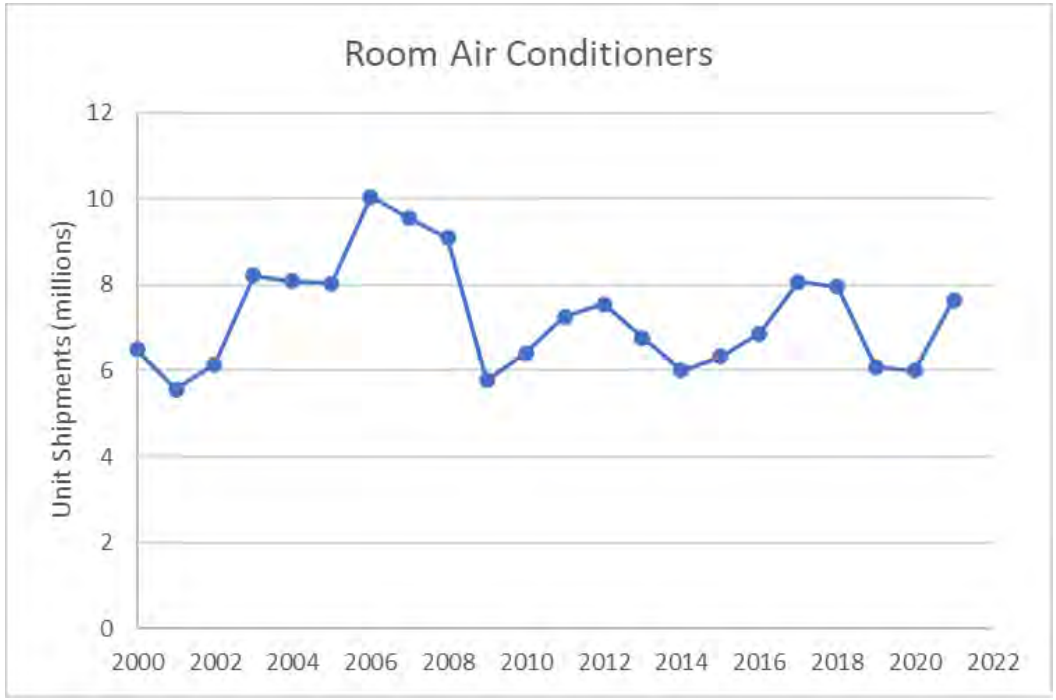
Annual shipments dropped sharply in 2009, likely due to the recession and an unusually cool summer in the Northeast. Sales have largely leveled off in the years since, fluctuating between 6 and 8 million.



Source: *RAC EERE 2022 NOPR*

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Residential Portable Air Conditioners

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DATA	2015	2020	2022[4]		2025		2030		2040		2050	
	Installed Base	Installed Base	Typical	High[5]	New Standard	High[5]	Typical	High[5]	Typical	High[5]	Typical	High[5]
Typical Capacity (kBtu/h)[1]	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6
CEER[2]	5.6	5.6	5.5	7.6	6.7	7.6	6.7	7.6	6.7	7.6	6.7	7.6
Average Life (y)	7	7	7	7	7	7	7	7	7	7	7	7
	12	12	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)	700	700	700	810	760	810	760	810	760	810	760	810
Total Installed Cost (2022$)[3]	700	700	700	810	760	810	760	810	760	810	760	810
Annual Maintenance Cost (2022$)[3]	0	0	0	0	0	0	0	0	0	0	0	0

1. All values are for the average capacity for single-duct and dual-duct portable air conditioners available on the market.
2. CEER is calculated for typical capacity using the equation provided in PAC EERE 2020.
3. Installation and maintenance costs are negligible.
4. The 2022 Typical estimates are based on PAC EERE 2020, which estimated majority of the market to be at EL1 in 2022 for the no-new standards case, which translates to a CEER of 5.5 for this analysis.
5. All High values are based on the most-efficient models available in the market, as specified in PAC EERE 2020.

Note:
A final rule for portable air cleaners published in January 2020 with an effective date of January 2025.
Costs are interpolated from the costs presented in PAC EERE 2020.
Range for lifetime represents typical values.

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Residential Portable Air Conditioners

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- A final rule establishing new energy conservation standards for portable air conditioners published in January 2020 with an effective date of January 2025.
- The final rule outlined an equation-based conservation standard (in CEER) for both single-duct and dual-duct portable ACs, based on the seasonally adjusted cooling capacity (SACC)

$$\text{Minimum CEER} = \text{PR} \times \frac{\text{SACC}}{(3.7117 \times \text{SACC}^{0.6384})}$$

- Efficiency improvements in portable air conditioners are attained by:
  - Higher efficiency compressor and fan motors (including variable speed motors), and
  - An increased heat transfer area in the evaporator and condenser using larger heat exchangers, finer fin spacing, micro-channel heat exchangers, and similar design options.

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Residential Portable Air Conditioners

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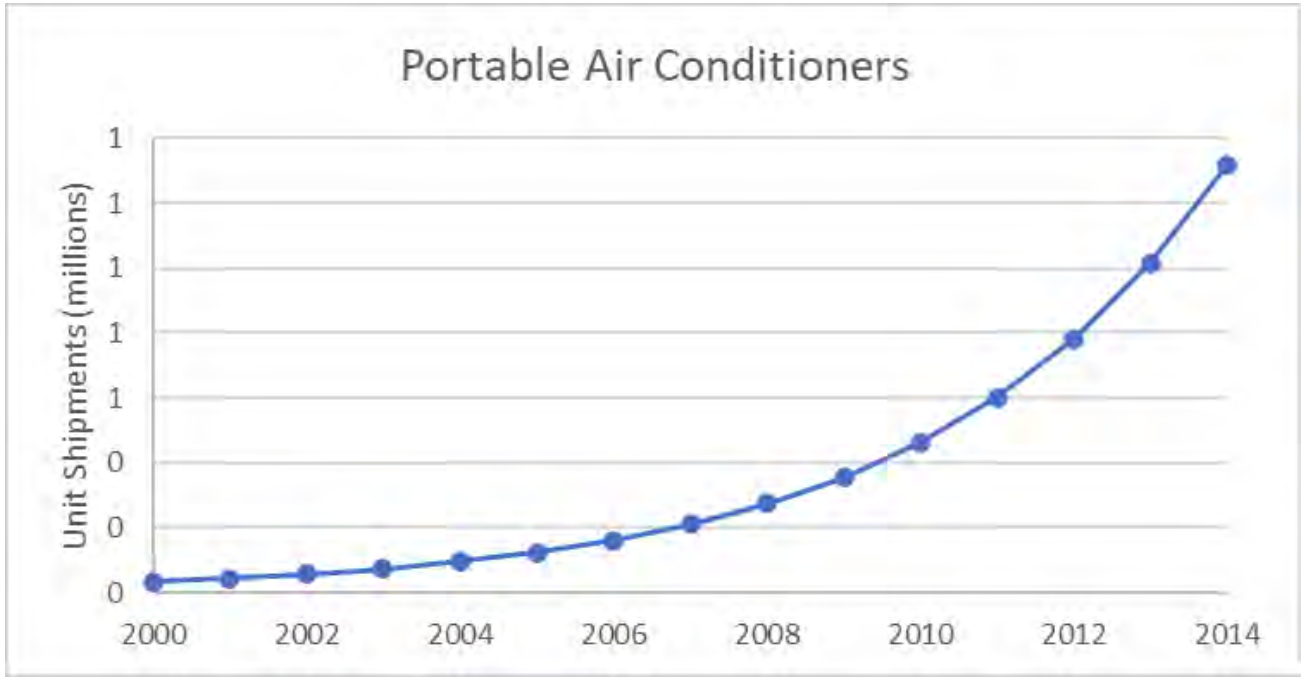
Annual shipments have seen an exponential growth through 2014. Shipments data since 2014 is not publicly available but it is expected that portable air conditioners shipments may have increased in recent years in response to indoor air quality concerns following COVID-19.



Source: *PAC EERE 2020*

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Residential Swamp Coolers

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DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Air Flow Rate (CFM)	3,800	3,800	3,800	4,700	3,800	4,700	3,800	4,700	3,800	4,700
Power (Hp)	1/3	1/3	1/3	1/2	1/3	1/2	1/3	1/2	1/3	1/2
Average Life (y)[1]	10	10	10	10	10	10	10	10	10	10
	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)	960	960	960	1,100	960	1,100	960	1,100	960	1,100
Total Installed Cost (2022$)	1,360	1,360	1,360	1,540	1,360	1,540	1,360	1,540	1,360	1,540
Annual Maintenance Cost (2022$)	330	330	330	330	330	330	330	330	330	330

1. Average lifetime provided by major swamp cooler installer in the U.S. Southwest.

Note:
Efficiency values were determined based on a sample of window-mounted swamp coolers.
Lifetime range represents span of typical values.

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Residential Swamp Coolers

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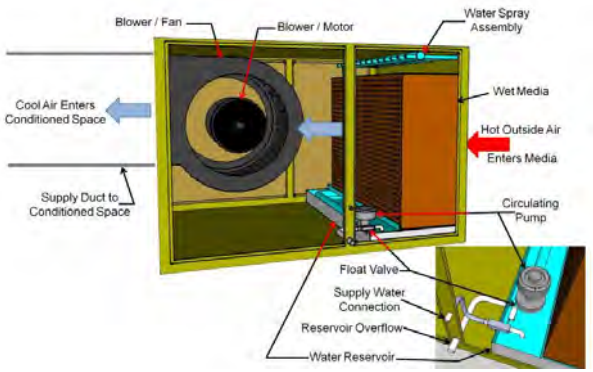
- Evaporative cooling (i.e., "swamp coolers") is a technology that takes advantage of water evaporation to cool incoming air. Energy is required to change water from a liquid to a vapor (i.e., the heat of vaporization), and in doing so, temperature of the air is reduced. Evaporative cooling is best suited for hot, dry climates.
- Swamp coolers come in a variety of different configurations, including centrally ducted units that are mounted outside a building or roof; window evaporative coolers that are window-mount units that pull in warm outdoor air, pass it through wet media to remove heat, and blow out the cooled air; or portable plug-in units. Window units were considered for this analysis due to the high model share count on distributor websites.
- The U.S. Environmental Protection Agency (EPA) has cautioned against using swamp coolers in wildfire-impacted areas in smoky conditions because it can result in more smoke bring brought inside.
- Swamp coolers are not a DOE-covered product.
- Swamp cooler metrics include power of the fan/blower, measured in horsepower (hp), and air flow rate, measured in cubic feet per minute (CFM).



Single-inlet direct swamp cooler. Source: *PNNL*

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Residential Air-Source Heat Pumps

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DATA	2015	2020	2022				2023				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.0	High	New Standard	ENERGY STAR V. 6.1	ENERGY STAR Cold Climate Criteria	High[4]	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
SEER (Cooling)[1]	13.1	15.3	14.0	15.3	15.0	22.6	15.0	16.0	NA	22.6	16.0	22.6	16.5	22.6	17.0	22.6
SEER2[2]	12.4	14.5	NA	14.5	NA	21.5	14.3	15.2	15.2	21.5	15.2	21.5	15.7	21.5	16.2	21.5
HSPF (Heating)[1]	7.9	8.6	8.2	8.6	8.5	12.4	8.8	9.2	NA	12.4	9.2	12.4	9.3	12.4	9.3	12.4
HSPF2[2]	6.7	7.3	NA	7.3	NA	10.6	7.5	7.8	8.1	10.6	7.8	10.6	7.9	10.6	7.9	10.6
Average Life (y)	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3
Retail Equipment Cost (2022$)[1]	3,290	4,270	3,970	4,270	4,110	6,740	4,110	4,380	4,380	6,740	4,380	6,740	5,000	6,740	5,100	6,740
Total Installed Cost (2022$)[1]	5,790	6,880	6,730	6,880	6,810	8,620	6,810	6,940	6,940	8,620	6,940	8,620	7,240	8,620	7,330	8,620
Annual Maintenance Cost (2022$)[3]	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150

1. Values shown are for split-system units in the 36 kBtu/h (3-ton) size class. Costs and efficiency levels are for "blower-coil" systems, meaning they include a blower. Note coil-only systems were analyzed for residential central air conditioners, which is why the "High" SEER levels are higher for heat pumps than for air conditioners.
2. In 2023, new energy conservation standards for Residential Central Air Conditioners and Heat Pumps took effect. The new standards specify different metrics for Air-Source Heat Pumps (SEER2 and heating seasonal performance factor 2 (HSPF2)). SEER to SEER2 and HSPF to HSPF2 conversions were determined using the RESNET website.
3. Annual maintenance include preventative maintenance and services provided by HVAC professionals for maintaining product operation. Examples include, calibrate and level thermostat, clean filters, clean indoor and condenser coil, flush/treat condensate drain with anti-algae, inspect condenser coil, monitor operating pressure of refrigerant, inspect fan blade, etc.
4. High costs derived from developing a cost-efficiency curve between retail/installed costs and SEER.

Note:
The previous standard went into effect in January 2015. The current standard went into effect in January 2023.
ENERGY STAR V. 5.0 went into effect in September 2015. ENERGY STAR V. 6.1 went into effect in January 2023.
Ranges represent the span of typical values for maintenance costs.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (15.88, 2, 1).

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Residential Air-Source Heat Pumps

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- The previous standards took effect in 2015; amended standards for all product classes went into effect in January 2023.
  - Amended standards are based on new metrics (SEER2, EER2, HSPF2).
  - SEER2 values are generally expected to be lower than SEER because a higher external static pressure is required during testing, which reduces measured performance.
- High efficiency cooling does not necessarily correlate with high efficiency heating. The range of SEER–HSPF combinations is very broad.
- Heat pumps are generally sized to meet the cooling load of the house. When the heating load exceeds heat pump heating capacity, electric resistance heat is used to supplement.
- Variable-speed compressors improve efficiency of heat pumps by reducing cyclic losses and by operating above their nominal speed, boosting heating capacity, and reducing the need for supplementary electric resistance heat.
- In addition to meeting the SEER2 and HSPF2 requirements, air source heat pumps must demonstrate low ambient performance to earn the Cold Climate designation by meeting the following:
  - Coefficient of Performance (COP) at 5 degrees Fahrenheit (°F) ≥ 1.75, measured in accordance with Appendix M1 $H4_2$ test
  - Percent of Heating Capacity at 5 °F ≥ 70% of that at 47 °F, with the 5 °F capacity measured per Appendix M1 $H4_2$ test and the 47 °F capacity measured as the nominal heating capacity per Appendix M1 (i.e., from the Appendix M1 $H1_N$ test for units having a variable-speed compressor where the compressor speed shall be the maximum speed that the system controls would operate at 47 °F, otherwise from the Appendix M1 $H1_2$ test)
  - Perform a controls verification procedure (CVP) to confirm that the above performance metrics measured at the Appendix M1 low ambient test point at 5 °F are achieved by the native controls operating as they would in a customer's home

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Residential Air-Source Heat Pumps

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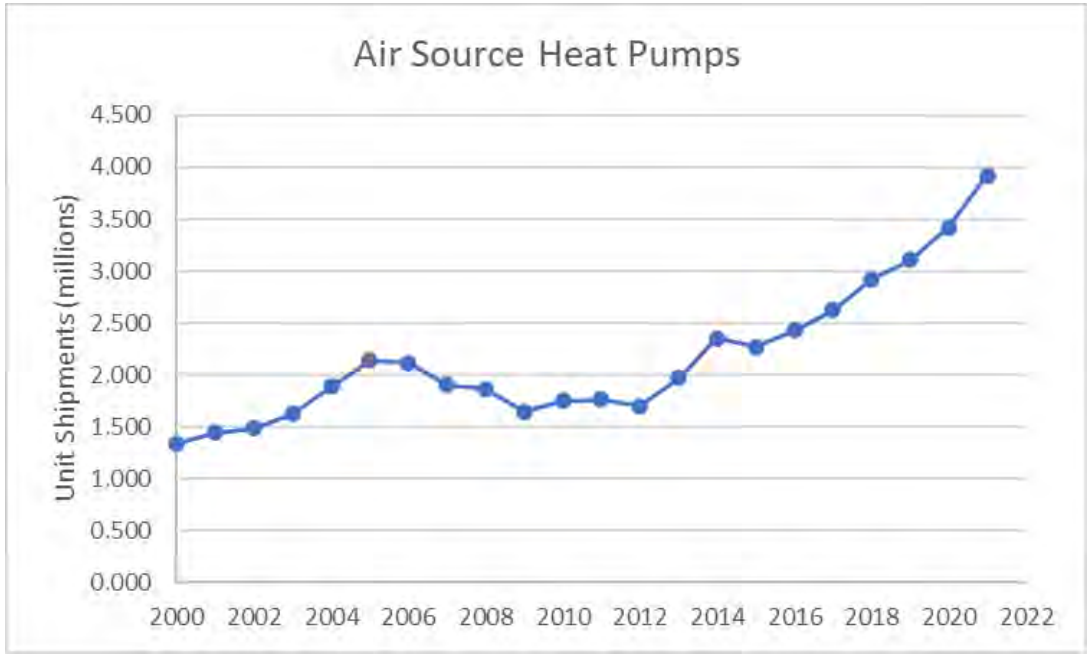
From 2000 to 2005 annual shipments increased nearly 60% to 2.1 million units, then dropped and leveled off around 1.7 million units. In 2014 annual shipments surpassed the 2005 peak and have been increasing uniformly since then.



Source: *AHRI*

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Residential Central Air Conditioners and Air-Source Heat Pumps

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- Principal energy efficiency drivers for central air conditioners and heat pumps:
  - Heat exchanger (surface area, number of tube rows)
  - Compressor (type and single-stage vs. two-stage vs. variable-speed operation)
  - Fan motor choices (PSC vs. ECM fan motors on inside and outside)
  - Control choices (i.e., piston, thermal, and electronic expansion valves)
- When the heat pump or air conditioner's capacity exceeds the heating or cooling load, the unit starts and stops more frequently, causing wear and tear on the components and an overall loss of efficiency. Multi-stage and/or variable-speed compressors can help, as does sophisticated refrigerant management.
- Typical high-efficiency unit (≥ 16 SEER) has very large heat exchanger, ECM evaporator fan motor, and two-stage scroll compressor.
- Variable-speed compressor technology typically leads to a significant SEER boost, making possible high-SEER condensing units with smaller heat exchangers, and thus, smaller enclosures.
- Efficiency levels > 21 SEER made possible through combining existing large heat exchangers with variable-speed compressors, ECM fan motors, and electronic expansion valves.

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Residential Ductless Mini-Split Air-Source Heat Pumps

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DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)[1]	12	12	12	12	12	12	12	12	12	12
SEER	16.0	16.0	21.9	33.1	21.9	33.1	21.9	33.1	21.9	33.1
EER	12.5	12.5	13.0	19.1	13.0	19.1	13.0	19.1	13.0	19.1
HSPF	10.0	10.0	11.1	14.0	11.1	14.0	11.1	14.0	11.1	14.0
Average Life (y)[2]	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3
Retail Equipment Cost (2022$)	1,580	1,580	1,580	1,580	1,580	1,580	1,580	1,580	1,580	1,580
Total Installed Cost (2022$)	2,030	2,030	2,030	2,030	2,030	2,030	2,030	2,030	2,030	2,030
Annual Maintenance Cost (2022$)[3]	100	100	100	100	100	100	100	100	100	100

1. Representative capacity determined from most frequent capacity in AHRI database
2. Assumed same lifespan and maintenance cost as air-source heat pumps given the technology is similar between air-source and ductless mini-split heat pumps, and ductwork itself is not expected to fail.
3. Annual maintenance covers the same services identified for air-source heat pumps.

Note:
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (15.88, 2, 1).

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Residential Ductless Mini-Split Air-Source Heat Pumps

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- Ductless systems can be useful in "spot cooling" certain high-use areas of a home, such as a living room, bedroom, or office.
- Mini-split heat pumps are generally more efficient (often > 20 SEER) and smaller in cooling capacity (often ≤ 24 kBtu/h) compared to split-system heat pumps.
  - A mini-split heat pump could be equal in capacity and efficiency to a split-system heat pump as there are no inherent design changes between split-system and mini-split heat pumps, aside from the ductwork. Mini-split heat pumps tend to be more efficient and smaller in capacity due to their prevalence for spot cooling, but the same technologies are used between the two product categories.
- Due to the similarities in design, cost estimations were determined based on smaller capacity (24 kBtu/h) split-system heat pumps and Gordian's RSMeans Data – Building Construction Costs 2023. Efficiency data was analyzed using the AHRI directory, which provides disaggregation of data on the basis of ducted and ductless heat pumps.
- Annual maintenance covers the same services identified for air-source heat pumps.

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Residential Ground-Source Heat Pumps

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DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.2	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	36	36	36	36	36	36	36	36	36	36	36	36
COP (Heating)[1]	3.1	3.7	3.2	3.6	3.6	4.5	3.6	4.5	3.6	4.5	3.6	4.5
EER (Cooling)[2]	13.3	17.3	14.1	17.3	17.1	22.0	17.3	22.0	17.3	22.0	17.3	22.0
Average Life (y)	8	8	8	8	8	8	8	8	8	8	8	8
	21	21	21	21	21	21	21	21	21	21	21	21
Retail Equipment Cost (2022$)	4,650	5,470	4,820	5,470	5,410	6,530	5,470	6,530	5,470	6,530	5,470	6,530
Total Installed Cost (2022$)	14,060	14,880	14,230	14,880	14,880	15,940	14,880	15,940	14,880	15,940	14,880	15,940
	22,290	23,120	22,470	23,120	23,120	24,170	23,120	24,170	23,120	24,170	23,120	24,170
Annual Maintenance Cost (2022$)	90	90	90	90	90	90	90	90	90	90	90	90

1. COP values listed are assessed at a "ground loop" test condition, which is representative of closed loop ground source heat pumps (GSHP) operating conditions. However, DOE sets standards at a "water loop" test condition. The AHRI directory lists COP ratings at both sets of test conditions and is used to convert between them where necessary.
2. EER values listed are assessed at a full-load "ground loop" test condition, which is representative of closed loop GSHP operating conditions. However, DOE sets standards at a full-load "water loop" test condition. The AHRI directory lists EER ratings at all sets of test conditions and is used to convert between them where necessary.

Note:
Residential and commercial GSHPs are very similar - the main difference in data presented is the different capacity (3-ton vs. 4-ton) and slightly higher installation costs for commercial GSHP. DOE does not distinguish between residential and commercial units in its regulations.
Current standards went into effect on October 9, 2015. COP and EER ratings are converted from the “water loop” test condition to “ground loop.”
ENERGY STAR V. 3.2 went into effect January 1, 2012.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay parameters: (17.04, 1.64, 1).

Residential Ground-Source Heat Pumps

- Heating COP does not correlate with cooling EER.
- The ENERGY STAR criteria for water-to-air ground-source heat pumps are:

Type	Heating COP	Cooling EER
Closed Loop	3.6	17.1
Open Loop	4.1	21.1
Direct Expansion	3.6	16

- The most common GSHP is a closed-loop system in which water or an anti-freeze solution is circulated through plastic pipes buried underground. Open loop systems that employ ground water or surface water (e.g., open well, pond, lake) are used in some parts of the country, but water supply and water quality issues impose limitations on such applications.
- Installation cost is for a closed loop system and includes necessary accessories. The ground loop heat exchanger represents a majority of the installation cost. Installed costs for these systems vary widely.
- Variable speed ECMs improve performance on high-end models.

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Residential Natural Gas Heat Pumps

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DATA	2015	2020	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical	Typical	Typical
Typical Capacity (kBtu/h)	60	60	60	60	60	60
COP (Heating)	1.3	1.3	1.3	1.3	1.3	1.3
COP (Cooling)	0.6	0.7	0.7	0.7	0.7	0.7
Annual Electric Use (kWh/y)[1]	1,500	1,500	1,500	1,500	1,500	1,500
Average Life (y)	12	12	12	12	12	12
	18	18	18	18	18	18
Retail Equipment Cost (2022$)[2]	12,940	12,940	12,940	12,940	12,940	12,940
	14,350	14,350	14,350	14,350	14,350	14,350
Total Installed Cost (2022$)[2]	14,700	14,700	14,700	14,700	14,700	14,700
	17,290	17,290	17,290	17,290	17,290	17,290
Annual Maintenance Cost (2022$)	200	200	200	200	200	200

1. Annual electric use accounts for the electricity consumption of components such as the heat pump fan.

Note:
Ranges represent the span of typical values observed in the market.

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Residential Natural Gas Heat Pumps

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- Residential natural gas heat pumps are not currently subject to DOE regulations. The California Energy Commission's (CEC) Title 24, Part 6 Section 112 does indicate cooling efficiency requirements for natural gas heat pumps.
- Natural gas heat pumps are much more popular in other parts of the world, such as Europe. Gas-fired cooling equipment currently comprises less than 1% of the residential air conditioning/heat pump market in the U.S.
- Currently, Robur is the predominant manufacturer of residential-sized natural gas heat pumps with sales operations in the U.S.. Robur units are 5-ton nominal cooling capacity, a size typically associated with larger homes. Since only one product is available, no mid-level or high efficiency categories are included in this analysis.
- The data represents air-source absorption heat pumps. Gas engine-driven vapor compression heat pumps are available in other parts of the world; York formerly offered the Triathlon gas engine-driven heat pump in the U.S. It is possible to couple either technology to the ground (ground-source) rather than the atmosphere (air-source).
- The absorption heat pump is a gas-fired, ammonia-water absorption cycle, combined with a high-efficiency low-pressure boiler integrated into one outdoor unit.
- The cooling efficiency of a gas-fired air-source absorption heat pump is considerably lower than for an electric air-source heat pump. Heating efficiency of an air-source heat pump (electric or gas-fired absorption) decreases as outdoor temperature decreases; however, the gas-fired absorption heat pump recovers waste heat from the combustion process to improve heating efficiency.

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Residential Cordwood Stoves

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DATA	2015[1]	2020[2]	2022[3]		2030[4]		2040[4]		2050[4]	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	50	50	50	50	50	50	50	50	50	50
Efficiency (Non-Catalytic) (HHV)[5]	63	71	71	80	71	80	71	80	71	80
Efficiency (Catalytic) (HHV)[5]	72	76	76	81	76	81	76	81	76	81
Average Life (y)	12	12	12	12	12	12	12	12	12	12
	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$) (Non-Catalytic)	2,880	1,670	1,670	2,300	1,670	2,300	1,670	2,300	1,670	2,300
Retail Equipment Cost (2022$) (Catalytic)	3,540	3,040	3,040	3,830	3,040	3,830	3,040	3,830	3,040	3,830
Total Installed Cost (2022$) (Non-Catalytic)[6]	8,290	7,090	7,090	7,710	7,090	7,710	7,090	7,710	7,090	7,710
Total Installed Cost (2022$) (Catalytic)[6]	8,950	8,460	8,460	9,240	8,460	9,240	8,460	9,240	8,460	9,240
Annual Maintenance Cost (2022$) (Non-Catalytic)[7]	190	190	190	190	190	190	190	190	190	190
Annual Maintenance Cost (2022$) (Catalytic)[7]	280	280	280	280	280	280	280	280	280	280

1. For 2015, assumed EPA default efficiencies, which were used by EPA to approximate the efficiency of stoves before the 2015 EPA rule required efficiency testing.
2. For 2020, assumed same efficiencies as estimated for 2022 given the most recent EPA rule went into effect in May 2020.
3. The 2022 High value is the highest EPA certified efficiency. The 2022 Typical value is the average of EPA certified efficiencies.
4. For 2030-2050, it is assumed that the same conditions as current would persist because no impending efficiency requirements are expected from EPA, given recency of 2020 rulemaking and current market factors.
5. Efficiency includes combustion and heat transfer efficiency and is based on the higher heating value (HHV) of the fuel.
6. Installed costs include the cost of hearth and stainless-steel chimney liner - materials and labor.
7. For catalytic stoves, annual maintenance cost includes periodic cost of replacing the catalytic combustor.

Note:
The range for average life represents the span of typical values.

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Residential Cordwood Stoves

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- Residential cordwood stoves that must meet EPA particulate limits fall into two broad classes based on whether they use a catalyst for air treatment. Catalytic wood stoves use a catalytic combustor to reduce emissions from the combustion air. Non-catalytic wood stoves use baffles and introduce secondary air above the flames to enable more complete combustion and reduce emissions.
- In 2015, EPA published an update to its New Source Performance Standards (NSPS), decreasing the emissions limit (previously set by 1988 EPA rule) to 4.5 grams per hour (g/h) for both catalytic and non-catalytic stoves. The new rule did not institute efficiency standards but required that manufacturers test and certify the efficiency of their stoves. This standard took full effect on January 1, 2016.
- In 2020, the NSPS limit for new room heaters was lowered to 2.5 g/h if tested with cord wood.
- Prior to the 2015 rule, manufacturers could either submit efficiency data from laboratory testing or certify with the default efficiency value designated by EPA. EPA's default efficiency values were 63% for non-catalytic wood stoves and 72% for catalytic wood stoves. Under this system, few manufacturers submitted efficiency test data to EPA.
- Multiple test standards are commonly used to assess stove efficiency, and data from product literature does not generally identify the efficiency test method.
- It is not possible to determine performance trends based on construction or configuration (e.g., cast iron vs. plate steel, powered blowers vs. no blowers, etc.) trends in specific equipment type or construction based on published efficiencies. Further, EPA certification data shows no significant relationship between emissions and heating efficiency.
- Cordwood stoves require chimneys for venting combustion gases. Whether conventional masonry chimneys are used or metal chimney liners, these add considerable cost to the overall system. Accordingly, installed costs can be twice that of the wood stove itself.

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Residential Cordwood Stoves

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Cordwood stove shipments have averaged 123,000 per year since 1999 and have fluctuated approximately in accordance with fuel oil costs.

Source: *HPBA, no post-2012 sales data was publicly available at time of publication.*

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Residential Wood Pellet Stoves

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DATA	2015[1]	2020[2]	2022[3]		2030[4]		2040[4]		2050[4]	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	50	50	50	50	50	50	50	50	50	50
Efficiency (HHV)[5]	70	73	73	85	73	85	73	85	73	85
Annual Electricity Consumption (kWh)[6]	600	600	600	600	600	600	600	600	600	600
Average Life (y)	12	12	12	12	12	12	12	12	12	12
	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)	3,900	3,120	3,120	4,000	3,120	4,000	3,120	4,000	3,120	4,000
Total Installed Cost (2022$)[7]	5,550	4,520	4,520	5,400	4,520	5,400	4,520	5,400	4,520	5,400
Annual Maintenance Cost (2022$)	310	310	310	310	310	310	310	310	310	310

1. For 2015, assumed EPA default efficiencies, which were used by EPA to approximate the efficiency of stoves before the 2015 EPA rule required efficiency testing.
2. For 2020, assumed same efficiencies as estimated for 2022 given the most recent EPA rule went into effect in May 2020.
3. The 2022 High value is the highest EPA certified efficiency. The 2022 Typical value is the average of EPA certified efficiencies.
4. For 2030-2050, it is assumed that the same conditions as current would persist because no impending efficiency requirements are expected from EPA, given recency of 2020 rulemaking and current market factors.
5. Efficiency includes combustion and heat transfer efficiency and is based on the HHV of the fuel.
6. The annual electric consumption estimates assume 6 months/year @ 100kW/mo based on DOE estimates.
7. Installed cost includes cost of hearth and vent pipe - materials and labor.

Note:
The range for average life represents the span of typical values.

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Residential Wood Pellet Stoves

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- In 2015, EPA published an update to its NSPS, limiting emissions for wood pellet stoves to 4.5 g/h. Prior to the 2015 EPA rule, most pellet stoves were exempt from EPA's NSPS requirements. The new rule did not institute efficiency standards but required that manufacturers test and certify the efficiency of their stoves. This standard took full effect on January 1, 2016.
- Prior to the 2015 rule, manufacturers could either submit efficiency data from laboratory testing or certify with the default efficiency value designated by EPA. EPA's default efficiency values were 63% for non-catalytic wood stoves and 72% for catalytic wood stoves. Under this system, few manufacturers submitted efficiency test data to EPA.
- Multiple test standards are commonly used to assess stove efficiency and data from product literature does not generally identify the efficiency test method.
- It is not possible to determine performance trends based on construction or configuration (e.g., cast iron vs. plate steel, powered blowers vs. no blowers, etc.) trends in specific equipment type or construction based on published efficiencies. Further, EPA certification data shows no significant relationship between emissions and heating efficiency.
- Wood pellet stoves may be able to be direct vented to the outdoors, eliminating the need for a chimney. This reduces the overall system cost as compared to a cord wood stove. However, they do use electricity to power the pellet feeder, the combustion air fan, and the blower. In the event of a power outage, a pellet stove can not operate without some back-up source of electricity (e.g., battery) .

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Residential Wood Pellet Stoves

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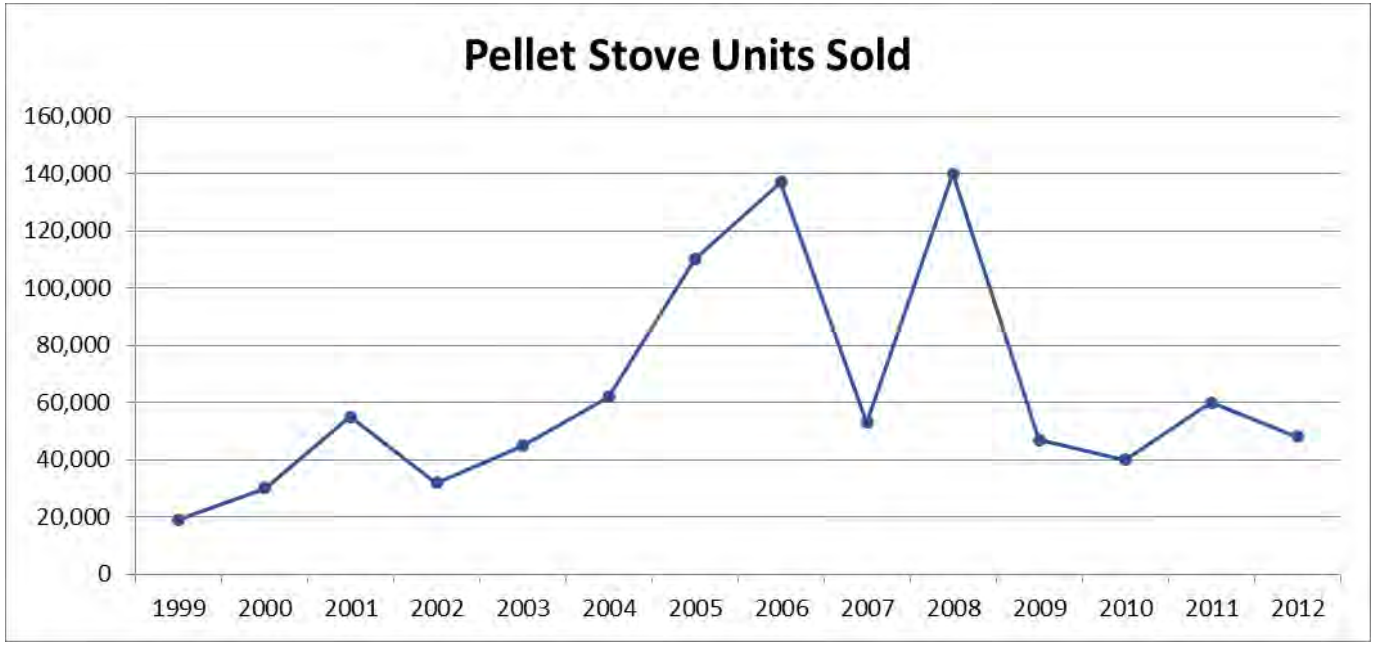
Wood pellet stove shipments grew substantially in the 2005 – 2008 time period but have averaged only 40,000 – 60,000 units since that time.



Source: *HPBA, no post-2012 sales data was publicly available at time of publication.*

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Residential Water Heating

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Residential Gas-Fired Storage Water Heaters

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DATA	2015	2020	2022				2023	2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.0	High	ENERGY STAR V. 5.0	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	40	40	40	40	40	40	40	40	40	40	40	40	40
Uniform Energy Factor (UEF)[1]	0.58	0.63	0.61	0.61	0.66	0.84	0.83	0.61	0.84	0.61	0.84	0.61	0.84
Average Life (y)	13	13	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5
Retail Equipment Cost (2022$)	590	880	420	420	490	720	700	420	720	420	720	420	720
	650	1,410	990	990	1,110	1,650	1,590	990	1,650	990	1,650	990	1,650
Total Installed Cost (2022$)	1,240	1,650	740	740	800	1,140	1,130	740	1,140	740	1,140	740	1,140
	1,240	2,880	1,690	1,690	1,850	3,130	3,160	1,690	3,130	1,690	3,130	1,690	3,130
Annual Maintenance Cost (2022$)[2]	20	20	20	20	20	20	20	20	20	20	20	20	20

1. Analysis is based on an average of medium and high draw pattern units, as this is most reflective of the market.
2. Maintenance includes manufacturer recommendation for the water heater to be drained and flushed annually to minimize deposition of sediment, maintain operating efficiency, and prolong product life. Available evidence indicates that this is performed in 10% of households.

Note:
Ranges represent the span of typical values.
Current standards went into effect April 16, 2015.
ENERGY STAR V. 4.0 went into effect January 5, 2022.
ENERGY STAR V. 5.0 will go into effect April 18, 2023
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (15.1, 1.76, 1).

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- The equations for Federal Standards and the voluntary ENERGY STAR requirements, if applicable, are:

Volume Range	Draw Pattern	Federal standard[1]	Federal minimum UEF for typical sizes	ENERGY STAR
≥ 20 gal and ≤ 55 gal	Very Small	UEF=0.3456-(0.002*Gal)	No models on the market	NA
	Low	UEF=0.5982-(0.0019*Gal)	0.54 for a 29-gallon water heater	NA
	Medium	UEF=0.6483-(0.0017*Gal)	0.58 for a 38-gallon water heater	0.64
	High	UEF=0.692-(0.0013*Gal)	0.64 for a 48-gallon water heater	0.68
> 55 gal and ≤ 100 gal	Very Small	UEF=0.647-(0.0006*Gal)	No models on the market	NA
	Low	UEF=0.7689-(0.0005*Gal)	No models on the market	NA
	Medium	UEF=0.7897-(0.0004*Gal)	No models on the market	0.78
	High	UEF=0.8072-(0.0003*Gal)	No models on the market	0.80

- There are currently no models on the market above 55 gallons (gal) due to the high UEF, which would require using condensing or gas-fired heat pump (e.g., absorption) technology to achieve.
- The cost of installation is typically $600 to $1200, which exceeds that of electric water heaters. This difference can be attributed to multiple differences; for example, gas-fired heaters require an extra 1.5 hours of labor for 2 plumbers.
- Condensing units are high efficiency and use PVC venting instead of stainless-steel. Condensing units also use an electrical supply for electronic ignition and power venting. Some building codes require condensate neutralizer filters.

[1]Energy Conservation Standards for Residential Water Heaters. 10 CFR 430.32(d).

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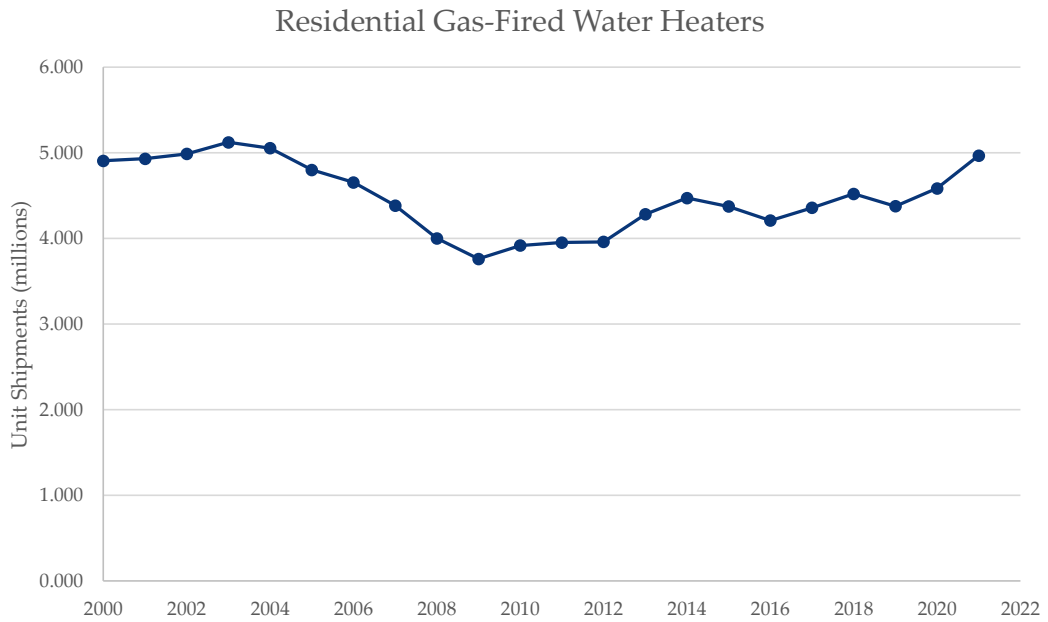
Shipments were flat at 5 million units per year through 2004, then declined gradually over 5 years to a new plateau at 4 million units until rising again back to 5 million units in 2021.



Source: *AHRI*

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DATA	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	32	32	32	32	32	32	32	32	32	32	32
Uniform Energy Factor[1]	0.51	0.67	0.64	0.66	0.68	0.66	0.68	0.66	0.68	0.66	0.68
Average Life (y)	13	13	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5
Retail Equipment Cost (2022$)	1,590	1,880	1,380	1,400	1,480	1,400	1,480	1,400	1,480	1,400	1,480
	1,710	2,410	2,810	2,870	3,030	2,870	3,030	2,870	3,030	2,870	3,030
Total Installed Cost (2022$)	2,350	2,650	2,620	2,650	2,730	2,650	2,730	2,650	2,730	2,650	2,730
	2,470	3,350	4,050	4,120	4,280	4,120	4,280	4,120	4,280	4,120	4,280
Annual Maintenance Cost (2022$)[2]	210	210	210	210	210	210	210	210	210	210	210

1. Analysis is based on an average of medium and high draw pattern units, as this is most reflective of the market.
2. Oil-fired storage water heaters are typically cleaned and maintained under maintenance contracts. The annual cost of typical maintenance is based on maintenance contract prices from different oil-fired product suppliers as specified in the CWH EERE 2022 Preliminary Analysis.

Note:
Ranges represent span of typical values.
Current standards went into effect April 16, 2015.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (16.2, 1.70, 1).

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- The equations for Federal Standards and the voluntary ENERGY STAR requirements, if applicable, are:

Volume Range	Draw Pattern	Federal standard[1]	Federal minimum UEF for typical sizes	ENERGY STAR
≤ 50 gal	Very Small	UEF=0.2509-(0.0012*Gal)	No models on the market	NA
	Low	UEF=0.533-(0.0016*Gal)	No models on the market	NA
	Medium	UEF=0.6078-(0.0016*Gal)	No models on the market	NA
	High	UEF=0.6815-(0.0014*Gal)	0.64 for a 29-gallon water heater	NA

- There are no ENERGY STAR requirements for oil-fired storage water heaters.
- Annual shipments of residential oil-fired storage water heaters are approximately 4,000, which is less than 1% of shipments of residential gas-fired storage water heaters.
- Oil-fired storage water heaters often have smaller tanks with larger input ratings relative to natural gas-fired and electric storage water heaters.
- No condensing residential oil-fired storage water heaters currently exist in the U.S. market. Condensing oil-fired water heaters are generally not considered technologically feasible because the sulfur content in fuel oil leads to the condensate becoming corrosive.
- Residential oil-fired water heaters utilize power burners and have at least some level of electrical power consumption.
- The most efficient models on the market use a proprietary “turbo-flue” design to increase heat transfer to water.

[1]Energy Conservation Standards for Residential Water Heaters. 10 CFR 430.32(d).

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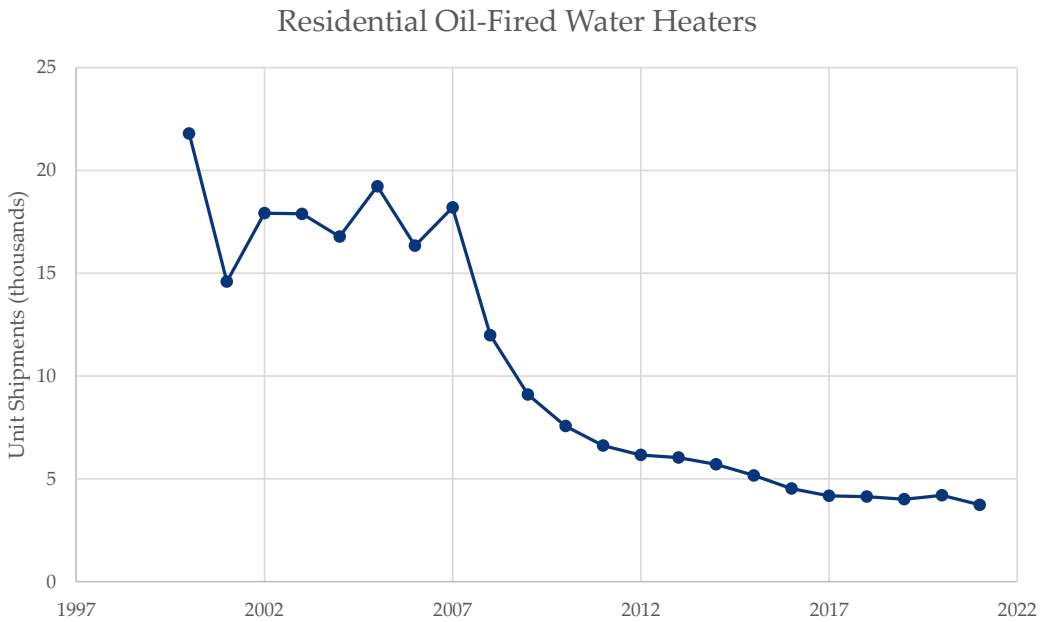
Shipments peaked at about 22,000 units in 2000 and have decreased since then, with an exponential decay occurring since 2007. Only about 4,000 units were shipped in 2021.



Source: *CWH EERE 2022 Preliminary Analysis*

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Residential Electric Resistance Storage Water Heaters

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DATA	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	36	36	36	36	36	36	36	36	36	36	36
Uniform Energy Factor[1]	0.88	0.93	0.92	0.92	0.93	0.92	0.93	0.92	0.93	0.92	0.93
Average Life (y)	13	13	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1
Retail Equipment Cost (2022$)	290	350	330	330	600	330	600	330	600	330	600
	530	650	760	760	850	760	850	760	850	760	850
Total Installed Cost (2022$)	590	710	500	500	550	500	550	500	550	500	550
	940	1,290	1,310	1,310	1,430	1,310	1,430	1,310	1,430	1,310	1,430
Annual Maintenance Cost (2022$)[2]	20	20	20	20	20	20	20	20	20	20	20

1. Beginning in 2016, the efficiency metric for water heaters changed from energy factor (EF) to UEF based on DOE test procedures. The UEF values for the installed base in 2015 are converted values equivalent to 0.90 EF. Analysis is based on an average of low and medium draw pattern units, as this is most reflective of the market.
2. Similar to gas-fired and oil-fired storage water heaters, manufacturers recommend that electric storage water heaters be drained and flushed annually to minimize deposition of sediment, maintain operating efficiency, and prolong product life. The available evidence indicates that this practice is done in 10% of households.

Note:
Ranges represent span of typical values.
Current standards went into effect April 16, 2015.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (15.7, 1.57, 1).

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- The equations for Federal Standards and the voluntary ENERGY STAR requirements, if applicable, are:

Volume Range	Draw Pattern	Federal standard[1]	Federal minimum UEF for typical sizes	ENERGY STAR
≥ 20 gal and ≤ 55 gal	Very Small	UEF=0.8808-(0.0008*Gal)	No models on the market	2.00
	Low	UEF=0.9254-(0.0003*Gal)	0.92 for a 27-gallon water heater	2.00
	Medium	UEF=0.9307-(0.0002*Gal)	0.92 for a 45-gallon water heater	2.00
	High	UEF=0.9349-(0.0001*Gal)	0.93 for a 50-gallon water heater	2.00
> 55 gal and ≤ 120 gal	Very Small	UEF=1.9236-(0.0011*Gal)	No models on the market	2.20
	Low	UEF=2.0440-(0.0011*Gal)	No models on the market	2.20
	Medium	UEF=2.1171-(0.0011*Gal)	2.05 for a 58-gallon water heater	2.20
	High	UEF=2.2418-(0.0011*Gal)	2.15 for a 80-gallon water heater	2.20

- The federal standards for residential electric storage water heaters apply to both electric resistance storage water heaters and heat pump water heaters.
  - The Federal standard levels for the ≤ 55-gallon range are achievable through electric resistance and heat pump technology.
  - The Federal standards for the > 55-gallon range and all ENERGY STAR levels are only achievable through heat pump technology.
- Typical storage volumes range from 25-55 gallons for electric resistance storage water heaters and 45-80 gallons for heat pump water heaters (HPWHs).

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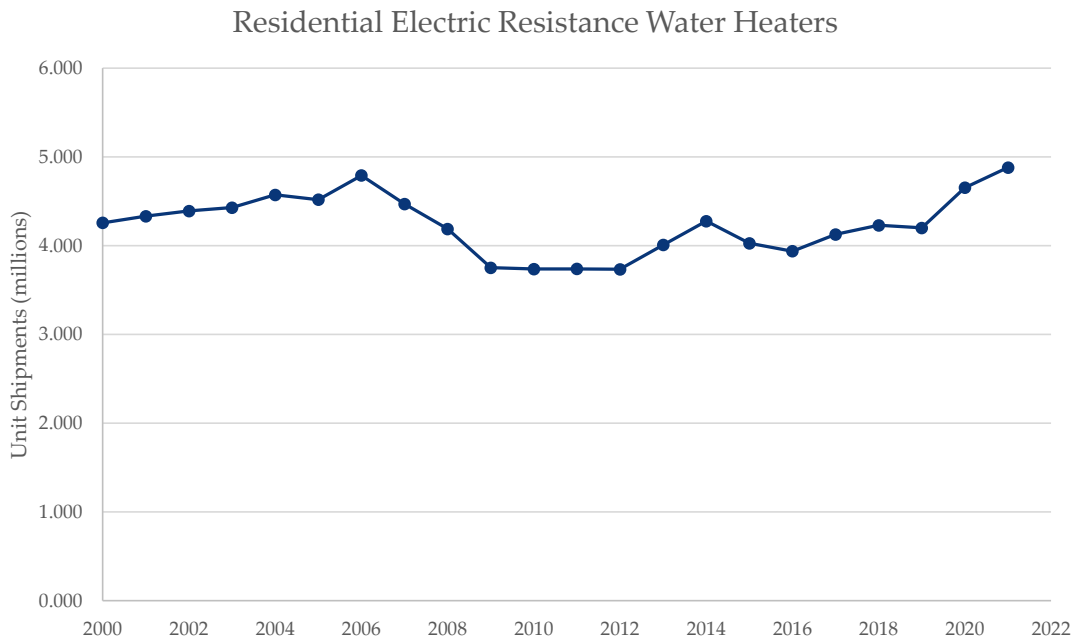
Shipments peaked in 2006 then dropped a total of 22 percent over three years. Shipments have gradually increased since then and were at the highest level in 2021.



Source: *AHRI*

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Residential Heat Pump Water Heaters

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DATA	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Typical	ENERGY STAR V. 4.0	High	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	36	36	36	36	36	36	36	36	36	36	36
Uniform Energy Factor[1]	2.05	3.28	3.33	3.30	3.73	3.33	3.73	3.33	3.73	3.33	3.73
Average Life (y)	13	13	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1
Retail Equipment Cost (2022$)[2]	1,290	1,410	630	630	670	630	670	630	670	630	670
	1,650	1,760	1,440	1,440	1,670	1,370	1,590	1,300	1,510	1,240	1,430
Total Installed Cost (2022$)[2]	1,710	1,880	870	870	980	870	980	870	980	870	980
	2,940	3,000	2,230	2,230	2,450	2,120	2,330	2,010	2,210	1,910	2,100
Annual Maintenance Cost (2022$)[3]	20	20	20	20	20	20	20	20	20	20	20

1. Analysis is based on an average of low and medium draw pattern units, as this is most reflective of the market.
2. It is expected that costs for HPWHs will decrease over time as these products become more common. This analysis estimates these cost decreases for the higher range of costs.
3. For heat pump water heater design options, DOE assumed higher maintenance cost to take into account annual cleaning of the air filter, preventative maintenance cost to check the evaporator and refrigeration system, inspection of the condensate withdrawal system, and replacement of the condensate neutralizer filter, if applicable. However, this maintenance is estimated to occur in only 10% of households, so overall maintenance cost is similar to that of other electric resistance water heaters.

Note:
Ranges represent span of typical values.
ENERGY STAR V. 4.0 went into effect January 5, 2022.
Assume same lifetime as electric resistance water heaters.

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- Technology improvements have advanced efficiency and reliability, but the high first-cost and lack of awareness among consumers and contractors still precludes high-volume market penetration.
- New Federal standards that came into effect in April 2015 effectively mandate heat pump technology for electric storage water heaters with storage volume > 55 gallons.
- Integrated models are the most common configuration for residential HPWHs. Several major water heater manufacturers produce such models, and other competitors offer integrated or add-on units (for existing electric or indirect storage water heaters).
- Sales are estimated to be driven partly by rebates and tax credits at the utility, local, state, and Federal level.
- Resistive heating elements are virtually 100% efficient, but there is a jump in efficiency when heat pump technology is adopted because heat pumps' COP are usually between 2.5 and 4.
- Heat pumps raise the water temperature more slowly than resistive heating elements, so most models use backup resistive elements along with the heat pump when hot water demand is high. Most HPWHs allow the consumer to control whether resistive elements are used in periods of high demand (e.g., "hybrid mode" or "heat pump only mode").

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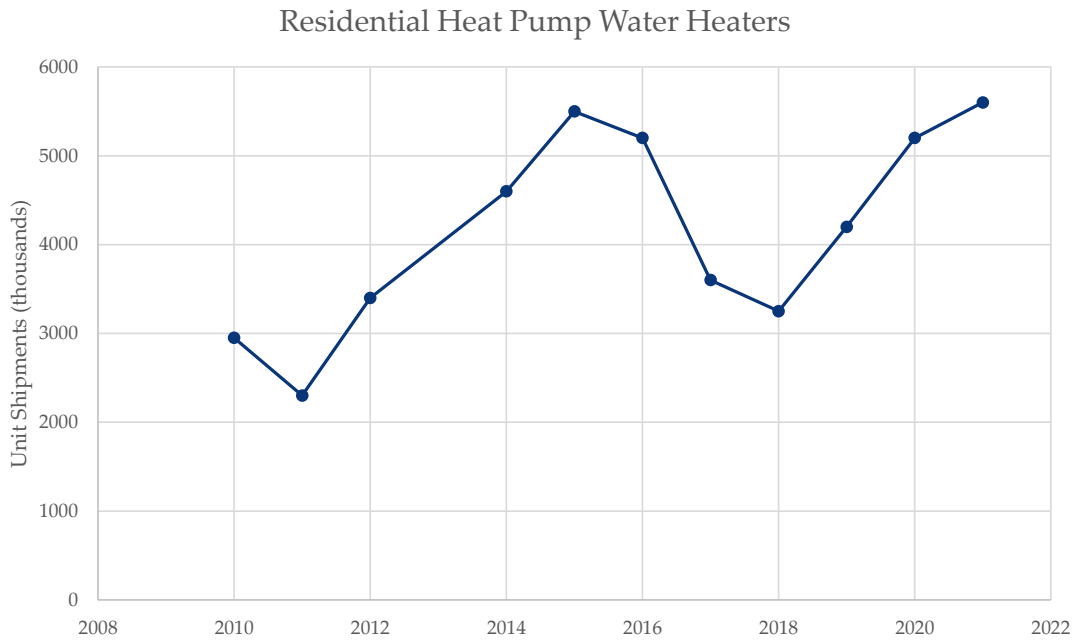
Shipments make up a small portion of electric resistance heaters, with a peak of only about 5,500 units, occurring in both 2015 and 2021.



Source: *ENERGY STAR*

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DATA	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	ENERGY STAR V. 4.0	Typical	Typical	Typical	Typical
Typical Capacity (ft^2)[1]	42	42	40	40	40	40	40
	65	65	54.4	54.4	54.4	54.4	54.4
Solar Uniform Energy Factor (SUEF)[2]	3.0	3.0	3.0	99.0	99.0	99.0	99.0
Average Life (y)	15	15	15	15	15	15	15
	30	30	30	30	30	30	30
Retail Equipment Cost (2022$)	7,710	7,710	6,430	6,430	6,430	6,430	6,430
Total Installed Cost (2022$)	10,650	10,650	8,060	8,060	8,060	8,060	8,060
Annual Maintenance Cost (2022$)[3]	80	80	80	80	80	80	80

1. Capacity selections are based on the range observed from medium draw units in the ENERGY STAR database. Medium draw represented the largest portion of units.
2. An SUEF of 3.0 is the required threshold for ENERGY STAR certification, yet a value of 99 was the most common observed SUEF among medium draw units. Note that an SUEF of 99 indicates that no backup heating was required for the applicable draw pattern, and all energy was provided by the solar collector. Since SUEF is a measure of hot water energy out divided by electrical or gas backup energy in, it will be infinite for cases where the collector provides all the hot water needed for the draw pattern – the Solar Rating and Certification Corporation's (SRCC's) OG-300 software is written to assign an SUEF of 99 to this case.
3. Annual maintenance is expected to be 0.5% to 1% of the total installation for 2022, 2030, 2040, and 2050.

Note:
Ranges represent span of typical values.
ENERGY STAR V. 4.0 went into effect January 5, 2022.

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- Solar water heaters are not subject to federal energy conservation standards. The ENERGY STAR requirements are:

Applicable Products	Backup Fuel	ENERGY STAR Requirement	Test Method
Whole-home solar units	Gas	SUEF ≥ 3.0	ICC 900/SRCC 300-2020 Solar Thermal System Standard, Appendix A: Solar Uniform Energy Factor Procedure for Solar Water Heating Systems
	Electric	SEF ≥ 1.8	

- Solar water heaters can be either active or passive. An active system uses an electric pump to circulate the heat transfer fluid; a passive system has no pump. Most solar water heaters in the U.S. are the active type.
- Solar water heaters are also characterized as open loop (also called "direct") or closed loop (also called "indirect"). An open-loop system circulates household (potable) water through the collector. A closed-loop system uses a heat transfer fluid (water or diluted antifreeze, for example) to collect heat and a heat exchanger to transfer the heat to household water. Direct systems were observed as the most common product type and subject of this analysis.
- In 2020, stakeholders from the solar thermal industry developed the Solar Uniform Energy Factor (SUEF) Specification for solar water heaters to align with the UEF metric used by DOE for other water heating technologies.
- SUEF is also the metric used by the current ENERGY STAR Specification, and it replaced the Solar Energy Factor (SEF) metric.
- Over two-third of the current solar water heater market is in the southern or western U.S. (including Hawaii). A collector area of 42 square feet (ft^2) would be typical for these areas. Colder areas of the U.S. would require a larger collector (e.g., 65 ft^2).
- Installed costs are higher for colder areas where larger collectors are required. Costs also vary widely depending on collector quality, type of system, and site-specific characteristics.

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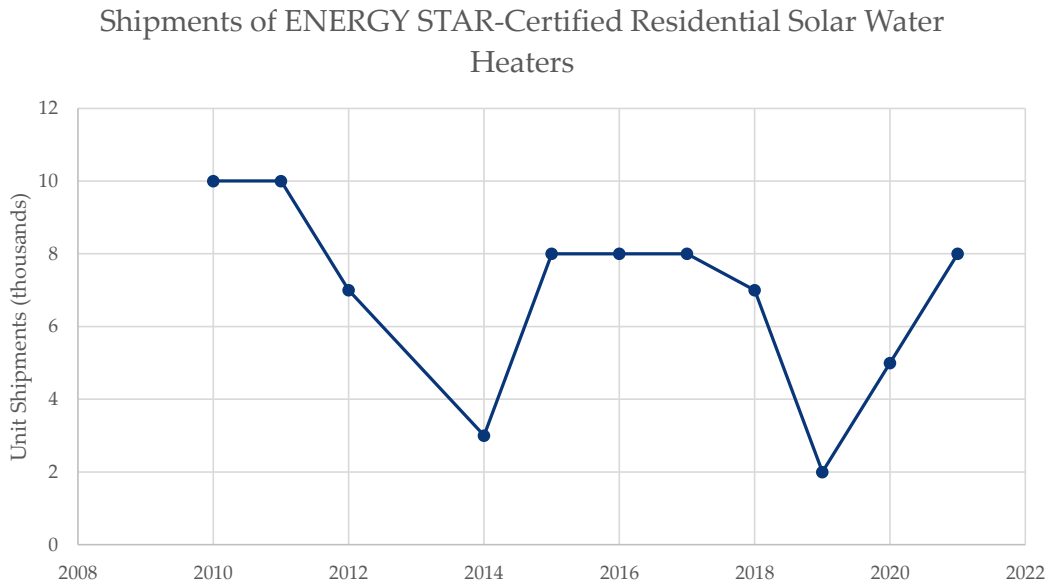
The shipments data below only represents ENERGY STAR-certified solar water heaters, as ENERGY STAR did not provide a market penetration rate. Solar water heaters have a small market share, with only 10,000 shipments at the peak in 2010 and 2011.



Source: *ENERGY STAR*

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Residential Gas-Fired Instantaneous Water Heaters

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DATA	2015	2020	2022				2023	2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.0	High	ENERGY STAR V. 5.0	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	199	199	199	199	199	199	199	199	199	199	199	199	199
Uniform Energy Factor (UEF)[1]	0.81	0.89	0.81	0.92	0.87	0.97	0.95	0.92	0.97	0.92	0.97	0.92	0.97
Average Life (y)	19	19	20	20	20	20	20	20	20	20	20	20	20
Retail Equipment Cost (2022$)	1,410	1,180	430	580	580	610	610	580	610	580	610	580	610
	1,760	1,410	1,020	1,360	1,350	1,430	1,430	1,360	1,430	1,360	1,430	1,360	1,430
Total Installed Cost (2022$)	2,590	1,760	920	1,070	950	1,090	1,090	1,070	1,090	1,070	1,090	1,070	1,090
	3,820	3,350	2,860	3,160	3,140	3,230	3,220	3,160	3,230	3,160	3,230	3,160	3,230
Annual Maintenance Cost (2022$)[2]	90	90	90	90	90	90	90	90	90	90	90	90	90

1. Analysis is based on an average of low, medium, and high draw pattern units, as this is most reflective of the market.
2. Annual maintenance includes deliming to minimize deposition of sediment in the heat exchanger, maintain operating efficiency and prolong product life. Also includes additional tasks, including inspection of the ignition device, gas valve, controls, thermostat, and venting.

Note:
Ranges represent span of typical values.
Current standards went into effect April 16, 2015.
ENERGY STAR V. 4.0 went into effect January 5, 2022.
ENERGY STAR V. 5.0 will go into effect April 18, 2023.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (21.3, 1.76, 1).

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Residential Gas-Fired Instantaneous Water Heaters

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- The equations for Federal Standards and the voluntary ENERGY STAR requirements, if applicable, are:

Volume Range	Draw Pattern	Federal standard[1]	Federal minimum UEF for typical sizes	ENERGY STAR
<2 gal and >50,000 Btu/h	Very Small	UEF=0.80	No models on the market	0.87
	Low	UEF=0.81	No models on the market	0.87
	Medium	UEF=0.81	0.81	0.87
	High	UEF=0.81	0.81	0.87

- The ENERGY STAR levels require the use of condensing technology.
- All of the major water heater manufacturers now offer an instantaneous water heater model.
- The maintenance costs include cleaning the water inlet filter and the heat exchanger of mineral deposits and replacing the water valve approximately once every five years for all instantaneous water heaters.
- When replacing a storage water heater with an instantaneous water heater, there are significant additional costs to upsize the gas supply line to ¾ inch from the typical ½ inch and change the venting.

[1]Energy Conservation Standards for Residential Water Heaters. 10 CFR 430.32(d).

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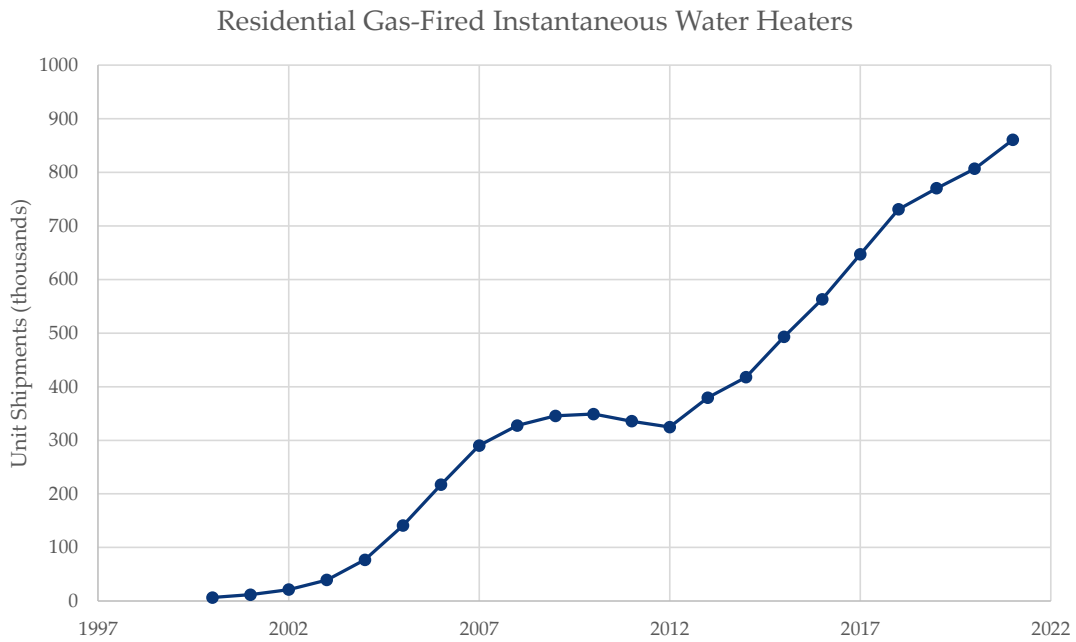
Shipments for Gas-Fired Instantaneous Water Heaters have grown steadily with nearly no shipments in 2000 and a peak of about 850,000 units in 2021.



Source: *CWH EERE 2022 Preliminary Analysis*

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DATA	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Representative Input Rate (kW)	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Uniform Energy Factor (UEF)[1]	0.96	0.96	0.91	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98
Average Life (y)	20	20	20	20	20	20	20	20	20	20	20
Retail Equipment Cost (2022$)	260	260	260	260	260	260	260	260	260	260	260
Total Installed Cost (2022$)	520	520	520	520	520	520	520	520	520	520	520
Annual Maintenance Cost (2022$)[2]	90	90	90	90	90	90	90	90	90	90	90

1. Analysis is based on an average of low, medium, and very small draw pattern units, as this is most reflective of the market.
2. Annual maintenance costs not provided in CWH EERE 2022 Preliminary Analysis. Maintenance costs determined from the following calculation: GIWH - (GSWH - ESWH) - i.e., the difference factor in maintenance between gas and electric storage heat pumps applied to gas instantaneous heat pumps.

Note:
Current standards went into effect April 16, 2015.
Assume same lifetime as gas-fired instantaneous water heaters.

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- The Federal standards are:

Volume Range	Draw Pattern	Federal standard[1]	Federal minimum UEF for typical sizes
<2 gal	Very Small	UEF=0.91	0.91
	Low	UEF=0.91	0.91
	Medium	UEF=0.91	No models on the market
	High	UEF=0.92	No models on the market

- Electric instantaneous water heaters use electric resistance heating elements to heat water when there is a demand. Resistive heating elements are virtually 100% efficient, and the small storage capacities of these products means that they do not lose significant amounts of heat to the environment.
- The federal standards for these products require UEFs of 0.91 for very small, low, and medium draw pattern models and 0.92 for high draw pattern models.
- Most products currently on the market are in the very small draw pattern or the low draw pattern because electric resistance elements can only supply a limited quantity of heat on an instantaneous basis due to circuit amperage limitations.
- Many products are designed for point-of-use applications, such that the water heater only supplies water to one faucet or showerhead.

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Residential Appliances

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Residential Refrigerator-Freezers (Top)

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DATA[1]	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)[2]	19	19	19	19	19	19	19	19	19	19	19	19
Energy Consumption (kWh/y)[3]	512	401	411	401	370	358	401	358	401	358	401	358
Average Life (y)	15	15	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)	670	750	740	750	760	760	750	760	750	760	750	760
Total Installed Cost (2022$)	670	750	740	750	760	760	750	760	750	760	750	760
Annual Maintenance Cost (2022$)[4]	10	10	10	10	10	10	10	10	10	10	10	10

1. Product Class 3 is used for this analysis (Refrigerator-freezers—automatic defrost with top-mounted freezer without through-the-door ice service and all-refrigerator—automatic defrost).
2. The volume shown here is the nominal total volume, not the adjusted volume, which is used to determine compliance with standards. The adjusted volume is equal to the fresh food internal volume plus the freezer internal volume times an adjustment factor, which depends on the product type.
3. The 2015 installed base energy consumption value is based on an adjusted volume of 21 cubic feet (ft^3). Energy consumption values for the 2020 installed base and 2022 and beyond are based on an adjusted volume of 22 ft^3, representing the current market.
4. Maintenance costs include cost of repairing integral components (e.g., compressor, evaporator fan, electronics, ice maker), not replaceable components (e.g., water filters).

Note:
Current standard went into effect in September 2014.
ENERGY STAR V. 5.1 went into effect in September 2014.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (10.26, 1.28, 5.13).

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Residential Refrigerator-Freezers (Side)

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DATA[1]	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)[2]	26	26	25	25	25	25	25	25	25	25	25	25
Energy Consumption (kWh/y)[3]	893	693	705	693	635	610	693	610	693	610	693	610
Average Life (y)	15	15	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)	1,400	1,130	1,130	1,130	1,160	1,470	1,130	1,470	1,130	1,470	1,130	1,470
Total Installed Cost (2022$)	1,400	1,130	1,130	1,130	1,160	1,470	1,130	1,470	1,130	1,470	1,130	1,470
Annual Maintenance Cost (2022$)[4]	30	20	20	20	20	30	20	30	20	30	20	30

1. Product Class 7 is used for this analysis (Refrigerator-freezers—automatic defrost with side-mounted freezer with through-the-door ice service).
2. The volume shown here is the nominal total volume, not the adjusted volume, which is used to determine compliance with standards. The adjusted volume is equal to the fresh food internal volume plus the freezer internal volume times an adjustment factor, which depends on the product type.
3. Based on an adjusted volume of 32 ft^3 for all analysis years.
4. Maintenance costs include cost of repairing integral components (e.g., compressor, evaporator fan, electronics, ice maker), not replaceable components (e.g., water filters).

Note:
Current standard went into effect in September 2014.
ENERGY STAR V. 5.1 went into effect in September 2014.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (10.26, 1.28, 5.13).

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Residential Refrigerator-Freezers (Bottom)

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DATA[1]	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)[2]	19	19	19	19	19	19	19	19	19	19	19	19
Energy Consumption (kWh/y)[3]	547	473	521	473	469	430	473	430	473	430	473	430
Average Life (y)	15	15	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)	1,190	920	920	920	920	930	920	930	920	930	920	930
Total Installed Cost (2022$)	1,190	920	920	920	920	930	920	930	920	930	920	930
Annual Maintenance Cost (2022$)[4]	30	20	20	20	20	20	20	20	20	20	20	20

1. Product Class 5 is used for this analysis (Refrigerator-freezers—automatic defrost with bottom-mounted freezer without through-the-door ice service).
2. The volume shown here is the nominal total volume, not the adjusted volume, which is used to determine compliance with standards. The adjusted volume is equal to the fresh food internal volume plus the freezer internal volume times an adjustment factor, which depends on the product type.
3. Based on an adjusted volume of 23 ft^3 for all analysis years.
4. Maintenance costs include cost of repairing integral components (e.g., compressor, evaporator fan, electronics, ice maker), not replaceable components (e.g., water filters).

Note:
Current standard went into effect in September 2014.
ENERGY STAR V. 5.1 went into effect in September 2014.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (10.26, 1.28, 5.13).

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Residential Refrigerator-Freezers

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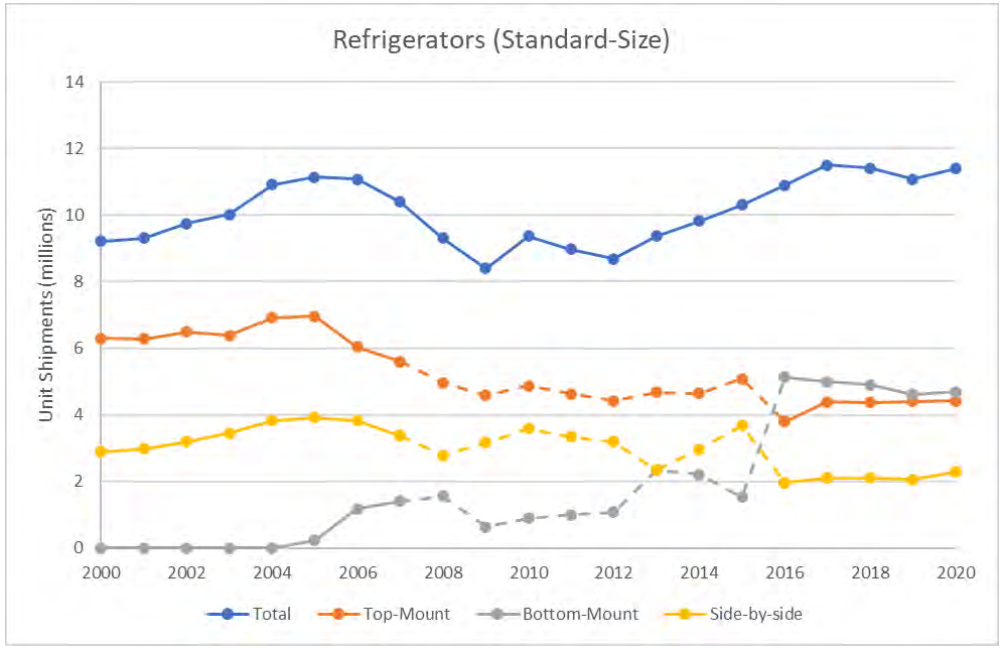
- Current Federal standards[1]:
  - Compliance required beginning September 15, 2014
  - Models divided into 32 product classes based on size (standard or compact), location of freezer (top, bottom, or side), type of defrost (automatic or manual), installation configuration (freestanding or built-in), and presence and configuration (through-the-door or inside cabinet) of automatic icemaker
  - Limits on annual electricity consumption expressed as functions of adjusted volume[2]
  - New product classes for built-in units
  - Amount by which standards are tightened varies by product class
- ENERGY STAR criteria limit annual electricity consumption to 10% less than the Federal standard
- Energy efficiency opportunities for refrigerators include:
  - More efficient compressor, including variable speed compressors
  - Brushless direct current (DC) fan motor (also known as ECM motor)
  - Variable defrost
  - Larger condenser
  - Dual evaporators
  - Vacuum-insulated panels
  - Refrigerants (Isobutane vs. R134a)

[1]Energy Conservation Standards for Residential Refrigerators, Refrigerator-Freezers, and Freezers. 10 CFR 430.32(a).
[2]Adjusted Volume (AV) = (Fresh Volume) + 1.76 × (Freezer Volume)

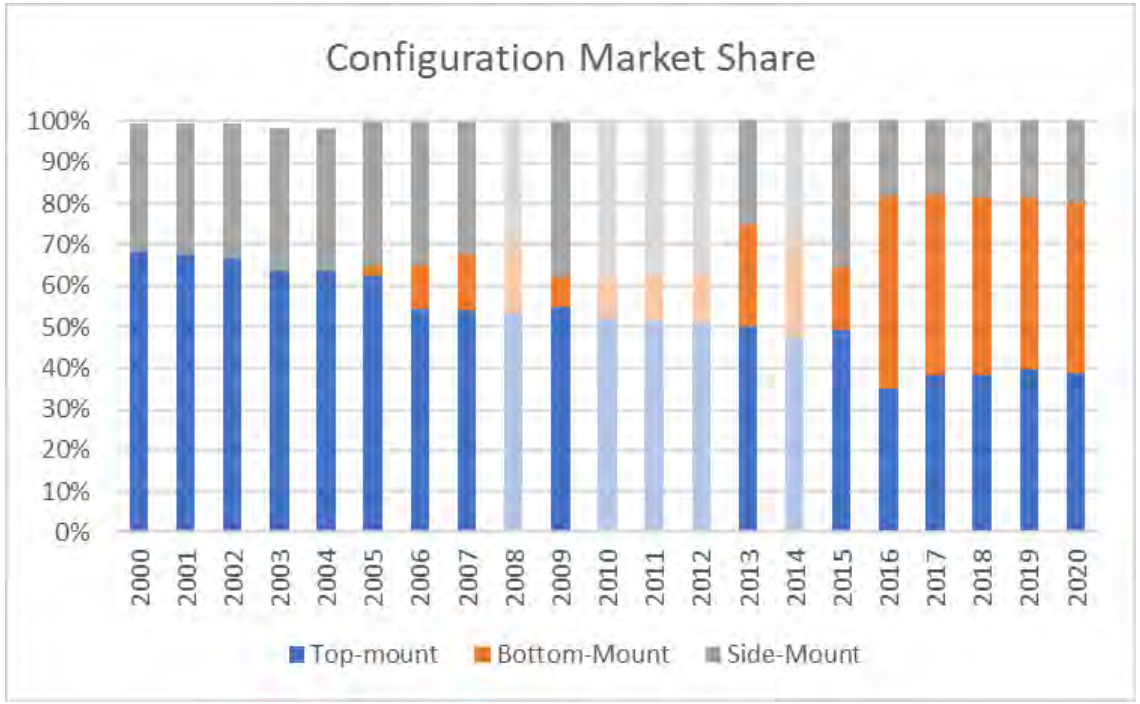
Residential Refrigerator-Freezers

Annual shipment volumes have rebounded from a sharp decline between 2006 and 2009, reaching approximately 11.4 million units in 2020.



Source: *Appliance Magazine; DOE's CCD, as of December 2017; ENERGY STAR Unit Shipment Data (2017-2020); Guidehouse analysis.* Dashed lines are a combination of interpolated and available data.

Bottom-mount units have gained market share, surpassing top-mount units since 2016.



Sources: *RF EERE 2021 Preliminary Analysis; DOE's CCD, as of December 2017; Guidehouse analysis.* Lightly shaded bars indicate interpolated data.

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Residential Freezers (Chest)

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DATA[1]	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)[2]	16	15	15	15	15	15	15	15	15	15	15
Energy Consumption (kWh/y)[3]	360	297	297	297	287	297	287	297	287	297	287
Average Life (y)	21	21	21	21	21	21	21	21	21	21	21
Retail Equipment Cost (2022$)	510	590	680	680	690	680	690	680	690	680	690
Total Installed Cost (2022$)	510	590	680	680	690	680	690	680	690	680	690
Annual Maintenance Cost (2022$)[4]	10	10	10	10	10	10	10	10	10	10	10

1. Product Class 10 is used for this analysis (Chest freezers and all other freezers except compact freezers).
2. The volume shown here is the nominal volume, not the adjusted volume, which is used to determine compliance with standards. The adjusted volume is equal to the fresh food internal volume (zero for freezers) plus the freezer internal volume times an adjustment factor, which depends on the product type.
3. Based on an adjusted volume of 26 ft^3, which is the average adjusted volume for units with a rounded total refrigerated volume of 15 ft^3 per the DOE CCD.
4. Maintenance costs include cost of repairing integral components (e.g., compressor, evaporator fan, electronics)

Note:
Current standard went into effect in September 2014.
ENERGY STAR excluded as no products at the typical capacity are ENERGY STAR compliant.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (21.96, 1.83, 1).

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Residential Freezers (Upright)

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DATA[1]	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)[2]	17	17	18	18	18	18	18	18	18	18	18	18
Energy Consumption (kWh/y)[3]	615	446	497	493	448	441	493	441	493	441	493	441
Average Life (y)	21	21	21	21	21	21	21	21	21	21	21	21
Retail Equipment Cost (2022$)	690	880	830	830	830	830	830	830	830	830	830	830
Total Installed Cost (2022$)	690	880	830	830	830	830	830	830	830	830	830	830
Annual Maintenance Cost (2022$)[4]	10	10	10	10	10	10	10	10	10	10	10	10

1. Product Class 9 is used for this analysis (Upright freezers with automatic defrost).
2. The volume shown here is the nominal volume, not the adjusted volume, which is used to determine compliance with standards. The adjusted volume is equal to the fresh food internal volume (zero for freezers) plus the freezer internal volume times an adjustment factor, which depends on the product type.
3. Based on an adjusted volume of 31 ft^3, which is the average adjusted volume for units with a rounded total refrigerated volume of 18 ft^3 per the DOE CCD.
4. Maintenance costs include cost of repairing integral components (e.g., compressor, evaporator fan electronics).

Note:
Current standard went into effect in September 2014.
ENERGY STAR V. 5.1 went into effect September 2014.
Assume same lifetime as chest freezers.

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Residential Freezers

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- Current Federal standards[1]:
  - Compliance required beginning September 15, 2014
  - Models divided into 10 product classes based on size (standard or compact), orientation (chest or upright), type of defrost (automatic or manual), installation configuration (freestanding or built-in), and presence of automatic icemaker
    - Current analysis focuses on the two representative product classes analyzed in the recent rulemaking, chest and upright freezers.
  - Limits on annual electricity consumption expressed as functions of adjusted volume[2]
    - Chest freezers and all other freezers except compact freezers (PC 9): 9.88AV + 143.7
    - Upright freezers with automatic defrost (PC 10): 12.43AV + 326.1
- ENERGY STAR criteria limit annual electricity consumption to 10% less than the Federal standard
  - No ENERGY STAR compliant products at the typical capacity for chest freezers
- Energy efficiency opportunities for freezers include:
  - Higher efficiency and/or variable-speed compressor systems
  - Larger heat exchangers
  - Permanent-magnet fan motor systems (vs. shaded pole motor (SPM) and PSC fan motors)
  - Demand defrost systems
  - Vacuum-insulated panels
  - Thicker insulation (though at a loss of consumer utility)
  - Refrigerants (Isobutane vs. R134a)
  - Variable anti-sweat heating
  - Use of forced convection condenser (for upright freezers)

[1]Energy Conservation Standards for Residential Refrigerators, Refrigerator-Freezers, and Freezers. 10 CFR 430.32(a).
[2]Adjusted Volume (AV) = (Fresh Volume) + 1.76 × (Freezer Volume).

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Residential Freezers

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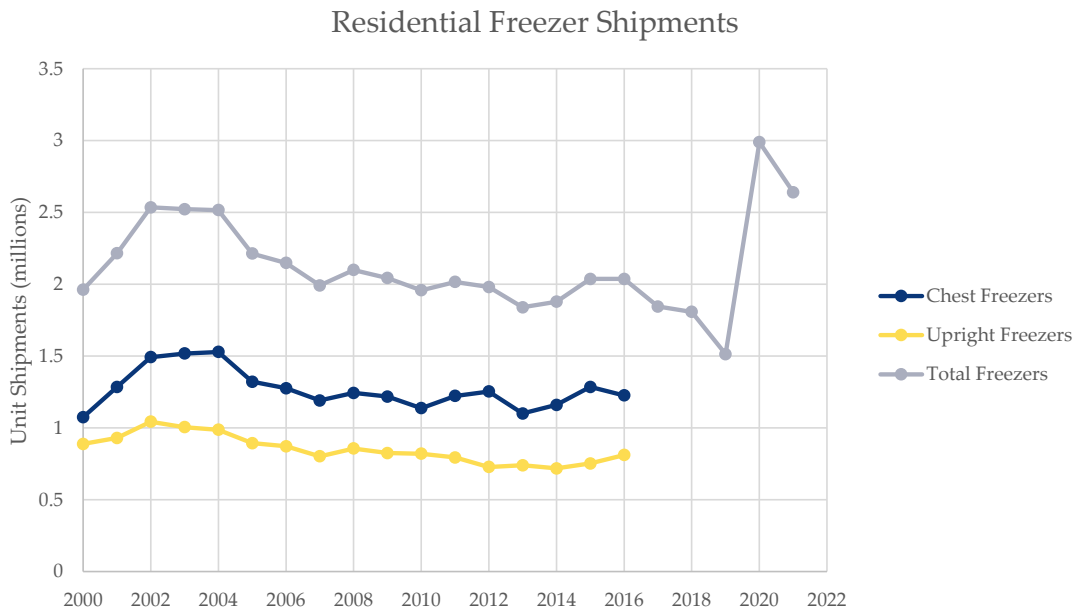
Shipment volumes held steady between 2007 to 2016 at about 2 million units per year. Shipments jumped to 3 million units in 2020. Chest freezers represent about 60% of the market.



Sources: *Appliance Magazine* from 2000 to 2016*; ENERGY STAR from 2017 to 2021*

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Residential Natural Gas Cooktops

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DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	9	9	9	9	9	9	9	9	9	9
	23	23	23	23	23	23	23	23	23	23
Integrated Annual Energy Consumption (kBtu/y)[1]	1,061	914	914	730	914	730	914	730	914	730
Cooking Efficiency (%)	40	45	45	52	45	52	45	52	45	52
Average Life (y)	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)[2]	290	310	310	330	310	330	310	330	310	330
Total Installed Cost (2022$)[2]	420	460	460	480	460	480	460	480	460	480
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-

1. Although there is no performance standard in effect, the test procedure metric has changed from Cooking Efficiency (%) to Integrated Annual Energy Consumption (IAEC) (kBtu/h). The Consumer Cooking Products EERE 2020 notice of proposed determination (NOPD) used for 2020 and beyond in this analysis also determined IAEC using a different test procedure than the Consumer Cooking Products EERE 2016 SNOPR.
2. Equipment and installed costs are for cooktops only (not combined range units).
3. Annual maintenance costs are negligible.

Note:
The range for typical capacity represents the span of typical values.
Average life is determined using a Weibull distribution characterized by the following scale (α) and shape (β) parameters: (14.56, 5.73).

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Residential Natural Gas Ovens

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DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	16	16	16	16	16	16	16	16	16	16
	18	18	18	18	18	18	18	18	18	18
Typical Cavity Volume (ft^3)	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Integrated Annual Energy Consumption (kBtu/y)[1]	2,038	1,960	1,960	1,831	1,960	1,831	1,960	1,831	1,960	1,831
Cooking Efficiency (%)	6.6	6.9	6.9	7.3	6.9	7.3	6.9	7.3	6.9	7.3
Average Life (y)	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)[2]	740	770	770	810	770	810	770	810	770	810
Total Installed Cost (2022$)[2]	870	920	920	950	920	950	920	950	920	950
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-

1. Although there is no performance standard in effect, the test procedure metric has changed from Cooking Efficiency (%) to IAEC (kBtu/y). The 2015 IAEC value is reflective of freestanding standard gas ovens, which was previously determined to be the most representative product class. IAEC for 2020 and beyond is reflective of freestanding self-clean gas ovens, which is the product class that makes up the majority of historical and projected gas oven shipments.
2. Equipment and installed costs are for ovens only (not combined ranges). Costs are reflective of freestanding self-clean oven units with single oven component, which represent the majority of the market.
3. Maintenance costs are negligible.

Note:
Ranges represent the span of typical values for a given parameter.
Average life is determined using a Weibull distribution characterized by the following scale (α) and shape (β) parameters: (14.56, 5.73).

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Residential Natural Gas Ranges

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DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity of Cooktop Component (kBtu/h)	9	9	9	9	9	9	9	9	9	9
	23	23	23	23	23	23	23	23	23	23
Typical Capacity of Oven Component (kBtu/h)	16	16	16	16	16	16	16	16	16	16
	18	18	18	18	18	18	18	18	18	18
Typical Cavity Volume of Oven Component (ft^3)	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Integrated Annual Energy Consumption (kBtu/y)[1]	3,099	2,874	2,874	2,561	2,874	2,561	2,874	2,561	2,874	2,561
Average Life (y)	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$) [2]	750	770	770	850	770	850	770	850	770	850
Total Installed Cost (2022$) [2]	900	920	920	1,000	920	1,000	920	1,000	920	1,000
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-

1. IAEC of a natural gas range is calculated as the sum of the IAEC for a natural gas cooktop and natural gas oven. IAEC of the oven component is reflective of freestanding self-clean gas ovens, which represent the majority of the market. The 2015 IAEC value of the oven component is reflective of freestanding standard gas ovens, which was previously determined to be the most representative product class.
2. Retail and installed cost are reflective of a typical unit with standard 30-inch width and 4 to 5 cooking top heating elements. Based on data from DOE rulemakings, Gordian's RSMeans Data – Building Construction Costs 2023, and distributors, total installed cost is estimated to be around $150 more than retail equipment cost.
3. Maintenance costs are negligible.

Note:
Ranges represent the span of typical values for a given parameter.
Average life is determined using a Weibull distribution characterized by the following scale (α) and shape (β) parameters: (14.56, 5.73).

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Residential Natural Gas Cooktops, Ovens, and Ranges

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- DOE analyzes cooktops and ovens separately, although they are often sold together in a single unit that combines both a cooktop and an oven into a product referred to as a range.
- Since January 1, 1990, gas cooking products with an electrical supply cord have been required to not be equipped with a constant burning pilot light. This requirement extended to gas cooking products without an electrical supply cord, as of April 9, 2012.
- DOE published a final rule in 2009[1] in which it determined that no standard for cooking efficiency would be cost-justified.
- DOE initiated a standards rulemaking in 2014 to consider amended standards for cooking products, including gas cooktops and ovens[2].
- On September 2, 2016, DOE proposed performance-based standards for gas cooktops and ovens that would take effect in 2020, if adopted.
- DOE established the new IAEC metric, in kBtu/y, to replace cooking efficiency (%).
- On December 14, 2020, DOE initially determined that amended energy conservation standards for consumer conventional cooking products would not be economically justified and would not result in significant conservation of energy[3].
- On February 2, 2023, DOE proposed new and amended energy conservation standards for consumer conventional cooking products[4].
- The IAEC of a range is calculated as the sum of the IAECs for cooktops and ovens. However, retail and installation costs for a range are similar to the cost of an oven.

[1]Energy Conservation Standards for Certain Consumer Products (Dishwashers, Dehumidifiers, Microwave Ovens, and Electric and Gas Kitchen Ranges and Ovens) and for Certain Commercial and Industrial Equipment (Commercial Clothes Washers); Final Rule. 74 FR 16040.
[2]Energy Conservation Standards for Residential Conventional Cooking Products; Supplemental notice of proposed rulemaking (SNOPR). 81 FR 60784.
[3]Energy Conservation Standards for Consumer Conventional Cooking Products; Notice of proposed determination (NOPD). 85 FR 80982.
[4]Energy Conservation Standards for Consumer Conventional Cooking Products; SNOPR. 88 FR 6818.

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Residential Natural Gas Cooktops, Ovens, and Ranges

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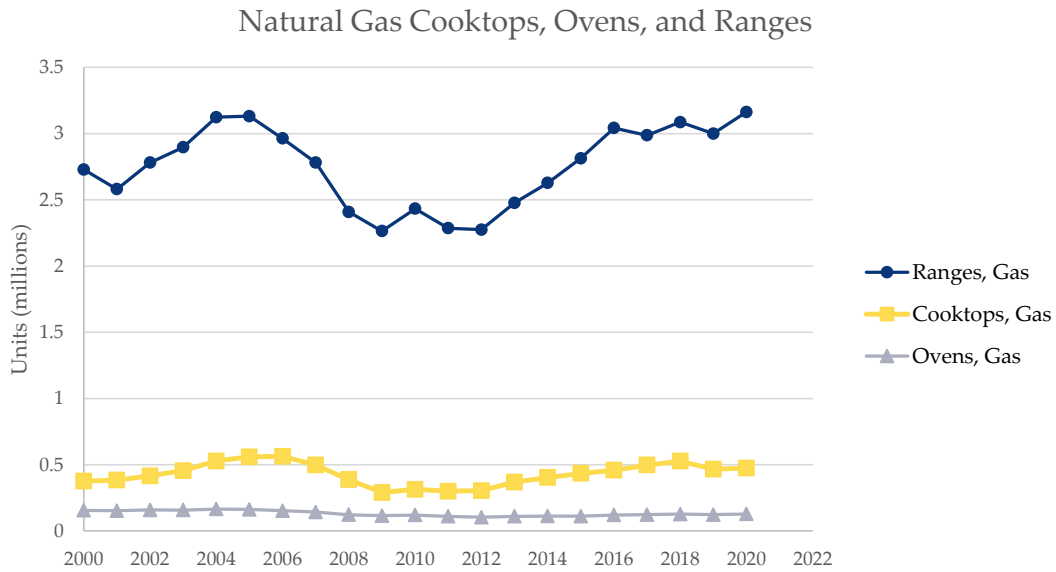
Shipments have been rising since 2012. In 2020, gas range shipments surpassed the peak reached in 2005.



Source: *Appliance Magazine and Consumer Cooking Products EERE 2022 SNOPR*

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Residential Electric Cooktops

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DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (W)	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700
Integrated Annual Energy Consumption (kWh/y)[1]	155	155	155	119	155	119	155	119	155	119
Average Life (y)	17	17	17	17	17	17	17	17	17	17
Retail Equipment Cost (2022$)[2]	470	470	470	810	470	810	470	810	470	810
Total Installed Cost (2022$)[2]	620	620	620	1,230	620	1,230	620	1,230	620	1,230
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-

1. Although there is no performance standard in effect, the test procedure metric has changed from Cooking Efficiency (%) to IAEC (kBtu/y). IAEC was determined using DOE rulemaking data for the most representative product class, electric smooth element cooking tops, which covers cooking tops with electric resistance heating elements and cooking tops with induction heating elements.
2. Equipment and installed costs are for cooktops only (not combined range units). Costs were determined using DOE rulemaking data for the most representative product class, electric smooth cooking tops, which includes cooking tops with electric resistance heating elements and cooking tops with induction heating elements. A high-end unit with induction technology is expected to have a greater retail equipment cost and greater installation cost in order to implement this technology.
3. Maintenance costs are negligible.

Note:
The range for typical capacity represents the span of typical values.
Average life is determined using a Weibull distribution characterized by the following scale (α) and shape (β) parameters: (16.88, 6.99).

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Residential Electric Ovens

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DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (W)	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400
Typical Cavity Volume (ft^3)	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Integrated Annual Energy Consumption (kWh/y)[1]	355	355	355	278	355	278	355	278	355	278
Average Life (y)	17	17	17	17	17	17	17	17	17	17
Retail Equipment Cost (2022$)[2]	630	630	630	730	630	730	630	730	630	730
Total Installed Cost (2022$)[2]	770	770	770	870	770	870	770	870	770	870
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-

1. Although there is no performance standard in effect, the test procedure metric has changed from Cooking Efficiency (%) to IAEC (kBtu/y). IAEC was determined using DOE rulemaking data for freestanding electric self-clean ovens, which represent the majority of the market.
2. Equipment and installed costs are for ovens only (not combined ranges). Costs are reflective of freestanding self-clean oven units with single oven component, which represent the majority of the market.
3. Maintenance costs are negligible.

Note:
Ranges represent the span of typical values for a given parameter.
Average life is determined using a Weibull distribution characterized by the following scale (α) and shape (β) parameters: (16.88, 6.99).

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Residential Electric Ranges

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DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity of Cooktop Component (W)	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700
Typical Capacity of Oven Component (W)	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400
Typical Cavity Volume of Oven Component (ft^3)	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Integrated Annual Energy Consumption (kWh/y)[1]	510	510	510	397	510	397	510	397	510	397
Average Life (y)	17	17	17	17	17	17	17	17	17	17
Retail Equipment Cost (2022$) [2]	630	630	630	900	630	900	630	900	630	900
Total Installed Cost (2022$) [2]	770	770	770	1,050	770	1,050	770	1,050	770	1,050
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-

1. IAEC of an electric range is calculated as the sum of the IAEC for an electric cooktop and an electric oven. IAEC of the electric cooktop component was determined using DOE rulemaking data for the most representative product class, electric smooth element cooking tops, which covers cooking tops with electric resistance heating elements and cooking tops with induction heating elements. IAEC of the electric oven component was determined using DOE rulemaking data for freestanding electric self-clean ovens, which represent the majority of the market.
2. Retail and installed cost are reflective of standard units that are 30-inch wide and have 4 to 5 cooking top heating elements. Based on data from DOE rulemakings, Gordian's RSMeans Data – Building Construction Costs 2023, and distributors, total installed cost is estimated to be around $140 more than retail equipment cost for a typical unit, and $150 more than retail equipment cost for a high-end unit. A high-end unit with an induction cooking top component is expected to have a greater retail equipment cost and greater installation cost in order to implement this technology.
3. Maintenance costs are negligible.

Note:
Ranges represent the span of typical values for a given parameter.
Average life is determined using a Weibull distribution characterized by the following scale (α) and shape (β) parameters: (16.88, 6.99).

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Residential Electric Cooktops, Ovens, and Ranges

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- DOE analyzes cooktops and ovens separately, although they are often sold together in a single unit that combines both a cooktop and an oven into a product referred to as a range.
- DOE initiated a standards rulemaking in 2014 to consider amended standards for cooking products, including electric cooktops and ovens[1].
- On September 2, 2016, DOE proposed performance-based standards for electric cooktops and ovens that would take effect in 2020 if adopted.
- DOE established the new IAEC metric, in kWh/y, to replace cooking efficiency (%).
- On December 14, 2020, DOE initially determined that amended energy conservation standards for consumer conventional cooking products would not be economically justified and would not result in a significant conservation of energy[2].
- On February 2, 2023, DOE proposed new and amended energy conservation standards for consumer conventional cooking products[3].
- The IAEC of a range is calculated as the sum of the IAECs for cooktops and ovens. However, retail and installation costs for a range are similar to the cost of an oven.

[1]Energy Conservation Standards for Residential Conventional Cooking Products; Supplemental notice of proposed rulemaking (SNOPR). 81 FR 60784.
[2]Energy Conservation Standards for Consumer Conventional Cooking Products; Notice of proposed determination (NOPD). 85 FR 80982.
[3]Energy Conservation Standards for Consumer Conventional Cooking Products; SNOPR. 88 FR 6818.

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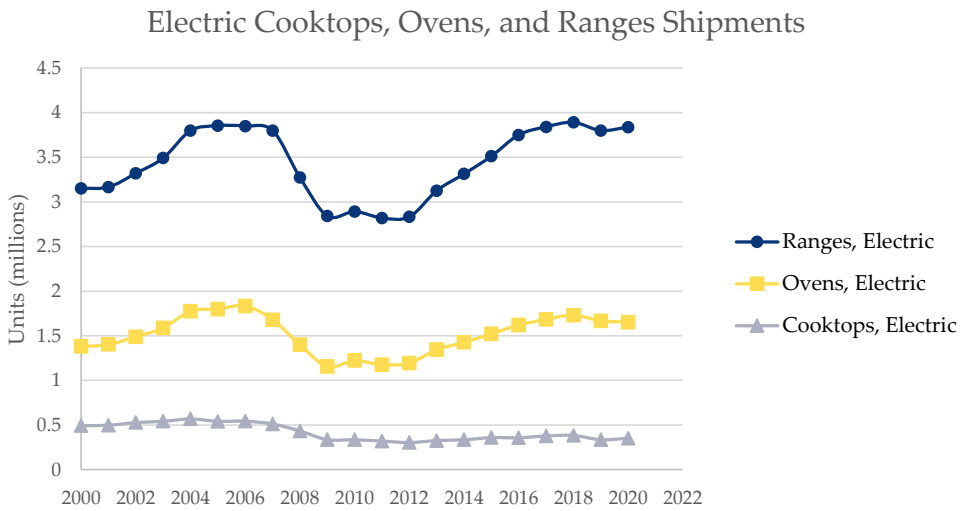
Shipments of electric cooking products reached a peak in 2006. Shipments of ranges and ovens have been rising again since 2012. In 2018, electric range shipments surpassed the peak reached in 2006.



Source: *Consumer Cooking Products EERE 2022 SNOPR*

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Residential Clothes Dryers (Electric)

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DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 1.1[1]	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	7.4	7.4	7.4	7.4	7.4	4.5	7.4	4.5	7.4	4.5	7.4	4.5
Combined Energy Factor, D1 (lb/kWh)[2]	3.59	3.73	3.73	3.73	NA	3.93	3.73	3.93	3.73	3.93	3.73	3.93
Combined Energy Factor, D2 (lb/kWh)[2]	3.59	3.93	3.73	3.93	3.93	11.00	3.93	11.00	3.93	11.00	3.93	11.00
Average Life (y)	8	8	8	8	8	8	8	8	8	8	8	8
	18	18	18	18	18	18	18	18	18	18	18	18
Retail Equipment Cost (2022$)	580	580	580	580	580	980	580	980	580	980	580	980
Total Installed Cost (2022$)	710	710	710	710	710	1,110	710	1,110	710	1,110	710	1,110
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-	-	-

1. ENERGY STAR V. 1.1 applies to vented and ventless standard electric clothes dryers.
2. The efficiency metric changed from EF to combined energy factor (CEF) in 2015. The 2015 Installed Base CEF data accounts for units tested to appendix D1 and appendix D2, because data specific to each appendix is not available for that year.
3. Maintenance costs are negligible. DOE estimated that on average 2.7 percent of electric and 3.3 percent of gas residential clothes dryers are repaired each year. (EERE 2014)

Note:
DOE test procedures for consumer clothes dryers appear at title 10 of the Code of Federal Regulations part 430, subpart B, appendix D1 and appendix D2. The second test method, appendix D2, was finalized in a final rule published by DOE on August 14, 2013. For current standard testing, units must be tested according to either the appendix D1 or the appendix D2 test method. ENERGY STAR V. 1.1 requires certified units to be tested according to the appendix D2 test method. The appendix D1 and appendix D2 test methods determine CEF differently.
The current standard went into effect in January 2015.
ENERGY STAR V. 1.1 went into effect in May 2017.
The range for average life represents the span of typical values.

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Residential Clothes Dryers (Gas)

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DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 1.1[1]	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Combined Energy Factor, D1 (lb/kWh)[2]	3.18	3.30	3.30	3.30	NA	3.48	3.30	3.48	3.30	3.48	3.30	3.48
Combined Energy Factor, D2 (lb/kWh)[2]	3.18	3.48	3.30	3.48	3.48	3.50	3.48	3.50	3.48	3.50	3.48	3.50
Average Life (y)	8	8	8	8	8	8	8	8	8	8	8	8
	18	18	18	18	18	18	18	18	18	18	18	18
Retail Equipment Cost (2022$)	660	670	660	670	670	670	670	670	670	670	670	670
Total Installed Cost (2022$)	860	870	870	870	870	870	870	870	870	870	870	870
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-	-	-

1. ENERGY STAR V. 1.1 applies to vented and ventless standard electric clothes dryers.
2. The efficiency metric changed from EF to CEF in 2015. The 2015 Installed Base CEF data accounts for units tested to appendix D1 and appendix D2, because data specific to each appendix is not available for that year.
3. Maintenance costs are negligible. DOE estimated that on average 2.7 percent of electric and 3.3 percent of gas residential clothes dryers are repaired each year. (EERE 2014)

Note:
DOE test procedures for consumer clothes dryers appear at title 10 of the Code of Federal Regulations part 430, subpart B, appendix D1 and appendix D2. The second test method, appendix D2, was finalized in a final rule published by DOE on August 14, 2013. For current standard testing, units must be tested according to either the appendix D1 or the appendix D2 test method. ENERGY STAR V. 1.1 requires certified units to be tested according to the appendix D2 test method. The appendix D1 and appendix D2 test methods determine CEF differently.
The current standard went into effect in January 2015.
ENERGY STAR V. 1.1 went into effect in May 2017.
The range for average life represents the span of typical values.

Residential Clothes Dryers

- Current standards[1] in effect since 2015:
  - For standard-size electric units : CEF ≥ 3.73 pound per kilowatt hours (lb/kWh)
  - For gas units: CEF ≥ 2.30 lb/kWh
  - Units may be tested according to the test method in appendix D1 or appendix D2, which was finalized in 2013.
- The main differences between appendix D1 and appendix D2 are:
  - Appendix D2 includes test methods that more accurately measure the effects of automatic cycle termination and that may result in differences in the total measured energy consumption of the test cycle as compared to the test methods in appendix D1.
  - Appendix D2 contains instructions for the testing of timer dryers, which include a lower final moisture content (FMC) of the test load as compared to the version of appendix D1 used for the 2011 rulemaking analysis.
- Efficiency improvement technologies for clothes dryers include:
  - Multi-step or modulating heat
  - Higher efficiency drum motors
  - Inlet air pre-heat
  - Better control systems for cycle termination
  - Heat pump (for electric clothes dryers)
- EPA developed ENERGY STAR V. 1.1, which became effective in 2017 and requires units to be tested according to the test method in appendix D2.
- Standard-size heat pump clothes dryers with CEF values up to 11.0 are currently available in the U.S. market. High initial cost has limited market penetration, but some utilities are offering rebates to support market penetration.

[1]Energy Conservation Standards for Consumer Clothes Dryers. 10 CFR 430.32(h).

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Residential Clothes Dryers

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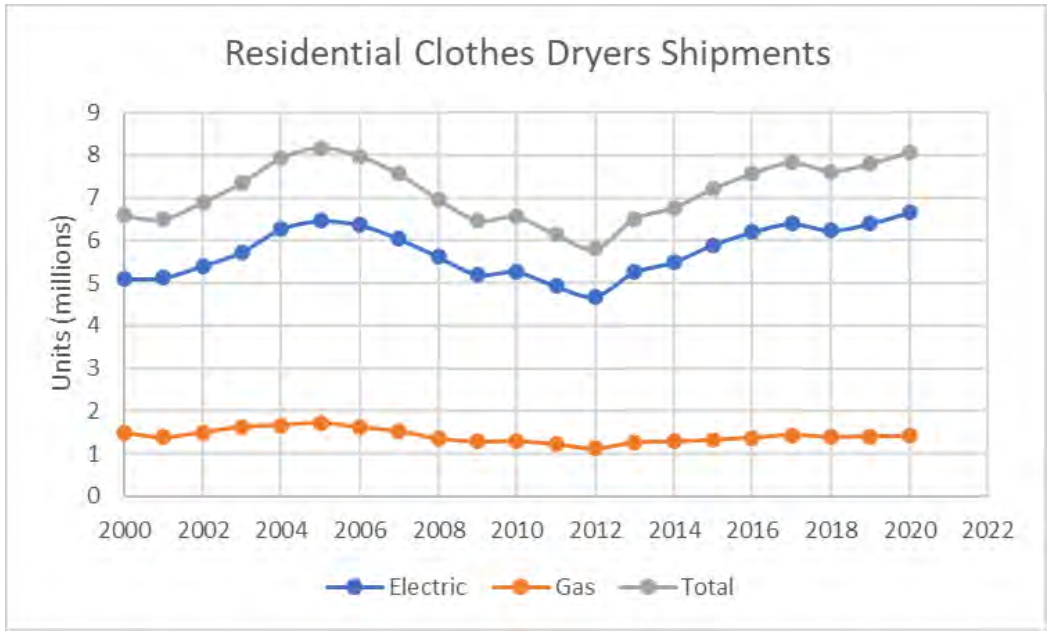
Shipment volumes have been on the rise since 2012. Gas dryers continue to account for about one-fifth of the market.



Source: *Consumer Clothes Dryers EERE 2022 NOPR*

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Residential Clothes Washers (Front)

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DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 8.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	3.7	4.1	3.4	4.5	4.5	5.0	4.5	5.0	4.5	5.0	4.5	5.0
Integrated Modified Energy Factor (ft^3/kWh/cycle)[1]	2.16	2.76	1.84	2.76	2.76	3.10	2.76	3.10	2.76	3.10	2.76	3.10
Integrated Water Factor (gal/cycle/ft^3)[2]	4.7	3.2	4.7	3.2	3.2	2.7	3.2	2.7	3.2	2.7	3.2	2.7
Average Life (y)	6	6	6	6	6	6	6	6	6	6	6	6
	17	17	17	17	17	17	17	17	17	17	17	17
Water Consumption (gal/cycle)	17	14	16	14	14	14	14	14	14	14	14	14
Hot Water Energy (kWh/cycle)	0.21	0.17	0.36	0.12	0.12	0.13	0.12	0.13	0.12	0.13	0.12	0.13
Machine Energy (kWh/cycle)	0.17	0.14	0.15	0.12	0.12	0.17	0.12	0.17	0.12	0.17	0.12	0.17
Dryer Energy (kWh/cycle)	1.31	1.24	1.34	1.17	1.17	1.56	1.17	1.56	1.17	1.56	1.17	1.56
Retail Equipment Cost (2022$)	735	1,000	705	930	930	950	930	950	930	950	930	950
Total Installed Cost (2022$)	915	1,175	880	1,130	1,130	1,150	1,130	1,150	1,130	1,150	1,130	1,150
Annual Maintenance Cost (2022$)	15	15	15	15	15	15	15	15	15	15	15	15

1. The efficiency metric changed from Modified Energy Factor to Integrated Modified Energy Factor (IMEF) in 2015.
2. The efficiency metric changed from Water Factor to Integrated Water Factor (IWF) in 2015.

Note:
The current standard went into effect in January 2018.
ENERGY STAR V. 8.1 went into effect in February 2018.
The range for average life represents the span of typical values.

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Residential Clothes Washers (Top)

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DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 8.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	3.3	3.4	3.5	3.5	4.4	5.5	3.5	5.5	3.5	5.5	3.5	5.5
Integrated Modified Energy Factor (ft^3/kWh/cycle)[1]	1.14	1.57	1.57	1.57	2.06	2.76	1.57	2.76	1.57	2.76	1.57	2.76
Integrated Water Factor (gal/cycle/ft^3)[2]	9.2	6.5	6.5	6.5	4.3	3.2	6.5	3.2	6.5	3.2	6.5	3.2
Average Life (y)	6	6	6	6	6	6	6	6	6	6	6	6
	17	17	17	17	17	17	17	17	17	17	17	17
Water Consumption (gal/cycle)	30	22	23	23	19	18	23	18	23	18	23	18
Hot Water Energy (kWh/cycle)	0.90	0.39	0.41	0.41	0.38	0.24	0.41	0.24	0.41	0.24	0.41	0.24
Machine Energy (kWh/cycle)	0.25	0.13	0.14	0.14	0.12	0.13	0.14	0.13	0.14	0.13	0.14	0.13
Dryer Energy (kWh/cycle)	1.73	1.63	1.68	1.68	1.64	1.61	1.68	1.61	1.68	1.61	1.68	1.61
Retail Equipment Cost (2022$)	590	590	520	520	640	725	520	725	520	725	520	725
Total Installed Cost (2022$)	765	765	715	715	840	920	715	920	715	920	715	920
Annual Maintenance Cost (2022$)	15	15	15	15	15	15	15	15	15	15	15	15

1. The efficiency metric changed from Modified Energy Factor to IMEF in 2015.
2. The efficiency metric changed from Water Factor to IWF in 2015.

Note:
The current standard went into effect in January 2018.
ENERGY STAR V. 8.1 went into effect in February 2018.
The range for average life represents the span of typical values.

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- The analysis treats front- and top-loading models separately due to their different energy use characteristics.
- Federal standards[1] for standard-capacity clothes washers (≥ 1.6 ft^3):

	Integrated Modified Energy Factor		Integrated Water Factor	
	Top-Loading	Front-Loading	Top-Loading	Front-Loading
Current DOE Standard (effective 1/1/2018)	≥ 1.57	≥ 1.84	≤ 6.5	≤ 4.7
Current ENERGY STAR V. 8.1 (effective 4/22/2021)	≥ 2.06	≥ 2.76	≤ 4.3	≤ 3.2

- In 2020, about 40% of top-loading models and almost all front-loading models achieved the ENERGY STAR level.
- Energy efficiency improvement technologies for clothes washers include:
  - Higher efficiency motors and higher spin speeds
  - Better load sensing for adaptive water fill control
  - Reduced water temperature and quantity, while providing equivalent cleaning and rinsing performance
- Maintenance costs include replacement or repair of the drain pump, control board, motor, rubber gaskets, or control panel knobs.
- The products on the market with the highest IMEF have significantly larger capacity and therefore use more energy per cycle than typical, smaller capacity products but still perform more efficiently on a per volume basis.

[1]Energy Conservation Standards for Consumer Clothes Washers. 10 CFR 430.32(g).

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Shipments have been on the rise since 2012 and reached a peak of about 10 million in 2020. Since 2012, top-loading and front-loading units represent approximately 75% and 25% of shipments, respectively.

Source: *AHAM Shipment Data; RCW EERE 2021 Preliminary Analysis*

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Residential Dishwashers

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DATA	2015	2020	2022				2023	2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 6.0	High	ENERGY STAR V. 7.0	Typical	High	Typical	High	Typical	High
Typical Annual Energy Use (kWh/y)	295	270	307	270	270	225	240	240	225	240	225	240	225
Water Consumption (gal/cycle)	4.25	3.50	5.00	3.50	3.50	2.40	3.20	3.20	2.40	3.20	2.40	3.20	2.40
Water Heating Energy Use (kWh/y)[1]	154	125	176	123	123	84	112	123	84	123	84	123	84
Average Life (y)	15	15	15	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)	440	380	310	340	340	500	430	340	500	340	500	340	500
Total Installed Cost (2022$)	840	570	490	520	520	690	610	520	690	520	690	520	690
Annual Maintenance Cost (2022$)[2]	-	-	-	-	-	-	-	-	-	-	-	-	-

1. Refers to that portion of "Typical Annual Energy Use" that is the energy used to heat water in a separate water heater before it enters the dishwasher. The energy used to heat water inside the dishwasher cannot be disaggregated from the total.
2. Maintenance costs are negligible.

Note:
All values in table reflect 215 cycles/year according to the current test procedure at 10 CFR 430 Appendix C1.
The current standard went into effect in May 2013.
ENERGY STAR V. 6.0 went into effect in January 2016.
ENERGY STAR V. 7.0 will go into effect in July 2023.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (15.9, 1.8, 1).

Residential Dishwashers

- Performance criteria for standard-capacity dishwashers (assumes 215 cycles/year):
  - Federal Standards:
    - May 30, 2013: ≤ 307 kWh/y, ≤ 5.0 gal/cycle (DOE Direct Final Rule, published May 2012)
  - ENERGY STAR Criteria:
    - Jan. 29, 2016: ≤ 270 kWh/y (5% allowance for connected), ≤ 3.5 gal/cycle (V. 6.0)
    - July 19, 2023: ≤ 240 kWh/y, ≤ 3.2 gal/cycle (V. 7.0, effective August 2023)
- ENERGY STAR has maintained a very high market share for several years (93% in 2021), so sales-weighted average efficiency has tracked ENERGY STAR levels.
  - Due to the historically high market penetration of ENERGY STAR products, it is expected that manufacturers will make the necessary adjustments so ENERGY STAR V. 7.0 levels will be typical in future projections.
- Test procedures:
  - Accounts for motor, dryer, booster heater (if present), and hot water from separate water heater, as well as standby and off-mode energy.
  - ENERGY STAR established a cleaning performance test method. While cleaning performance reporting is currently optional, V. 7.0 requires a cleaning index of 65 or higher for ENERGY STAR certification.
  - In January 2023, DOE established a test procedure at Appendix C2, which would go into effect at the time of any amended energy conservation standards. Appendix C2 establishes a minimum cleaning index threshold of 70 as a condition for a valid test cycle. The cleaning index threshold of 70 established by DOE is equivalent to the cleaning index threshold of 65 specified in ENERGY STAR V. 7.0.
- Efficiency improvement technologies for dishwashers include:
  - Better soil sensing
  - Control strategies
  - Water distribution (small pipes, fine filter, small sump, multiple spray arms, alternating water use) and controls (flow meter, temperature sensor)
  - Inline water heater (to minimize sump volume)
  - Separate drain pump, high-efficiency, variable-speed circulation pump motor
  - Condensation drying (rather than power dry)

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Residential Dishwashers

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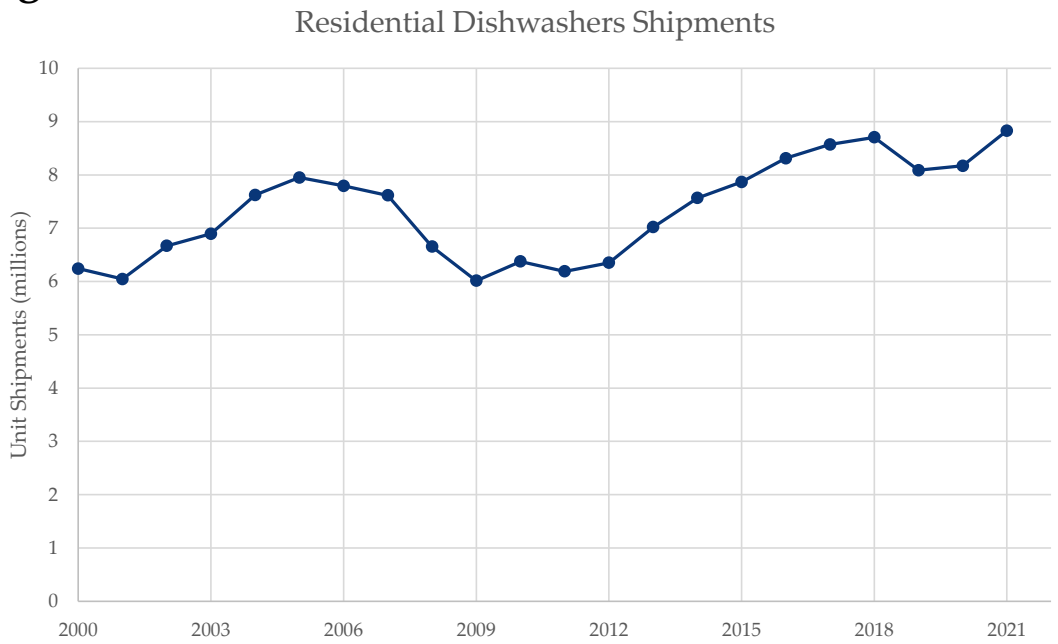
Shipments increased steadily from the early 1990s until the 2008-2009 recession. Shipments have resumed similar growth since then.



Source: *DW EERE 2022 Preliminary Analysis*

Commercial Space Heating and Cooling

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Commercial Gas-Fired Furnaces

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DATA	2012	2018	2022			2023[1]		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	High	New Standard	Typical	Typical	Typical	Typical
Typical Input Capacity (kBtu/h)[2]	400	400	250	250	250	250	250	250	250	250
Thermal Efficiency (%)[3]	80	80	80	81	81	81	81	81	81	81
Typical Output Capacity (kBtu/h)	320	320	200	203	203	203	203	203	203	203
Average Life (y)	23	23	23	23	23	23	23	23	23	23
Retail Equipment Cost (2022$)	1,230	1,230	1,230	1,260	1,260	1,260	1,260	1,260	1,260	1,260
Total Installed Cost (2022$)	2,540	2,540	2,540	2,580	2,580	2,580	2,580	2,580	2,580	2,580
Total Installed Cost (2022$/kBtu/h)	8	8	13	13	13	13	13	13	13	13
Annual Maintenance Cost (2022$)	200	200	200	200	200	200	200	200	200	200
Annual Maintenance Cost (2022$/kBtu/h)	1	1	1	1	1	1	1	1	1	1

1. In 2023, the new Energy Conservation Standards for Commercial Warm Air Furnaces (CWAF) took effect. These projections reflect the 2023 minimum thermal efficiency requirement for gas-fired furnaces, 81%.
2. When this analysis was previously conducted in EIA Technology Forecast Updates (2018), a typical input capacity of 400 kBtu/h was listed. An updated typical input capacity value of 250 kBtu/h was determined through an evaluation of the units in the DOE CCD as of August 2022. CWAF EERE 2015 also listed a representative input capacity of 250 kBtu/h.
3. DOE's efficiency metric for commercial furnaces accounts only for flue losses, not jacket losses.

Note:
The previous standard went into effect in January 1994. The current standard went into effect in January 2023.

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- Until 2022, the Federal standard required minimum 80% thermal efficiency. This metric, more commonly called "combustion efficiency" in other contexts, accounts only for flue losses, not jacket losses.
  - The Federal standard applied to all units manufactured on or after January 1, 1994, with maximum rated heat input ≥ 225,000 Btu per hour.
  - On January 1, 2023, the minimum Federal standard increased to 81% thermal efficiency.
- ASHRAE Standard 90.1, which is used as a commercial building code in many states, stipulates that furnaces that are not within the conditioned space shall not have jacket losses exceeding 0.75% of the input rating.
- Commercial furnaces are typically non-condensing with thermal efficiencies ranging from 80% to 81%. Condensing commercial furnaces, which can achieve up to 95% thermal efficiency, were previously introduced to the market but are not currently available due to cost and reliability concerns. The highest thermal efficiency included in DOE's CCD at this time is 81%.
- Besides capacity, commercial units can differ from residential furnaces in terms of the control system (i.e., integration with a Building Management System, twinning, or other staging strategies). Commercial systems may also use a heat recovery system to pre-heat inlet air.

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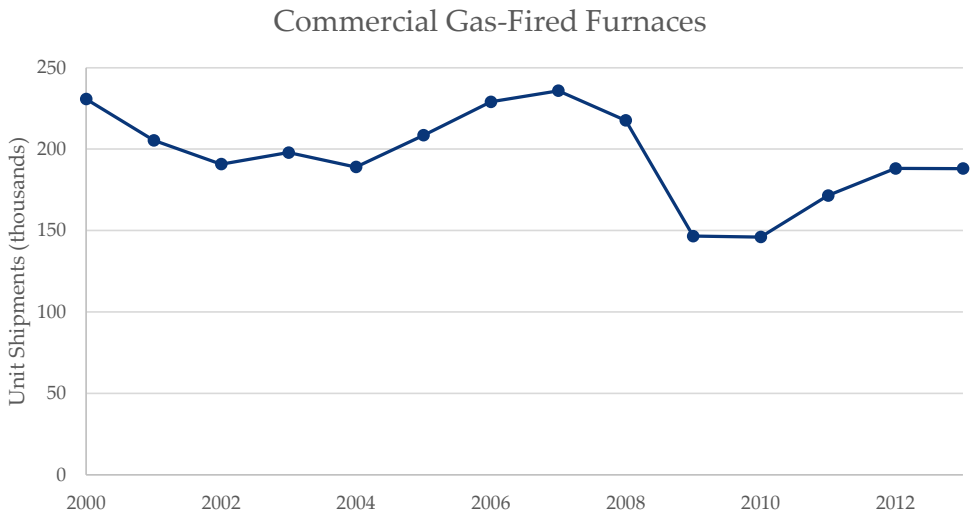
Annual shipments reached a peak of 235.9 thousand units in 2007. Following a decline in shipments after 2007, shipments increased to 188.1 thousand units in 2013. Shipment data after 2013 is not available.



Source: *AHRI*

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Commercial Oil-Fired Furnaces

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DATA	2012	2018	2022			2023[1]	2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	New Standard	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	400	400	250	250	250	250	250	250	250	250	250	250
Thermal Efficiency (%)[2]	81	82	81	82	85	82	82	85	82	85	82	85
Typical Output Capacity (kBtu/h)	324	328	203	205	213	205	205	213	205	213	205	213
Average Life (y)	23	23	23	23	23	23	23	23	23	23	23	23
Retail Equipment Cost (2022$)	5,500	5,560	5,500	5,560	6,020	5,560	5,560	6,020	5,560	6,020	5,560	6,020
Total Installed Cost (2022$)	7,740	7,810	7,740	7,810	8,380	7,810	7,810	8,380	7,810	8,380	7,810	8,380
Total Installed Cost (2022$/kBtu/h)	24	24	38	38	39	38	38	39	38	39	38	39
Annual Maintenance Cost (2022$)	360	360	360	360	370	360	360	370	360	370	360	370
Annual Maintenance Cost (2022$/kBtu/h)	1	1	2	2	2	2	2	2	2	2	2	2

1. In 2023, the new Energy Conservation Standards for CWAF took effect. These projections reflect the 2023 minimum thermal efficiency requirement for oil-fired furnaces, 82%.
2. DOE's efficiency metric for commercial furnaces accounts only for flue losses, not jacket losses.

Note:
The previous standard went into effect in January 1994. The current standard went into effect in January 2023.

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- Until 2022, the Federal standard required minimum 81% thermal efficiency. This metric, more commonly called "combustion efficiency" in other contexts, accounts only for flue losses, not jacket losses.
  - The Federal standard applied to all units manufactured on or after January 1, 1994, with maximum rated heat input ≥ 225,000 Btu per hour.
  - On January 1, 2023, the minimum Federal standard increased to 82% thermal efficiency.
- ASHRAE Standard 90.1, which is used as a commercial building code in many states, stipulates that furnaces that are not within the conditioned space shall not have jacket losses exceeding 0.75% of the input rating.
- Commercial oil-fired furnaces have thermal efficiencies ranging from 81% to 85% and are non-condensing (i.e., not designed for condensation of flue gases).
- Besides capacity, commercial units can differ in terms of the control system (i.e., integration with a Building Management System, twinning, or other staging strategies). Commercial systems may also use a heat recovery system to pre-heat inlet air.
- The maintenance cost estimate assumes two cleanings per year.

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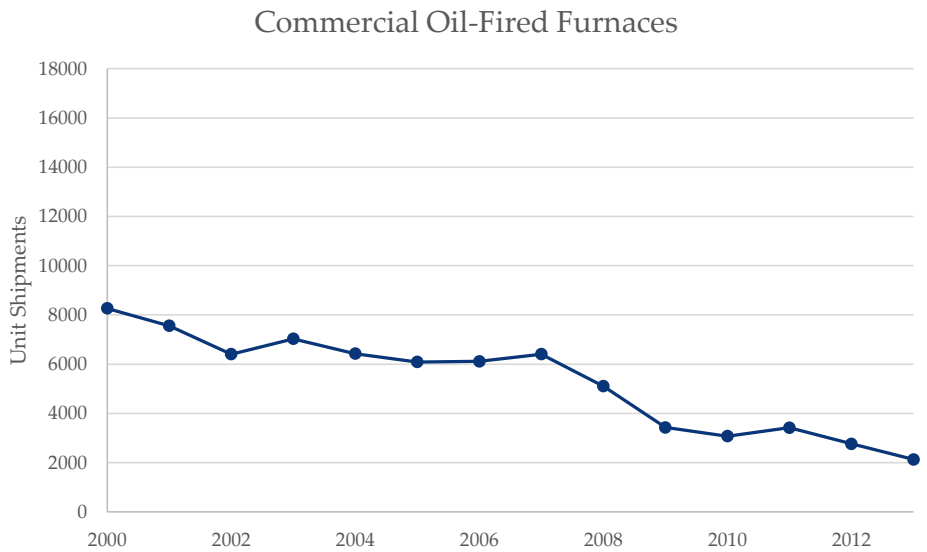
Annual shipments for commercial oil-fired furnaces have steadily decreased over time to 2,127 units in 2013. Shipment data after 2013 is not available.



Source: *AHRI*

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Commercial Electric Resistance Heaters

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DATA	2012		2018		2022		2030		2040		2050	
	Installed Base: Small	Installed Base: Large	Installed Base: Small	Installed Base: Large	Small	Large	Small	Large	Small	Large	Small	Large
Typical Capacity (kBtu/h)[1]	17	170	17	170	17	170	17	170	17	170	17	170
Efficiency (%)	100	100	100	100	100	100	100	100	100	100	100	100
Average Life (y)	18	18	18	18	18	18	18	18	18	18	18	18
Retail Equipment Cost (2022$)	1,000	6,320	1,000	6,320	500	4,630	500	4,630	500	4,630	500	4,630
Total Installed Cost (2022$)	1,240	7,470	1,240	7,470	660	5,470	660	5,470	660	5,470	660	5,470
Total Installed Cost (2022$/kBtu/h)	73	44	73	44	39	32	39	32	39	32	39	32
Annual Maintenance Cost (2022$)[2]	-	-	-	-	-	-	-	-	-	-	-	-
Annual Maintenance Cost (2022$/kBtu/h)	-	-	-	-	-	-	-	-	-	-	-	-

1. Capacity is output.
2. Annual Maintenance Cost is negligible.

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Commercial Electric Resistance Heaters

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- This analysis examined standard suspended electric wall and ceiling unit heaters, which are more common in commercial settings than baseboard electric heaters that were considered for the residential analysis.
- Electric unit heaters range in capacity from 2 to 80 kW (7 to 270 kBtu/h), with 5 to 50 kW (17 to 170 kBtu/h) being the most typical units on the market.
- Electric resistance heaters are considered near 100% efficient because there is no heat loss through ducts or combustion.
- Installation time and costs are estimated to be minimal.

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Commercial Electric Boilers

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DATA	2012	2018	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical	Typical	Typical
Typical Capacity (kW)[1]	165	165	165	165	165	165
Efficiency (%)	98	98	98	98	98	98
Average Life (y)	15	15	15	15	15	15
Retail Equipment Cost (2022$)[2]	11,620	11,590	9,790	9,790	9,790	9,790
Total Installed Cost (2022$)[2]	17,500	13,820	11,950	11,950	11,950	11,950
Total Installed Cost (2022$/kBtu/h)	31	25	21	21	21	21
Annual Maintenance Cost (2022$)[2]	170	130	130	130	130	130
Annual Maintenance Cost (2022$/kBtu/h)	-	-	-	-	-	-

1. Capacity is output.
2. Retail and installed costs for 2022 and forecasts for 2030 and beyond are based on Gordian's RSMeans Data – Building Construction Costs 2023. Maintenance costs are same as EIA Technology Forecast Updates (2018), updated to reflect 2022$. The costs shown are for one 165kW unit, which would equate to a steady load of approximately 550,000 Btu/h. Annual maintenance in a typical application would include draining the unit for removal of any accumulated scale or sludge buildup.

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Commercial Electric Boilers

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- There are currently no federal standards associated with electric boilers.
- The costs shown are for one 165kW unit, which would equate to a steady load of approximately 550,000 Btu/h.
- Service life is determined mainly by water quality. Water conditioning (e.g., filters, softeners, de-alkalizers, chemical feeders) may be necessary for a given application.
- Annual maintenance in a typical application would include draining the unit for removal of any accumulated scale or sludge buildup.
- Minor end-use inefficiencies for electric boilers result from heat loss through the boiler (jacket losses).

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Commercial Gas-Fired Boilers

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DATA	2012	2018	2022			2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard[1]	Typical	High	New Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	800	800	800	800	800	800	800	800	800	800	800	800	800	800
Thermal Efficiency (%)[2]	77	85	80	85	99	84	85	99	85	99	85	99	85	99
Average Life (y)	30	25	25	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)	15,530	25,910	19,150	25,910	42,670	24,320	25,910	42,670	25,910	42,670	25,910	42,670	25,910	42,670
Total Installed Cost (2022$)	24,600	38,330	30,470	38,330	55,230	35,650	38,330	55,230	38,330	55,230	38,330	55,230	38,330	55,230
Total Installed Cost (2022$/kBtu/h)	40	56	48	56	70	53	56	70	56	70	56	70	56	70
Annual Maintenance Cost (2022$)[3]	1,710	2,100	2,100	2,100	2,140	2,100	2,100	2,140	2,100	2,140	2,100	2,140	2,100	2,140
Annual Maintenance Cost (2022$/kBtu/h)	3	3	3	3	3	3	3	3	3	3	3	3	3	3

1. The standard level shown here is for small (300 kBtu/h to 2500 kBtu/h) gas-fired hot water commercial packaged boilers, which are the most common type of boilers available on the market.
2. DOE's efficiency metric for most boiler types accounts for both flue and jacket losses; previously it did not. DOE continues to uses a combustion efficiency metric instead, for hot water boilers with heat input > 2,500,000 Btu/h.
3. Maintenance costs for 2018 and post-2018 are based on Commercial Packaged Boilers EERE 2020. The annualized maintenance costs estimated in the final rule differ for condensing vs. non-condensing boilers. Appendix 8E of the Commercial Packaged Boilers EERE 2020 TSD provides additional information on how the values are calculated.

Note:
The previous standard went into effect in March 2012.
The current standard went into effect in January 2023.
In December 2016, DOE issued a final rule titled Energy Conservation Program: Energy Conservation Standards for Commercial Packaged Boilers. This rule published in January 2020 with an effective date for January 2023.

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Commercial Gas-Fired Boilers

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- Commercial packaged gas-fired boilers are classified by:
  - Heat input capacity
  - Produce steam or hot water
  - Draft type (natural draft or not) – for steam boilers
- The most common type of commercial gas-fired boilers are small gas-fired hot water boilers with 300,000-2,500,000 Btu/h rated heat input.
- Similar technologies to those used in the residential gas-fired boilers market can be leveraged in the commercial arena. The higher efficiency units typically include electronic ignition, power burners, and improved heat exchangers. Some gas-fired boilers also condense water vapor from the flue gases to improve heating efficiency.
- DOE published a final rule for commercial packaged boilers in January 2020 that updated the efficiency ratings of gas-fired commercial packaged boilers beginning January 2023.

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Commercial Gas-Fired Boilers

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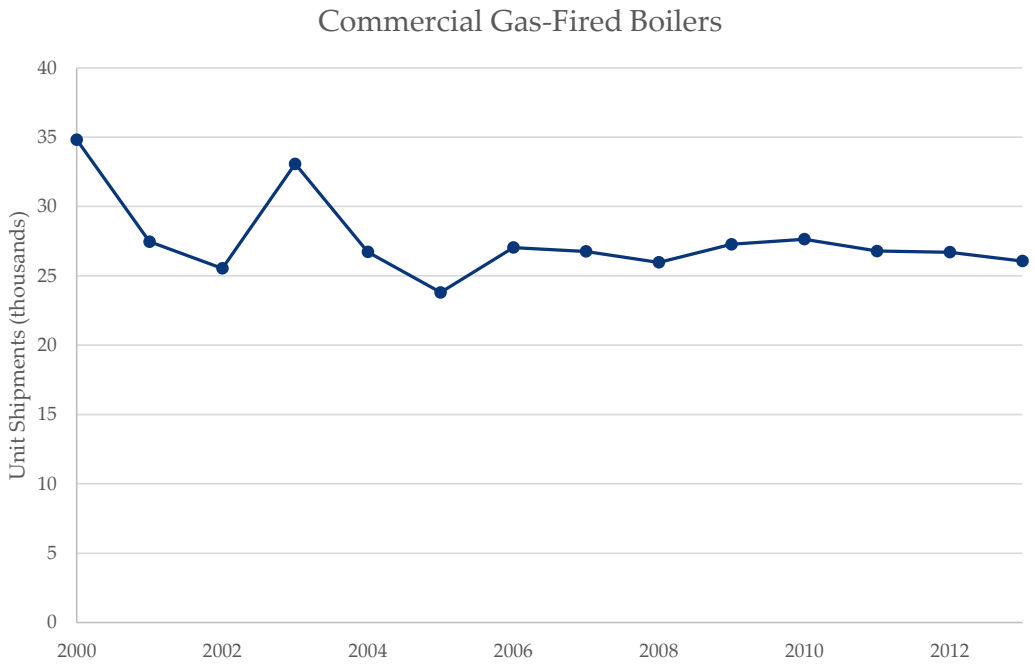
Shipments of commercial gas-fired boilers peaked in 2000 and have been steadily declining since 2010. Shipment data after 2013 is not available.



Source: *Commercial Packaged Boilers EERE 2020*

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Commercial Oil-Fired Boilers

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DATA	2012	2018	2022			2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard[1]	Typical	High	New Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	1,200	800	800	800	800	800	800	800	800	800	800	800	800	800
Thermal Efficiency (%)[2]	81	85	82	85	97	87	87	97	87	97	87	97	87	97
Average Life (y)	30	25	25	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)	16,830	26,810	23,190	26,810	51,480	29,730	29,730	51,480	29,730	51,480	29,730	51,480	29,730	51,480
Total Installed Cost (2022$)	22,000	37,240	33,100	37,240	62,910	40,160	40,160	62,910	40,160	62,910	40,160	62,910	40,160	62,910
Total Installed Cost (2022$/kBtu/h)	23	55	50	55	81	58	58	81	58	81	58	81	58	81
Annual Maintenance Cost (2022$)[3]	1,710	2,690	2,690	2,690	2,690	2,690	2,690	2,690	2,690	2,690	2,690	2,690	2,690	2,690
Annual Maintenance Cost (2022$/kBtu/h)	2	4	4	4	3	4	4	3	4	3	4	3	4	3

1. The standard level shown here is for small (300 kBtu/h to 2500 kBtu/h) oil-fired hot water commercial packaged boilers, which are the most common type of boilers available on the market.
2. DOE's efficiency metric for most boiler types accounts for both flue and jacket losses; previously it did not. DOE continues to uses a combustion efficiency metric instead, for hot water boilers with heat input > 2,500,000 Btu/h.
3. Maintenance costs for 2018 and post-2018 are based on Commercial Packaged Boilers EERE 2020. The annualized maintenance costs estimated in the final rule differ for condensing vs. non-condensing boilers. Appendix 8E of the Commercial Packaged Boilers EERE 2020 TSD provides additional information on how the values are calculated.

Note:
The previous standard went into effect in March 2012.
The current standard went into effect in January 2023.
In December 2016, DOE issued a final rule titled Energy Conservation Program: Energy Conservation Standards for Commercial Packaged Boilers. This rule published in January 2020 with an effective date for January 2023.

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Commercial Oil-Fired Boilers

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- Commercial packaged oil-fired boilers are classified by:
  - Heat input capacity
  - Produce steam or hot water
- The most common type of commercial oil-fired boilers are small hot water boilers with 300,000-2,500,000 Btu/h rated heat input.
- The higher efficiency units typically include improved heat exchangers, and multi-step or variable-output power burners.
- DOE published a final rule for commercial packaged boilers in January 2020 that updated the efficiency ratings of oil-fired commercial packaged boilers beginning January 2023.

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Commercial Oil-Fired Boilers

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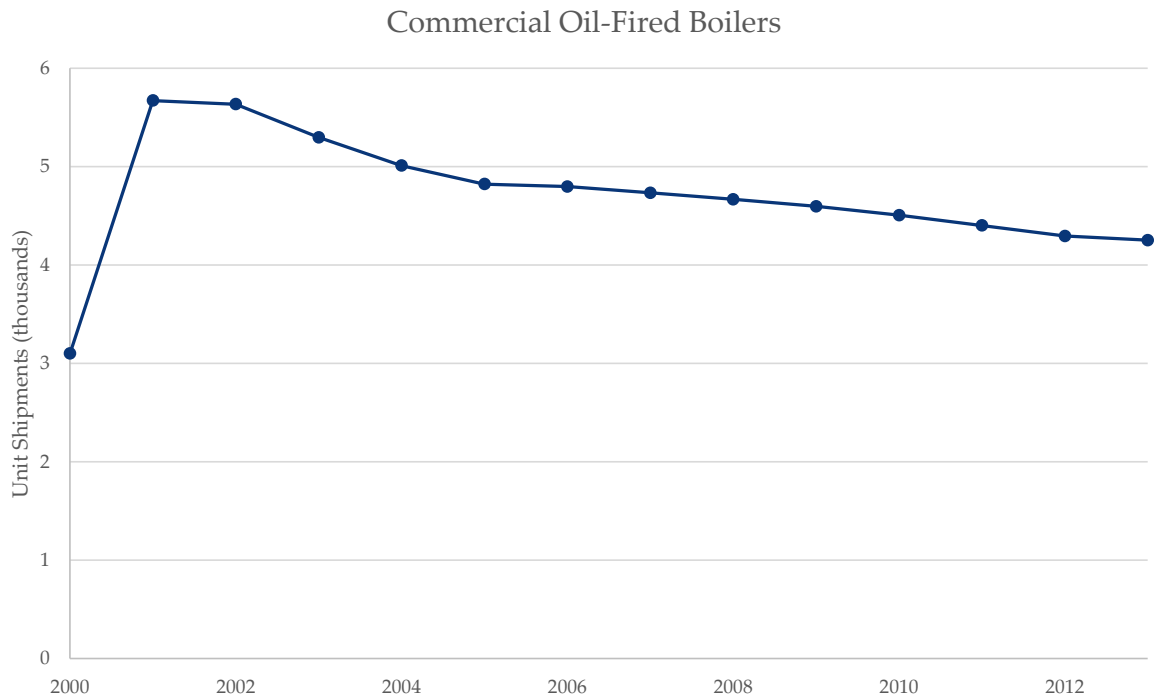
Shipments of commercial oil-fired boilers peaked in 2001 and have been decreasing since then.



Source: *Commercial Packaged Boilers EERE 2020*

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Commercial Centrifugal Chillers (Water-Cooled)

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DATA	2012	2018	2022[2]			2030		2040		2050	
	Installed Base	Installed Base	ASHRAE 90.1-2019	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (tons)[1]	400	400	400	400	400	400	400	400	400	400	400
	600	600	600	600	600	600	600	600	600	600	600
Efficiency [full-load] (kW/ton)	0.66	0.53	0.56	0.52	0.45	0.49	0.42	0.46	0.41	0.45	0.40
Efficiency [IPLV] (kW/ton)	0.61	0.37	0.50	0.31	0.30	0.30	0.28	0.29	0.26	0.28	0.25
COP [full-load]	5.4	6.6	6.3	6.8	7.8	7.2	8.4	7.6	8.6	7.8	8.8
COP [IPLV]	5.9	9.5	7.0	11.3	11.7	11.7	12.6	12.1	13.5	12.6	14.1
Average Life (y)	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$/ton)	380	500	480	500	680	590	760	660	780	690	810
Total Installed Cost (2022$/ton)	440	560	480	560	740	640	820	720	840	740	870
	500	590	540	590	760	670	830	740	860	760	880
Total Installed Cost (2022$/kBtu/h)	39	48	43	48	63	55	69	61	71	63	73
Annual Maintenance Cost (2022$/ton)	30	30	30	30	30	30	30	30	30	30	30
	40	40	40	40	40	40	40	40	40	40	40
Annual Maitnenance Cost (2022$/kBtu/h)	3	3	3	3	3	3	3	3	3	3	3

1. Capacity is output.
2. ASHRAE 90.1 data are for units larger than 400 tons and for full-load optimized applications (Path A in ASHRAE 90.1-2019). Typical and high efficiency levels are determined based on the range of products currently available on the market.

Note:

For most chillers (including those in single-chiller applications and for peaking units in multi-chiller applications), the seasonal performance (represented by the integrated part-load value (IPLV)) is more indicative of annual expected performance than the full-load performance; performance of baseload chillers in multi-chiller applications, which typically operate at full-load, are well represented by the full-load efficiency value.

ASHRAE 90.1 went into effect in October 2019.

Ranges represent the span of typical values for a given parameter.

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Commercial Centrifugal Chillers (Water-Cooled)

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- ASHRAE 90.1-2019 stipulates minimum efficiencies for centrifugal chillers separately from positive displacement water-cooled chillers. They are separated into 5 size categories, with categories divided at: 150, 300, 400, and 600 tons; ASHRAE 90.1-2019 also distinguishes between whether the unit will be optimized for full-load (Path A) or part-load operation (Path B). Data here are for Path A; a Path B chiller may have slightly high full-load consumption in exchange for much lower part-load consumption. For example, for a 600-ton unit:
  - Path A: ≥ 0.56 kW/ton full-load and ≥ 0.50 kW/ton IPLV
  - Path B: ≥ 0.585 kW/ton full-load and ≥ 38 kW/ton IPLV
- Federal Energy Management Program (FEMP) recommendations, last updated in 2020, match ASHRAE 90.1-2019.
- The highest efficiency centrifugal chillers incorporate some of the following:
  - Variable speed drive (VSD) compressors
  - Dedicated heat recovery (heat pump chiller)
  - Magnetic bearing technology (oil-free operation)
  - Greater heat exchanger surface areas; enhanced tube configurations (counterflow)
  - Optimized fluid flow velocities
  - High efficiency electric motors
  - Improved turbomachinery design, resulting in higher compressor efficiency
  - Better piping and valving, including electronic expansion valves
  - Evaporative condenser for the heat rejection equipment
- Installed costs vary widely depending on equipment needed for installation (e.g., crane) and size of system. This is a mature market with centrifugal chillers representing 75% of commercial chiller sales larger than 200 tons.
- Water-cooled chiller ratings do not include energy consumption of the cooling tower and therefore are not directly comparable to rating for air-cooled chillers. Water-cooled centrifugal chillers were selected for analysis due to a higher model share on the AHRI directory in comparison to air-cooled chillers.

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Commercial Reciprocating Chillers (Air-Cooled Only)

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DATA	2012	2018	2022[2]			2030		2040		2050	
	Installed Base	Installed Base	ASHRAE 90.1-2019[3]	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (tons)[1]	100	100	100	100	100	100	100	100	100	100	100
	200	200	200	200	200	200	200	200	200	200	200
Efficiency [full-load] (kW/ton)	1.26	1.19	1.19	1.15	1.00	1.15	1.00	1.15	1.00	1.15	1.00
Efficiency [IPLV] (kW/ton)	1.13	0.86	0.86	0.86	0.80	0.80	0.79	0.80	0.79	0.80	0.79
COP [full-load]	2.8	3.0	3.0	3.0	3.5	3.1	3.5	3.1	3.5	3.1	3.5
COP [IPLV]	3.1	4.1	4.1	4.1	4.5	4.4	4.5	4.4	4.5	4.4	4.5
Average Life (y)	20	20	20	20	20	20	20	20	20	20	20
Retail Equipment Cost (2022$/ton)	725	820	820	820	1,030	820	1,030	820	1,030	820	1,030
	600	730	730	730	880	730	880	730	880	730	880
Total Installed Cost (2022$/ton)	800	880	880	880	1,180	880	1,180	880	1,180	880	1,180
	700	760	760	760	1,090	760	1,090	760	1,090	760	1,090
Total Installed Cost (2022$/kBtu/h)	63	68	68	68	95	68	95	68	95	68	95
Annual Maintenance Cost (2022$/ton)	45	45	50	50	50	45	50	45	50	45	50
	25	25	30	30	30	25	30	25	30	25	30
Annual Maintenance Cost (2022$/kBtu/h)	3	3	3	3	3	3	3	3	3	3	3

1. Capacity is output.
2. ASHRAE 90.1 data are for units larger than 150 tons and for full-load optimized applications (Path A in ASHRAE 90.1-2019). Typical and high efficiency levels are determined based on the range of products currently available on the market.

Note:

This analysis covers air-cooled chillers only.

For most chillers (including those in single-chiller applications and for peaking units in multi-chiller applications), the seasonal performance (represented by the IPLV) is more indicative of annual expected performance than the full-load performance; performance of baseload chillers in multi-chiller applications, which typically operate at full-load, are well represented by the full-load efficiency value.

ASHRAE 90.1 went into effect in October 2019.

Ranges represent the span of typical values for a given parameter.

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Commercial Reciprocating Chillers (Air-Cooled Only)

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- Reciprocating chillers are most cost effective for small loads (30 to 150-ton range). However, reciprocating chiller market share continues to be supplanted by screw and scroll chillers. This trend has accelerated with the phase out of R-22, which was the refrigerant of choice for reciprocating products, which has in turn driven major manufacturers to replace their reciprocating product lines with scroll products (rather than redesign reciprocating products for new refrigerants). As a result, product options are very limited.
- Reciprocating chillers can be used in either air-cooled or water-cooled applications. Reciprocating chillers shown in the data are air-cooled. Air-cooled chillers are less efficient than the water-cooled models. Listed efficiencies include matched condensers and their associated energy use.
- ASHRAE 90.1-2019 stipulates minimum efficiencies for all air-cooled chillers together, including reciprocating chillers, while water-cooled chillers are separated by positive displacement (e.g., reciprocating) versus centrifugal models. Air-cooled chiller efficiencies are further split by size for more and less than 150 tons. ASHRAE 90.1-2019 also distinguishes between whether the unit will be optimized for full-load (Path A) or part-load operation (Path B). Data here are for Path A; a Path B chiller may have slightly lower full-load efficiency in exchange for much higher part-load efficiency. For example, for a 100-ton unit:
  - Path A: ≥ 10.1 EER full-load and ≥ 13.7 IPLV EER
  - Path B: ≥ 9.7 EER full-load and ≥ 15.8 IPLV EER
- FEMP (2022) recommendations for air-cooled chillers are:
  - Path A (<150 tons): ≥ 10.89 EER full-load and ≥ 13.7 IPLV EER
  - Path B (<150 tons): ≥ 9.7 EER full-load and ≥ 16.86 IPLV EER (same as 90.1-2019)
- The highest efficiency reciprocating chillers incorporate some of the following:
  - Multiple compressors for staged capacity control
  - Improved heat-exchangers

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Commercial Screw Chillers (Air-Cooled Only)

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DATA	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	ASHRAE 90.1-2019[1]	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (tons)	100	100	100	100	100	100	100	100	100	100	100
	300	300	300	300	300	300	300	300	300	300	300
Efficiency [full-load] (kW/ton)	1.26	1.18	1.19	1.15	0.92	1.13	0.91	1.04	0.86	0.98	0.81
Efficiency [IPLV] (kW/ton)	1.13	0.84	0.86	0.81	0.55	0.79	0.53	0.72	0.49	0.68	0.45
COP [full-load]	2.8	3.0	3.0	3.1	3.8	3.1	3.9	3.4	4.1	3.6	4.3
COP [IPLV]	3.1	4.2	4.1	4.4	6.4	4.5	6.6	4.9	7.2	5.2	7.8
Average Life (y)	20	20	20	20	20	20	20	20	20	20	20
Retail Equipment Cost (2022$/ton)	760	970	1,130	1,130	1,230	1,140	1,230	1,180	1,250	1,200	1,270
	620	850	770	770	870	780	870	820	890	840	910
Total Installed Cost (2022$/ton)	910	1,150	1,250	1,250	1,350	1,260	1,350	1,300	1,370	1,320	1,390
	850	940	820	820	920	830	920	870	940	890	960
Total Installed Cost (2022$/kBtu/h)	73	87	86	86	95	87	95	90	96	92	98
Annual Maintenance Cost (2022$/ton)	50	50	50	50	50	50	50	50	50	50	50
	20	20	20	20	20	20	20	20	20	20	20
Annual Maintenance Cost (2022$/kBtu/h)	3	3	3	3	3	3	3	3	3	3	3

1. ASHRAE 90.1 data for units larger than 150 tons and for full-load optimized applications (Path A in ASHRAE 90.1-2019).

Note:
For most chillers (including those in single-chiller applications and for peaking units in multi-chiller applications), the seasonal performance (represented by the IPLV) is more indicative of annual expected performance than the full-load performance; performance of baseload chillers in multi-chiller applications, which typically operate at full-load, are well represented by the full-load efficiency value.
ASHRAE 90.1 went into effect in October 2019.
Ranges represent the span of typical values for a given parameter.

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Commercial Screw Chillers (Air-Cooled Only)

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- Screw chillers are common in 150 to 500-ton capacities but are most cost effective for small (<300 tons) loads; screw chillers dominate the current market for small to mid-size chillers.
- Screw chillers can be used in either air-cooled or water-cooled applications. Screw chillers shown in the data are air-cooled. Air-cooled chillers are less efficient than the water-cooled models. Listed efficiencies include matched condensers and their associated energy use.
- ASHRAE 90.1-2019 stipulates minimum efficiencies for all air-cooled chillers together, including screw chillers, while water-cooled chillers are separated by positive displacement (e.g., screw) versus centrifugal models. Air-cooled chiller efficiencies are further split by size for more and less than 150 tons. ASHRAE 90.1-2019 also distinguishes between whether the unit will be optimized for full-load (Path A) or part-load operation (Path B). Data here are for Path A; a Path B chiller may have slightly lower full-load efficiency in exchange for much higher part-load efficiency. For example, for a ≥ 150-ton unit:
  - Path A: ≥ 10.1 EER full-load and ≥ 14.0 IPLV EER
  - Path B: ≥ 9.7 EER full-load and ≥ 16.1 IPLV EER
- FEMP recommendations for air-cooled chillers (updated June 2020) are:
  - Path A (≥ 150 tons): ≥ 10.7 EER full-load and ≥ 14.0 IPLV EER
  - Path B (≥ 150 tons): ≥ 9.7 EER full-load and ≥ 16.4 IPLV EER
- The highest efficiency screw chillers incorporate some of the following:
  - Variable speed compressors and/or multiple compressors
  - Economizers
  - Improved heat-exchangers

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Commercial Scroll Chillers (Air-Cooled Only)

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DATA	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	ASHRAE 90.1-2019[1]	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (tons)	50	50	50	50	50	50	50	50	50	50	50
	140	140	140	140	140	140	140	140	140	140	140
Efficiency [full-load] (kW/ton)	1.23	1.16	1.19	1.15	1.07	1.11	1.06	1.07	1.02	1.02	0.97
Efficiency [IPLV] (kW/ton)	0.99	0.77	0.88	0.77	0.70	0.73	0.68	0.71	0.65	0.69	0.62
COP [full-load]	2.9	3.0	3.0	3.1	3.3	3.2	3.3	3.3	3.4	3.4	3.6
COP [IPLV]	3.7	4.6	4.0	4.6	5.0	4.8	5.2	5.0	5.4	5.1	5.7
Average Life (y)	20	20	20	20	20	20	20	20	20	20	20
Retail Equipment Cost (2022$/ton)	680	1,000	1,060	1,060	1,160	1,120	1,160	1,150	1,200	1,200	1,240
	560	820	530	530	630	590	630	620	670	670	710
Total Installed Cost (2022$/ton)	970	1,210	1,170	1,170	1,270	1,230	1,270	1,260	1,310	1,310	1,350
	850	970	860	860	960	920	960	950	1,000	1,000	1,040
Total Installed Cost (2022$/kBtu/h)	76	91	85	85	93	90	93	92	96	96	100
Annual Maintenance Cost (2022$/ton)	60	60	60	60	60	60	60	60	60	60	60
	40	40	40	40	40	40	40	40	40	40	40
Annual Maintenance Cost (2022$/kBtu/h)	4	4	4	4	4	4	4	4	4	4	4

1. ASHRAE 90.1 data for units less than 150 tons and for full-load optimized applications (Path A in ASHRAE 90.1-2019).

Note:
For most chillers (including those in single-chiller applications and for peaking units in multi-chiller applications), the seasonal performance (represented by the IPLV) is more indicative of annual expected performance than the full-load performance; performance of baseload chillers in multi-chiller applications, which typically operate at full-load, are well represented by the full-load efficiency value.
ASHRAE 90.1 went into effect in October 2019.
Ranges represent the span of typical values for a given parameter.

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Commercial Scroll Chillers (Air-Cooled Only)

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- Scroll chillers range in size from ~20 tons to ~200 tons and can be used in either air-cooled or water-cooled applications. They are the most common type of chiller for small chiller plants. The scroll chillers shown in the data are air-cooled, which is most common. Air-cooled chillers are less efficient than the water-cooled models. Listed efficiencies include matched condensers and their associated energy use.
- ASHRAE 90.1-2019 stipulates minimum efficiencies for all air-cooled chillers together, including scroll chillers, while water-cooled chillers are separated by positive displacement (e.g., scroll) versus centrifugal models. Air-cooled chiller efficiencies are distinct for more and less than 150 tons. ASHRAE 90.1-2019 also distinguishes between whether the unit will be optimized for full-load (Path A) or part-load operation (Path B). Data here are for Path A; a Path B chiller may have slightly lower full-load efficiency in exchange for much higher part-load efficiency. For example, for a 100-ton unit:
  - Path A: ≥ 10.1 EER full-load and ≥ 13.7 IPLV EER
  - Path B: ≥ 9.7 EER full-load and ≥ 15.8 IPLV EER
- FEMP recommendations for air-cooled chillers (updated June 2020) are:
  - Path A (< 150 tons): ≥ 10.7 EER full-load and ≥ 13.7 IPLV EER
  - Path B (< 150 tons): ≥ 9.7 EER full-load and ≥ 15.9 IPLV EER
- The highest efficiency scroll chillers incorporate some of the following:
  - Multiple compressors for staged capacity control
  - Improved heat-exchangers
  - Variable speed compressor (or other modulation controls)
- With the phase out of R-22, manufacturers have replaced many of their small reciprocating chiller products with equivalent scroll products, making them a primary choice for small tonnage applications.

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Commercial Gas-Fired Chillers (Water-Cooled, Direct-Fired Only)

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DATA	2012		2018		2022				2030		2040		2050	
	Installed Base: Absorption	Installed Base: Engine-Driven	Installed Base: Absorption	Installed Base: Engine-Driven	ASHRAE 90.1-2019 Absorption	CA Title 24 – Engine-Driven	Absorption	Engine-Driven	Absorption	Engine-Driven	Absorption	Engine-Driven	Absorption	Engine-Driven
Typical Capacity (tons)[1]	150	150	150	150	150	150	150	150	150	150	150	150	150	150
	1,500	400	1,500	400	1,500	400	1,500	400	1,500	400	1,500	400	1,500	400
COP [full-load]	1.1	1.7	1.2	1.7	1.0	1.2	1.2	1.7	1.3	1.8	1.4	1.8	1.4	1.8
COP [IPLV]	NA	NA	1.6	2.6	1.0	2.0	1.6	2.6	1.6	2.6	1.6	2.6	1.6	2.6
Average Life (y)	23	25	23	25	23	25	23	25	23	25	23	25	23	25
Retail Equipment Cost (2022$/ton)	1,060	1,000	1,060	1,000	1,200	1,000	1,200	1,000	1,200	1,000	1,200	1,000	1,200	1,000
	880	880	880	880	870	880	870	880	870	880	870	880	870	880
Total Installed Cost (2022$/ton)	1,290	1,240	1,180	1,240	1,110	1,240	1,110	1,240	1,110	1,240	1,110	1,240	1,110	1,240
	1,000	1,000	1,000	1,000	850	1,000	850	1,000	850	1,000	850	1,000	850	1,000
Total Installed Cost (2022$/kBtu/h)	95	93	91	93	82	93	82	93	82	93	82	93	82	93
Annual Maintenance Cost (2022$/ton)	40	60	40	60	40	60	40	60	40	60	40	60	40	60
	20	40	20	40	20	40	20	40	20	40	20	40	20	40
Annual Maintenance Cost (2022$/kBtu/h)	3	4	3	4	3	4	3	4	3	4	3	4	3	4

1. Capacity is output.

Note:
This analysis assumes a water-cooled chiller; both gas-fired chiller types (absorption and engine-driven) are shown. COP values for double-effect absorption chillers are shown.
For most chillers (including those in single-chiller applications and for peaking units in multi-chiller applications), the seasonal performance (represented by the IPLV) is more indicative of annual expected performance than the full-load performance; performance of baseload chillers in multi-chiller applications, which typically operate at full-load, are well represented by the full-load efficiency value.
ASHRAE 90.1 went into effect in October 2019.
CA Title 24 went into effect in January 2020.
Ranges represent the span of typical values for a given parameter.

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Commercial Gas-Fired Chillers (Water-Cooled, Direct-Fired Only)

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- Gas-fired chillers are available as either air-cooled (~25-50 tons) or water-cooled (150+ tons). This analysis covers only water-cooled chillers of two varieties: absorption and engine-driven vapor compression (direct-fired only; indirect steam or hot water driven units are excluded).
- Direct gas firing provides high enough temperatures to operate double effect absorption chillers, which operate at a 50-60% higher COP than single effect systems. Triple effect chillers, though not commercially available, can boost cooling COP 30-50% beyond double effect chillers. Some companies have worked on prototype direct-fired triple effect absorption chillers, but prohibitively high cost of advanced high heat/corrosion-resistant materials required for triple effect absorption chillers suggests that this technology will not likely have an impact on the market in the near-term.
- Gas-fired engine-driven chillers pair conventional vapor compression systems (typically screw or centrifugal compressors) with natural gas powered-reciprocating engines. They exhibit higher peak cooling COP than absorbers, and engine modulation results in better part-load performance. Future efficiency improvements for engine-driven chillers are not anticipated. Engine-driven chillers allow the opportunity to recover waste heat for useful purposes.
- Maintenance costs for engine-driven chillers are higher than for other chillers because they include all the typical components of a vapor compression chiller in addition to an engine; the engine maintenance costs vary depending on the annual run hours of the unit.
- Limited sales data suggest that the U.S. market for gas-fired chillers is very limited and is mostly for replacement units, not for new installations. Recent increases in electric chiller efficiency have narrowed the operating cost differential with gas chillers. Asia has the majority of the global gas-fired chiller market.
- Gas-fired chiller installations are particularly valuable in locations where electric rates are high and gas prices are low (i.e., low spark spread), where digester or landfill gas sources are available, or where waste heat sources are available (e.g., an industrial process or microturbine CHP system) that could be used with a hybrid direct/indirect-fired absorption chiller to offset the use of natural gas.

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Commercial Rooftop Air Conditioners

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DATA	2012	2018	2022[4]				2023				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.1	High	New Standard	Typical	ENERGY STAR V. 4.0	High	Typical	High	Typical	High	Typical	High
Typical Output Capacity (kBtu/h)	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Part Load Efficiency (IEER)[1]	12.4	12.9	12.9	12.9	14.0	23.3	14.8	14.8	18.0	23.3	15.1	23.3	15.1	23.3	15.1	23.3
Efficiency (EER)[2]	10.6	11.5	11.5	11.5	12.2	12.8	12.2	12.2	12.7	12.8	12.2	12.8	12.2	12.8	12.2	12.8
Efficiency Conversion	3.6	3.8	3.8	3.8	4.1	6.8	4.3	4.3	5.3	6.8	4.4	6.8	4.4	6.8	4.4	6.8
Average Life (y)	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Retail Equipment Cost (2022$)	7,760	8,280	8,280	8,280	9,090	12,210	9,490	9,490	10,340	12,210	9,590	12,210	9,590	12,210	9,590	12,210
Total Installed Cost (2022$)	10,350	11,870	11,870	11,870	13,020	17,600	13,560	13,560	14,970	17,600	13,720	17,600	13,720	17,600	13,720	17,600
Total Installed Cost (2022$/kBtu/h)	115	132	132	132	145	196	151	151	166	196	152	196	152	196	152	196
Annual Maintenance Cost (2022$)[3]	370	370	370	370	370	370	370	370	370	370	370	370	370	370	370	370
Annual Maintenance Cost (2022$/kBtu/h)	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4

1. Values shown are for air-cooled small commercial packaged air conditioners with either electric resistance heating or no heating within the same enclosure. DOE published a direct final rule for commercial packaged air conditioners and heat pumps in January 2016 with initial standards becoming effective in 2018 and additional standards becoming effective in 2023. As part of this rulemaking, DOE changed the regulated metric from EER to integrated energy efficiency ratio (IEER).
2. DOE investigated the relationship between IEER and EER. Because the relationship between IEER and EER is weak, this analysis estimates EER values based on the average of the values seen at a given IEER.
3. Examples of annual maintenance services include, check tensions, condition, and alignment of belts and adjust as necessary; lubricate shaft and motor bearings; replace air filters; clean coils, drain pan and piping, blowers, fan motors as required; check refrigerant pressure and compressor oil level; etc.
4. The 2022 typical efficiency is based on the average IEER from DOE's CCD. The 2022 high efficiency is based on the most-efficient model in DOE's CCD, but costs are estimated based on the most efficient unit analyzed in CUAC EERE 2016, which had an IEER of 21.5.

Note:
EER is the ratio of the cooling capacity (in Btu/h) to the power input (in watts) and provides a measure of the efficiency of equipment operating at full load (i.e., 100 percent cooling capacity) in high-ambient-temperature conditions (i.e., 95 °F). IEER is a single number part-load efficiency based on weighting of EER at various load capacities. Efficiency Conversion is the conversion of IEER from a [(Btu/h)/W] metric to a metric in the same units.
The previous standard went into effect in January 2018. The current standard went into effect in January 2023.
ENERGY STAR V. 3.1 went into effect in January 2018. ENERGY STAR V. 4.0 went into effect in January 2023.

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Commercial Rooftop Air Conditioners

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- Air-Cooled Commercial Packaged Air Conditioners

Cooling Capacity (kBtu/h)	Heating Type	Federal Standard Effective 1/1/2018 Min. IEER	Federal Standard Effective 1/1/2023 Min. IEER
Small (≥ 65 and < 135)	Electric resistance or none	12.9	14.8
	Any other type	12.7	14.6
Large (≥ 135 and < 240)	Electric resistance or none	12.4	14.2
	Any other type	12.2	14.0

- This analysis focused on small air-cooled commercial packaged rooftop air conditioners (90 kBtu/h or 7.5 tons), though there are also standards for many other types of commercial air conditioners.
- Amended standards in terms of IEER for all equipment classes took effect in January 2018. More stringent standards in terms of IEER for all equipment classes took effect in January 2023.

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Commercial Gas-Fired Engine-Drive Rooftop Air Conditioners

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DATA	2012[1]	2018	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical	Typical	Typical
Typical Capacity (tons)	18	11	11	11	11	11
Heating COP	1.4	1.4	1.4	1.4	1.4	1.4
Cooling COP	0.9	1.2	1.2	1.2	1.2	1.2
Average Life (y)	15	15	15	15	15	15
Retail Equipment Cost ($/ton)	3,350	2,820	3,710	3,710	3,710	3,710
Total Installed Cost ($/ton)	3,820	3,290	4,110	4,110	4,110	4,110
Total Installed Cost ($/kBtu/h)	318	274	343	343	343	343
Annual Maintenance Cost (2022$)	70	70	70	70	70	70
Annual Maintenance Cost (2022$/kBtu/h)	6	6	6	6	6	6

1. The 2012 typical capacity and cooling COP were estimated as a simple average between obsolete pre-2003 units and 2013 units, which first became available in 2010; this assumes that each vintage represents about half of the installed base.

Note:
Only one product was available in 2012; the market has grown slightly in years since. Typical capacity and COP for 2018 and later are averages of units available as of 2017.

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Commercial Gas-Fired Engine-Drive Rooftop Air Conditioners

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- There are only a few gas-fired engine-driven rooftop units currently available in the U.S. market. The first unit was introduced in 2010. It is an 11-ton packaged heat pump with dual scroll compressors, variable refrigerant flow, and a variable speed supply fan. Engine coolant heat recovery improves the heating mode COP.
- There are currently no Federal requirements on gas-fired engine-driven rooftop air conditioners or heat pumps.
- Annual sales of the engine-driven rooftop heat pump are estimated at less than 5,000 units per year.

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Commercial Rooftop Heat Pumps

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DATA	2012	2018	2022				2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.1	High	New Standard	ENERGY STAR V. 4.0	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Part Load Efficiency (IEER)[1]	12.0	11.3	12.2	14.3	12.8	20.3	14.1	15.3	20.3	14.4	20.3	15.3	20.3	15.3	20.3
EER	10.2	11.2	11.3	11.5	11.8	13.0	12.0	11.8	13.0	11.7	13.1	11.7	13.1	11.7	13.1
COP (Heating)	3.3	3.3	3.3	3.4	3.4	3.7	3.4	3.5	3.7	3.4	3.7	3.5	3.7	3.5	3.7
Average Life (y)	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Retail Equipment Cost (2022$)	7,490	7,490	9,000	10,250	9,380	12,920	10,160	10,600	12,920	10,290	12,920	10,600	12,920	10,600	12,920
Total Installed Cost (2022$)	9,350	9,350	12,900	14,940	13,530	18,860	14,810	15,520	18,860	15,000	18,860	15,510	18,860	15,510	18,860
Total Installed Cost (2022$/kBtu/h)	104	104	143	166	150	210	165	172	210	167	210	172	210	172	210
Annual Maintenance Cost (2022$)	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380
Annual Maintenance Cost (2022$/kBtu/h)	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4

1. Values shown are for air-cooled small commercial packaged heat pumps with either electric resistance heating or no heating within the same enclosure. DOE published a direct final rule for commercial packaged air conditioners and heat pumps in January 2016 with initial standards becoming effective in 2018 and additional standards becoming effective in 2023. As part of this rulemaking, DOE changed the regulated metric from EER to IEER.

Note:
The previous standard went into effect in January 2018. The current standard went into effect in January 2023.
ENERGY STAR V. 3.1 went into effect in January 2018. ENERGY STAR V. 4.0 went into effect in January 2023.

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Commercial Rooftop Heat Pumps

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- Air-Cooled Commercial Packaged Heat Pumps

Cooling Capacity (kBtu/h)	Heating Type	Federal Standard Effective 1/1/2018 Min. IEER	Federal Standard Effective 1/1/2023 Min. IEER
Small (≥ 65 and < 135)	Electric resistance or none	12.2	14.1
	Any other type	12.0	13.9
Large (≥ 135 and < 240)	Electric resistance or none	11.6	13.5
	Any other type	11.4	13.3

- This analysis focused on small air-cooled commercial packaged rooftop heat pumps (90 kBtu/h or 7.5 tons), though there are also standards for many other types of commercial heat pumps.
- Amended standards in terms of IEER for all equipment classes took effect in 2018. More stringent standards in terms of IEER for all equipment classes took effect in 2023.

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Commercial Ground-Source Heat Pumps

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DATA	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	48	48	48	48	48	48	48	48	48	48	48
COP (Heating)[1]	3.1	3.7	3.2	3.5	3.6	3.5	3.6	3.5	3.6	3.5	3.6
EER (Cooling)[2]	12.7	17.4	14.1	17.0	21.6	17.0	21.6	17.0	21.6	17.0	21.6
Average Life (y)	8	8	8	8	8	8	8	8	8	8	8
	21	21	21	21	21	21	21	21	21	21	21
Retail Equipment Cost (2022$)	10,470	6,470	5,590	6,470	7,880	6,470	7,880	6,470	7,880	6,470	7,880
Total Installed Cost (2022$)	19,760	18,230	17,350	18,230	19,650	18,230	19,650	18,230	19,650	18,230	19,650
	44,820	26,520	25,580	26,520	27,880	26,520	27,880	26,520	27,880	26,520	27,880
Total Installed Cost (2022$/kBtu/h)	673	466	447	466	495	466	495	466	495	466	495
Annual Maintenance Cost (2022$)	180	180	180	180	180	180	180	180	180	180	180
Annual Maintenance Cost (2022$/kBtu/h)	4	4	4	4	4	4	4	4	4	4	4

1. COP values listed are assessed at a "ground loop" test condition, which is representative of closed loop GSHP operating conditions. However, DOE sets standards at a "water loop" test condition. The AHRI directory lists COP ratings at both sets of test conditions and is used to convert between them where necessary.
2. EER values listed are assessed at a full-load "ground loop" test condition, which is representative of closed loop GSHP operating conditions. However, DOE sets standards at a full-load "water loop" test condition. The AHRI directory lists EER ratings at all sets of test conditions and is used to convert between them where necessary.

Note:
Residential and commercial GSHPs are very similar - the main difference in data presented is the different capacity (3-ton vs. 4-ton) and slightly higher installation costs for commercial GSHP. DOE does not distinguish between residential and commercial units in its regulations.

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Commercial Ground-Source Heat Pumps

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- The most common commercial ground-source heat pump systems are closed-loop in which water or anti-freeze solution is circulated through plastic pipes buried underground. Commercial water-to-air heat pumps (WAHPs) range in size from 1 ton or less to over 500 tons depending on whether a distributed or centralized architecture is used. Distributed systems are more prevalent.
- Most geothermal WAHPs are rated for capacity and efficiency based on the ISO 13256-1 standard. Heating and cooling efficiency measurements under this standard include input energy for fans and pumps on a proportional basis that only includes that power required to transport air and liquid through the heat pump. The reason for this method is to simplify comparisons between heat pumps and to allow equipment to be optimized for real world conditions without suffering rating penalties. Real world energy use will exceed ratings predictions as a result of higher fluid static pressure requirements.
- ISO 13256-1 cooling rating conditions require 77 °F entering water temperature and 80.6 °F entering air temperature. More typical peak design criteria would be 80-90 °F entering water temperature and 75 °F entering air temperature. As a result, ISO 13256-1 rated cooling efficiency would be higher than typical design peak operation.
- Some WAHPs include efficiency data for a part-load operating condition as allowed by ISO 13256-1 for multiple stage or variable speed compressors. No seasonal energy efficiency metric (analogous to SEER or IEER) currently applies to WAHPs. The annual performance of a geothermal WAHP system can vary more widely than for other system types due to the large influence of ground loop design and characteristics.
- The ENERGY STAR criteria for ground-source heat pumps apply only to residential applications.
- Installation cost is for a closed loop system and includes necessary accessories. The ground loop heat exchanger and distribution pumping systems represent a majority of the installation cost.
- Low end WAHPs utilize single stage compressors. Higher efficiency units incorporate multiple stage or variable speed compressor controls to improve efficiency as well as humidity and temperature control. Variable speed ECM fan motors also improve overall energy efficiency.

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Packaged Terminal Air Conditioners

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DATA	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High[2]	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)[1]	9	9	9	9	9	9	9	9	9	9	9
Efficiency (EER)	11.3	11.3	11.3	11.3	13.1	11.3	13.1	11.3	13.1	11.3	13.1
Efficiency	3.3	3.3	3.3	3.3	3.8	3.3	3.8	3.3	3.8	3.3	3.8
Average Life (y)	8	8	8	8	8	8	8	8	8	8	8
Retail Equipment Cost (2022$)	1,460	1,460	1,460	1,460	1,560	1,460	1,560	1,460	1,560	1,460	1,560
Total Installed Cost (2022$)	1,740	1,740	1,740	1,740	1,840	1,740	1,840	1,740	1,840	1,740	1,840
Total Installed Cost (2022$/kBtu/h)	193	193	193	193	204	193	204	193	204	193	204
Annual Maintenance Cost (2022$)	70	70	70	70	70	70	70	70	70	70	70
Annual Maintenance Cost (2022$/kBtu/h)	8	8	8	8	8	8	8	8	8	8	8

1. Typical capacity is representative of units with the most shipments. It was also the representative cooling capacity for DOE's analysis in packaged terminal air conditioners (PTAC) and packaged terminal heat pumps (PTHP) EERE 2022 NOPD.
2. High values for 2022 and beyond are based on the max-tech level from PTAC & PTHP EERE 2022 NOPD.

Note:
The current standard went into effect in January 2017.

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Packaged Terminal Air Conditioners

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- PTAC are a self-contained, ductless air conditioning system used for commercial applications.
- Analysis was conducted for the standard equipment class at the representative cooling capacity of 9000 Btu/h.

Cooling Capacity (kBtu/h)	Equipment Size	Equipment Class	Federal Standard EER
PTAC	Standard	< 7000	11.9
		≥7,000 Btu/h and ≤15,000 Btu/h	14.0 – (0.3 x Cap)
		> 15,000 Btu/h	9.5

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Packaged Terminal Heat Pumps

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DATA	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical[2]	High[3]	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)[1]	9	9	9	9	9	9	9	9	9	9	9
Efficiency (EER)	11.3	11.3	11.3	11.3	13.1	11.5	13.1	11.5	13.1	11.5	13.1
Efficiency	3.3	3.3	3.3	3.3	3.8	3.4	3.8	3.4	3.8	3.4	3.8
COP (Heating)	3.2	3.2	3.2	3.2	3.6	3.3	3.6	3.3	3.6	3.3	3.6
Average Life (y)	8	8	8	8	8	8	8	8	8	8	8
Retail Equipment Cost (2022$)	1,620	1,620	1,620	1,620	1,720	1,630	1,720	1,630	1,720	1,630	1,720
Total Installed Cost (2022$)	1,910	1,910	1,910	1,910	2,010	1,910	2,010	1,910	2,010	1,910	2,010
Total Installed Cost (2022$/kBtu/h)	212	212	212	212	223	212	223	212	223	212	223
Annual Maintenance Cost (2022$)	70	70	70	70	70	70	70	70	70	70	70
Annual Maintenance Cost (2022$/kBtu/h)	8	8	8	8	8	8	8	8	8	8	8

1. Typical capacity is representative of units with the most shipments. It was also the representative cooling capacity for DOE's analysis in PTAC & PTHP EERE 2022 NOPD.
2. Typical values for 2022 and beyond are based on the efficiency level that has the largest market share per PTAC & PTHP EERE 2022 NOPD.
3. High values for 2022 and beyond are based on the max-tech level from PTAC & PTHP EERE 2022 NOPD.

Note:
The current standard went into effect in October 2012.

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Packaged Terminal Heat Pumps

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- PTHP are self-contained heat pumps primarily used for commercial applications.
- Analysis was conducted for the standard equipment class at the representative cooling capacity of 9000 Btu/h.

Cooling Capacity (kBtu/h)	Equipment Size	Equipment Class	Federal Standard EER	Federal Standard COP
PTHP	Standard	< 7000	11.9	3.3
		≥7,000 Btu/h and ≤15,000 Btu/h	14.0 – (0.3 x Cap)	3.7 – (0.052 x Cap)
		> 15,000 Btu/h	9.5	2.9
PTHP	Non-Standard	< 7000	9.3	2.7
		≥7,000 Btu/h and ≤15,000 Btu/h	10.8 – (0.213 x Cap)	2.9 – (0.026 x Cap)
		> 15,000 Btu/h	7.6	2.5

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Commercial Water Heating

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Commercial Gas-Fired Storage Water Heaters

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DATA	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 2.0	High	Typical	High	Typical	High	Typical	High
Typical Storage Capacity (gal)	100	100	100	100	100	100	100	100	100	100	100	100
Typical Input Capacity (kBtu/h)	199	199	199	199	199	199	199	199	199	199	199	199
Thermal Efficiency (%)[1]	81	82	80	82	94	99	95	99	95	99	95	99
Average Life (y)	13	10	10	10	10	10	10	10	10	10	10	10
Retail Equipment Cost (2022$)	3,870	3,890	3,850	3,890	4,180	4,290	4,200	4,290	4,200	4,290	4,200	4,290
	5,170	5,200	5,140	5,200	5,530	5,650	5,550	5,650	5,550	5,650	5,550	5,650
Total Installed Cost (2022$)	5,170	5,190	5,140	5,190	6,630	6,730	6,640	6,730	6,640	6,730	6,640	6,730
	8,440	8,460	8,410	8,460	8,590	8,710	8,610	8,710	8,610	8,710	8,610	8,710
Total Installed Cost (2022$/kBtu/h)	42	42	43	42	41	39	40	39	40	39	40	39
Annual Maintenance Cost (2022$)[2]	320	320	320	320	330	330	330	330	330	330	330	330
Annual Maintenance Cost (2022$/kBtu/h)	2	2	2	2	2	2	2	2	2	2	2	2

1. Different levels of standby loss were not included in this analysis.
2. Maintenance consists of sediment and scale removal once or twice per year and replacement of miscellaneous components such as gaskets and sealants. Condensing units have an additional cost for replacement of condensate neutralizer media every two years.

Note:
The current standard went into effect in October 2015.
ENERGY STAR V. 2.0 went into effect in October 2018.
The range of retail and installed costs represent the range from replacement market to new construction market.

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Commercial Gas-Fired Storage Water Heaters

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- Input capacity > 155 kBtu/h and storage capacity ≤ 140 gal
- Federal standard:
  - Minimum thermal efficiency: 80%
  - Maximum standby loss (Btu/h) : Input Rate/800 + 110 × (Rated Volume)$^{1/2}$
- ENERGY STAR requirements:
  - Minimum thermal efficiency: 94%
  - Maximum standby loss (Btu/h): 0.84 × [(Input Rate/800) + 110 × (Rated Volume)$^{1/2}$]
- Baseline units are typically constructed similarly to residential units, though with higher input capacities (and often higher storage volumes).
- High-efficiency units include condensing heat exchangers (typically stainless or enameled steel) to extract additional heat by condensing water vapor in flue gases. Condensing units also include an inducer fan system or power burner. The heat exchanger is typically contained within the tank, but some designs consist of an external heating module attached to a storage tank. Condensing units are expected to be the majority market share by 2030.
- Maintenance consists of sediment and scale removal once or twice per year and replacement of miscellaneous components such as gaskets and sealants. Condensing units have an additional cost for replacement of condensate neutralizer media every two years.

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Commercial Gas-Fired Storage Water Heaters

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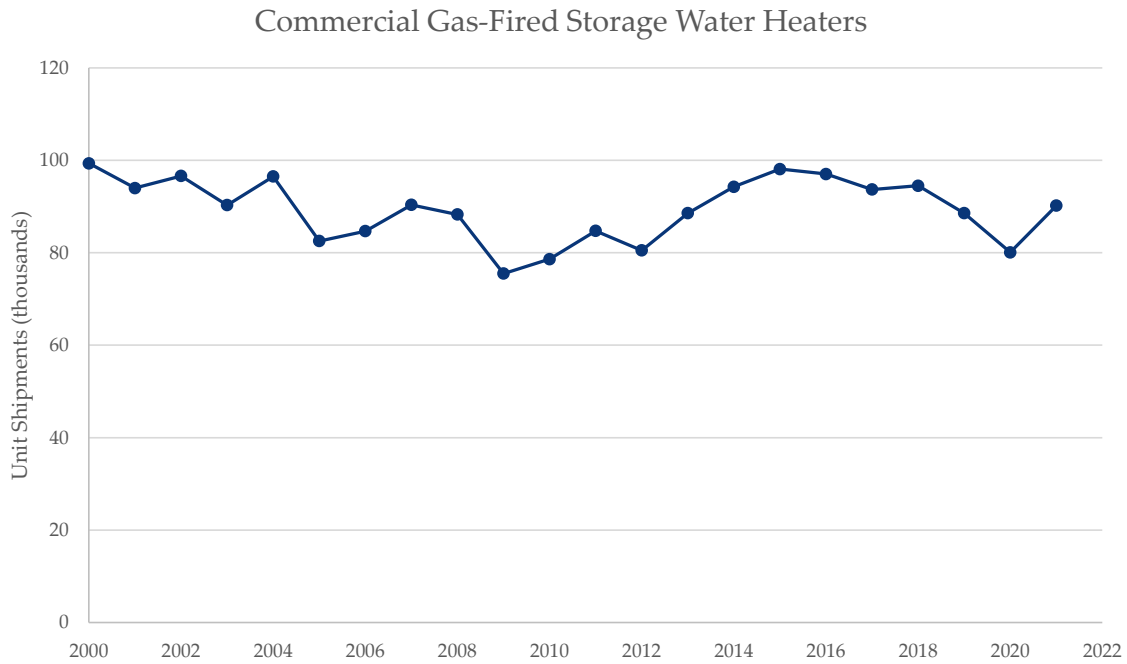
Annual shipments have fluctuated from 99,000 units in 2000 to 75,000 units in 2009, back to 99,000 units in 2015 and gradually decreasing since then until 2020.



Source: CWH EERE 2022 NOPR and AHRI

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Commercial Electric Resistance Storage Water Heaters

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DATA	2012	2018	2022		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	Typical	Typical	Typical
Typical Storage Capacity (gal)	119	119	119	119	119	119	119
Typical Input Capacity (kW)[1]	18	18	18	18	18	18	18
Typical Input Capacity (kBtu/h)	60	60	60	60	60	60	60
Thermal Efficiency (%)	98	98	98	98	98	98	98
Average Life (y)	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)	3,180	3,180	3,180	3,180	3,180	3,180	3,180
	3,750	3,750	3,750	3,750	3,750	3,750	3,750
Total Installed Cost (2022$)	4,460	4,460	4,460	4,460	4,460	4,460	4,460
	4,690	4,690	4,690	4,690	4,690	4,690	4,690
Total Installed Cost (2022$/kBtu/h)	76	76	76	76	76	76	76
Annual Maintenance Cost (2022$)	50	50	50	50	50	50	50
Annual Maintenance Cost (2022$/kBtu/h)	1	1	1	1	1	1	1

1. Different levels of standby loss were not included in this analysis.

Note:
No new standards rulemaking has been initiated for commercial electric resistance water heaters since CWH EERE 2016 NOPR. Accordingly, the results are the same as EIA Technology Forecast Updates (2018), updated to 2022$.
The range of retail equipment and installed costs represents the range from replacement market to new construction market.

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Commercial Electric Resistance Storage Water Heaters

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- Federal standard:
  - Maximum standby loss (%/h) : 0.30 + 27/Measured Storage Volume
  - Minimum thermal efficiency: no standard, but all units have an efficiency ≥ 98%
- Storage capacity: typically, 50 to 120 gallons, though smaller and larger units exist for specialized applications
- Commercial units are typically constructed similar to residential units, though with higher input capacities (and often higher storage volumes).
- There is very little variation in thermal efficiency on the market; variation in standby loss is typically due to tank design and insulation thickness.
- Maintenance consists of sediment and scale removal once or twice per year.

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Commercial Electric Resistance Storage Water Heaters

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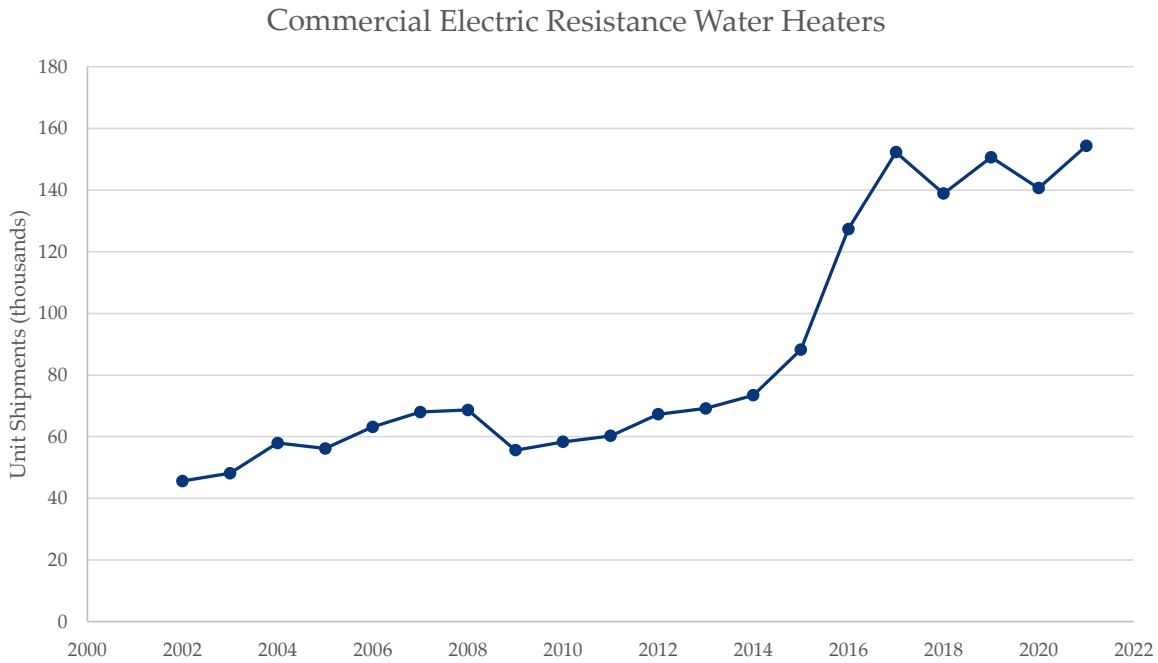
Annual shipments increased by almost 50% between 2002 and 2008. After a small dip in shipments in 2009, annual shipments have increased by about 173% between 2009 and 2017, stabilizing between 140-150 thousand shipments per year since then.



Source: AHRI

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Commercial Heat Pump Water Heaters

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DATA	2012	2018	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	ENERGY STAR V. 2.0	Typical	Typical	Typical
Water Flow Rate (gal/min)[1]	34	34	34	34	34	34	34
Typical Output Capacity (kW)[1]	50	50	50	50	50	50	50
Typical Output Capacity (kBtu/h)	171	171	171	171	171	171	171
Coefficient of Performance (COP_h)	3.9	3.9	3.9	3.0	3.9	3.9	3.9
Average Life (y)	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)[2]	55,406	55,406	55,406	55,406	55,406	55,406	55,406
Total Installed Cost (2022$)[2]	59,940	59,940	59,940	59,940	59,940	59,940	59,940
Total Installed Cost (2022$/kBtu/h)	351	351	351	351	351	351	351
Annual Maintenance Cost (2022$)[2]	120	120	120	120	120	120	120
Annual Maintenance Cost (2022$/kBtu/h)	1	1	1	1	1	1	1

1. Water flow rate scales with typical capacity. The storage tanks must be purchased and installed separately from the HP unit. The typical output and flow rate provided are near the median of the products available on the market currently.
2. Costs are same as EIA Technology Forecast Updates (2018), updated to 2022$. Updated representative costs for commercial heat pump water heaters are not available due to the extremely small market for these products.

Note:
ENERGY STAR V. 2.0 went into effect in October 2018.

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Commercial Heat Pump Water Heaters

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- Typical commercial HPWHs (CHPWHs) are add-on units designed to be used with a storage tank(s); integrated CHPWHs have emerged on the market (i.e., heat pump module and storage tank combined in one unit) in recent years.
- CHPWHs serve only a small portion of the commercial water heating (CWH) market, with the ENERGY STAR database listing only two manufacturers, each with one basic model listed.
- CHPWHs can extract heat from either air or water for heating potable water ("air-source" or "water-source"). The capacity of air-source CHPWHs falls at lower ambient air temperatures.
- Air-source CHPWHs cool the surrounding air, which can be desirable when installed indoors in applications with a year-round cooling load (e.g., a commercial kitchen).
- Output capacities for CHPWHs range from 17 kW to over 70 kW for air-source units and over 600 kW for water-source units.
- Some commercial applications require water as hot as 180 °F, such as dishwashing; however, most CHPWHs cannot deliver hot water at temperatures higher than 150 °F.
- There are no current Federal standards for CHPWHs, but DOE prescribes a test procedure for determining COP_h for CHPWHs.
- The most recent ENERGY STAR V. 2.0 specification for CWH equipment went into effect in October 2018. It specifies a COP_h level of 3.0 for CHPWHs.

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Commercial Oil-Fired Storage Water Heaters

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DATA	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Storage Capacity (gal)	70	85	85	85	85	85	85	85	85	85	85
Typical Input Capacity (kBtu/h)	300	300	300	300	300	300	300	300	300	300	300
Thermal Efficiency (%)[1]	79	81	80	81	82	81	82	81	82	81	82
Average Life (y)	13	13	13	13	13	13	13	13	13	13	13
Retail Equipment Cost (2022$)	5,470	5,470	5,470	5,470	5,470	5,470	5,470	5,470	5,470	5,470	5,470
Total Installed Cost (2022$)	6,120	6,120	6,120	6,120	6,120	6,120	6,120	6,120	6,120	6,120	6,120
Total Installed Cost (2022$/kBtu/h)	26	25	26	25	25	25	25	25	25	25	25
Annual Maintenance Cost (2022$)	200	200	200	200	200	200	200	210	210	210	210
Annual Maintenance Cost (2022$/kBtu/h)	1	1	1	1	1	1	1	1	1	1	1

1. Different levels of standby loss were not included in this analysis.

Note:
The commercial oil-fired water heaters market is very small; currently, there are only 4 basic models in DOE's CCD. DOE's rulemaking analysis for oil-fired water heaters has not been updated since 2001. The retail, installed, and maintenance costs have been updated from EIA Technology Forecast Updates (2018) to 2022$.
The current standard went into effect in October 2015.

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Commercial Oil-Fired Storage Water Heaters

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- Input capacity > 155 kBtu/h and storage capacity ≤ 140 gal
- Federal standard:
  - Minimum thermal efficiency: 80%
  - Maximum standby loss (Btu/h) : Input Rate/800 + 110 × (Rated Volume)$^{1/2}$
- Condensing units do not exist, thus the highest thermal efficiency on the market is 82%.
- Commercial units are typically constructed similar to residential units, though with higher input capacities (and often higher storage volumes).
- Maintenance costs include sediment and scale removal once or twice per year.
- The market for commercial oil-fired storage water heaters is very small; shipments are approximately 3% of shipments for commercial gas-fired storage water heaters.

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Commercial Electric Booster Water Heaters

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DATA	2012	2018	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical	Typical	Typical
Typical Capacity (gal)	6	6	6	6	6	6
	16	16	16	16	16	16
Typical Output Capacity (kBtu/h)	1,374	1,374	1,374	1,374	1,374	1,374
Thermal Efficiency (%)	98	98	98	98	98	98
Average Life (y)	3	3	3	3	3	3
	10	10	10	10	10	10
Retail Equipment Cost (2022$)[1]	1,530	1,530	1,920	1,920	1,920	1,920
	3,290	3,530	4,560	4,560	4,560	4,560
Total Installed Cost (2022$) [1]	1,730	1,730	2,120	2,120	2,120	2,120
	3,490	3,730	4,760	4,760	4,760	4,760
Total Installed Cost (2022$/kBtu/h)	2	2	3	3	3	3
Annual Maintenance Cost (2022$)[2]	-	-	-	-	-	-
Annual Maintenance Cost (2022$/kBtu/h)	-	-	-	-	-	-

1. The 2012 and 2018 installed base costs are the same as EIA Technology Forecast Updates (2018), updated to 2022$. Retail costs for 2022 and later are based on the range of costs for products on the market today. Installed costs assume a $200 installation price.
2. Maintenance costs are negligible.

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Commercial Gas-Fired Booster Water Heaters

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DATA	2012	2018	2022		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	Typical	Typical	Typical
Typical Capacity (gal)	3	3	3	3	3	3	3
	5	5	5	5	5	5	5
Typical Output Capacity (kBtu/h)	500	500	500	500	500	500	500
Thermal Efficiency (%)[1]	80	80	80	80	80	80	80
Average Life (y)	5	5	5	5	5	5	5
	10	10	10	10	10	10	10
Retail Equipment Cost (2022$)[2]	5,530	5,760	7,130	7,130	7,130	7,130	7,130
	8,000	9,060	11,120	11,120	11,120	11,120	11,120
Total Installed Cost (2022$)[2]	5,830	6,060	7,430	7,430	7,430	7,430	7,430
	8,300	9,360	11,420	11,420	11,420	11,420	11,420
Total Installed Cost (2022$/kBtu/h)	14	15	19	19	19	19	19
Annual Maintenance Cost (2022$)	160	160	160	160	160	160	160
Annual Maintenance Cost (2022$/kBtu/h)	0	0	0	0	0	0	0

1. While EIA Technology Forecast Updates (2018) included high values reflecting condensing models, models currently available in the market do not exceed 80% efficiency.
2. The 2012 and 2018 installed base costs are the same as EIA Technology Forecast Updates (2018), updated to 2022$. Retail costs for 2022 and later are based on the range of costs for products on the market today. Installed costs assume a $300 installation price.

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Commercial Booster Water Heaters

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- Booster water heaters are installed, often at the point of use, in series with the main service water heating system to boost service water temperatures. The main service water heating system may provide 110-140 °F water, and the booster water heater may increase that temperature to 180-195 °F. Typical commercial applications for booster water heaters include commercial dishwashers, laundromats, hospitals, and car washes.
- Commercial booster water heaters are regulated by DOE as either storage or instantaneous water heaters, depending on the ratio of input capacity to storage volume. Units with input capacity < 4,000 Btu/h per gallon of stored water are storage water heaters; all other units are instantaneous water heaters.
- DOE's regulations do not currently include standards for electric instantaneous water heaters, but standards are included for electric storage water heaters, gas-fired instantaneous water heaters, and gas-fired storage water heaters.
- Condensing gas-fired booster water heaters, those with an efficiency of 90% of more, were analyzed previously. There are no condensing units currently on the market. Condensing gas-fired booster water heaters can only operate if the incoming water temperature is below 130 °F so there is enough heat transfer to condense.
- Booster water heaters typically have short lifetimes because of high usage and extreme temperatures.
- Shipments are small due to the limited number of applications.

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Commercial Gas-Fired Instantaneous Water Heaters

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DATA	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 2.0	High[2]	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	250	250	250	250	250	250	250	250	250	250	250	250
	399	399	399	399	399	399	399	399	399	399	399	399
Thermal Efficiency (%)	80	92	80	92	94	99	96	99	96	99	96	99
Average Life (y)	17	17	17	17	17	17	17	17	17	17	17	17
	25	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)[1]	1,630	1,840	1,630	1,840	1,880	7,990	1,930	7,990	1,930	7,990	1,930	7,990
	4,400	8,610	4,400	8,610	9,000	9,990	9,400	9,990	9,400	9,990	9,400	9,990
Total Installed Cost (2022$)[1]	2,430	3,980	2,430	3,980	4,010	13,000	4,070	13,000	4,070	13,000	4,070	13,000
	10,380	13,560	10,380	13,560	13,950	14,950	14,350	14,950	14,350	14,950	14,350	14,950
Total Installed Cost (2022$/kBtu/h)	25	29	25	29	29	44	30	44	30	44	30	44
Annual Maintenance Cost (2022$)[3]	90	100	90	100	100	820	100	820	100	820	100	820
	760	820	760	820	820	830	830	830	830	830	830	830
Annual Maintenance Cost (2022$/kBtu/h)	2	2	2	2	2	3	1	3	1	3	1	3

1. Commercial gas-fired instantaneous water heaters are categorized into two groups: tankless water heater and hot water supply boiler. Tankless units are similar in design to residential tankless units. The hot water supply boiler has a much higher input and is similar in design to boilers. The large variation of total input capacity and design causes a large range of costs. The range of retail, installed, and maintenance costs represent the differences in design, as well as the cost ranges arising from replacement versus new construction markets.
2. High efficiency was determined based on DOE's CCD. The most efficient tankless water heater has a thermal efficiency of 96%. The most efficient hot water supply boiler has a thermal efficiency of 99%.
3. Maintenance consists replacement of miscellaneous components such as gaskets and sealants. Condensing units have an additional cost for replacement of condensate neutralizer media every two years.

Note:
For the installed base, current standard, and typical costs, low values represent costs for tankless water heaters in the replacement market while high values represent costs for hot water supply boilers in the new construction market. The range of costs for the High values are estimated costs for hot water supply boilers in the replacement and new construction market.
ENERGY STAR V. 2.0 went into effect in October 2018.

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Commercial Gas-Fired Instantaneous Water Heaters

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- Storage Capacity < 10 gallons and ≥ 10 gallons
- Federal standard:
  - Minimum thermal efficiency: 80%
  - Maximum standby loss (Btu/h): Input Rate/800 + 110 x (Rated Volume)$^{1/2}$
- ENERGY STAR requirements:
  - Minimum thermal efficiency: 94%
- Wall-mounted ("tankless") units typically do not exceed ~400,000 Btu/h and are similar in design to residential tankless units. Floor-mounted units ("circulating" or "volume" water heaters) are similar in design to boilers and can have input capacities in the millions of Btu/h. Floor-mounted units are typically installed with a storage tank.
- Despite high available input capacities, some installations use multiple units staged together, which may have reliability and/or efficiency benefits.
- Similar to storage water heaters, higher efficiencies are achieved with condensing operation, which requires a condensing heat exchanger and inducer fan or power burner. Some units include both non-condensing and condensing heat exchangers, while others include a single condensing heat exchanger.
- When replacing a storage water heater with an instantaneous water heater, there may be significant additional costs to upsize the gas supply line and change the venting.

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Commercial Gas-Fired Instantaneous Water Heaters

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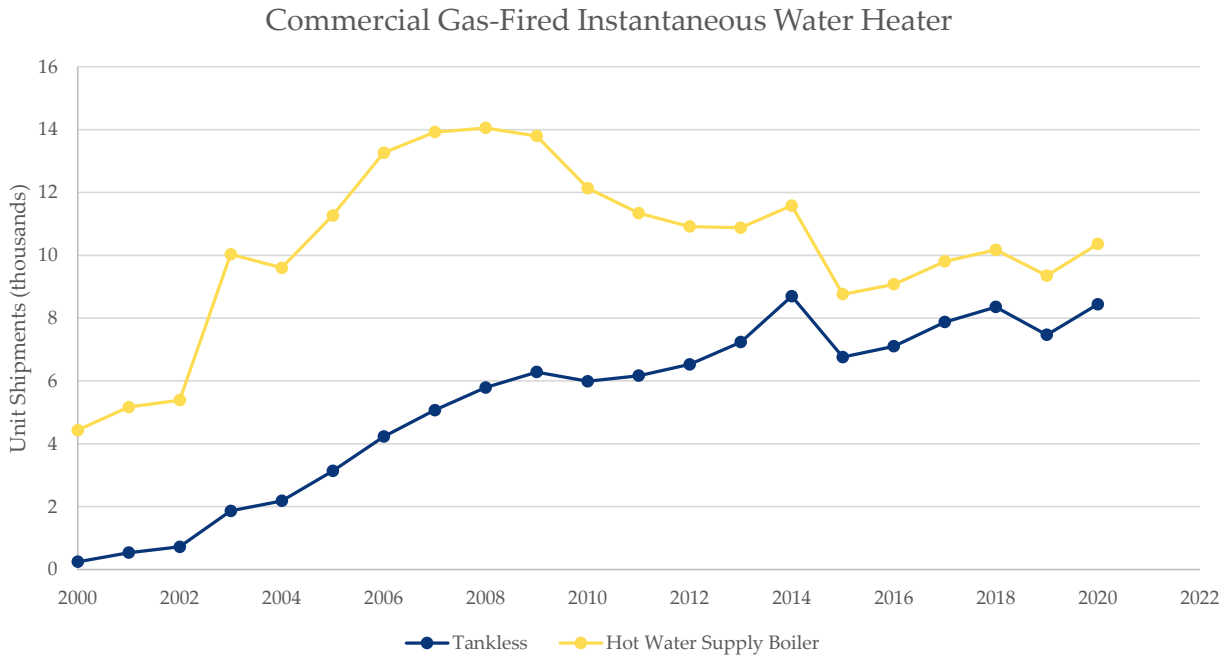
Annual shipments for gas-fired instantaneous tankless water heaters have gradually increased since 2000 while those for gas-fired instantaneous hot water supply boiler water heaters peaked in 2008 and have been decreasing since then, recently stabilizing around 10,000 annual shipments.



Source: CWH EERE 2022 NOPR

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Commercial Solar Water Heaters

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DATA	2012	2018	2022		2023	2030	2040	2050
	Installed Base	Installed Base	Typical	ENERGY STAR V. 4.0	ENERGY STAR V. 5.0	Typical	Typical	Typical
Typical Capacity (sq. ft.)[1]	85	85	85	85	85	85	85	85
Typical Capacity (m^2)	7.90	7.90	7.90	7.90	7.90	7.90	7.90	7.90
Typical Capacity (Input) (kBtu/h) – North	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05
Typical Capacity (Input) (kBtu/h) – South	6.74	6.74	6.74	6.74	6.74	6.74	6.74	6.74
Solar Uniform Energy Factor (SUEF)[2]	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Average Life (y)	20	20	20	20	20	20	20	20
Retail Equipment Cost (2022$)[3]	10,470	10,470	10,280	10,280	10,280	10,280	10,280	10,280
Total Installed Cost (2022$)[3]	14,180	14,180	12,640	12,640	12,640	12,640	12,640	12,640
Total Installed Cost (2022$/kBtu/h) – North	936	936	834	834	834	834	834	834
Total Installed Cost (2022$/kBtu/h) – South	702	702	626	626	626	626	626	626
Annual Maintenance Cost (2022$)[4]	100	100	100	100	100	100	100	100
Annual Maintenance Cost (2022$/kBtu/h) - North	7	7	7	7	7	7	7	7
Annual Maintenance Cost (2022$/kBtu/h) - South	5	5	5	5	5	5	5	5

1. Typical capacity refers to the solar collector panel area. It was determined using the SRCC database as the average value of the largest bin (in terms of capacity) with the greatest number of units.
2. In 2020, the efficiency metric for solar water heaters changed from SEF to SUEF. There is no equation or scaling factor readily available to translate SEF to SUEF. Accordingly, for the 2012 and 2018 installed base, SUEF was determined using the 2020 ENERGY STAR data set assuming the typical SEF/SUEF value was similar between 2012-2020. For 2022 and beyond, due to lack of SUEF data, it is assumed that a typical electric backup unit would meet the ENERGY STAR criteria. ENERGY STAR specifies a minimum SUEF of 3.0 for electric backup units and 1.8 for gas backup units.
3. Costs are for an indirect (active closed loop) system, including tank and backup heater. Smaller capacity/cost systems are typical for southern & western states (>two-third of the current market). Higher capacity/cost systems are required in colder/cloudier regions. The 2012 and 2018 installed base costs are updated from EIA Technology Forecast Updates (2018) to 2022$.
4. Annual maintenance is expected to be 0.5% to 1% of the total installation.

Note:
ENERGY STAR V. 4.0 went into effect in January 2022. ENERGY STAR V. 5.0 will go into effect in April 2023 but the ENERGY STAR criteria for solar water heaters will remain the same in ENERGY STAR V. 5.0.

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Commercial Solar Water Heaters

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- In 2020, a diverse group of stakeholders from the solar thermal industry developed the SUEF Specification for solar water heaters. The goal of this specification is to align with the UEF metric used by DOE for other water heating technologies.
- SUEF is also the metric used by the current ENERGY STAR Specification, and it replaced the SEF metric.
- EIA Technology Forecast Updates (2018) presented results using SEF and solar fraction (SF). SEF is currently not used in either the ENERGY STAR or SRCC databases; accordingly, this report presents results according to SUEF. SF is the portion of the total conventional hot water heating load (delivered energy and tank standby losses). SF varies from 0 to 1.0. Typical solar fraction values are 0.5–0.75.
- There is no equation or scaling factor readily available to translate SEF to SUEF. Accordingly, for the 2012 and 2018 installed base, SUEF was determined using the 2020 ENERGY STAR data set assuming the typical SEF/SUEF value was similar between 2012-2020. For 2022 and beyond, SUEF is the average SUEF for solar water heaters with a "high-usage" draw pattern from the current ENERGY STAR qualified product list.
- Commercial solar water heaters are typically custom designed for a specific installation.
- Commercial solar water heaters may include backup heating, from sources such as electric resistance or hydronic heat (supplied from a gas-fired boiler or geothermal heat pump).
- Storage volumes of tanks for commercial solar water heaters can span from 140 gallons to over 2,000 gallons.
- SRCC's OG-300 can be used to certify commercial systems, but most commercial systems are larger and unique; this certification program is mostly used for residential solar water heaters.
  - Many incentive programs require that solar collectors for commercial systems be certified to SRCC's certification program for collectors, OG-100.

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Commercial Cooking Products

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Commercial Natural Gas Range with Griddle and Oven

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DATA	2012	2018	2022			2023	2030		2040		2050	
	Installed Base	Installed Base	Typical	ENERGY STAR V. 2.2[1]	High	ENERGY STAR V. 3.0[2]	Typical	High	Typical	High	Typical	High
Griddle - Cooking Energy Efficiency (%)	30	30	40	38	69	NA	40	69	40	69	40	69
Oven - Cooking Energy Efficiency (%)	35	35	35	46	69	49	35	69	35	69	35	69
Range - Cooking Energy Efficiency (%)	30	30	30	NA	40	NA	30	40	30	40	30	40
Combined Energy Efficiency (%)[3]	31	31	35	NA	58	NA	35	58	35	58	35	58
Griddle - Normalized Idle Energy Rate (Btu/h/ft^2)	3,000	3,000	3,000	2,650	1,724	NA	3,000	1,724	3,000	1,724	3,000	1,724
Oven - Idle Energy Rate (Btu/h)	18,000	18,000	18,000	12,000	3,516	9,500	18,000	3,516	18,000	3,516	18,000	3,516
Range - Idle Energy Rate (Btu/h)	3,600	3,600	3,600	NA	1,900	NA	3,600	1,900	3,600	1,900	3,600	1,900
Combined Idle Energy Rate (Btu/h)[3]	10,350	10,350	10,350	NA	4,178	NA	10,350	4,178	10,350	4,178	10,350	4,178
Average Life (y)	12	12	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)[4]	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760
Total Installed Cost (2022$)	8,940	8,940	8,940	8,940	8,940	8,940	8,940	8,940	8,940	8,940	8,940	8,940
Total Installed Cost (2022$/kBtu/h)	864	864	864	NA	2,140	NA	864	2,140	864	2,140	864	2,140
Annual Maintenance Cost (2022$)[5]	–	–	–	–	–	–	–	–	–	–	–	–
Annual Maintenance Cost (2022$/kBtu/h)	–	–	–	–	–	–	–	–	–	–	–	–

1. ENERGY STAR does not cover combination products that include griddles, ranges, and ovens in one single package. The ENERGY STAR levels provided here reflect specifications for individual products. Range tops are not covered by ENERGY STAR.
2. ENERGY STAR V. 3.0 updated the requirements for commercial ovens from V. 2.2, effective January 2023. Data shown is reflective of a standard full-size convection oven that holds 5 or more pans.
3. Combined energy efficiency and combined idle energy rate are calculated as a weighted average of each component using typical daily operating hours sourced from Food Service Technology Center (FSTC). Typical daily operating hours are assumed to be 12 hours for the griddle component, 8 hours for the oven component, and 12 hours for the range component.
4. Products in the commercial cooking market generally do not scale in price with relation to cooking efficiency. Distributors also do not provide this information.
5. Maintenance costs are negligible.

Note:
ENERGY STAR V. 2.2 went into effect in October 2015. ENERGY STAR V. 3.0 went into effect in January 2023.

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Commercial Electric Range with Griddle and Oven

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DATA	2012	2018	2022			2023	2030		2040		2050	
	Installed Base	Installed Base	Typical	ENERGY STAR V. 2.2[1]	High	ENERGY STAR V. 3.0[2]	Typical	High	Typical	High	Typical	High
Griddle - Cooking Energy Efficiency (%)	65	70	72	70	91	NA	72	91	72	91	72	91
Oven - Cooking Energy Efficiency (%)	65	65	65	71	86	76	65	86	65	86	65	86
Range - Cooking Energy Efficiency (%)	75	75	75	NA	87	NA	75	87	75	87	75	87
Combined Energy Efficiency (%)[3]	69	71	71	NA	88	NA	71	88	71	88	71	88
Griddle - Normalized Idle Energy Rate (kW/ft^2)	0.44	0.34	0.30	0.32	0.21	NA	0.30	0.21	0.30	0.21	0.30	0.21
Oven - Idle Energy Rate (kW)	1.5	1.5	1.5	1.6	0.6	1.4	1.5	0.6	1.5	0.6	1.5	0.6
Range - Idle Energy Rate (kW)[4]	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Combined Idle Energy Rate (kW)[3]	1.7	1.4	1.3	1.4	0.8	NA	1.3	0.8	1.3	0.8	1.3	0.8
Average Life (y)	12	12	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)[5]	11,230	11,230	11,230	11,230	11,230	11,230	11,230	11,230	11,230	11,230	11,230	11,230
Total Installed Cost (2022$)	11,410	11,410	11,410	11,410	11,410	11,410	11,410	11,410	11,410	11,410	11,410	11,410
Total Installed Cost (2022$/kBtu/h)	2,019	2,362	2,533	2,375	4,423	NA	2,533	4,423	2,533	4,423	2,533	4,423
Annual Maintenance Cost (2022$)[6]	–	–	–	–	–	–	–	–	–	–	–	–
Annual Maintenance Cost (2022$/kBtu/h)	–	–	–	–	–	–	–	–	–	–	–	–

1. ENERGY STAR does not cover combination products that include griddles, ranges, and ovens in one single package. The ENERGY STAR levels provided here reflect specifications for individual products. Range tops are not covered by ENERGY STAR.
2. ENERGY STAR V. 3.0 updated the requirements for commercial ovens from V. 2.2, effective January 2023. Data shown is reflective of a standard full-size convection oven that holds 5 or more pans.
3. Combined energy efficiency and combined idle energy rate are calculated as a weighted average of each component using typical daily operating hours sourced from FSTC. Typical daily operating hours are assumed to be 12 hours for the griddle component, 8 hours for the oven component, and 12 hours for the range component.
4. No data on electric range top idle energy rates.
5. Products in the commercial cooking market generally do not scale in price with relation to cooking efficiency. Distributors also do not provide this information.
6. Maintenance costs are negligible.

Note:
ENERGY STAR V. 2.2 went into effect in October 2015. ENERGY STAR V. 3.0 goes into effect in January 2023.

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Commercial Ranges with Griddle and Oven

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- Combined product that typically includes 2-6 range tops, a 24 in. x 24 in. griddle surface, and one or two half- or full-size ovens.
- Combined product is not covered by ENERGY STAR. However, the individual product ENERGY STAR V. 2.2 specifications are provided below.

Product	ENERGY STAR V. 2.2 Requirements	Gas	Electric
Griddle	Cooking Energy Efficiency	≥ 38%	≥ 70%
	Normalized Idle Energy Rate	≤ 2,650 Btu/h per ft^2	≤ 0.320 kW per ft^2
Oven	Cooking Energy Efficiency	≥ 46%	≥ 71%
	Idle Energy Rate	≤ 12,000 Btu/h	Half size: ≤1.00 kW Full size: ≤1.60 kW

- ENERGY STAR does not provide certification for range tops.
- There are no Federal standards for commercial cooking products.
- Product pricing in this market do not scale with efficiency, but rather depend on a number of other factors such as brand name, aesthetics, and additional features.

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Commercial Ranges with Griddle and Oven

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- ENERGY STAR V. 3.0 requirements for commercial ovens went into effect in January 2023:

Product	ENERGY STAR Requirements	Gas	Electric
Oven	Cooking Energy Efficiency	≥ 49%	Half size: ≥ 71% Full size: ≥ 76%
	Idle Energy Rate	≤ 9,500 Btu/h	Half size: ≤1.00 kW Full size ≥ 5 Pans: ≤1.40 kW Full size ≤ 5 Pans: ≤1.00 kW

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Commercial Ranges with Griddle and Oven

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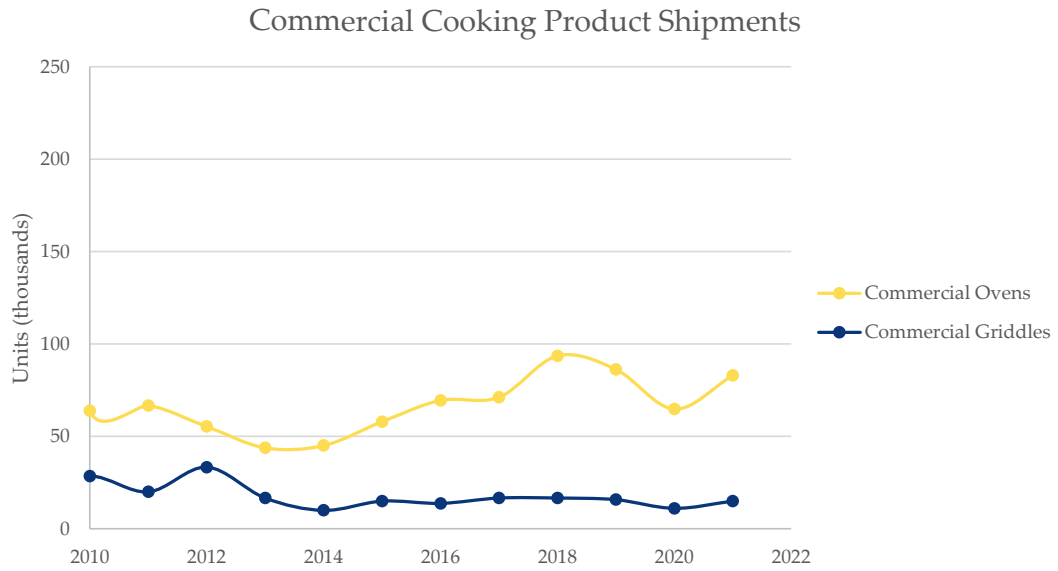
Commercial oven shipments have gradually increased since 2013, decreasing recently, in 2020. Commercial griddle shipments have remained steady since 2014.



Source: *ENERGY STAR (Unit Shipment Data)*

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Commercial Hot Food Holding Cabinets – Small

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DATA	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	State Standards	Typical	ENERGY STAR V. 2.0	High	Typical	High	Typical	High	Typical	High
Interior Volume (ft^3)[1]	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Maximum Idle Energy Rate (W)[2]	312	312	312	312	168	168	312	168	312	168	312	168
Annual Energy Use (kWh/y)[3]	1,025	1,025	1,025	1,025	552	552	1,025	552	1,025	552	1,025	552
Average Life (y)	12	12	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)[4]	3,200	3,200	3,200	3,200	3,800	3,800	3,200	3,800	3,200	3,800	3,200	3,800
Total Installed Cost (2022$)[5]	3,200	3,200	3,200	3,200	3,800	3,800	3,200	3,800	3,200	3,800	3,200	3,800
Total Installed Cost (2022$/kBtu/h)	8,016	8,016	8,016	8,016	17,677	17,677	8,016	17,677	8,016	17,677	8,016	17,677
Annual Maintenance Cost (2022$)[5]	–	–	–	–	–	–	–	–	–	–	–	–
Annual Maintenance Cost (2022$/kBtu/h)	–	–	–	–	–	–	–	–	–	–	–	–

1. Interior volume is characterized by the product size classes reported by ENERGY STAR. The small size class covers units with interior volume less than 13 ft^3. Interior volume for the small size class was determined based on the units in the ENERGY STAR database, accessed February 2023.
2. Maximum idle energy rate is a function of interior volume. For the small size class, ENERGY STAR and high values were determined for a representative 7.8 ft^3 using the ENERGY STAR database, accessed February 2023. The typical value was assumed to be equivalent to the state standard for a representative 7.8 ft^3 unit.
3. Annual energy use is determined using the latest FEMP data from December 2021, which assumes that a typical 22.4 ft^3 commercial hot food holding cabinet uses an average of 9 hours per day and 365 days per year. The small size class is assumed to use the same number of annual usage hours as the medium size class.
4. Retail equipment costs were determined using distributor information for undercounter, half-size, and full-size hot food holding cabinets.
5. Additional installation costs and maintenance costs are negligible.

Note:

ENERGY STAR V. 2.0 went into effect in October 2011 and was revised in December 2022. Massachusetts, Nevada, and Rhode Island state standards have adopted the ENERGY STAR V. 2.0 criteria that went into effect in October 2011. The majority of state standards (California, Colorado, Connecticut, DC, Maryland, New Hampshire, Oregon, Rhode Island, Vermont, and Washington) implement the ENERGY STAR V. 1.0 specification that went into effect in August 2003, which is recorded in the table. ENERGY STAR V. 1.0 specifies a maximum idle energy rate of 40 W per cubic foot of interior volume.

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Commercial Hot Food Holding Cabinets – Medium

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DATA	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	State Standards	Typical	ENERGY STAR V. 2.0	High	Typical	High	Typical	High	Typical	High
Interior Volume (ft^3)[1]	21.4	21.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4
Maximum Idle Energy Rate (W)[2]	900	856	896	896	299	298	896	298	896	298	896	298
Annual Energy Use (kWh/y)[3]	2,957	2,812	2,943	2,943	982	979	2,943	979	2,943	979	2,943	979
Average Life (y)	12	12	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)[4]	2,940	4,530	4,600	4,600	5,000	5,000	4,600	5,000	4,600	5,000	4,600	5,000
Total Installed Cost (2022$)[5]	2,940	4,530	4,600	4,600	5,000	5,000	4,600	5,000	4,600	5,000	4,600	5,000
Total Installed Cost (2022$/kBtu/h)	2,553	4,136	4,012	4,012	13,078	13,113	4,012	13,113	4,012	13,113	4,012	13,113
Annual Maintenance Cost (2022$)[5]	–	–	–	–	–	–	–	–	–	–	–	–
Annual Maintenance Cost (2022$/kBtu/h)	–	–	–	–	–	–	–	–	–	–	–	–

1. Interior volume is characterized by the product size classes reported by ENERGY STAR. The medium size class covers units with interior volume between 13 ft^3 to 28 ft^3. For the medium size class, the interior volume increase from 21.4 ft^3 to 22.4 ft^3 in 2022 reflects the current representative product volume reported by FEMP, last updated December 2021.
2. Maximum idle energy rate is a function of interior volume. For the medium size class, the maximum idle energy rate for 2022 onward is reflective of a representative 22.4 ft^3 unit, using the latest FEMP data from December 2021.
3. Annual energy use is determined using the latest FEMP data from December 2021, which assumes that a typical 22.4 ft^3 commercial hot food holding cabinet uses an average of 9 hours per day and 365 days per year.
4. Retail equipment costs were determined using distributor information for undercounter, half-size, and full-size hot food holding cabinets.
5. Additional installation costs and maintenance costs are negligible.

Note:
ENERGY STAR V. 2.0 went into effect in October 2011 and was revised in December 2022. Massachusetts, Nevada, and Rhode Island state standards have adopted the ENERGY STAR V. 2.0 criteria that went into effect in October 2011. The majority of state standards (California, Colorado, Connecticut, DC, Maryland, New Hampshire, Oregon, Rhode Island, Vermont, and Washington) implement the ENERGY STAR V. 1.0 specification that went into effect in August 2003, which is recorded in the table. ENERGY STAR V. 1.0 specifies a maximum idle energy rate of 40 W per cubic foot of interior volume.

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Commercial Hot Food Holding Cabinets – Large

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DATA	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	State Standards	Typical	ENERGY STAR V. 2.0	High	Typical	High	Typical	High	Typical	High
Interior Volume (ft^3)[1]	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0
Maximum Idle Energy Rate (W)[2]	1,333	1,333	1,760	1,333	400	310	1,333	310	1,333	310	1,333	310
Annual Energy Use (kWh/y)[3]	4,380	4,380	5,782	4,380	1,314	1,018	4,380	1,018	4,380	1,018	4,380	1,018
Average Life (y)	12	12	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)[4]	5,500	5,500	5,500	5,500	6,000	6,000	5,500	6,000	5,500	6,000	5,500	6,000
Total Installed Cost (2022$)[5]	5,500	5,500	5,500	5,500	6,000	6,000	5,500	6,000	5,500	6,000	5,500	6,000
Total Installed Cost (2022$/kBtu/h)	3,224	3,224	2,442	3,224	11,723	15,126	3,224	15,126	3,224	15,126	3,224	15,126
Annual Maintenance Cost (2022$)[5]	–	–	–	–	–	–	–	–	–	–	–	–
Annual Maintenance Cost (2022$/kBtu/h)	–	–	–	–	–	–	–	–	–	–	–	–

1. Interior volume is characterized by the product size classes reported by ENERGY STAR. The large size class covers units with interior volume greater than or equal to 28 ft^3. Interior volume for the large size class was determined based on the units in the ENERGY STAR database, accessed February 1, 2023.
2. Maximum idle energy rate is a function of interior volume. For the large size class, ENERGY STAR and high values were determined using the ENERGY STAR database, and the typical value uses the assumption that ENERGY STAR units are reported to be 70% more efficient than typical units.
3. Annual energy use is determined using the latest FEMP data from December 2021, which assumes that a typical 22.4 ft^3 commercial hot food holding cabinet uses an average of 9 hours per day and 365 days per year. The large size class is assumed to use the same number of annual usage hours as the medium size class.
4. Retail equipment costs were determined using distributor information for undercounter, half-size, and full-size hot food holding cabinets.
5. Additional installation costs and maintenance costs are negligible.

Note:
ENERGY STAR V. 2.0 went into effect in October 2011 and was revised in December 2022. Massachusetts, Nevada, and Rhode Island state standards have adopted the ENERGY STAR V. 2.0 criteria that went into effect in October 2011. The majority of state standards (California, Colorado, Connecticut, DC, Maryland, New Hampshire, Oregon, Rhode Island, Vermont, and Washington) implement the ENERGY STAR V. 1.0 specification that went into effect in August 2003, which is recorded in the table. ENERGY STAR V. 1.0 specifies a maximum idle energy rate of 40 W per cubic foot of interior volume.

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Commercial Hot Food Holding Cabinets

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- Hot food holding cabinets are used in commercial kitchens to keep food warm until it is served.
- While available in many shapes and sizes, interior volumes around 21.4 ft^3 were reported as typical in many settings in EIA Technology Forecast Updates (2018). FEMP currently lists 22.4 ft^3 as a representative unit size.
- Annual unit energy consumption can range from < 1,000 to > 30,000 kWh/y, depending on size, efficiency, and usage.
- Energy performance metric is "Idle Energy Consumption Rate" in Watts, measured using ASTM Standard F2140-11.
- There are no Federal standards for hot food holding cabinets, but seven States have identical standards.
  - The first State standard took effect in California in 2006; this standard is now considered the typical or "baseline" product. It is also equivalent to the ENERGY STAR V. 1.0 Specification that went into effect in August 2003.
  - ENERGY STAR V. 2.0 went into effect in October 2011.
- Maximum Idle Energy Consumption Rate for products $12 \leq V < 28$:
  - State standards: $\leq 40 \times V$ (baseline)
  - ENERGY STAR V. 2.0: $\leq 2.0 \times V + 254$ (about 65% below baseline)

  where V is interior volume in ft^3.
- The most efficient products are about 80% below baseline.
- Energy savings achieved with insulation, automatic door closers, magnetic door gaskets, and Dutch doors (half-doors).

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Commercial Hot Food Holding Cabinets

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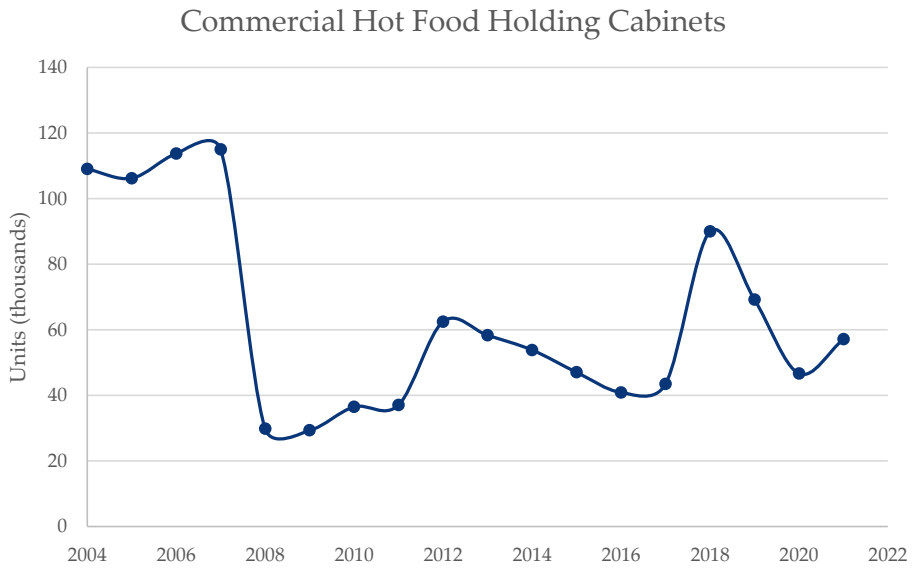
Commercial hot food holding cabinet shipments peaked in 2007 at 115,000 units, followed by a peak of 90,000 units in 2019.



Source: *ENERGY STAR (Unit Shipment Data)*

Appendix A
Data Sources

Guidehouse
1676 International Drive
McLean, VA 22102

And

Leidos
11951 Freedom Drive
Reston, VA 20190

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Residential Space Heating and Cooling

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Residential Gas-Fired Furnaces (North)

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR (North) V. 4.1	High	Typical / High		
Typical Input Capacity (kBtu/h)	Residential Furnaces EERE 2022 NOPR								
AFUE (%)	CFR			DOE CCD	ENERGY STAR V. 4.1	DOE CCD	Residential Furnaces EERE 2022 NOPR		
Electric Consumption (kWh/y)	Residential Furnaces EERE 2016		Residential Furnaces EERE 2022 NOPR						
Average Life (y)	Residential Furnaces EERE 2022 NOPR								
Retail Equipment Cost (2022$)	Residential Furnaces EERE 2016		Residential Furnaces EERE 2022 NOPR						
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)									

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Residential Gas-Fired Furnaces (Rest of Country)

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR (ROC) V. 4.1	High	Typical / High		
Typical Input Capacity (kBtu/h)	Residential Furnaces EERE 2022 NOPR								
AFUE (%)	CFR			DOE CCD	ENERGY STAR V. 4.1	DOE CCD	Residential Furnaces EERE 2022 NOPR		
Electric Consumption (kWh/y)	Residential Furnaces EERE 2016		Residential Furnaces EERE 2022 NOPR						
Average Life (y)	Residential Furnaces EERE 2022 NOPR								
Retail Equipment Cost (2022$)	Residential Furnaces EERE 2016		Residential Furnaces EERE 2022 NOPR						
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)									

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Residential Oil-Fired Furnaces

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.1	High	Typical / High		
Typical Input Capacity (kBtu/h)	Residential Furnaces EERE 2011								
AFUE (%)	CFR			DOE CCD	ENERGY STAR V. 4.1	DOE CCD			
Electric Consumption (kWh/y)	Residential Furnaces EERE 2011								
Average Life (y)									
Retail Equipment Cost (2022$)									
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)									

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Residential Gas-Fired Boilers

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.0	High	Typical / High		
Typical Input Capacity (kBtu/h)	Boilers EERE 2016	Boilers EERE 2022 Preliminary Analysis							
AFUE (%)		Boilers EERE 2022 Preliminary Analysis		DOE CCD	ENERGY STAR V. 3.0	Boilers EERE 2022 Preliminary Analysis			
Electric Consumption (kWh/y)		Boilers EERE 2022 Preliminary Analysis							
Average Life (y)									
Retail Equipment Cost (2022$)									
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)									

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Residential Oil-Fired Boilers

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.0	High	Typical / High		
Typical Input Capacity (kBtu/h)	Boilers EERE 2016	Boilers EERE 2022 Preliminary Analysis							
AFUE (%)		Boilers EERE 2022 Preliminary Analysis		DOE CCD	ENERGY STAR V. 3.0	Boilers EERE 2022 Preliminary Analysis			
Electric Consumption (kWh/y)		Boilers EERE 2022 Preliminary Analysis							
Average Life (y)									
Retail Equipment Cost (2022$)									
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)									

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Residential Electric Resistance Furnaces

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	Typical		
Typical Input Capacity (kBtu/h)	Distributors				Guidehouse		
AFUE (%)	DOE / ASHRAE						
Average Life (y)	Distributors						
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)	Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse					
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse						

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Residential Electric Resistance Unit Heaters

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SOURCES	2015	2020	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical		
Typical Capacity (kBtu/h)	Distributors		Utilities/Distributors	Guidehouse		
Efficiency (%)	DOE		DOE			
Average Life (y)	Guidehouse		Guidehouse			
Retail Equipment Cost (2022$)			Distributors			
Total Installed Cost (2022$)			Home Remodeling Service			
Annual Maintenance Cost (2022$)			Guidehouse			

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Residential Central Air Conditioners – North (Not Hot-Dry or Hot-Humid)

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SOURCES	2015	2020	2022				2023			2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.0	High	New Standard	ENERGY STAR V. 6.1	High	Typical / High		
Typical Input Capacity (kBtu/h)	CAC and HP EERE 2016									Guidehouse		
SEER	CAC and HP EERE 2016 / Guidehouse		CFR	DOE CCD	ENERGY STAR V. 5.0	CAC and HP EERE 2016	RESNET		CAC and HP EERE 2016			
SSER2	RESNET						CAC and HP EERE 2016	ENERGY STAR V. 6.1	RESNET			
Average Life (y)	CAC and HP EERE 2016											
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)	CAC and HP EERE 2016 / Less (2021)											
Annual Maintenance Cost (2022$)	CAC and HP EERE 2016											

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Residential Central Air Conditioners – South (Hot-Dry and Hot-Humid)

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SOURCES	2015	2020	2022				2023			2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.0	High	New Standard	ENERGY STAR V. 6.1	High	Typical / High		
Typical Input Capacity (kBtu/h)	CAC and HP EERE 2016									Guidehouse		
SEER	CAC and HP EERE 2016 / Guidehouse		CFR	DOE CCD	ENERGY STAR V. 5.0	CAC and HP EERE 2016	RESNET		CAC and HP EERE 2016			
SSER2	RESNET						CAC and HP EERE 2016	ENERGY STAR V. 6.1	RESNET			
Average Life (y)	CAC and HP EERE 2016											
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)	CAC and HP EERE 2016 / Less (2021)											
Annual Maintenance Cost (2022$)	CAC and HP EERE 2016											

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Residential Room Air Conditioners

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SOURCES	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.2	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	Distributors		RAC EERE 2022 NOPR									
CEER (Btu/Wh)	Guidehouse		CFR	DOE CCD	ENERGY STAR V. 4.2	DOE CCD	RAC EERE 2022 NOPR	DOE CCD	RAC EERE 2022 NOPR	DOE CCD	RAC EERE 2022 NOPR	DOE CCD
Average Life (y)	RAC EERE 2011		RAC EERE 2022 NOPR									
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Annual Maintenance Cost (2022$)												

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Residential Portable Air Conditioners

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SOURCES	2015	2020	2022		2025		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	New Standard	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	PAC EERE 2020/Guidehouse											
CEER												
Average Life (y)												
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Annual Maintenance Cost (2022$)												

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Residential Swamp Coolers

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SOURCES	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
CFM	Product Literature / Guidehouse				Guidehouse					
Power (Hp)										
Average Life (y)	TLC Plumbing / Guidehouse									
Retail Equipment Cost (2022$)	Product Literature / Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse									
Total Installed Cost (2022$)										
Annual Maintenance Cost (2022$)										

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Residential Air-Source Heat Pumps

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SOURCES	2015	2020	2022				2023				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.0	High	New Standard	ENERGY STAR V. 6.1	ENERGY STAR Cold Climate Criteria	High	Typical/High		
Typical Capacity (kBtu/h)	CACs and HPs EERE 2016 Direct Final Rule												
SEER (Cooling)	CACs and HPs EERE 2016 Direct Final Rule/ Guidehouse		CFR	DOE CCD/ Guidehouse	ENERGY STAR V. 5.0	CACs and HPs EERE 2016 Direct Final Rule	CACs and HPs EERE 2016 Direct Final Rule/ Guidehouse	ENERGY STAR V. 6.1	ENERGY STAR V. 6.1	CACs and HPs EERE 2016 Direct Final Rule	CACs and HPs EERE 2016 Direct Final Rule/Guidehouse		
HSPF (Heating)													
Average Life (y)	CACs and HPs EERE 2016 Direct Final Rule										Guidehouse		
Retail Equipment Cost (2022$)													
Total Installed Cost (2022$)													
Annual Maintenance Cost (2022$)													

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Residential Ductless Mini-Split Air-Source Heat Pumps

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SOURCES	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	AHRI/Guidehouse				Guidehouse					
SEER										
EER										
HSPF										
Average Life (y)	CACs and HPs EERE 2016 Direct Final Rule									
Retail Equipment Cost (2022$)	Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse									
Total Installed Cost (2022$)										
Annual Maintenance Cost (2022$)	CACs and HPs EERE 2016 Direct Final Rule									

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Residential Ground-Source Heat Pumps

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SOURCES	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.2	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	Water-Source Unitary Heat Pumps EERE 2015 Final Rule / DOE CCD		Guidehouse									
COP (Heating)	AHRI Database	AHRI Database / DOE CCD										
EER (Cooling)												
Average Life (y)	Guidehouse / Water-Source Unitary Heat Pumps EERE 2015 Final Rule											
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Annual Maintenance Cost (2022$)												

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Residential Natural Gas Heat Pumps

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SOURCES	2015	2020	2022	2030	2040	2050
	Installed Base		Typical			
Typical Capacity (kBtu/h)	Manufacturer		Guidehouse			
COP (Heating)	Product Literature					
COP (Cooling)						
Annual Electric Use (kWh/y)						
Average Life (y)	Guidehouse					
Retail Equipment Cost (2022$)	PERC					
Total Installed Cost (2022$)	Guidehouse					
Annual Maintenance Cost (2022$)						

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Residential Cordwood Stoves

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SOURCES	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	Distributors / Product Literature				Guidehouse					
Efficiency (Non-Catalytic) (HHV)	Guidehouse / Literature	EPA Certified Wood Stove Database (Room Heaters)								
Efficiency (Catalytic) (HHV)										
Average Life (y)	Guidehouse									
Retail Equipment Cost (2022$)	Product Literature/Dealers									
Total Installed Cost (2022$)	Dealers	Dealers/Guidehouse								
Annual Maintenance Cost (2022$)	Dealers/Guidehouse									

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Residential Wood Pellet Stoves

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SOURCES	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	Distributors / Product Literature				Guidehouse					
Efficiency (HHV)	EPA Default/ Literature/ Guidehouse	EPA Certified Wood Stove Database (Room Heaters)								
Average Life (y)	Guidehouse									
Retail Equipment Cost (2022$)	Product Literature/ Dealers									
Total Installed Cost (2022$)	Dealers/Guidehouse									
Annual Maintenance Cost (2022$)										

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Residential Water Heating

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Residential Gas-Fired Storage Water Heaters

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SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.0	High	ENERGY STAR V. 5.0	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	Guidehouse	CWH EERE 2010 Final Rule /AHRI	CWH EERE 2022 Preliminary Analysis					Guidehouse					
Uniform Energy Factor		DOE CCD	CWH EERE 2022 Preliminary Analysis		ENERGY STAR	CWH EERE 2022 Preliminary Analysis	ENERGY STAR						
Average Life (y)	CWH EERE 2010 Final Rule		CWH EERE 2022 Preliminary Analysis										
Retail Equipment Cost (2022$)	Distributors	CWH EERE 2010 Final Rule											
Total Installed Cost (2022$)	EIA Technology Forecast Updates (2018)	CWH EERE 2010 Final Rule											
Annual Maintenance Cost (2022$)	CWH EERE 2010 Final Rule												

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Residential Oil-Fired Water Heaters

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SOURCES	2015	2020	2022			2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	High	Typical / High		
Typical Capacity (gal)	AHRI	CWH EERE 2010 Final Rule/AHRI	CWH EERE 2022 Preliminary Analysis			Guidehouse		
Uniform Energy Factor	Guidehouse	AHRI/DOE CCD						
Average Life (y)	CWH EERE 2010 Final Rule							
Retail Equipment Cost (2022$)								
Total Installed Cost (2022$)								
Annual Maintenance Cost (2022$)								

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Residential Electric Resistance Storage Water Heaters

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SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	AHRI	CWH EERE 2010 Final Rule/AHRI	CWH EERE 2022 Preliminary Analysis			Guidehouse					
Uniform Energy Factor	Guidehouse	AHRI/ DOE CCD									
Average Life (y)	CWH EERE 2010 Final Rule										
Retail Equipment Cost (2022$)											
Total Installed Cost (2022$)											
Annual Maintenance Cost (2022$)											

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Residential Heat Pump Water Heaters

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SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Typical	ENERGY STAR V. 4.0	High	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	Guidehouse	AHRI	CWH EERE 2022 Preliminary Analysis			Guidehouse					
Uniform Energy Factor		DOE CCD	CWH EERE 2022 Preliminary Analysis	ENERGY STAR	CWH EERE 2022 Preliminary Analysis						
Average Life (y)	CWH EERE 2010 Final Rule		CWH EERE 2022 Preliminary Analysis								
Retail Equipment Cost (2022$)	CWH EERE 2010 Final Rule	Distributors									
Total Installed Cost (2022$)	CWH EERE 2010 Final Rule										
Annual Maintenance Cost (2022$)											

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Residential Solar Water Heaters

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	ENERGY STAR V. 4.0	Typical	Typical	Typical	Typical
Typical Capacity (sq. ft.)	SRCC / Guidehouse		ENERGY STAR		Guidehouse		
Solar Uniform Energy Factor (SUEF)			DOE				
Average Life (y)	DOE / Guidehouse						
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)		Gordian's RSMeans Data – Building Construction Costs 2023				
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse		DOE				

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Residential Gas-Fired Instantaneous Water Heaters

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SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.0	High	ENERGY STAR V. 5.0	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	AHRI	CWH EERE 2010 Final Rule /AHRI	CWH EERE 2022 Preliminary Analysis					Guidehouse					
Uniform Energy Factor	Guidehouse	DOE CCD	CWH EERE 2022 Preliminary Analysis		ENERGY STAR	CWH EERE 2022 Preliminary Analysis	ENERGY STAR						
Average Life (y)	CWH EERE 2010 Final Rule		CWH EERE 2022 Preliminary Analysis										
Retail Equipment Cost (2022$)													
Total Installed Cost (2022$)													
Annual Maintenance Cost (2022$)													

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Residential Electric Instantaneous Water Heaters

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SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	Guidehouse		CWH EERE 2022 Preliminary Analysis			Guidehouse					
Uniform Energy Factor			CWH EERE 2022 Preliminary Analysis/DOE CCD								
Average Life (y)			Gordian's RSMeans Data – Building Construction Costs 2023								
Retail Equipment Cost (2022$)											
Total Installed Cost (2022$)											
Annual Maintenance Cost (2022$)			Guidehouse								

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Residential Appliances

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Residential Refrigerator-Freezers (Top)

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SOURCES	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	RF EERE 2011 / Guidehouse	RF EERE 2021 Preliminary Analysis / Guidehouse					RF EERE 2021 Preliminary Analysis / Guidehouse					
Energy Consumption (kWh/y)		DOE CCD/ Guidehouse	CFR	DOE CCD	ENERGY STAR	DOE CCD						
Average Life (y)		RF EERE 2021 Preliminary Analysis / Guidehouse										
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Annual Maintenance Cost (2022$)												

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Residential Refrigerator-Freezers (Side)

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SOURCES	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	RF EERE 2011 / Guidehouse	RF EERE 2021 Preliminary Analysis / Guidehouse					RF EERE 2021 Preliminary Analysis / Guidehouse					
Energy Consumption (kWh/y)		DOE CCD/ Guidehouse	CFR	DOE CCD	ENERGY STAR	DOE CCD						
Average Life (y)		RF EERE 2021 Preliminary Analysis / Guidehouse										
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Annual Maintenance Cost (2022$)												

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Residential Refrigerator-Freezers (Bottom)

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SOURCES	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	RF EERE 2011 / Guidehouse	RF EERE 2021 Preliminary Analysis / Guidehouse					RF EERE 2021 Preliminary Analysis / Guidehouse					
Energy Consumption (kWh/y)		DOE CCD/ Guidehouse	CFR	DOE CCD	ENERGY STAR	DOE CCD						
Average Life (y)		RF EERE 2021 Preliminary Analysis / Guidehouse										
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Annual Maintenance Cost (2022$)												

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Residential Freezers (Chest)

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SOURCES	2015	2020	2022			2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	High	Typical / High		
Typical Capacity (ft^3)	RF EERE 2011 / Guidehouse		RF EERE Preliminary Analysis 2021/DOE CCD			Guidehouse		
Energy Consumption (kWh/y)	Guidehouse		RF EERE Preliminary Analysis 2021	RF EERE Preliminary Analysis 2021/DOE CCD	DOE CCD			
Average Life (y)	RF EERE 2011 / Guidehouse		RF EERE Preliminary Analysis 2021		RF EERE Preliminary Analysis 2021			
Retail Equipment Cost (2022$)					RF EERE Preliminary Analysis 2021/DOE CCD			
Total Installed Cost (2022$)								
Annual Maintenance Cost (2022$)								

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Residential Freezers (Upright)

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SOURCES	2015	2022	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical / High		
Typical Capacity (ft^3)	RF EERE 2011/ Guidehouse		RF EERE Preliminary Analysis 2021/ DOE CCD				Guidehouse		
Energy Consumption (kWh/y)	Guidehouse		RF EERE Preliminary Analysis 2021	RF EERE Preliminary Analysis 2021/ DOE CCD	ENERGY STAR	DOE CCD			
Average Life (y)	RF EERE 2011 / Guidehouse		RF EERE Preliminary Analysis 2021			RF EERE Preliminary Analysis 2021			
Retail Equipment Cost (2022$)						RF EERE Preliminary Analysis 2021/ DOE CCD			
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)									

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Residential Natural Gas Cooktops

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	High	Typical / High		
Typical Capacity (kBtu/h)	Distributors / Product Literature				Guidehouse		
Integrated Annual Energy Consumption (kBtu/y)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						
Cooking Efficiency (%)	Guidehouse						
Average Life (y)	Consumer Cooking Products EERE 2020 NOPD						
Retail Equipment Cost (2022$)	Consumer Cooking Products EERE 2016 SNOPR / Consumer Cooking Products EERE 2020 NOPD						
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						

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Residential Natural Gas Ovens

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	High	Typical / High		
Typical Capacity (kBtu/h)	Consumer Cooking Products EERE 2016 SNOPR / Product Literature				Guidehouse		
Typical Cavity Volume (ft^3)	Consumer Cooking Products EERE 2016 SNOPR	Consumer Cooking Products EERE 2020 NOPD					
Integrated Annual Energy Consumption (kBtu/y)							
Cooking Efficiency (%)	Guidehouse						
Average Life (y)	Consumer Cooking Products EERE 2020 NOPD	Consumer Cooking Products EERE 2020 NOPD					
Retail Equipment Cost (2022$)	Consumer Cooking Products EERE 2016 SNOPR						
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						

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Residential Natural Gas Ranges

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	High	Typical / High		
Typical Capacity of Cooktop Component (kBtu/h)	Distributors / Product Literature				Guidehouse		
Typical Capacity of Oven Component (kBtu/h)	Consumer Cooking Products EERE 2016 SNOPR / Product Literature						
Typical Cavity Volume of Oven Component (ft^3)	Consumer Cooking Products EERE 2020 NOPD	Consumer Cooking Products EERE 2020 NOPD					
Integrated Annual Energy Consumption (kBtu/y)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						
Average Life (y)	Consumer Cooking Products EERE 2020 NOPD						
Retail Equipment Cost (2022$)	Guidehouse / Distributors / Gordian's RSMeans Data – Building Construction Costs 2023						
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						

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Residential Electric Cooktops

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	High	Typical / High		
Typical Capacity (W)	Consumer Cooking Products EERE 2016 SNOPR / Distributors				Guidehouse		
Integrated Annual Energy Consumption (kWh/y)	Consumer Cooking Products EERE 2020 NOPD						
Average Life (y)							
Retail Equipment Cost (2022$)							
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						

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Residential Electric Ovens

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	High	Typical / High		
Typical Capacity (W)	Consumer Cooking Products EERE 2016 SNOPR / Distributors				Guidehouse		
Typical Cavity Volume (ft^3)	Consumer Cooking Products EERE 2016 SNOPR	Consumer Cooking Products EERE 2020 NOPD					
Integrated Annual Energy Consumption (kWh/y)							
Average Life (y)	Consumer Cooking Products EERE 2020 NOPD						
Retail Equipment Cost (2022$)	Consumer Cooking Products EERE 2020 NOPD						
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						

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Residential Electric Ranges

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Residential Electric Clothes Dryers

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SOURCES	2015	2020	2022				2030	2040	2040
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 1.1	High	Typical / High		
Typical Capacity (ft^3)	DOE CCD					Guidehouse / DOE CCD / ENERGY STAR	Guidehouse		
CEF, D1 (lb/kWh)	Consumer Clothes Dryers EERE 2022 NOPR / Guidehouse	DOE CCD	Consumer Clothes Dryers EERE 2022 NOPR	DOE CCD	ENERGY STAR V. 1.1	DOE CCD			
CEF, D2 (lb/kWh)						ENERGY STAR			
Average Life (y)	Consumer Clothes Dryers EERE 2022 NOPR								
Retail Equipment Cost (2022$)	Consumer Clothes Dryers EERE 2022 NOPR / Guidehouse								
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)	Consumer Clothes Dryers EERE 2022 NOPR								

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Residential Natural Gas Clothes Dryers

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 1.1	High	Typical / High		
Typical Capacity (ft^3)	DOE CCD						Guidehouse		
CEF, D1 (lb/kWh)	Consumer Clothes Dryers EERE 2022 NOPR / Guidehouse	DOE CCD	Consumer Clothes Dryers EERE 2022 NOPR	DOE CCD	ENERGY STAR V. 1.1	DOE CCD			
CEF2, D2 (lb/kWh)									
Average Life (y)	Consumer Clothes Dryers EERE 2022 NOPR								
Retail Equipment Cost (2022$)	Consumer Clothes Dryers EERE 2022 NOPR / Guidehouse								
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)	Consumer Clothes Dryers EERE 2022 NOPR								

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Residential Clothes Washers (Front)

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 8.1	High	Typical / High		
Typical Capacity (ft^3)	Guidehouse	DOE CCD / Guidehouse	DOE CCD	DOE CCD	DOE CCD	DOE CCD	Guidehouse		
Integrated Modified Energy Factor (ft^3/kWh/cycle)	AHAM / Guidehouse		RCW EERE 2021 Preliminary Analysis		ENERGY STAR V. 8.1				
Integrated Water Factor (gal/cycle/ft^3)									
Average Life (y)	RCW EERE 2021 Preliminary Analysis								
Water Consumption (gal/cycle)	Guidehouse / RCW EERE 2021 Preliminary Analysis								
Hot Water Energy (kWh/cycle)									
Machine Energy (kWh/cycle)									
Dryer Energy (kWh/cycle)									
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)	RCW EERE 2021 Preliminary Analysis/ Distributors							
Total Installed Cost (2022$)		RCW EERE 2021 Preliminary Analysis/ Guidehouse							
Annual Maintenance Cost (2022$)	RCW EERE 2021 Preliminary Analysis / Guidehouse								

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Residential Clothes Washers (Top)

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 8.1	High	Typical / High		
Typical Capacity (ft^3)	Guidehouse	Guidehouse	DOE CCD	DOE CCD	DOE CCD	DOE CCD	Guidehouse		
Integrated Modified Energy Factor (ft^3/kWh/cycle)	AHAM / Guidehouse	RCW EERE 2021 Preliminary Analysis			ENERGY STAR V. 8.1	DOE CCD			
Integrated Water Factor (gal/cycle/ft^3)									
Average Life (y)	RCW EERE 2021 Preliminary Analysis								
Water Consumption (gal/cycle)	RCW EERE 2021 Preliminary Analysis / Guidehouse								
Hot Water Energy (kWh/cycle)	Guidehouse	RCW EERE 2021 Preliminary Analysis / Guidehouse							
Machine Energy (kWh/cycle)									
Dryer Energy (kWh/cycle)									
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)								
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)	RCW EERE 2021 Preliminary Analysis / Guidehouse								

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Residential Dishwashers

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SOURCES	2015	2020	2022				2023	2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 6.0	High	ENERGY STAR V. 7.0	Typical / High		
Typical Annual Energy Use (kWh/y)	AHAM 2014 / DW EERE 2012 Final Rule	Guidehouse / DOE CCD / ENERGY STAR	CFR	Guidehouse / DOE CCD / ENERGY STAR	ENERGY STAR	DW EERE 2022 Preliminary Analysis	ENERGY STAR	Guidehouse		
Water Consumption (gal/cycle)										
Water Heating Energy Use (kWh/y)	AHAM 2014 / DW EERE 2012 Final Rule	DW EERE 2016 Direct Final Rule	DW EERE 2022 Preliminary Analysis							
Average Life (y)	DW EERE 2016 Direct Final Rule/Guidehouse									
Retail Equipment Cost (2022$)	DW EERE 2012 Final Rule	DW EERE 2016 Direct Final Rule								
Total Installed Cost (2022$)										

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Commercial Space Heating and Cooling

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Commercial Gas-Fired Furnaces

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SOURCES	2012	2018	2022			2023		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	High	New Standard	Typical	Typical		
Typical Input Capacity (kBtu/h)	AHRI	CWAF EERE 2015	DOE CCD				Guidehouse	Guidehouse		
Thermal Efficiency (%)		DOE CCD	CFR	DOE CCD		CFR				
Typical Output Capacity (kBtu/h)	Guidehouse									
Average Life (y)	CWAF EERE 2015									
Retail Equipment Cost (2022$)										
Total Installed Cost (2022$)										
Total Installed Cost (2022$/kBtu/h)										
Annual Maintenance Cost (2022$)										
Annual Maintenance Cost (2022$/kBtu/h)										

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Commercial Oil-Fired Furnaces

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SOURCES	2012	2018	2022			2023		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	High	New Standard	Typical	Typical/High		
Typical Input Capacity (kBtu/h)	AHRI	DOE CCD	DOE CCD				Guidehouse	Guidehouse		
Thermal Efficiency (%)			10 CFR 431.77	DOE CCD		10 CFR 431.77				
Typical Output Capacity (kBtu/h)	Guidehouse									
Average Life (y)	CWAF EERE 2015									
Retail Equipment Cost (2022$)										
Total Installed Cost (2022$)										
Total Installed Cost (2022$/kBtu/h)										
Annual Maintenance Cost (2022$)										
Annual Maintenance Cost (2022$/kBtu/h)										

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Commercial Electric Resistance Heaters

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SOURCES	2012		2018		2022		2030		2040		2050	
	Small	Large	Small	Large	Small	Large	Small	Large	Small	Large	Small	Large
Typical Capacity (kBtu/h)	Distributors/Guidehouse						Guidehouse					
Efficiency (%)	Guidehouse/DOE											
Average Life (y)	Technology Cost and Performance File for Commercial Model for AEO2010											
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)				Gordian's RSMeans Data – Building Construction Costs 2023							
Total Installed Cost (2022$)												
Total Installed Cost (2022$/kBtu/h)												
Annual Maintenance Cost (2022$)	Guidehouse											
Annual Maintenance Cost (2022$/kBtu/h)												

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Commercial Electric Boilers

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SOURCES	2012	2018	2022	2030	2040	2050
	Installed Base	Installed Base	Typical			
Typical Capacity (kW)	BSRIA		Guidehouse			
Efficiency (%)	EERE / Guidehouse					
Average Life (y)	ASHRAE 2007 HVAC Applications	ASHRAE 2015 HVAC Applications	ASHRAE 2019 HVAC Applications			
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)		Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse			
Total Installed Cost (2022$)			Gordian's RSMeans Data – Building Construction Costs 2023			
Total Installed Cost (2022$/kBtu/h)						
Annual Maintenance Cost (2022$)			EIA Technology Forecast Updates (2018)			
Annual Maintenance Cost (2022$/kBtu/h)						

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Commercial Gas-Fired Boilers

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SOURCES	2012	2018	2022			2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	New Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	Guidehouse	Comm. Packaged Boilers EERE 2020												
Thermal Efficiency (%)	ASHRAE Standard 90.1-2004 / Guidehouse	Comm. Packaged Boilers EERE 2020 / Guidehouse	DOE CCD			Comm. Packaged Boilers EERE 2020/Guidehouse								
Average Life (y)	Comm. Heating, AC, WH EERE 2009	Comm. Packaged Boilers EERE 2020												
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)													
Total Installed Cost (2022$)														
Total Installed Cost (2022$/kBtu/h)														
Annual Maintenance Cost (2022$)	Comm. Heating, AC, WH EERE 2009													
Annual Maintenance Cost (2022$/kBtu/h)														

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Commercial Oil-Fired Boilers

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SOURCES	2012	2018	2022			2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	New Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	Guidehouse	Comm. Packaged Boilers EERE 2020												
Thermal Efficiency (%)	ASHRAE Standard 90.1-2004 / Guidehouse	Comm. Packaged Boilers EERE 2020 / Guidehouse	DOE CCD			Comm. Packaged Boilers EERE 2020/Guidehouse								
Average Life (y)	Comm. Heating, AC, WH EERE 2009	Comm. Packaged Boilers EERE 2020												
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)													
Total Installed Cost (2022$)														
Total Installed Cost (2022$/kBtu/h)														
Annual Maintenance Cost (2022$)	Comm. Heating, AC, WH EERE 2009													
Annual Maintenance Cost (2022$/kBtu/h)														

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Commercial Centrifugal Chillers (Water-Cooled)

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SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	ASHRAE 90.1-2019	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (tons)	IPCC/ARB/TEAP/Guidehouse					Guidehouse					
Efficiency (kW/ton)	ASHRAE 90.1-2010/FEMP/ eSource/ Product Literature	ASHRAE 90.1-2019/Product Lit									
COP											
Average Life (y)	2007 ASHRAE Applications Handbook	2015 ASHRAE Applications Handbook A37 Table 4									
Retail Equipment Cost (2022$/ton)	EIA Technology Forecast Updates (2018)	Gordian's RSMeans Data – Building Construction Costs 2023									
Total Installed Cost (2022$/ton)											
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$/ton)	Guidehouse/Alabama Power										
Annual Maitnenance Cost (2022$/kBtu/h)											

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Commercial Reciprocating Chillers (Air-Cooled Only)

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SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	ASHRAE 90.1-2019	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (tons)	BSRIA/DEER		Guidehouse			Guidehouse					
Efficiency (kW/ton)	ASHRAE 90.1-2010/DEER/ FEMP/Product Literature	ASHRAE 90.1-2016 (>150 TR)	ASHRAE 90.1-2019		Product Lit						
COP	ASHRAE 90.1-2010/DEER/ FEMP/Product Literature	ASHRAE 90.1-2016 (>150 TR)									
Average Life (y)	Manufacturers	2015 ASHRAE Applications Handbook A37 Table 4									
Retail Equipment Cost (2022$/ton)	EIA Technology Forecast Updates (2018)		Gordian's RSMeans Data – Building Construction Costs 2023								
Total Installed Cost (2022$/ton)											
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$/ton)	Guidehouse/Alabama Power										
Annual Maintenance Cost (2022$/kBtu/h)											

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Commercial Screw Chillers (Air-Cooled Only)

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SOURCES	2012	2018	2022			2030	2040	2050
	Installed Base	Installed Base	ASHRAE 90.1-2019	Typical	High	Typical/High		
Typical Capacity (tons)	Guidehouse					Guidehouse		
Efficiency (kW/ton)	Guidehouse	ASHRAE 90.1-2016 (>150 TR)	ASHRAE 90.1-2019 (>150 TR)	ASHRAE 90.1-2019 (>150 TR)/Product Lit	Product Lit			
COP								
Average Life (y)	Manufacturers	FacilitiesNet						
Retail Equipment Cost (2022$/ton)	EIA Technology Forecast Updates (2018)		Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse					
Total Installed Cost (2022$/ton)								
Total Installed Cost (2022$/kBtu/h)								
Annual Maintenance Cost (2022$/ton)	Guidehouse/Alabama Power							
Annual Maintenance Cost (2022$/kBtu/h)								

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Commercial Scroll Chillers (Air-Cooled Only)

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SOURCE	2012	2018	2022			2030	2040	2050
	Installed Base	Installed Base	ASHRAE 90.1-2019	Typical	High	Typical / High		
Typical Capacity (tons)	Guidehouse/Manufacturers					Guidehouse		
Efficiency [full-load/IPLV] (kW/ton)	Guidehouse	Product Lit/ Guidehouse	ASHRAE 90.1-2019 (>150 TR)	Product Lit/ Guidehouse	Product Lit			
COP [full-load/IPLV]								
Average Life (y)	Manufacturers							
Retail Equipment Cost (2022$/ton)	EIA Technology Forecast Updates (2018)		Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse					
Total Installed Cost (2022$/ton)								
Total Installed Cost (2022$/kBtu/h)								
Annual Maintenance Cost (2022$/ton)	Guidehouse/Alabama Power							
Annual Maintenance Cost (2022$/kBtu/h)								

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Commercial Gas-Fired Chillers (Water-Cooled, Direct-Fired Only)

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SOURCES	2012		2018		2022				2030	2040	2050
	Installed Base: Absorption	Installed Base: Engine-Driven	Installed Base: Absorption	Installed Base: Engine-Driven	ASHRAE 90.1-2019 Absorption	CA Title 24 – Engine-Driven	Absorption	Engine-Driven	Absorption/Engine-Driven		
Typical Capacity (tons)	BSRIA/Distributors								Guidehouse		
COP [full-load]	Product Literature/ Guidehouse		Product Lit		ASHRAE 90.1-2019 Direct-fired Double Effect	CA Title 24 Gas Engine Standard	Product Lit				
COP [IPLV]											
Average Life (y)	2007 ASHRAE Applications Handbook/ Distributors		2015 ASHRAE Applications Handbook A37 Table 4								
Retail Equipment Cost (2022$/ton)	EIA Technology Forecast Updates (2018)				Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse						
Total Installed Cost (2022$/ton)											
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$/ton)	Guidehouse/Alabama Power										
Annual Maintenance Cost (2022$/kBtu/h)											

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Commercial Rooftop Air Conditioners

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SOURCES	2012	2018	2022				2023				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.1	High	New Standard	Typical	ENERGY STAR V. 4.0	High	Typical	High	Typical	High	Typical	High
Typical Output Capacity (kBtu/h)	AHRI / Guidehouse	CUAC EERE 2016									CUAC EERE 2016 / Guidehouse					
Part Load Efficiency (IEER)	CUAC EERE 2016				ENERGY STAR	CUAC EERE 2016			ENERGY STAR	CUAC EERE 2016						
Efficiency (EER)	CUAC EERE 2016 / Guidehouse															
Efficiency Conversion	Calculated															
Average Life (y)	CUAC EERE 2016															
Retail Equipment Cost (2022$)	Distributors / Guidehouse / DEER, 2008	CUAC EERE 2016														
Total Installed Cost (2022$)																
Total Installed Cost (2022$/kBtu/h)	Calculated															
Annual Maintenance Cost (2022$)	CUAC EERE 2016															
Annual Maintenance Cost (2022$/kBtu/h)	Calculated															

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Commercial Gas-Fired Engine-Drive Rooftop Air Conditioners

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SOURCES	2012	2018	2022	2030	2040	2050
	Installed Base		Typical			
Typical Capacity (tons)	EIA Technology Forecast Updates (2018)		Guidehouse			
Heating COP						
Cooling COP						
Average Life (y)						
Retail Equipment Cost ($/ton)			Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse			
Total Installed Cost ($/ton)						
Total Installed Cost ($/kBtu/h)						
Annual Maintenance Cost (2022$)						
Annual Maintenance Cost (2022$/kBtu/h)						

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Commercial Rooftop Heat Pumps

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SOURCES	2012	2018	2022				2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.1	High	New Standard	ENERGY STAR V. 4.0	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	EECUHP EERE 2016									CUHP EERE 2016 / Guidehouse					
Part Load Efficiency (IEER)	CUHP EERE 2016 / Guidehouse				ENERGY STAR	CUHP EERE 2016		ENERGY STAR	CUHP EERE 2016						
COP (Heating)															
Average Life (y)	EIA Technology Forecast Updates (2018)		CUHP EERE 2016												
Retail Equipment Cost (2022$)															
Total Installed Cost (2022$)															
Total Installed Cost (2022$/kBtu/h)															
Annual Maintenance Cost (2022$)															
Annual Maintenance Cost (2022$/kBtu/h)															

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Commercial Ground-Source Heat Pumps

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SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	U.S. DOE/EIA	Water-Source Unitary Heat Pumps EERE 2015 Final Rule				Guidehouse					
COP (Heating)	Guidehouse	AHRI Database									
EER (Cooling)											
Average Life (y)	Guidehouse / Water-Source Unitary Heat Pumps EERE 2015 Final Rule										
Retail Equipment Cost (2022$)	Distributors/Guidehouse	Water-Source Unitary Heat Pumps 2015 EERE Final Rule / Guidehouse									
Total Installed Cost (2022$)	U.S. DOD/IGSHPA/MA DOER/CEFIA/ ASHRAE										
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$)	Geothermal Heat Pump Consortium, Inc. (U.S. DOE Contract DE-FG07-95ID13347)										
Annual Maintenance Cost (2022$/kBtu/h)											

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Packaged Terminal Air Conditioners

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SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	PTAC & PTHP EERE 2022 NOPD					PTAC & PTHP EERE 2022 NOPD / Guidehouse					
Efficiency (EER)											
Efficiency											
Average Life (y)											
Retail Equipment Cost (2022$)											
Total Installed Cost (2022$)											
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$)											
Annual Maintenance Cost (2022$/kBtu/h)											

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Packaged Terminal Heat Pumps

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SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	PTAC & PTHP EERE 2022 NOPD					PTAC & PTHP EERE 2022 NOPD / Guidehouse					
Efficiency (EER)											
Efficiency											
COP (Heating)											
Average Life (y)											
Retail Equipment Cost (2022$)											
Total Installed Cost (2022$)											
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$)											
Annual Maintenance Cost (2022$/kBtu/h)											

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Commercial Water Heating

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Commercial Gas-Fired Storage Water Heaters

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SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 2.0	High	Typical	High	Typical	High	Typical	High
Typical Storage Capacity (gal)	EIA Technology Forecast Updates (2018)	CWH EERE 2022 NOPR										
Typical Input Capacity (kBtu/h)												
Thermal Efficiency (%)		DOE CCD / Guidehouse	CFR	DOE CCD/ Guidehouse	ENERGY STAR	DOE CCD	CWH EERE 2022 NOPR / Guidehouse					
Average Life (y)		CWH EERE 2022 NOPR										
Retail Equipment Cost (2022$)	CWH EERE 2022 NOPR											
Total Installed Cost (2022$/kBtu/h)												
Annual Maintenance Cost (2022$)												
Annual Maintenance Cost (2022$/kBtu/h)												
Annual Maintenance Cost (2022$/kBtu/h)												

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Commercial Electric Resistance Storage Water Heaters

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SOURCES	2012	2018	2022		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	Typical		
Typical Storage Capacity (gal)	Product Literature / Guidehouse	CWH EERE 2016 NOPR			Guidehouse		
Typical Input Capacity (kW)	Product Literature						
Typical Input Capacity (kBtu/h)							
Thermal Efficiency (%)	Guidehouse						
Average Life (y)	CWH EERE 2016 NOPR						
Retail Equipment Cost (2022$)	CWH EERE 2016 NOPR / Guidehouse	CWH EERE 2016 NOPR					
Total Installed Cost (2022$)							
Total Installed Cost (2022$/kBtu/h)							
Annual Maintenance Cost (2022$)							
Annual Maintenance Cost (2022$/kBtu/h)							

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Commercial Heat Pump Water Heaters

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SOURCES	2012	2018	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	ENERGY STAR V. 2.0	Typical	Typical	Typical
Water Flow Rate (gal/min)	Distributors/Guidehouse		Guidehouse				
Typical Output Capacity (kW)							
Typical Output Capacity (kBtu/h)							
Coefficient of Performance (COP_h)							
Average Life (y)	EERE/Guidehouse						
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)						
Total Installed Cost (2022$)							
Total Installed Cost (2022$/kBtu/h)							
Annual Maintenance Cost (2022$)	Guidehouse						
Annual Maintenance Cost (2022$/kBtu/h)							

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Commercial Oil-Fired Storage Water Heaters

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SOURCES	2012	2018	2022			2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	High	Typical/High		
Typical Storage Capacity (gal)	AHRI / Guidehouse	DOE CCD/Guidehouse				Guidehouse		
Typical Input Capacity (kBtu/h)								
Thermal Efficiency (%)	Guidehouse		CFR	DOE CCD				
Average Life (y)	Commercial Heating, Air Conditioning and Water Heating Equipment EERE 2001							
Retail Equipment Cost (2022$)	Distributors / Guidehouse							
Total Installed Cost (2022$)								
Total Installed Cost (2022$/kBtu/h)								
Annual Maintenance Cost (2022$)								
Annual Maintenance Cost (2022$/kBtu/h)								

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Commercial Electric Booster Water Heaters

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SOURCES	2012	2018	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical	Typical	Typical
Typical Capacity (gal)	Product Literature / Guidehouse					
Typical Output Capacity (kBtu/h)						
Thermal Efficiency (%)						
Average Life (y)						
Retail Equipment Cost (2022$)						
Total Installed Cost (2022$)						
Total Installed Cost (2022$/kBtu/h)						
Annual Maintenance Cost (2022$)						
Annual Maintenance Cost (2022$/kBtu/h)						

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Commercial Gas-Fired Booster Water Heaters

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SOURCES	2012	2018	2022		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	Typical	Typical	Typical
Typical Capacity (gal)	Product Literature / Guidehouse						
Typical Output Capacity (kBtu/h)							
Thermal Efficiency (%)							
Average Life (y)							
Retail Equipment Cost (2022$)							
Total Installed Cost (2022$)							
Total Installed Cost (2022$/kBtu/h)							
Annual Maintenance Cost (2022$)							
Annual Maintenance Cost (2022$/kBtu/h)							

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Commercial Gas-Fired Instantaneous Water Heaters

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SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 2.0	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	DOE CCD						DOE CCD / Guidehouse					
Thermal Efficiency (%)	Guidehouse/DOE CCD		DOE CCD		ENERGY STAR	DOE CCD						
Average Life (y)	CWH EERE 2022 NOPR											
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Total Installed Cost (2022$/kBtu/h)												
Annual Maintenance Cost (2022$)												
Annual Maintenance Cost (2022$/kBtu/h)												

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Commercial Solar Water Heaters

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SOURCES	2012	2018	2022		2023	2030	2040	2050
	Installed Base	Installed Base	Typical	ENERGY STAR V. 4.0	ENERGY STAR V. 5.0	Typical	Typical	Typical
Typical Capacity (sq. ft.)	SRCC / Guidehouse					Guidehouse		
Typical Capacity (m^2)								
Typical Capacity (Input) (kBtu/h) - North								
Typical Capacity (Input) (kBtu/h) - South								
Solar Uniform Energy Factor (SUEF)	ENERGY STAR / Guidehouse							
Average Life (y)	SRCC / Guidehouse							
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)		Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse					
Total Installed Cost (2022$)								
Total Installed Cost (2022$/kBtu/h) - North	Guidehouse							
Total Installed Cost (2022$/kBtu/h) - South								
Annual Maintenance Cost (2022$)	DOE / Guidehouse							
Annual Maintenance Cost (2022$/kBtu/h) - North								
Annual Maintenance Cost (2022$/kBtu/h) - South								

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Commercial Cooking Products

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Commercial Natural Gas Range with Griddle and Oven

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SOURCES	2012	2018	2022			2023	2030	2040	2050
	Installed Base	Installed Base	Typical	ENERGY STAR V. 2.2	High	ENERGY STAR V. 3.0	Typical/High		
Griddle - Cooking Energy Efficiency (%)	Guidehouse	FSTC	ENERGY STAR / FSTC	ENERGY STAR	ENERGY STAR	NA	Guidehouse		
Oven - Cooking Energy Efficiency (%)						ENERGY STAR			
Range - Cooking Energy Efficiency (%)			FEMP / CEC	NA	FEMP / CEC	NA			
Combined Energy Efficiency (%)	Guidehouse / FSTC								
Griddle - Normalized Idle Energy Rate (Btu/h/ft^2)	Guidehouse	FSTC	ENERGY STAR / FSTC	ENERGY STAR	ENERGY STAR	NA			
Oven - Idle Energy Rate (Btu/h)	FEMP		ENERGY STAR			ENERGY STAR			
Range - Idle Energy Rate (Btu/h)	FSTC			NA	FSTC	NA			
Combined Idle Energy Rate (Btu/h)	Guidehouse / FSTC / Distributors								
Average Life (y)	FSTC								
Retail Equipment Cost (2022$)	Distributors								
Total Installed Cost (2022$)	FSTC / Guidehouse								
Total Installed Cost (2022$/kBtu/h)									
Annual Maintenance Cost (2022$)	FSTC								
Annual Maintenance Cost (2022$/kBtu/h)									

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Commercial Electric Range with Griddle and Oven

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SOURCES	2012	2018	2022			2023	2030	2040	2050
	Installed Base	Installed Base	Typical	ENERGY STAR V. 2.2	High	ENERGY STAR V. 3.0	Typical/High		
Griddle - Cooking Energy Efficiency (%)	Guidehouse	FSTC	FSTC / ENERGY STAR / Guidehouse	ENERGY STAR	ENERGY STAR	NA	Guidehouse		
Oven - Cooking Energy Efficiency (%)						ENERGY STAR			
Range - Cooking Energy Efficiency (%)				NA	CEC	NA			
Combined Energy Efficiency (%)	Guidehouse / FSTC								
Griddle - Normalized Idle Energy Rate (kW/ft²)	Guidehouse	FSTC	FSTC / ENERGY STAR / Guidehouse	ENERGY STAR	ENERGY STAR	NA			
Oven - Idle Energy Rate (kW)						ENERGY STAR			
Range - Idle Energy Rate (kW)	NA								
Combined Idle Energy Rate (kW)	Guidehouse / FSTC / Distributors								
Average Life (y)	FSTC								
Retail Equipment Cost (2022$)	Distributors								
Total Installed Cost (2022$)	FSTC / Guidehouse								
Total Installed Cost (2022$/kBtu/h)									
Annual Maintenance Cost (2022$)	FSTC								
Annual Maintenance Cost (2022$/kBtu/h)									

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Commercial Hot Food Holding Cabinets – Small

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SOURCES	2012	2018	2022				2030	2040
	Installed Base	Installed Base	State Standards	Typical	ENERGY STAR V. 2.0	High	Typical/High	
Interior Volume (ft^3)	FEMP / ENERGY STAR						Guidehouse	
Maximum Idle Energy Rate (W)	CEE / Guidehouse	FEMP	ASAP	ASAP / ENERGY STAR	ENERGY STAR V. 2.0	FEMP / ENERGY STAR		
Annual Energy Use (kWh/y)	FEMP							
Average Life (y)								
Retail Equipment Cost (2022$)	Distributors / ENERGY STAR Savings Calculator / Guidehouse							
Total Installed Cost (2022$)	Guidehouse							
Total Installed Cost (2022$/kBtu/h)								
Annual Maintenance Cost (2022$)	FSTC							
Annual Maintenance Cost (2022$/kBtu/h)								

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Commercial Hot Food Holding Cabinets – Medium

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SOURCES	2012	2018	2022				2030	2040
	Installed Base	Installed Base	State Standards	Typical	ENERGY STAR V. 2.0	High	Typical/High	
Interior Volume (ft^3)	FEMP / ENERGY STAR						Guidehouse	
Maximum Idle Energy Rate (W)	CEE / Guidehouse	FEMP	ASAP	ASAP / ENERGY STAR	ENERGY STAR V. 2.0	FEMP / ENERGY STAR		
Annual Energy Use (kWh/y)	FEMP							
Average Life (y)								
Retail Equipment Cost (2022$)	Distributors / ENERGY STAR Savings Calculator / Guidehouse							
Total Installed Cost (2022$)	Guidehouse							
Total Installed Cost (2022$/kBtu/h)								
Annual Maintenance Cost (2022$)	FSTC							
Annual Maintenance Cost (2022$/kBtu/h)								

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Commercial Hot Food Holding Cabinets – Large

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SOURCES	2012	2018	2022				2030	2040
	Installed Base	Installed Base	State Standards	Typical	ENERGY STAR V. 2.0	High	Typical/High	
Interior Volume (ft^3)	FEMP / ENERGY STAR						Guidehouse	
Maximum Idle Energy Rate (W)	CEE / Guidehouse	FEMP	ASAP	ASAP / ENERGY STAR	ENERGY STAR V. 2.0	FEMP / ENERGY STAR		
Annual Energy Use (kWh/y)	FEMP							
Average Life (y)								
Retail Equipment Cost (2022$)	Distributors / ENERGY STAR Savings Calculator / Guidehouse							
Total Installed Cost (2022$)	Guidehouse							
Total Installed Cost (2022$/kBtu/h)								
Annual Maintenance Cost (2022$)	FSTC							
Annual Maintenance Cost (2022$/kBtu/h)								

Appendix B
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Guidehouse
1676 International Drive
McLean, VA 22102

And

Leidos
11951 Freedom Drive
Reston, VA 20190

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March 2023

APPENDIX B

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Final

EIA - Technology Forecast Updates – Residential and Commercial Building Technologies – Advanced Case

Presented to:

U.S. Energy Information Administration

Prepared by:

Guidehouse
1676 International Drive
McLean, VA 22102

And

Leidos
11951 Freedom Drive
Reston, VA 20190

March 3, 2023

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Objective

The objective of this study is to develop baseline and projected performance/cost characteristics for residential and commercial end-use equipment.

- Installed base in 2012 and 2018 (for commercial products) or 2015 and 2020 (for residential products) and current market (2022)
  - Review literature, standards, installed base, contractor, and manufacturer information
  - Provide a relative comparison and characterization of the cost/efficiency of a generic product
- Forecast of technology improvements that are projected to be available through 2050
  - Review trends in standards, product enhancements, and Research and Development (R&D)
  - Project impact of product improvements and enhancement to technology

The performance/cost characterization of end-use equipment developed in this study will assist EIA in projecting national primary energy consumption.

Methodology

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Input from industry stakeholders, including government, R&D organizations, and manufacturers, was used to project product enhancements concerning equipment performance and cost attributes.

- Technology forecasting involves many uncertainties.
- Technology developments impact performance and cost forecasts.
- Varied sources ensure a balanced view of technology progress and the probable timing of commercial availability.
- Only currently published efficiency standards and regulations are considered when predicting technology developments; unpublished future regulatory action is not predicted.
- All costs are shown in 2022 dollars (2022$).
- Ranges, when given, represent the span of typical values for a given parameter (e.g., installed cost for equipment meeting the federal standard) not the highest and lowest available on the market.

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Advanced Case Assumptions

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The Advanced Case and Reference Case both assume current level of effort for standards. However, the Advanced Case assumes an increase in market incentive and federal R&D. The general approach for the Advanced Case is outlined below.

- The Advanced Case considers future changes to product groups such as:
  - Product or component changes that are fully developed but have not yet been commercialized
  - Expected incremental improvements in existing technologies due to increased R&D
  - Increased adoption of existing higher efficiency technology options due to increased market incentives
- The Advanced Case did *not* include future changes to product groups that are due to:
  - Prototype technology changes or products that are in preliminary research that may have performance improvements but have only been demonstrated in theoretical calculations

Definitions

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The following tables represent the current and projected efficiencies for residential and commercial building equipment ranging from the installed base in 2012 and 2018 (for commercial products) or 2015 and 2020 (for residential products) to the highest efficiency equipment that is expected to be commercially available by 2050, assuming incremental adoption. Below are definitions for the terms used in characterizing the status of each technology.

- Installed Base: Efficiency values are for those units installed and "in use" in that year. Cost values are for the typical new unit sold in that year.
- Current Standard: The minimum efficiency (or maximum energy use) that is required (allowed) by current U.S. Department of Energy (DOE) standards, when applicable.
- ENERGY STAR: The minimum efficiency that is required (or maximum energy use allowed) to meet the ENERGY STAR criteria, when applicable. The performance data that are presented are representative of certified products that just meet current ENERGY STAR specifications.
- Typical: Efficiency and cost values are for the average, or "typical," product being sold in the particular timeframe. This may represent either the shipments-weighted average product performance or the most common product on the market.
- High: Efficiency and cost values are for the product with the highest efficiency available in the particular timeframe.

Market Transformation

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The market for the reviewed products has changed since this analysis was previously conducted.[1] These changes are noted and reflected in the efficiency and cost characteristics.

- In some categories the typical new product purchased today is more efficient than the average product in the installed base in 2012 (commercial) or 2015 (residential):
  - Residential sector: boilers, central air conditioners, room air conditioners, gas-fired furnaces (North), gas-fired furnaces (Rest of Country), oil-fired furnaces, electric resistance furnaces, heat pump water heaters, gas-fired instantaneous water heaters, natural gas cooktops, natural gas ovens, refrigerator-freezers, freezers, clothes dryers, clothes washers, and dishwashers
  - Commercial sector: gas-fired furnaces, oil-fired boilers, commercial rooftop heat pumps, commercial ground-source heat pumps, gas-fired instantaneous water heater, natural gas and electric ranges, griddles, and ovens
- More stringent Federal standards have taken effect for the following products:
  - Gas-fired and oil-fired boilers in 2021
  - Rooftop air conditioners and rooftop heat pumps in 2018
- Federal standards are slated to take effect in the coming years for the following products:
  - Central air conditioners, residential air-source heat pumps, gas-fired furnaces, oil-fired furnaces, gas-fired boilers, oil-fired boilers, rooftop air conditioners, and rooftop heat pumps in 2023
  - Portable air conditioners in 2025
- ENERGY STAR continues to raise the bar with revised criteria for:
  - Central air conditioners, residential air-source heat pumps, rooftop air conditioners, rooftop heat pumps, residential water heaters, and dishwashers in 2023

Note: The previous analysis is available in the EIA Technology Forecast Updates (2018) report.

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Residential Space Heating and Cooling

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Residential Gas-Fired Furnaces (North)

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Same as Reference Case

DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR (North) V. 4.1	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)[1]	80	80	80	80	80	80	80	80	80	80	80	80
AFUE (%)	80	80	80	90	95	99	95	99	95	99	95	99
Electric Consumption (kWh/y)[2]	374	374	386	636	631	725	631	725	631	725	631	725
Average Life (y)[3]	17	17	17	17	17	17	17	17	17	17	17	17
	26	26	26	26	26	26	26	26	26	26	26	26
Retail Equipment Cost (2022$)	1,300	1,300	1,080	1,200	1,220	1,390	1,220	1,390	1,220	1,390	1,220	1,390
Total Installed Cost (2022$)	2,880	2,880	3,690	4,130	4,150	4,320	4,150	4,320	4,150	4,320	4,150	4,320
Annual Maintenance Cost (2022$)	60	60	120	130	130	130	130	130	130	130	130	130

1. Typical input capacity is represented in terms of thousand British thermal units (kBtu) per hour (i.e., kBtu/h).
2. Electric consumption, represented in terms of kilowatt hours per year (kWh/y), accounts for the electricity consumption of components such as the furnace fan, draft inducer, and the ignitor. In some high efficiency products, this component also includes auxiliary equipment, such as condensate pumps and heat tape.
3. In the Residential Furnaces EERE 2022 Notice of Proposed Rulemaking (NOPR) Technical Support Document (TSD), an average lifetime of 22.5 years is calculated for gas-fired furnaces (North). Lifetime range was calculated using the Weibull Distribution in the Residential Furnaces EERE 2022 NOPR.

Note:
Models on the market can be either weatherized or non-weatherized. The majority (74%) are non-weatherized, and the values in the table use only non-weatherized data.
Electric consumption and cost values for 2022 and beyond are for a national sample and use the Residential Furnaces EERE 2022 NOPR Life-Cycle-Cost (LCC) spreadsheet.
Electric consumption and costs for the 2030, 2040, and 2050 high values are estimated based on the maximum-efficiency level analyzed in Residential Furnaces EERE 2022 NOPR, which is 98% annual fuel utilization efficiency (AFUE).
The current standard went into effect in November 2015.
ENERGY STAR V. 4.1 went into effect in February 2013.
The range for average life represents the span of typical values.

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Residential Gas-Fired Furnaces (Rest of Country)

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DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR (ROC) V. 4.1	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	80	80	80	80	80	80	80	80	80	80	80	80
AFUE (%)	80	80	80	90	90	99	95	99	95	99	95	99
Electric Consumption (kWh/y)[1]	279	279	386	636	636	725	631	725	631	725	631	725
Average Life (y)[2]	16	16	16	16	16	16	16	16	16	16	16	16
	25	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)	1,260	1,260	1,080	1,200	1,200	1,390	1,220	1,390	1,220	1,390	1,220	1,390
Total Installed Cost (2022$)	2,380	2,380	3,690	4,130	4,130	4,320	4,150	4,320	4,150	4,320	4,150	4,320
Annual Maintenance Cost (2022$)	40	40	120	130	130	130	130	130	130	130	130	130

1. Electric consumption accounts for the electricity consumption of components such as the furnace fan, draft inducer, and the ignitor. In some high efficiency products, this component also includes auxiliary equipment, such as condensate pumps and heat tape.
2. In the Residential Furnaces EERE 2022 NOPR, an average lifetime of 21.5 years is calculated for gas-fired furnaces (Rest of Country). Lifetime range was calculated using the Weibull Distribution in the Residential Furnaces EERE 2022 NOPR.

Note:
Models on the market can be either weatherized or non-weatherized. The majority (74%) are non-weatherized, and the values in the table use only non-weatherized data.
Electric consumption and cost values for 2022 and beyond are for a national sample and use the Residential Furnaces EERE 2022 NOPR LCC spreadsheet.
Electric consumption and costs for the 2030, 2040, and 2050 high values are estimated based on the maximum-efficiency level analyzed in Residential Furnaces EERE 2022 NOPR, which is 98% AFUE.
The current standard went into effect in November 2015.
ENERGY STAR V. 4.1 went into effect in February 2013.
The range for average life represents the span of typical values.

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Residential Gas-Fired Furnaces

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- Current Federal standards for non-weatherized gas furnaces:
  - AFUE ≥ 80%
- ENERGY STAR V. 4.1 criteria for gas furnaces:
  - South: AFUE ≥ 90%
  - North: AFUE ≥ 95%
  - Furnaces must be equipped with electronically commutated fan motor and have less than or equal to 2.0% air leakage
- Most efficient unit currently available: 99.0% AFUE. The current market is nearly evenly split between non-condensing units (AFUE≤82%) and condensing units (AFUE≥90%).
- The maximum AFUE for non-condensing gas furnaces is 82%; above this level, the potential for exhaust gas condensation increases. This condensate is corrosive and requires cost restrictive corrosion resistant venting.
- High-efficiency condensing furnaces typically have high-grade stainless steel (AL 29-4C) heat exchangers.
- Many condensing furnaces are available as direct vent and sealed combustion systems, which do not use room air for combustion, but instead draw combustion air directly from outdoors.
- Depending on the location of the home, piping materials in use, and other considerations, condensing furnaces may need an acid neutralizer and/or lift pump for the condensate.
- Furnaces may contain permanent split capacitor (PSC) fan motors or electronically commutated motors (ECMs). The type of motor affects the electrical consumption of the furnace as well as the seasonal energy efficiency ratio (SEER) / energy efficiency ratio (EER) of the associated air conditioner.
  - The 2016 Energy Conservation Standards for Residential Furnace Fans Final Rule requires that all furnaces use ECM fans.
  - Most non-weatherized gas furnaces employ ECMs and can fully modulate rather than cycling on and off. Because they modulate, there is an increase in total fan-on time.

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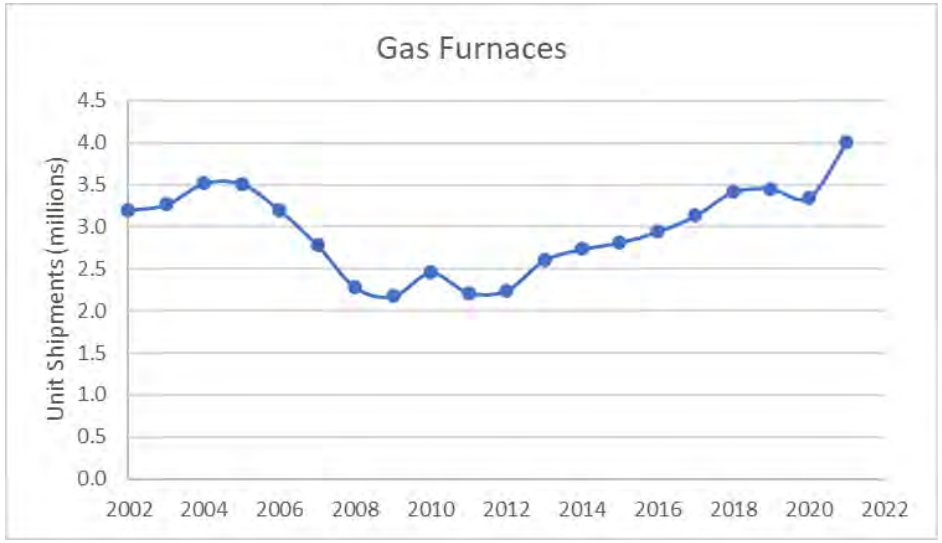
Annual shipments reached 3.5 million units in 2005 and then declined each year until 2009, leveling off at about 2.25 million units. Since 2012, shipments have increased steadily and reached a peak of 4.0 million units in 2021.



Source: *Air-Conditioning, Heating, and Refrigeration Institute (AHRI)*

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Residential Oil-Fired Furnaces

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Same as Reference Case

DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.1	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	105	105	105	105	105	105	105	105	105	105	105	105
AFUE (%)	83	83	83	85	85	97	85	97	85	97	85	97
Electric Consumption (kWh/y)[1]	477	477	477	466	466	410	466	410	466	410	466	410
Average Life (y)[2]	20	20	20	20	20	20	20	20	20	20	20	20
	33	33	33	33	33	33	33	33	33	33	33	33
Retail Equipment Cost (2022$)	2,620	2,620	2,620	2,650	2,650	3,170	2,650	3,170	2,650	3,170	2,650	3,170
	3,450	3,450	3,450	3,490	3,490	4,090	3,490	4,090	3,490	4,090	3,490	4,090
Total Installed Cost (2022$)	3,250	3,250	3,250	3,480	3,480	5,140	3,480	5,140	3,480	5,140	3,480	5,140
	6,520	6,520	6,520	6,820	6,820	10,110	6,820	10,110	6,820	10,110	6,820	10,110
Annual Maintenance Cost (2022$)	80	80	80	80	80	240	80	240	80	240	80	240

1. Electric consumption accounts for the electricity consumption of components such as the furnace fan, draft inducer, and the ignitor. In some high efficiency products, this component also includes auxiliary equipment, such as condensate pumps and heat tape.
2. Lifetime range was calculated using the Weibull Distribution in Residential Furnaces EERE 2011.

Note:
The current standard went into effect in May 2013.
ENERGY STAR V. 4.1 went into effect in February 2013.
Ranges represent the span of typical values for a given parameter.

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Residential Oil-Fired Furnaces

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- Current Federal standards:
  - AFUE ≥ 83%
  - ≤ 11 watts of electrical power when in standby and off modes (non-weatherized models only)
- ENERGY STAR V. 4.1 criteria: AFUE ≥ 85%
- Since the latent heat content of oil is lower than that for either propane or natural gas, oil-fired appliances can typically operate at a higher AFUE rating than comparable gas-fired appliances before condensation issues arise.
- Most efficient unit currently available: 96.7% AFUE – condensing units with tiny market share (<1%), due to market acceptance issues.
- Condensate from condensing oil furnaces is typically even more corrosive than that of gas-fired systems due to the higher sulfur content in fuel oil. Hence, condensing oil furnaces also likely require the use of an acid neutralizer.
- Oil-fired furnaces, like gas-fired furnaces, achieve condensing conditions through the use of a secondary heat exchanger. Typically, these secondary heat exchangers use a high-grade stainless steel (AL 29-4C).
- Sooting is an issue for all oil-fired appliances, but secondary heat exchangers, with their narrow passages, are even more prone to be plugged by soot. Because of this, condensing oil furnaces typically require frequent cleaning and maintenance.

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Residential Oil-Fired Furnaces

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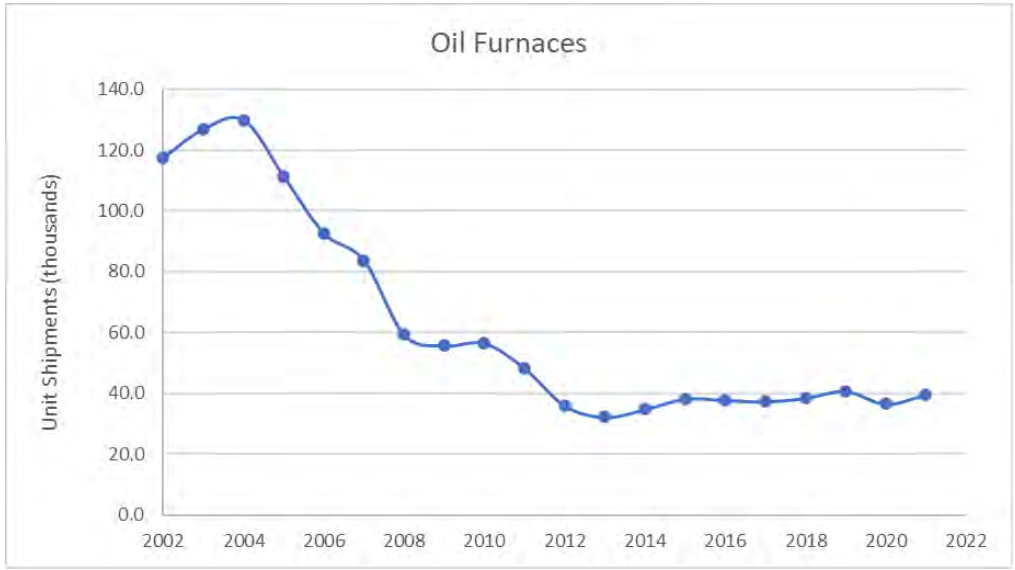
Annual shipments declined rapidly after 2004, likely due, at least in part, to an increase in fuel oil prices, which more than tripled from 2002 to 2008. Since 2012 shipments have largely leveled off.



Source: *AHRI*

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Same as Reference Case

DATA	2015	2020[1]	2022				2030[2]		2040[2]		2050[2]	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.0	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	100	100	100	100	100	100	100	100	100	100	100	100
AFUE (%)	82	95	84	95	90	96	95	96	95	96	95	96
Electric Consumption (kWh/y)[3]	197	506	282	506	527	502	506	502	506	502	506	502
Average Life (y)	20	20	20	20	20	20	20	20	20	20	20	20
	30	30	30	30	30	30	30	30	30	30	30	30
Retail Equipment Cost (2022$)	2,540	2,890	1,820	2,890	2,440	3,670	2,890	3,670	2,890	3,670	2,890	3,670
Total Installed Cost (2022$)	7,760	5,940	8,700	5,940	6,700	6,710	5,940	6,710	5,940	6,710	5,940	6,710
Annual Maintenance Cost (2022$)[4]	110	160	150	160	160	160	160	160	160	160	160	160

1. The 2020 AFUE is estimated based on EERE 2022 preliminary analysis, which estimates that gas-fired boilers with the highest market share in 2020 have an AFUE of 95%.
2. The 2030, 2040, 2050 projections are estimated based on the EERE 2022 preliminary analysis, which notes that majority of the market is expected to be condensing, if new standards are not implemented. The EERE 2022 preliminary analysis estimates a minimum efficiency of 95% AFUE for condensing units.
3. Electric Consumption accounts for the electricity consumption of auxiliary electrical components including circulating pump, the boiler pump (condensing boilers only), the draft inducer (if present), and the ignitor. It also accounts for the electricity consumption of auxiliary equipment such as a condensate pump and heat tape, which are sometimes installed with higher efficiency boilers. Additionally, it accounts for the additional cooling load due to heat loss from the boiler and water heater as a result of water heating during the cooling season.
4. Maintenance cost is the routine annual cost to the consumer of general maintenance for product operation. Maintenance cost is higher for condensing boilers for the inspection of condensate system and replacement of condensate neutralizer filter.

Note:
The current standard went into effect in January 2021.
ENERGY STAR V. 3.0 went into effect in December 2013.
Water boilers considered. Steam boilers also exist but make up a small percentage of the market.
The range for average life represents the span of typical values.

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Residential Gas-Fired Boilers

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- Federal standard for gas-fired hot-water boilers (more common than steam):
  - AFUE ≥ 84%
  - Standard went into effect on January 21, 2021
- ENERGY STAR criteria: AFUE ≥ 90%
- Most efficient gas-fired boiler available: 96.4% AFUE
- Gas-fired boilers have lost market share to furnaces and heat pumps over the past 30 years.
- U.S. gas hot water boiler sales are split approximately 60/40 between condensing and non-condensing.[1] Condensing boilers typically have heat exchangers made of stainless steel, and non-condensing boilers typically have heat exchangers made of cast iron.
- Typically, condensing boilers are low-mass in construction with modulating burners, variable-speed inducer fan systems or sealed powered direct-vent combustion, multiple sensor technologies, and electronic ignition and control.
- Due to incentives and market pressure, the U.S. boiler industry has been shifting towards also providing condensing boilers. Most of these boilers are private-labeled products sourced from Europe, where the hydronic market is much bigger and condensing appliances are much more common and/or required by law.
- Most value-added components for condensing boilers are sourced abroad, even when the condensing boiler is assembled in North America (e.g., heat exchanger, gas valve, burner, sensors, and/or controls).

Source: EERE 2022 Preliminary Analysis TSD, Chapter 3

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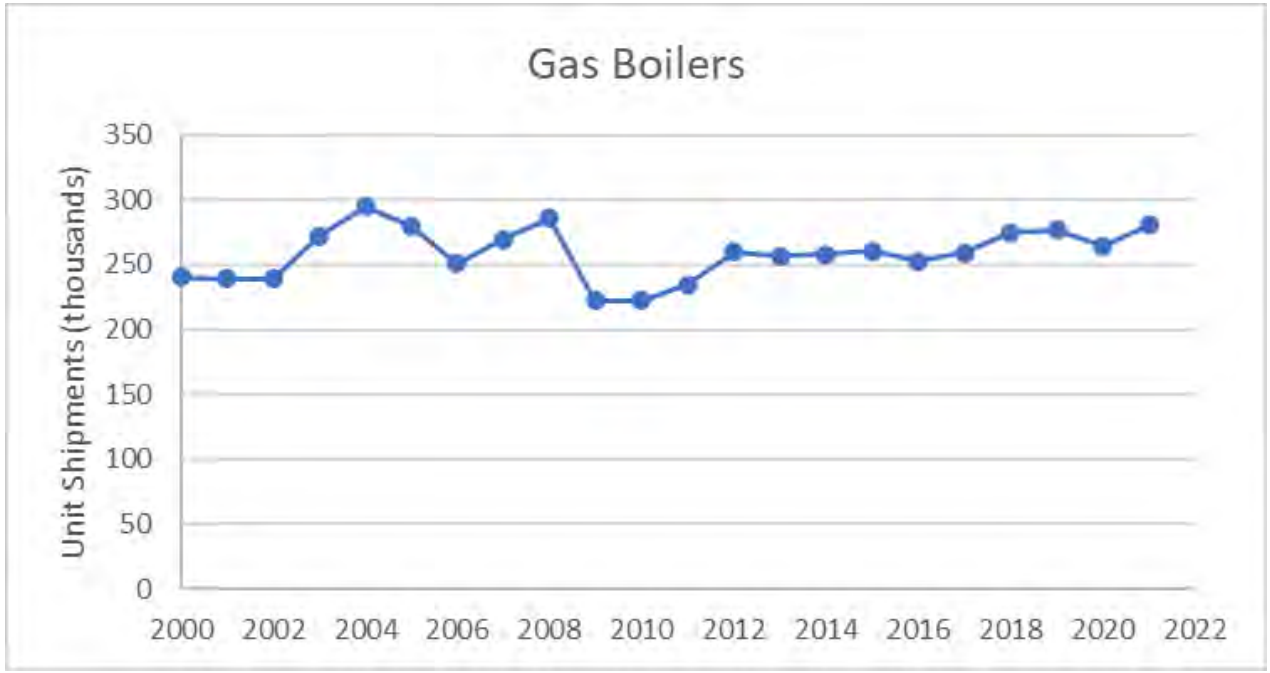
Annual shipments had a significant decrease following the 2009 financial crisis and a steady recovery in the years since.



Source: *Boilers EERE 2022 Preliminary Analysis*

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Residential Oil-Fired Boilers

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Typical AFUE and costs increase to ENERGY STAR levels. High AFUE and costs increase to condensing units.

DATA	2015	2020[1]	2022				2030[2]		2040[2]		2050[2]	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.0	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	140	140	140	140	140	140	140	140	140	140	140	140
AFUE (%)	84	86	86	86	87	88	87	95	87	95	87	95
Electric Consumption (kWh/y)[3]	230	310	310	310	307	305	307	265	307	265	307	265
Average Life (y)[4]	18	18	18	18	18	18	18	18	18	18	18	18
	28	28	28	28	28	28	28	28	28	28	28	28
Retail Equipment Cost (2022$)	4,850	3,590	3,590	3,590	3,680	3,770	3,680	6,890	3,680	6,890	3,680	6,890
Total Installed Cost (2022$)	9,800	5,510	5,510	5,510	5,600	5,690	5,600	11,910	5,600	11,910	5,600	11,910
Annual Maintenance Cost (2022$)[4]	160	170	170	170	170	170	170	170	170	170	170	170

1. The 2020 AFUE is estimated based on EERE 2022 preliminary analysis, which estimates that oil-fired boilers with the highest market share in 2020 have an AFUE of 86%.
2. The 2030, 2040, 2050 projections are estimated based on the EERE 2022 preliminary analysis, which notes that majority of the market is expected to be at 86% AFUE, if new standards are not implemented.
3. Electric Consumption accounts for the electricity consumption of auxiliary electrical components including circulating pump, the ignitor, condensate pump, and heat tape, which are sometimes installed with higher efficiency boilers. Additionally, it accounts for the additional cooling load due to heat loss from the boiler and water heater as a result of water heating during the cooling season.
4. Maintenance cost is the routine annual cost to the consumer of general maintenance for product operation.

Note:
The current standard went into effect in January 2021.
ENERGY STAR V. 3.0 went into effect in December 2013.
Water boilers considered. Steam boilers also exist but make up a small percentage of the market.
The range for average life represents the span of typical values.

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Residential Oil-Fired Boilers

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- Federal standard for oil-fired hot-water boilers (more common than steam):
  - AFUE ≥ 86%
  - Standard went into effect on January 21, 2021
- ENERGY STAR criteria: AFUE ≥ 87%
- Most efficient oil-fired boiler available: 88% AFUE
- Since the latent heat content of oil is lower than that for either propane or natural gas, oil-fired appliances can typically operate at a higher AFUE rating than comparable gas-fired appliances before condensation issues arise.
- Oil boilers have heat exchangers made of cast iron or steel.
- No condensing oil-fired boilers currently exist in the U.S. market. The high sulfur content in fuel-oil causes heat exchanger fouling if the flue gases from an oil-fired boiler were to condense. As a result, condensing oil-fired boilers would require more frequent maintenance and repair, if installed.
- Advanced Case: Increased incentives move typical efficiency products to ENERGY STAR levels by 2030. The current typical efficiency product is at 86% AFUE, while ENERGY STAR is at 87%, with only a small difference in costs. It is expected that with more market incentives, manufacturers will produce more products that can be ENERGY STAR certified at the 87% level.
- Advanced Case: High efficiencies expected to be at 95% AFUE for condensing oil-fired boilers. These models are already seen in Europe and would be expected to re-enter the U.S. market as well.

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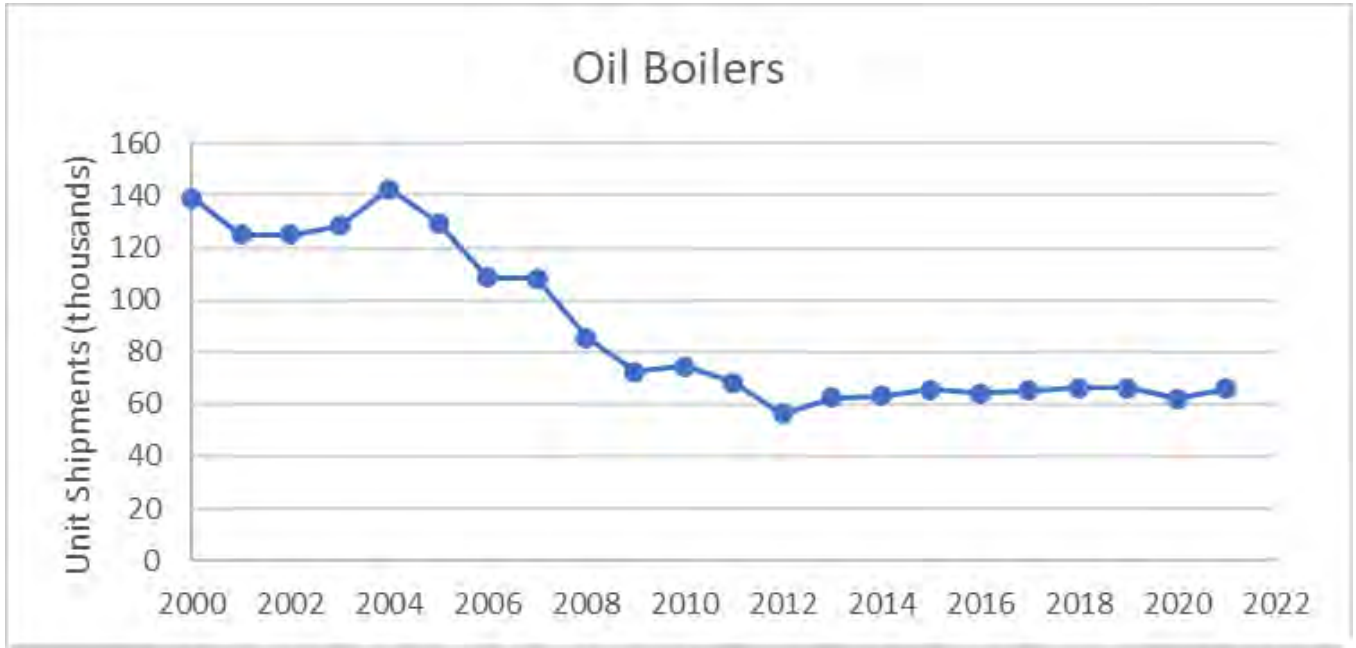
Annual shipments declined rapidly after 2004, likely due, at least in part, to an increase in fuel oil prices, which more than tripled from 2002 to 2008. Since 2012 shipments have largely leveled off.



Source: *Boilers EERE 2022 Preliminary Analysis*

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Residential Electric Resistance Furnaces

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Same as Reference Case

DATA	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	Typical	Typical	Typical
Typical Input Capacity (kBtu/h)	68	68	68	68	68	68	68
AFUE (%)	98	98	100	100	100	100	100
Average Life (y)	15	15	15	15	15	15	15
	30	30	30	30	30	30	30
Retail Equipment Cost (2022$)[1]	760	760	950	950	950	950	950
Total Installed Cost (2022$)[1]	1,290	1,290	1,480	1,480	1,480	1,480	1,480
Annual Maintenance Cost (2022$)[1]	50	50	50	50	50	50	50

1. Costs for a 100% AFUE unit are assumed to be equal to the costs of a 98% AFUE unit.

Note:
The current standard went into effect in January 1992.
The range for average life represents the span of typical values.

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Residential Electric Resistance Furnaces

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- Federal standards for electric furnaces:
  - AFUE ≥ 78%
  - Standby and off mode power consumption ≤ 10 watts
- According to preliminary Residential Energy Consumption Survey (RECS) data released May 2022, electric central warm-air furnaces are the main source of space heating in approximately 17.5 million U.S. homes or about 14%.
- Electric furnaces range in capacity from 10 to 25 kW (34 to 85 kBtu/h), with 20 kW (68 kBtu/h) being the typical for units on the market.
- Electric resistance furnaces are considered near 100% efficient because there is no flue heat loss, and any jacket losses are contained within the home.
  - ASHRAE Standard 103, the test method for furnaces incorporated by reference into the federal test procedure, specifies that for electric furnaces AFUE = 100 – 1.7 x jacket losses. Jacket losses can be determined either through testing or assumed to be 1%. Thus, the minimum AFUE of electric furnaces is 98.3%.

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Residential Electric Resistance Unit Heaters

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DATA	2015	2020	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical	Typical	Typical
Typical Capacity (kBtu/h)	3.5	3.5	5.1	5.1	5.1	5.1
Efficiency (%)	100	100	100	100	100	100
Average Life (y)[1]	15	15	15	15	15	15
	30	30	30	30	30	30
Retail Equipment Cost (2022$)[2]	90	90	85	85	85	85
	240	240	340	340	340	340
Total Installed Cost (2022$)[3]	150	150	390	390	390	390
	320	320	1,190	1,190	1,190	1,190
Annual Maintenance Cost (2022$)[4]	-	-	-	-	-	-

1. Assumes similar lifetime to Electric Furnaces on the basis that both products have heating elements that burn out and lead to product failure.
2. The lower bound of the equipment costs represents the average retail price listed at the typical capacity for electric baseboard heaters through a retailer website. The upper bound represents the average retail price for compact recessed electric wall heaters at the same capacity.
3. Range represents the estimated minimum and maximum installation costs.
4. Maintenance costs are negligible.

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Residential Electric Resistance Unit Heaters

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- Electric resistance unit heaters include electric wall and baseboard heaters. Plug-in space heaters are not included.
- There are currently no federal efficiency requirements for electric resistance unit heaters.
- According to preliminary RECS data released May 2022, electric resistance unit heaters are the main source of space heating in approximately 8.25 million U.S. homes or about 7%.
- Electric heaters range in capacity from 500 to 2,500 watts (1.7 to 8.5 kBtu/h), with 1,500 watts (5.1 kBtu/h) being the most typical for units on the market.
- Electric resistance heating is considered 100% energy efficient; all incoming electric energy is converted to heat.

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Residential Central Air Conditioners – North (Not Hot-Dry or Hot-Humid)

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Higher typical efficiencies with the same costs as ref. case despite increased efficiency.

DATA	2015	2020	2022				2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.0	High	New Standard	ENERGY STAR V. 6.1	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
SEER[1]	12.5	13.9	13.0	14.1	15.0	17.0	14.1	16.0	17.0	15.0	17.0	15.5	17.0	15.5	17.0
SEER2[2]	11.9	13.2	NA	13.4	NA	16.2	13.4	15.2	16.2	14.3	16.2	14.7	16.2	14.7	16.2
Average Life (y)	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)	2,410	2,670	2,580	2,700	3,110	3,950	2,680	3,750	3,950	2,760	3,950	2,760	3,950	2,760	3,950
Total Installed Cost (2022$)	4,000	4,300	5,250	5,320	5,520	5,980	5,310	5,880	5,980	5,350	5,980	5,350	5,980	5,350	5,980
Annual Maintenance Cost (2022$)[3]	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150

1. Values shown are for split-system units in the 36 kBtu/h (3-ton) size class. Costs and efficiency levels are for "coil-only" systems, meaning they do not include a blower. Note blower-coil systems were analyzed for residential air-source heat pumps, which is why the "High" SEER levels are higher for heat pumps than for air conditioners.
2. In 2023, new energy conservation standards for Residential Central Air Conditioners and Heat Pumps took effect. The new standards specify a different metric for central air conditioners (SEER2). SEER to SEER2 conversions were determined using the RESNET website.
3. Annual maintenance include preventative maintenance and services provided by HVAC professionals for maintaining product operation. Examples include, calibrate and level thermostat, clean filters, clean indoor and condenser coil, flush/treat condensate drain with anti-algae, inspect condenser coil, monitor operating pressure of refrigerant, inspect fan blade, etc.

Note:
The previous standard went into effect in January 2015. The current standard went into effect in January 2023.
ENERGY STAR V. 5.0 went into effect in September 2015. ENERGY STAR V. 6.1 went into effect in January 2023.
Ranges represent the span of typical values for a given parameter.

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Residential Central Air Conditioners – South (Hot-Dry and Hot-Humid)

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Higher typical efficiencies with the same costs as ref. case despite increased efficiency.

DATA	2015	2020	2022				2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.0	High	New Standard	ENERGY STAR V. 6.1	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
SEER[1]	13.0	14.4	14.0	14.6	15.0	17.0	15.1	16.0	17.0	15.5	17.0	16.0	17.0	16.0	17.0
SEER2[2]	12.4	13.7	NA	13.9	NA	16.2	14.3	15.2	16.2	14.7	16.2	15.2	16.2	15.2	16.2
Average Life (y)	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)	2,410	2,760	2,680	2,850	3,110	3,950	3,110	3,750	3,950	3,190	3,950	3,190	3,950	3,190	3,950
Total Installed Cost (2022$)	4,000	4,390	5,310	5,390	5,520	5,980	5,520	5,880	5,980	5,570	5,980	5,570	5,980	5,570	5,980
Annual Maintenance Cost (2022$)[3]	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150

1. Values shown are for split-system units in the 36 kBtu/h (3-ton) size class. Costs and efficiency levels are for "coil-only" systems, meaning they do not include a blower. Note blower-coil systems were analyzed for residential air-source heat pumps, which is why the "High" SEER levels are higher for heat pumps than for air conditioners.
2. In 2023, new energy conservation standards for Residential Central Air Conditioners and Heat Pumps took effect. The new standards specify a different metric for central air conditioners (SEER2). SEER to SEER2 conversions were determined using the RESNET website.
3. Annual maintenance include preventative maintenance and services provided by HVAC professionals for maintaining product operation. Examples include, calibrate and level thermostat, clean filters, clean indoor and condenser coil, flush/treat condensate drain with anti-algae, inspect condenser coil, monitor operating pressure of refrigerant, inspect fan blade, etc.

Note:
The previous standard went into effect in January 2015. The current standard went into effect in January 2023.
ENERGY STAR V. 5.0 went into effect in September 2015. ENERGY STAR V. 6.1 went into effect in January 2023.
Ranges represent the span of typical values for a given parameter.

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- The previous standards took effect in 2015; amended standards for all product classes went into effect in January 2023.
  - Amended standards are based on new metrics (SEER2, EER2).
  - SEER2 values are generally expected to be lower than SEER because a higher external static pressure is required during testing, which reduces measured performance.
- Systems installed in the Southwest (CA, AZ, NM, and NV) must also meet an EER standard that varies by cooling capacity and system configuration.
- Advanced Case: Due to increases in R&D, improvements in current technology (e.g., more cost-effective variable speed technology) are expected to increase efficiency without substantially increasing costs.

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Residential Central Air Conditioners

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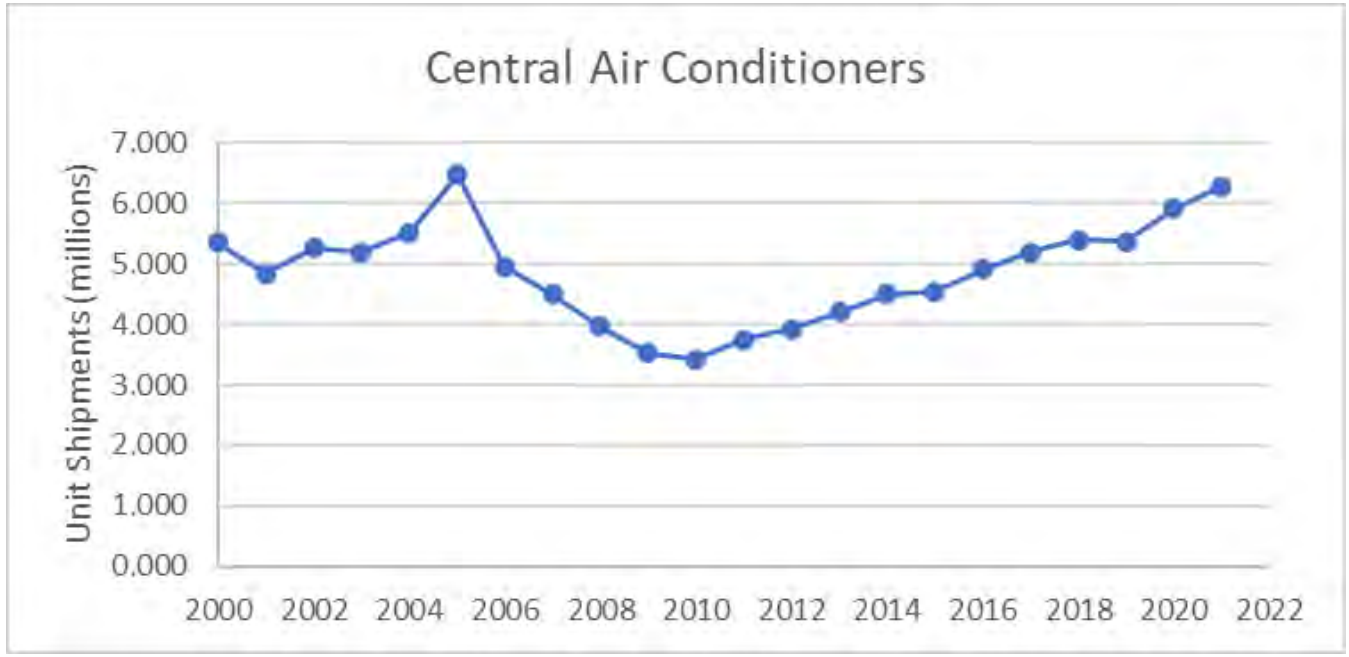
Annual shipments spiked at 6.5 million units in 2005 at the peak of the housing boom and just before more stringent Federal standards took effect in 2006. Annual shipments have been steadily increasing since 2010 and have almost reached the previous high in 2021.



Source: *AHRI*

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Residential Room Air Conditioners

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Increased efficiency with corresponding cost increases.

DATA	2015	2020	2022				2030[2]		2040[2]		2050[2]	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.2	High[1]	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	10	10	10	10	10	10	10	10	10	10	10.0	10.0
CEER (Btu/Wh)	10.9	10.9	10.9	12.0	12.0	15.7	16.0	16.5	17.0	17.5	17.5	18.0
Average Life (y)	6	6	6	6	6	6	6	6	6	6	6	6
	13	13	13	13	13	13	13	13	13	13	13	13
Retail Equipment Cost (2022$)	560	330	330	340	340	450	450	450	460	460	470	470
	710	480	480	480	480	590	590	590	610	610	620	620
Total Installed Cost (2022$)	640	490	490	490	490	600	600	600	610	610	630	630
	830	630	630	640	640	750	750	750	760	760	770	770
Annual Maintenance Cost (2022$)[3]	0	0	0	0	0	0	0	0	0	0	0	0

1. RAC EERE 2022 NOPR has analysis for combined energy efficiency ratio (CEER) of 16 Btu/Wh, which represents variable speed room air conditioners. However, maximum CEER identified in DOE's Compliance Certification Database (CCD) in August 2022 was 15.7 Btu/Wh. Accordingly, the high CEER is estimated to be 15.7 for 2022 and beyond. Cost values for a representative unit with a CEER of 16 Btu/Wh were used.
2. The 2030, 2040, 2050 projections are estimated based on RAC EERE 2022 NOPR, which notes that in the absence of no new standards, room air conditioners with a CEER of 12 Btu/Wh are expected to have the maximum market share.
3. Maintenance costs are negligible per RAC EERE 2011 and RAC EERE 2022 NOPR.

Note:
All values are for the most common product class, Product Class 3 (without reverse cycle, with louvered sides, and 8,000 to 13,999 Btu/h).
The current standard went into effect in June 2014.
ENERGY STAR V. 4.2 went into effect in October 2015.
Ranges represent the span of typical values for a given parameter (for example, installed cost for equipment meeting the federal standard) not the highest and lowest available on the market.

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Residential Room Air Conditioners

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- Analyzed the most common type of room air conditioners: louvered sides (window air conditioners) without reverse cycle and having cooling capacity of 8,000–13,999 Btu/h (DOE Product Class 3).
- Federal standards for Product Class 3:
  - CEER ≥ 10.9 (beginning June 1, 2014)
- CEER incorporates energy use in cooling mode and standby and off modes.
- ENERGY STAR V. 4.2 criteria for Product Class 3:
  - CEER ≥ 12.0 (effective October 26, 2015)
- Efficiency improvements in room air conditioners are attained by:
  - Higher efficiency compressor and fan motors (including variable speed motors), and
  - An increased heat transfer area in the evaporator and condenser using larger heat exchangers, finer fin spacing, micro-channel heat exchangers, and similar design options.
- Advanced Case: Due to increases in R&D, improvements in current technology (e.g., more efficient motors and compressors, larger cross-section heat exchangers, adoption of variable speed technologies) are expected to increase efficiency with corresponding increases in cost.

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Residential Room Air Conditioners

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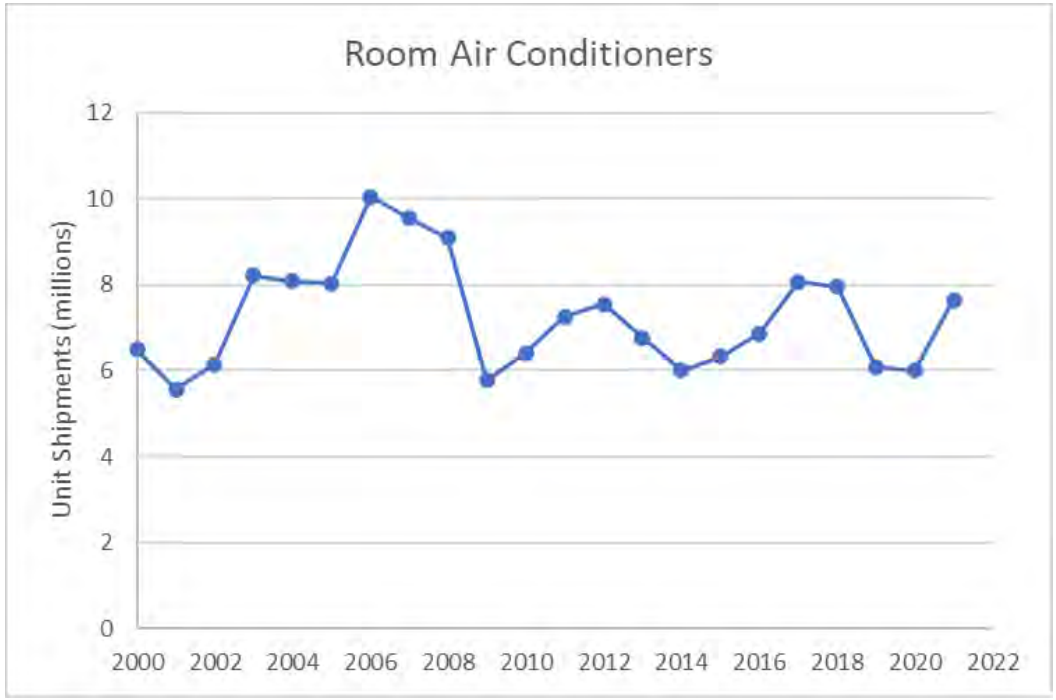
Annual shipments dropped sharply in 2009, likely due to the recession and an unusually cool summer in the Northeast. Sales have largely leveled off in the years since, fluctuating between 6 and 8 million.



Source: *RAC EERE 2022 NOPR*

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Residential Portable Air Conditioners

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Increased efficiency with corresponding cost increases.

DATA	2015	2020	2022[4]		2025		2030		2040		2050	
	Installed Base	Installed Base	Typical	High[5]	New Standard	High[5]	Typical	High[5]	Typical	High[5]	Typical	High[5]
Typical Capacity (kBtu/h)[1]	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6
CEER[2]	5.6	5.6	5.5	7.6	6.7	7.6	7.8	8.8	8.9	10.1	10.2	11.6
Average Life (y)	7	7	7	7	7	7	7	7	7	7	7	7
	12	12	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)	700	700	700	810	760	810	810	810	820	820	830	830
Total Installed Cost (2022$)[3]	700	700	700	810	760	810	810	810	820	820	830	830
Annual Maintenance Cost (2022$)[3]	0	0	0	0	0	0	0	0	0	0	0	0

1. All values are for the average capacity for single-duct and dual-duct portable air conditioners available on the market.
2. CEER is calculated for typical capacity using the equation provided in PAC EERE 2020.
3. Installation and maintenance costs are negligible.
4. The 2022 Typical estimates are based on PAC EERE 2020, which estimated majority of the market to be at EL1 in 2022 for the no-new standards case, which translates to a CEER of 5.5 for this analysis.
5. All High values are based on the most-efficient models available in the market, as specified in PAC EERE 2020.

Note:
A final rule for portable air cleaners published in January 2020 with an effective date of January 2025.
Costs are interpolated from the costs presented in PAC EERE 2020.
Range for lifetime represents typical values.

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Residential Portable Air Conditioners

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- A final rule establishing new energy conservation standards for portable air conditioners published in January 2020 with an effective date of January 2025.
- The final rule outlined an equation-based conservation standard (in CEER) for both single-duct and dual-duct portable ACs, based on the seasonally adjusted cooling capacity (SACC)

$$\text{Minimum CEER} = \text{PR} \times \frac{\text{SACC}}{(3.7117 \times \text{SACC}^{0.6384})}$$

- Efficiency improvements in portable air conditioners are attained by:
  - Higher efficiency compressor and fan motors (including variable speed motors), and
  - An increased heat transfer area in the evaporator and condenser using larger heat exchangers, finer fin spacing, micro-channel heat exchangers, and similar design options.
- Advanced Case: Due to increases in R&D, improvements in current technology (e.g., more efficient motors and compressors, larger cross-section heat exchangers, adoption of variable speed technologies) are expected to increase efficiency with corresponding increases in cost.

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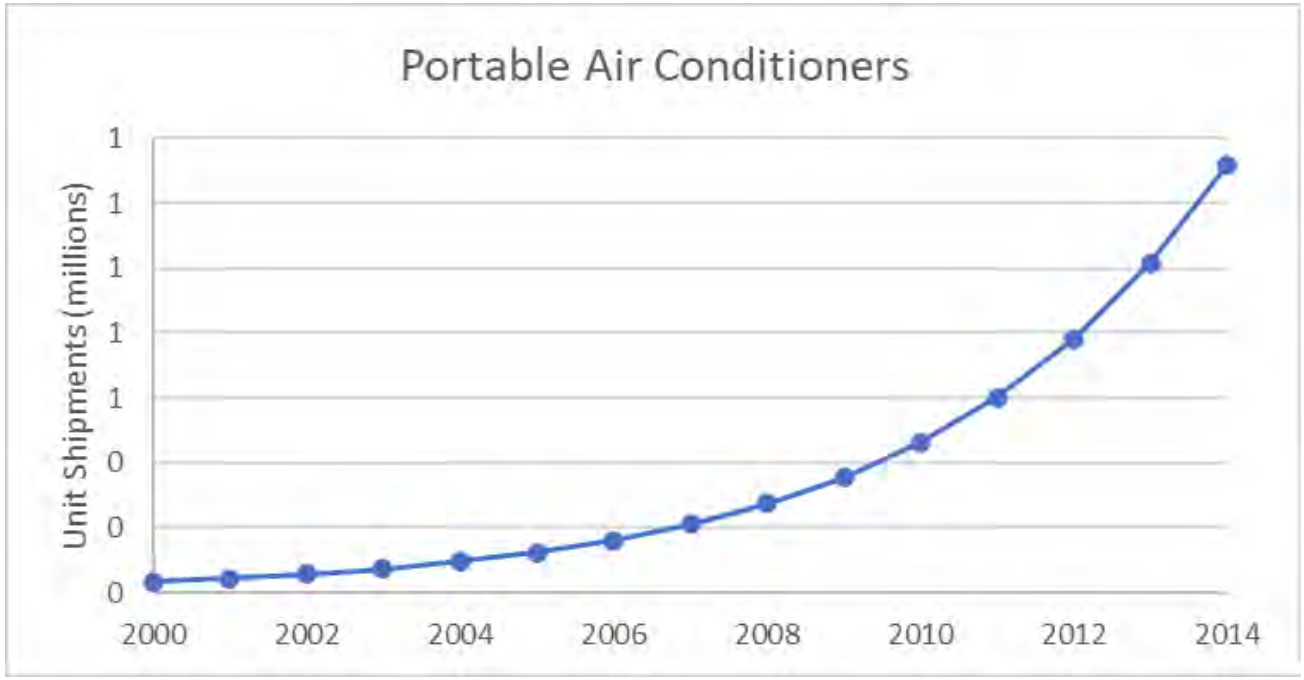
Annual shipments have seen an exponential growth through 2014. Shipments data since 2014 is not publicly available but it is expected that portable air conditioners shipments may have increased in recent years in response to indoor air quality concerns following COVID-19.



Source: *PAC EERE 2020*

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Residential Swamp Coolers

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Same as reference case

DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Air Flow Rate (CFM)	3,800	3,800	3,800	4,700	3,800	4,700	3,800	4,700	3,800	4,700
Power (Hp)	1/3	1/3	1/3	1/2	1/3	1/2	1/3	1/2	1/3	1/2
Average Life (y)[1]	10	10	10	10	10	10	10	10	10	10
	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)	960	960	960	1,100	960	1,100	960	1,100	960	1,100
Total Installed Cost (2022$)	1,360	1,360	1,360	1,540	1,360	1,540	1,360	1,540	1,360	1,540
Annual Maintenance Cost (2022$)	330	330	330	330	330	330	330	330	330	330

1. Average lifetime provided by major swamp cooler installer in the U.S. Southwest.

Note:
Efficiency values were determined based on a sample of window-mounted swamp coolers.
Lifetime range represents span of typical values.

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Residential Swamp Coolers

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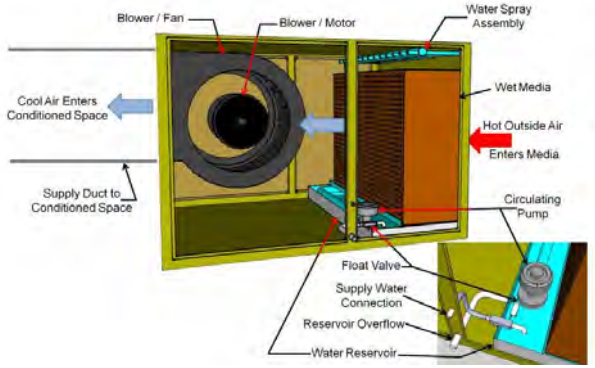
- Evaporative cooling (i.e., "swamp coolers") is a technology that takes advantage of water evaporation to cool incoming air. Energy is required to change water from a liquid to a vapor (i.e., the heat of vaporization), and in doing so, temperature of the air is reduced. Evaporative cooling is best suited for hot, dry climates.
- Swamp coolers come in a variety of different configurations, including centrally ducted units that are mounted outside a building or roof; window evaporative coolers that are window-mount units that pull in warm outdoor air, pass it through wet media to remove heat, and blow out the cooled air; or portable plug-in units. Window units were considered for this analysis due to the high model share count on distributor websites.
- The U.S. Environmental Protection Agency (EPA) has cautioned against using swamp coolers in wildfire-impacted areas in smoky conditions because it can result in more smoke bring brought inside.
- Swamp coolers are not a DOE-covered product.
- Swamp cooler metrics include power of the fan/blower, measured in horsepower (hp), and air flow rate, measured in cubic feet per minute (CFM).



Single-inlet direct swamp cooler. Source: *PNNL*

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Residential Air-Source Heat Pumps

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Higher typical efficiencies with the same costs as reference case despite increased efficiency

DATA	2015	2020	2022				2023				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.0	High	New Standard	ENERGY STAR V. 6.1	ENERGY STAR Cold Climate Criteria	High[4]	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
SEER (Cooling)[1]	13.1	15.3	14.0	15.3	15.0	22.6	15.0	16.0	NA	22.6	16.5	22.6	17.0	22.6	17.5	22.6
SEER2[2]	12.4	14.5	NA	14.5	NA	21.5	14.3	15.2	15.2	21.5	15.7	21.5	16.2	21.5	16.6	21.5
HSPF (Heating)[1]	7.9	8.6	8.2	8.6	8.5	12.4	8.8	9.2	NA	12.4	9.3	12.4	9.3	12.4	9.4	12.4
HSPF2[2]	6.7	7.3	NA	7.3	NA	10.6	7.5	7.8	8.1	10.6	7.9	10.6	7.9	10.6	8.0	10.6
Average Life (y)	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3
Retail Equipment Cost (2022$)[1]	3,290	4,270	3,970	4,270	4,110	6,740	4,110	4,380	4,380	6,740	4,380	6,740	5,000	6,740	5,100	6,740
Total Installed Cost (2022$)[1]	5,790	6,880	6,730	6,880	6,810	8,620	6,810	6,940	6,940	8,620	6,940	8,620	7,240	8,620	7,330	8,620
Annual Maintenance Cost (2022$)[3]	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150

1. Values shown are for split-system units in the 36 kBtu/h (3-ton) size class. Costs and efficiency levels are for "blower-coil" systems, meaning they include a blower. Note coil-only systems were analyzed for residential central air conditioners, which is why the "High" SEER levels are higher for heat pumps than for air conditioners.
2. In 2023, new energy conservation standards for Residential Central Air Conditioners and Heat Pumps took effect. The new standards specify different metrics for Air-Source Heat Pumps (SEER2 and heating seasonal performance factor 2 (HSPF2)). SEER to SEER2 and HSPF to HSPF2 conversions were determined using the RESNET website.
3. Annual maintenance include preventative maintenance and services provided by HVAC professionals for maintaining product operation. Examples include, calibrate and level thermostat, clean filters, clean indoor and condenser coil, flush/treat condensate drain with anti-algae, inspect condenser coil, monitor operating pressure of refrigerant, inspect fan blade, etc.
4. High costs derived from developing a cost-efficiency curve between retail/installed costs and SEER.

Note:
The previous standard went into effect in January 2015. The current standard went into effect in January 2023.
ENERGY STAR V. 5.0 went into effect in September 2015. ENERGY STAR V. 6.1 went into effect in January 2023.
Ranges represent the span of typical values for maintenance costs.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (15.88, 2, 1).

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Residential Air-Source Heat Pumps

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- The previous standards took effect in 2015; amended standards for all product classes went into effect in January 2023.
  - Amended standards are based on new metrics (SEER2, EER2, HSPF2).
  - SEER2 values are generally expected to be lower than SEER because a higher external static pressure is required during testing, which reduces measured performance.
- High efficiency cooling does not necessarily correlate with high efficiency heating. The range of SEER–HSPF combinations is very broad.
- Heat pumps are generally sized to meet the cooling load of the house. When the heating load exceeds heat pump heating capacity, electric resistance heat is used to supplement.
- Variable-speed compressors improve efficiency of heat pumps by reducing cyclic losses and by operating above their nominal speed, boosting heating capacity, and reducing the need for supplementary electric resistance heat.
- In addition to meeting the SEER2 and HSPF2 requirements, air source heat pumps must demonstrate low ambient performance to earn the Cold Climate designation by meeting the following:
  - Coefficient of Performance (COP) at 5 degrees Fahrenheit (°F) ≥ 1.75, measured in accordance with Appendix M1 $H4_2$ test
  - Percent of Heating Capacity at 5 °F ≥ 70% of that at 47 °F, with the 5 °F capacity measured per Appendix M1 $H4_2$ test and the 47 °F capacity measured as the nominal heating capacity per Appendix M1 (i.e., from the Appendix M1 $H1_N$ test for units having a variable-speed compressor where the compressor speed shall be the maximum speed that the system controls would operate at 47 °F, otherwise from the Appendix M1 $H1_2$ test)
  - Perform a controls verification procedure (CVP) to confirm that the above performance metrics measured at the Appendix M1 low ambient test point at 5 °F are achieved by the native controls operating as they would in a customer's home
- Advanced Case: Due to increases in R&D, improvements in current technology (e.g., more cost-effective variable speed technology) are expected to increase efficiency without substantially increasing costs.

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Residential Air-Source Heat Pumps

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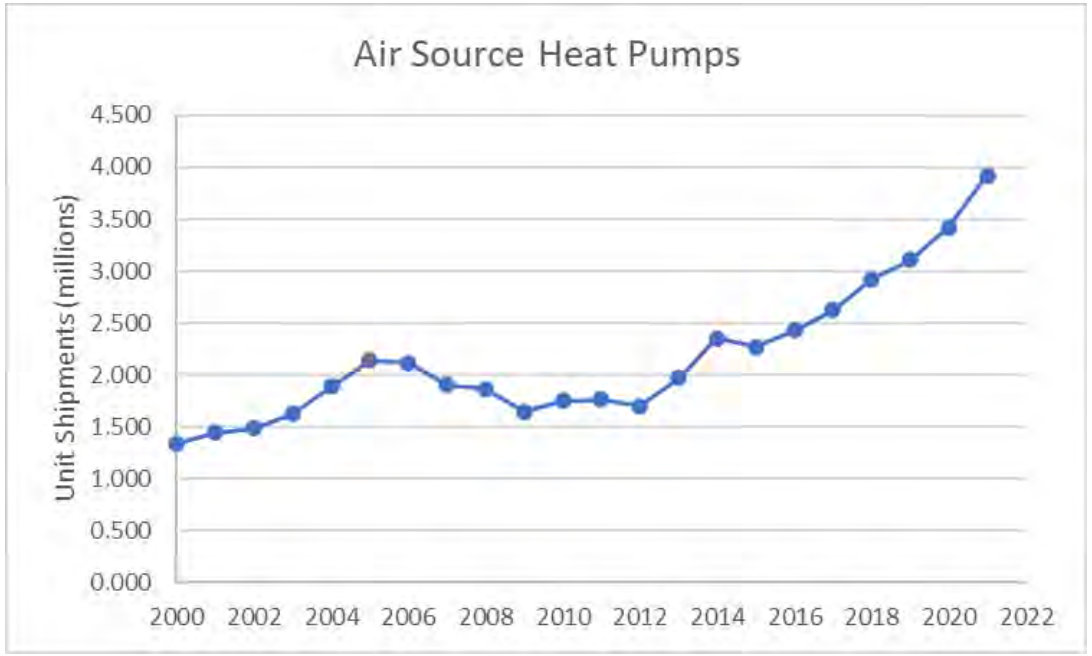
From 2000 to 2005 annual shipments increased nearly 60% to 2.1 million units, then dropped and leveled off around 1.7 million units. In 2014 annual shipments surpassed the 2005 peak and have been increasing uniformly since then.



Source: *AHRI*

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Residential Central Air Conditioners and Air-Source Heat Pumps

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- Principal energy efficiency drivers for central air conditioners and heat pumps:
  - Heat exchanger (surface area, number of tube rows)
  - Compressor (type and single-stage vs. two-stage vs. variable-speed operation)
  - Fan motor choices (PSC vs. ECM fan motors on inside and outside)
  - Control choices (i.e., piston, thermal, and electronic expansion valves)
- When the heat pump or air conditioner's capacity exceeds the heating or cooling load, the unit starts and stops more frequently, causing wear and tear on the components and an overall loss of efficiency. Multi-stage and/or variable-speed compressors can help, as does sophisticated refrigerant management.
- Typical high-efficiency unit (≥ 16 SEER) has very large heat exchanger, ECM evaporator fan motor, and two-stage scroll compressor.
- Variable-speed compressor technology typically leads to a significant SEER boost, making possible high-SEER condensing units with smaller heat exchangers, and thus, smaller enclosures.
- Efficiency levels > 21 SEER made possible through combining existing large heat exchangers with variable-speed compressors, ECM fan motors, and electronic expansion valves.

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Residential Ductless Mini-Split Air-Source Heat Pumps

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Same as reference case

DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)[1]	12	12	12	12	12	12	12	12	12	12
SEER	16.0	16.0	21.9	33.1	21.9	33.1	21.9	33.1	21.9	33.1
EER	12.5	12.5	13.0	19.1	13.0	19.1	13.0	19.1	13.0	19.1
HSPF	10.0	10.0	11.1	14.0	11.1	14.0	11.1	14.0	11.1	14.0
Average Life (y)[2]	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3
Retail Equipment Cost (2022$)	1,580	1,580	1,580	1,580	1,580	1,580	1,580	1,580	1,580	1,580
Total Installed Cost (2022$)	2,030	2,030	2,030	2,030	2,030	2,030	2,030	2,030	2,030	2,030
Annual Maintenance Cost (2022$)[3]	100	100	100	100	100	100	100	100	100	100

1. Representative capacity determined from most frequent capacity in AHRI database
2. Assumed same lifespan and maintenance cost as air-source heat pumps given the technology is similar between air-source and ductless mini-split heat pumps, and ductwork itself is not expected to fail.
3. Annual maintenance covers the same services identified for air-source heat pumps.

Note:
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (15.88, 2, 1).

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Residential Ductless Mini-Split Air-Source Heat Pumps

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- Ductless systems can be useful in "spot cooling" certain high-use areas of a home, such as a living room, bedroom, or office.
- Mini-split heat pumps are generally more efficient (often > 20 SEER) and smaller in cooling capacity (often ≤ 24 kBtu/h) compared to split-system heat pumps.
  - A mini-split heat pump could be equal in capacity and efficiency to a split-system heat pump as there are no inherent design changes between split-system and mini-split heat pumps, aside from the ductwork. Mini-split heat pumps tend to be more efficient and smaller in capacity due to their prevalence for spot cooling, but the same technologies are used between the two product categories.
- Due to the similarities in design, cost estimations were determined based on smaller capacity (24 kBtu/h) split-system heat pumps and Gordian's RSMeans Data – Building Construction Costs 2023. Efficiency data was analyzed using the AHRI directory, which provides disaggregation of data on the basis of ducted and ductless heat pumps.
- Annual maintenance covers the same services identified for air-source heat pumps.

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Residential Ground-Source Heat Pumps

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Same typical efficiencies with the lower costs as ref. case despite same efficiency.

DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.2	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	36	36	36	36	36	36	36	36	36	36	36	36
COP (Heating)[1]	3.1	3.7	3.2	3.6	3.6	4.5	3.6	4.5	3.6	4.5	3.6	4.5
EER (Cooling)[2]	13.3	17.3	14.1	17.3	17.1	22.0	17.3	22.0	17.3	22.0	17.3	22.0
Average Life (y)	8	8	8	8	8	8	8	8	8	8	8	8
	21	21	21	21	21	21	21	21	21	21	21	21
Retail Equipment Cost (2022$)	4,650	5,470	4,820	5,470	5,410	6,530	4,920	5,880	4,920	5,880	4,920	5,880
Total Installed Cost (2022$)	14,060	14,880	14,230	14,880	14,880	15,940	13,390	14,350	13,390	14,350	13,390	14,350
	22,290	23,120	22,470	23,120	23,120	24,170	20,810	21,750	20,810	21,750	20,810	21,750
Annual Maintenance Cost (2022$)	90	90	90	90	90	90	90	90	90	90	90	90

1. COP values listed are assessed at a "ground loop" test condition, which is representative of closed loop ground source heat pumps (GSHP) operating conditions. However, DOE sets standards at a "water loop" test condition. The AHRI directory lists COP ratings at both sets of test conditions and is used to convert between them where necessary.
2. EER values listed are assessed at a full-load "ground loop" test condition, which is representative of closed loop GSHP operating conditions. However, DOE sets standards at a full-load "water loop" test condition. The AHRI directory lists EER ratings at all sets of test conditions and is used to convert between them where necessary.

Note:
Residential and commercial GSHPs are very similar - the main difference in data presented is the different capacity (3-ton vs. 4-ton) and slightly higher installation costs for commercial GSHP. DOE does not distinguish between residential and commercial units in its regulations.
Current standards went into effect on October 9, 2015. COP and EER ratings are converted from the "water loop" test condition to "ground loop."
ENERGY STAR V. 3.2 went into effect January 1, 2012.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (17.04, 1.64, 1).

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Residential Ground-Source Heat Pumps

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- Heating COP does not correlate with cooling EER.
- The ENERGY STAR criteria for water-to-air ground-source heat pumps are:

Type	Heating COP	Cooling EER
Closed Loop	3.6	17.1
Open Loop	4.1	21.1
Direct Expansion	3.6	16

- The most common GSHP is a closed-loop system in which water or an anti-freeze solution is circulated through plastic pipes buried underground. Open loop systems that employ ground water or surface water (e.g., open well, pond, lake) are used in some parts of the country, but water supply and water quality issues impose limitations on such applications.
- Installation cost is for a closed loop system and includes necessary accessories. The ground loop heat exchanger represents a majority of the installation cost. Installed costs for these systems vary widely.
- Variable speed ECMs improve performance on high-end models.
- Advanced Case: GSHP are already highly efficient and have not changed much in terms of efficiency in recent years. With increased R&D, it is anticipated that the equipment and installation costs will be reduced over time, but efficiency will likely stay the same.

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Residential Natural Gas Heat Pumps

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Same as reference case

DATA	2015	2020	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical	Typical	Typical
Typical Capacity (kBtu/h)	60	60	60	60	60	60
COP (Heating)	1.3	1.3	1.3	1.3	1.3	1.3
COP (Cooling)	0.6	0.7	0.7	0.7	0.7	0.7
Annual Electric Use (kWh/y)[1]	1,500	1,500	1,500	1,500	1,500	1,500
Average Life (y)[2]	12	12	12	12	12	12
	18	18	18	18	18	18
Retail Equipment Cost (2022$)[2]	12,940	12,940	12,940	12,940	12,940	12,940
	14,350	14,350	14,350	14,350	14,350	14,350
Total Installed Cost (2022$)[2]	14,700	14,700	14,700	14,700	14,700	14,700
	17,290	17,290	17,290	17,290	17,290	17,290
Annual Maintenance Cost (2022$)	200	200	200	200	200	200

1. Annual electric use accounts for the electricity consumption of components such as the heat pump fan.

Note:
Ranges represent the span of typical values observed in the market.

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Residential Natural Gas Heat Pumps

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- Residential natural gas heat pumps are not currently subject to DOE regulations. The California Energy Commission's (CEC) Title 24, Part 6 Section 112 does indicate cooling efficiency requirements for natural gas heat pumps.
- Natural gas heat pumps are much more popular in other parts of the world, such as Europe. Gas-fired cooling equipment currently comprises less than 1% of the residential air conditioning/heat pump market in the U.S.
- Currently, Robur is the predominant manufacturer of residential-sized natural gas heat pumps with sales operations in the U.S.. Robur units are 5-ton nominal cooling capacity, a size typically associated with larger homes. Since only one product is available, no mid-level or high efficiency categories are included in this analysis.
- The data represents air-source absorption heat pumps. Gas engine-driven vapor compression heat pumps are available in other parts of the world; York formerly offered the Triathlon gas engine-driven heat pump in the U.S. It is possible to couple either technology to the ground (ground-source) rather than the atmosphere (air-source).
- The absorption heat pump is a gas-fired, ammonia-water absorption cycle, combined with a high-efficiency low-pressure boiler integrated into one outdoor unit.
- The cooling efficiency of a gas-fired air-source absorption heat pump is considerably lower than for an electric air-source heat pump. Heating efficiency of an air-source heat pump (electric or gas-fired absorption) decreases as outdoor temperature decreases; however, the gas-fired absorption heat pump recovers waste heat from the combustion process to improve heating efficiency.

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Residential Cordwood Stoves

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Same as reference case

DATA	2015[1]	2020[2]	2022[3]		2030[4]		2040[4]		2050[4]	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	50	50	50	50	50	50	50	50	50	50
Efficiency (Non-Catalytic) (HHV)[5]	63	71	71	80	71	80	71	80	71	80
Efficiency (Catalytic) (HHV)[5]	72	76	76	81	76	81	76	81	76	81
Average Life (y)	12	12	12	12	12	12	12	12	12	12
	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$) (Non-Catalytic)	2,880	1,670	1,670	2,300	1,670	2,300	1,670	2,300	1,670	2,300
Retail Equipment Cost (2022$) (Catalytic)	3,540	3,040	3,040	3,830	3,040	3,830	3,040	3,830	3,040	3,830
Total Installed Cost (2022$) (Non-Catalytic)[6]	8,290	7,090	7,090	7,710	7,090	7,710	7,090	7,710	7,090	7,710
Total Installed Cost (2022$) (Catalytic)[6]	8,950	8,460	8,460	9,240	8,460	9,240	8,460	9,240	8,460	9,240
Annual Maintenance Cost (2022$) (Non-Catalytic)[7]	190	190	190	190	190	190	190	190	190	190
Annual Maintenance Cost (2022$) (Catalytic)[7]	280	280	280	280	280	280	280	280	280	280

1. For 2015, assumed EPA default efficiencies, which were used by EPA to approximate the efficiency of stoves before the 2015 EPA rule required efficiency testing.
2. For 2020, assumed same efficiencies as estimated for 2022 given the most recent EPA rule went into effect in May 2020.
3. The 2022 High value is the highest EPA certified efficiency. The 2022 Typical value is the average of EPA certified efficiencies.
4. For 2030-2050, it is assumed that the same conditions as current would persist because no impending efficiency requirements are expected from EPA, given recency of 2020 rulemaking and current market factors.
5. Efficiency includes combustion and heat transfer efficiency and is based on the higher heating value (HHV) of the fuel.
6. Installed costs include the cost of hearth and stainless-steel chimney liner - materials and labor.
7. For catalytic stoves, annual maintenance cost includes periodic cost of replacing the catalytic combustor.

Note:
The range for average life represents the span of typical values.

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Residential Cordwood Stoves

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- Residential cordwood stoves that must meet EPA particulate limits fall into two broad classes based on whether they use a catalyst for air treatment. Catalytic wood stoves use a catalytic combustor to reduce emissions from the combustion air. Non-catalytic wood stoves use baffles and introduce secondary air above the flames to enable more complete combustion and reduce emissions.
- In 2015, EPA published an update to its New Source Performance Standards (NSPS), decreasing the emissions limit (previously set by 1988 EPA rule) to 4.5 grams per hour (g/h) for both catalytic and non-catalytic stoves. The new rule did not institute efficiency standards but required that manufacturers test and certify the efficiency of their stoves. This standard took full effect on January 1, 2016.
- In 2020, the NSPS limit for new room heaters was lowered to 2.5 g/h if tested with cord wood.
- Prior to the 2015 rule, manufacturers could either submit efficiency data from laboratory testing or certify with the default efficiency value designated by EPA. EPA's default efficiency values were 63% for non-catalytic wood stoves and 72% for catalytic wood stoves. Under this system, few manufacturers submitted efficiency test data to EPA.
- Multiple test standards are commonly used to assess stove efficiency, and data from product literature does not generally identify the efficiency test method.
- It is not possible to determine performance trends based on construction or configuration (e.g., cast iron vs. plate steel, powered blowers vs. no blowers, etc.) trends in specific equipment type or construction based on published efficiencies. Further, EPA certification data shows no significant relationship between emissions and heating efficiency.
- Cordwood stoves require chimneys for venting combustion gases. Whether conventional masonry chimneys are used or metal chimney liners, these add considerable cost to the overall system. Accordingly, installed costs can be twice that of the wood stove itself.

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Residential Cordwood Stoves

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Cordwood stove shipments have averaged 123,000 per year since 1999 and have fluctuated approximately in accordance with fuel oil costs.

Source: *HPBA, no post-2012 sales data was publicly available at time of publication.*

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Residential Wood Pellet Stoves

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Same as reference case

DATA	2015[1]	2020[2]	2022[3]		2030[4]		2040[4]		2050[4]	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	50	50	50	50	50	50	50	50	50	50
Efficiency (HHV)[5]	70	73	73	85	73	85	73	85	73	85
Annual Electricity Consumption (kWh)[6]	600	600	600	600	600	600	600	600	600	600
Average Life (y)	12	12	12	12	12	12	12	12	12	12
	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)	3,900	3,120	3,120	4,000	3,120	4,000	3,120	4,000	3,120	4,000
Total Installed Cost (2022$)[7]	5,550	4,520	4,520	5,400	4,520	5,400	4,520	5,400	4,520	5,400
Annual Maintenance Cost (2022$)	310	310	310	310	310	310	310	310	310	310

1. For 2015, assumed EPA default efficiencies, which were used by EPA to approximate the efficiency of stoves before the 2015 EPA rule required efficiency testing.
2. For 2020, assumed same efficiencies as estimated for 2022 given the most recent EPA rule went into effect in May 2020.
3. The 2022 High value is the highest EPA certified efficiency. The 2022 Typical value is the average of EPA certified efficiencies.
4. For 2030-2050, it is assumed that the same conditions as current would persist because no impending efficiency requirements are expected from EPA, given recency of 2020 rulemaking and current market factors.
5. Efficiency includes combustion and heat transfer efficiency and is based on the HHV of the fuel.
6. The annual electric consumption estimates assume 6 months/year @ 100kW/mo based on DOE estimates.
7. Installed cost includes cost of hearth and vent pipe - materials and labor.

Note:
The range for average life represents the span of typical values.

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Residential Wood Pellet Stoves

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- In 2015, EPA published an update to its NSPS, limiting emissions for wood pellet stoves to 4.5 g/h. Prior to the 2015 EPA rule, most pellet stoves were exempt from EPA's NSPS requirements. The new rule did not institute efficiency standards but required that manufacturers test and certify the efficiency of their stoves. This standard took full effect on January 1, 2016.
- Prior to the 2015 rule, manufacturers could either submit efficiency data from laboratory testing or certify with the default efficiency value designated by EPA. EPA's default efficiency values were 63% for non-catalytic wood stoves and 72% for catalytic wood stoves. Under this system, few manufacturers submitted efficiency test data to EPA.
- Multiple test standards are commonly used to assess stove efficiency and data from product literature does not generally identify the efficiency test method.
- It is not possible to determine performance trends based on construction or configuration (e.g., cast iron vs. plate steel, powered blowers vs. no blowers, etc.) trends in specific equipment type or construction based on published efficiencies. Further, EPA certification data shows no significant relationship between emissions and heating efficiency.
- Wood pellet stoves may be able to be direct vented to the outdoors, eliminating the need for a chimney. This reduces the overall system cost as compared to a cord wood stove. However, they do use electricity to power the pellet feeder, the combustion air fan, and the blower. In the event of a power outage, a pellet stove can not operate without some back-up source of electricity (e.g., battery) .

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Residential Wood Pellet Stoves

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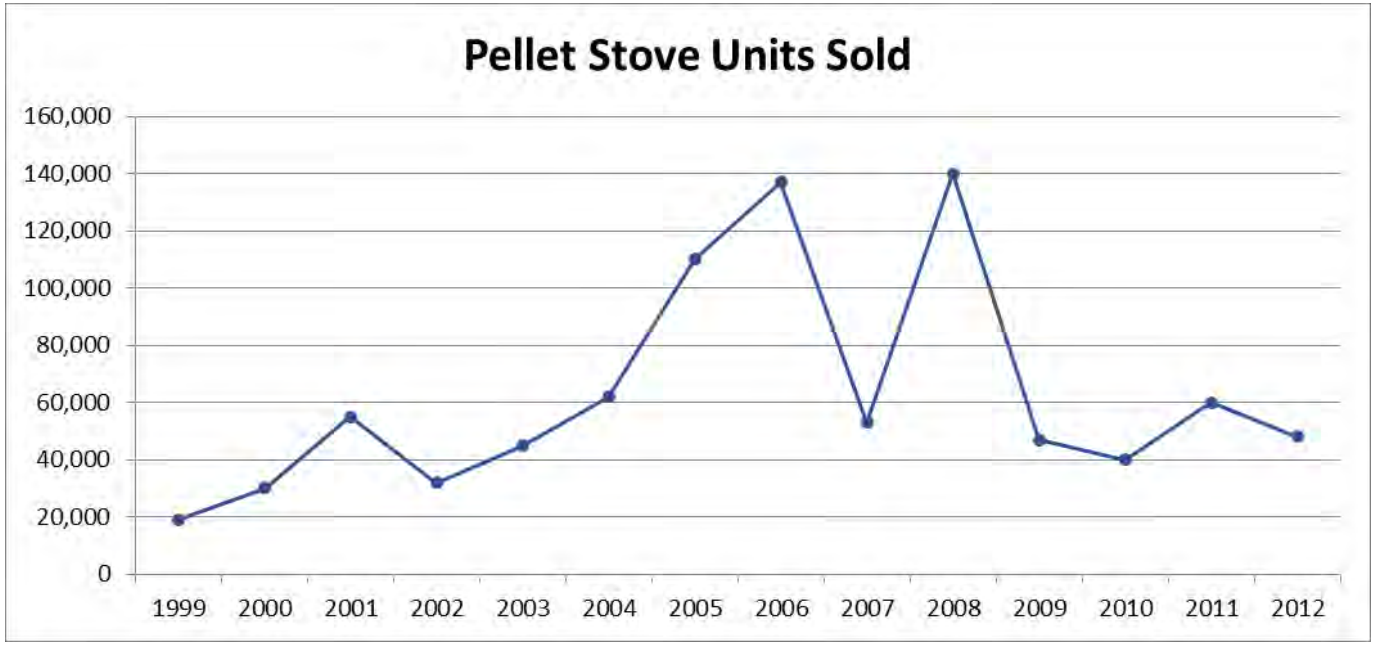
Wood pellet stove shipments grew substantially in the 2005 – 2008 time period but have averaged only 40,000 – 60,000 units since that time.



Source: *HPBA, no post-2012 sales data was publicly available at time of publication.*

Residential Water Heating

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Residential Gas-Fired Storage Water Heaters

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Increased typical efficiencies with associated increase in costs to reflect condensing units.

DATA	2015	2020	2022				2023	2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.0	High	ENERGY STAR V. 5.0	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	40	40	40	40	40	40	40	40	40	40	40	40	40
Uniform Energy Factor (UEF)[1]	0.58	0.63	0.61	0.61	0.66	0.84	0.83	0.78	0.84	0.78	1.33	0.78	1.33
Average Life (y)	13	13	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5
Retail Equipment Cost (2022$)	590	880	420	420	490	720	700	420	720	420	720	420	720
	650	1,410	990	990	1,110	1,650	1,590	990	1,650	990	1,650	990	1,650
Total Installed Cost (2022$)	1,240	1,650	740	740	800	1,140	1,130	740	1,140	740	1,140	740	1,140
	1,240	2,880	1,690	1,690	1,850	3,130	3,160	1,690	3,130	1,690	3,130	1,690	3,130
Annual Maintenance Cost (2022$)[2]	20	20	20	20	20	20	20	20	20	20	20	20	20

1. Analysis is based on an average of medium and high draw pattern units, as this is most reflective of the market.
2. Maintenance includes manufacturer recommendation for the water heater to be drained and flushed annually to minimize deposition of sediment, maintain operating efficiency, and prolong product life. Available evidence indicates that this is performed in 10% of households.

Note:
Ranges represent the span of typical values.
Current standards went into effect April 16, 2015.
ENERGY STAR V. 4.0 went into effect January 5, 2022
ENERGY STAR V. 5.0 will go into effect April 18, 2023
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (15.1, 1.76, 1).

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Residential Gas-Fired Storage Water Heaters

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- The equations for Federal Standards and the voluntary ENERGY STAR requirements, if applicable, are:

Volume Range	Draw Pattern	Federal standard[1]	Federal minimum UEF for typical sizes	ENERGY STAR
≥ 20 gal and ≤ 55 gal	Very Small	UEF=0.3456-(0.002*Gal)	No models on the market	NA
	Low	UEF=0.5982-(0.0019*Gal)	0.54 for a 29-gallon water heater	NA
	Medium	UEF=0.6483-(0.0017*Gal)	0.58 for a 38-gallon water heater	0.64
	High	UEF=0.692-(0.0013*Gal)	0.64 for a 48-gallon water heater	0.68
> 55 gal and ≤ 100 gal	Very Small	UEF=0.647-(0.0006*Gal)	No models on the market	NA
	Low	UEF=0.7689-(0.0005*Gal)	No models on the market	NA
	Medium	UEF=0.7897-(0.0004*Gal)	No models on the market	0.78
	High	UEF=0.8072-(0.0003*Gal)	No models on the market	0.80

- There are currently no models on the market above 55 gallons (gal) due to the high UEF, which would require using condensing or gas-fired heat pump (e.g., absorption) technology to achieve.
- The cost of installation is typically $600 to $1200, which exceeds that of electric water heaters. This difference can be attributed to multiple differences; for example, gas-fired heaters require an extra 1.5 hours of labor for 2 plumbers.
- Condensing units are high efficiency and use PVC venting instead of stainless-steel. Condensing units also use an electrical supply for electronic ignition and power venting. Some building codes require condensate neutralizer filters.
- Advanced Case: Condensing gas-fired storage water heaters are expected to dominate the market by 2030, with corresponding price increases.

[1]Energy Conservation Standards for Residential Water Heaters. 10 CFR 430.32(d).

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Residential Gas-Fired Storage Water Heaters

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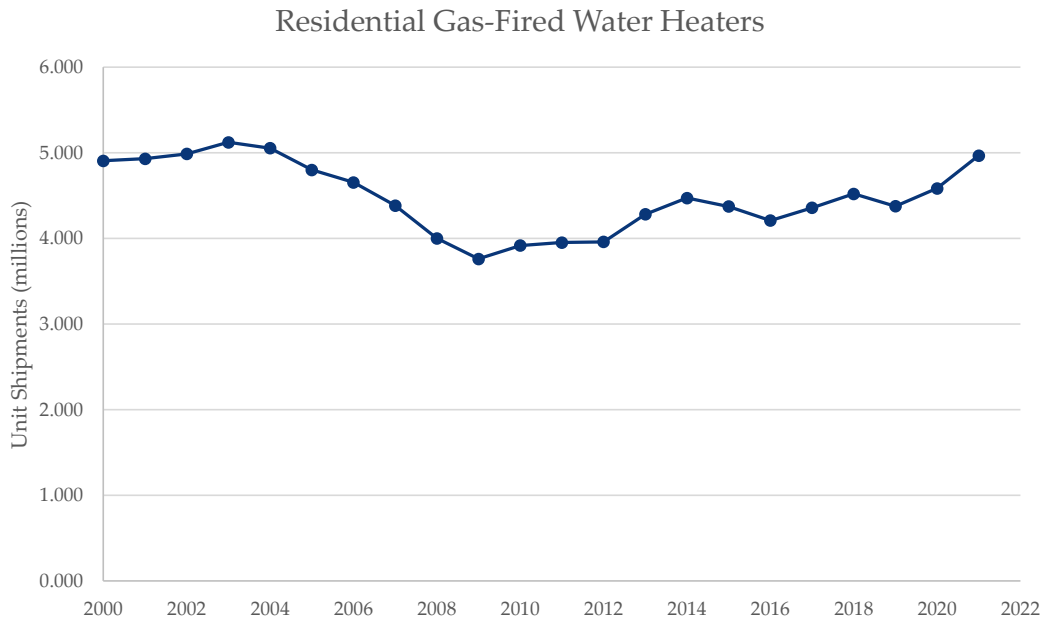
Shipments were flat at 5 million units per year through 2004, then declined gradually over 5 years to a new plateau at 4 million units until rising again back to 5 million units in 2021.



Source: *AHRI*

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Residential Oil-Fired Water Heaters

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Same as Reference Case

DATA	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	32	32	32	32	32	32	32	32	32	32	32
Uniform Energy Factor[1]	0.51	0.67	0.64	0.66	0.68	0.66	0.68	0.66	0.68	0.66	0.68
Average Life (y)	13	13	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5
Retail Equipment Cost (2022$)	1,590	1,880	1,380	1,400	1,480	1,400	1,480	1,400	1,480	1,400	1,480
	1,710	2,410	2,810	2,870	3,030	2,870	3,030	2,870	3,030	2,870	3,030
Total Installed Cost (2022$)	2,350	2,650	2,620	2,650	2,730	2,650	2,730	2,650	2,730	2,650	2,730
	2,470	3,350	4,050	4,120	4,280	4,120	4,280	4,120	4,280	4,120	4,280
Annual Maintenance Cost (2022$)[2]	210	210	210	210	210	210	210	210	210	210	210

1. Analysis is based on an average of medium and high draw pattern units, as this is most reflective of the market.
2. Oil-fired storage water heaters are typically cleaned and maintained under maintenance contracts. The annual cost of typical maintenance is based on maintenance contract prices from different oil-fired product suppliers as specified in the CWH EERE 2022 Preliminary Analysis.

Note:
Ranges represent span of typical values.
Current standards went into effect April 16, 2015.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (16.2, 1.70, 1).

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Residential Oil-Fired Water Heaters

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- The equations for Federal Standards and the voluntary ENERGY STAR requirements, if applicable, are:

Volume Range	Draw Pattern	Federal standard[1]	Federal minimum UEF for typical sizes	ENERGY STAR
≤ 50 gal	Very Small	UEF=0.2509-(0.0012*Gal)	No models on the market	NA
	Low	UEF=0.533-(0.0016*Gal)	No models on the market	NA
	Medium	UEF=0.6078-(0.0016*Gal)	No models on the market	NA
	High	UEF=0.6815-(0.0014*Gal)	0.64 for a 29-gallon water heater	NA

- There are no ENERGY STAR requirements for oil-fired storage water heaters.
- Annual shipments of residential oil-fired storage water heaters are approximately 4,000, which is less than 1% of shipments of residential gas-fired storage water heaters.
- Oil-fired storage water heaters often have smaller tanks with larger input ratings relative to natural gas-fired and electric storage water heaters.
- No condensing residential oil-fired storage water heaters currently exist in the U.S. market. Condensing oil-fired water heaters are generally not considered technologically feasible because the sulfur content in fuel oil leads to the condensate becoming corrosive.
- Residential oil-fired water heaters utilize power burners and have at least some level of electrical power consumption.
- The most efficient models on the market use a proprietary "turbo-flue" design to increase heat transfer to water.

[1]Energy Conservation Standards for Residential Water Heaters. 10 CFR 430.32(d).

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Residential Oil-Fired Water Heaters

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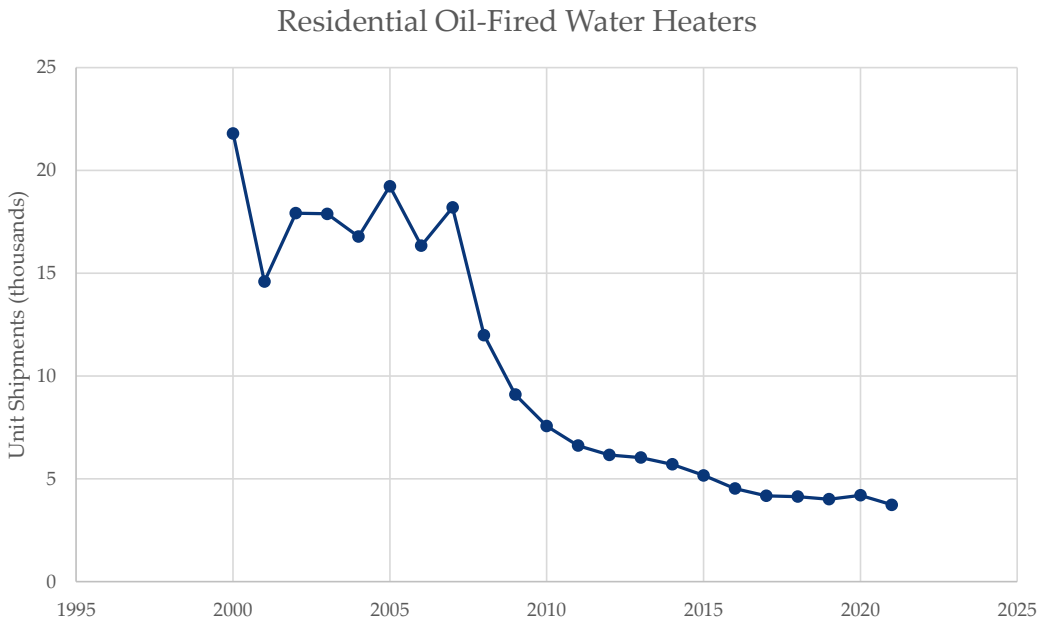
Shipments peaked at about 22,000 units in 2000 and have decreased since then, with an exponential decay occurring since 2007. Only about 4,000 units were shipped in 2021.



Source: *CWH EERE 2022 Preliminary Analysis*

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Residential Electric Resistance Storage Water Heaters

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Same as Reference Case

DATA	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	50	50	50	50	50	50	50	50	50	50	50
Uniform Energy Factor[1]	0.88	0.93	0.92	0.92	0.93	0.92	0.93	0.92	0.93	0.92	0.93
Average Life (y)	13	13	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1
Retail Equipment Cost (2022$)	290	350	330	330	600	330	600	330	600	330	600
	530	650	760	760	850	760	850	760	850	760	850
Total Installed Cost (2022$)	590	710	500	500	550	500	550	500	550	500	550
	940	1,290	1,310	1,310	1,430	1,310	1,430	1,310	1,430	1,310	1,430
Annual Maintenance Cost (2022$)[2]	20	20	20	20	20	20	20	20	20	20	20

1. Beginning in 2016, the efficiency metric for water heaters changed from energy factor (EF) to UEF based on DOE test procedures. The UEF values for the installed base in 2015 are converted values equivalent to 0.90 EF. Analysis is based on an average of low and medium draw pattern units, as this is most reflective of the market.
2. Similar to gas-fired and oil-fired storage water heaters, manufacturers recommend that electric storage water heaters be drained and flushed annually to minimize deposition of sediment, maintain operating efficiency, and prolong product life. The available evidence indicates that this practice is done in 10% of households.

Note:
Ranges represent span of typical values.
Current standards went into effect April 16, 2015.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (15.7, 1.57, 1).

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Residential Electric Resistance Storage Water Heaters

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- The equations for Federal Standards and the voluntary ENERGY STAR requirements, if applicable, are:

Volume Range	Draw Pattern	Federal standard[1]	Federal minimum UEF for typical sizes	ENERGY STAR
≥ 20 gal and ≤ 55 gal	Very Small	UEF=0.8808-(0.0008*Gal)	No models on the market	2.00
	Low	UEF=0.9254-(0.0003*Gal)	0.92 for a 27-gallon water heater	2.00
	Medium	UEF=0.9307-(0.0002*Gal)	0.92 for a 45-gallon water heater	2.00
	High	UEF=0.9349-(0.0001*Gal)	0.93 for a 50-gallon water heater	2.00
> 55 gal and ≤ 120 gal	Very Small	UEF=1.9236-(0.0011*Gal)	No models on the market	2.20
	Low	UEF=2.0440-(0.0011*Gal)	No models on the market	2.20
	Medium	UEF=2.1171-(0.0011*Gal)	2.05 for a 58-gallon water heater	2.20
	High	UEF=2.2418-(0.0011*Gal)	2.15 for a 80-gallon water heater	2.20

- The federal standards for residential electric storage water heaters apply to both electric resistance storage water heaters and heat pump water heaters.
  - The Federal standard levels for the ≤ 55-gallon range are achievable through electric resistance and heat pump technology.
  - The Federal standards for the > 55-gallon range and all ENERGY STAR levels are only achievable through heat pump technology.
- Typical storage volumes range from 25-55 gallons for electric resistance storage water heaters and 45-80 gallons for heat pump water heaters (HPWHs).

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Residential Electric Resistance Storage Water Heaters

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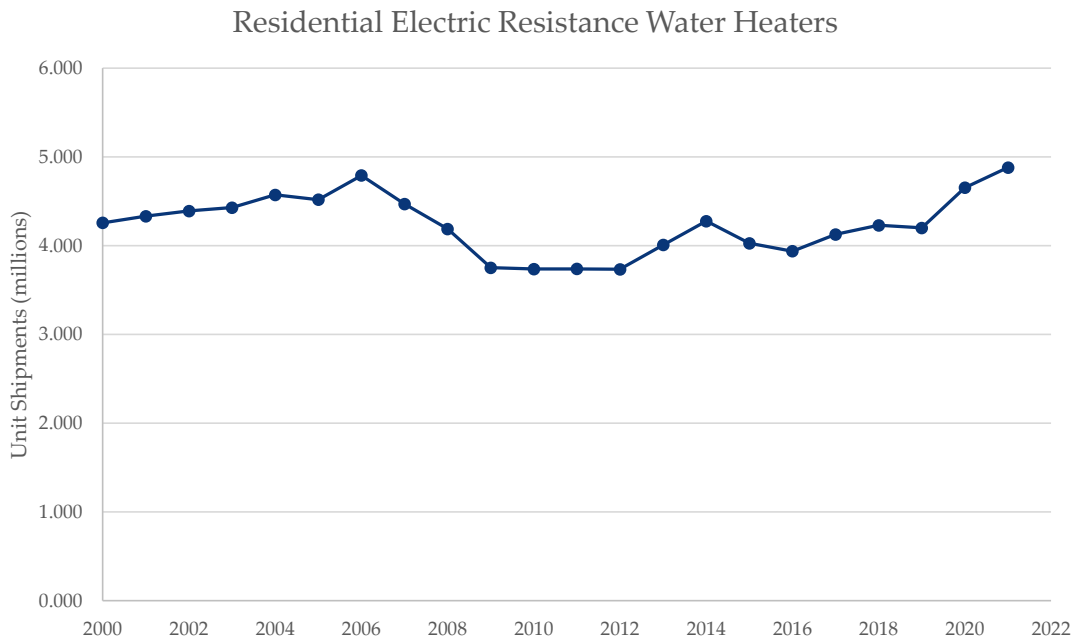
Shipments peaked in 2006 then dropped a total of 22 percent over three years. Shipments have gradually increased since then and were at the highest level in 2021.



Source: *AHRI*

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Residential Heat Pump Water Heaters

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Same as Reference Case

DATA	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Typical	ENERGY STAR V. 4.0	High	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	50	50	50	50	50	50	50	50	50	50	50
Uniform Energy Factor[1]	2.05	3.28	3.33	3.30	3.73	3.33	3.73	3.33	3.73	3.33	3.73
Average Life (y)	13	13	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1
Retail Equipment Cost (2022$)[2]	1,290	1,410	630	630	670	630	670	630	670	630	670
	1,650	1,760	1,440	1,440	1,670	1,370	1,590	1,300	1,510	1,240	1,430
Total Installed Cost (2022$)[2]	1,710	1,880	870	870	980	870	980	870	980	870	980
	2,940	3,000	2,230	2,230	2,450	2,120	2,330	2,010	2,210	1,910	2,100
Annual Maintenance Cost (2022$)[3]	20	20	20	20	20	20	20	20	20	20	20

1. Analysis is based on an average of low and medium draw pattern units, as this is most reflective of the market.
2. It is expected that costs for HPWHs will decrease over time as these products become more common. This analysis estimates these cost decreases for the higher range of costs.
3. For heat pump water heater design options, DOE assumed higher maintenance cost to take into account annual cleaning of the air filter, preventative maintenance cost to check the evaporator and refrigeration system, inspection of the condensate withdrawal system, and replacement of the condensate neutralizer filter, if applicable. However, this maintenance is estimated to occur in only 10% of households, so overall maintenance cost is similar to that of other electric resistance water heaters.

Note:
Ranges represent span of typical values.
ENERGY STAR V. 4.0 went into effect January 5, 2022.
Assume same lifetime as electric resistance water heaters.

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Residential Heat Pump Water Heaters

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- Technology improvements have advanced efficiency and reliability, but the high first-cost and lack of awareness among consumers and contractors still precludes high-volume market penetration.
- New Federal standards that came into effect in April 2015 effectively mandate heat pump technology for electric storage water heaters with storage volume > 55 gallons.
- Integrated models are the most common configuration for residential HPWHs. Several major water heater manufacturers produce such models, and other competitors offer integrated or add-on units (for existing electric or indirect storage water heaters).
- Sales are estimated to be driven partly by rebates and tax credits at the utility, local, state, and Federal level.
- Resistive heating elements are virtually 100% efficient, but there is a jump in efficiency when heat pump technology is adopted because heat pumps' COP are usually between 2.5 and 4.
- Heat pumps raise the water temperature more slowly than resistive heating elements, so most models use backup resistive elements along with the heat pump when hot water demand is high. Most HPWHs allow the consumer to control whether resistive elements are used in periods of high demand (e.g., "hybrid mode" or "heat pump only mode").

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Residential Heat Pump Water Heaters

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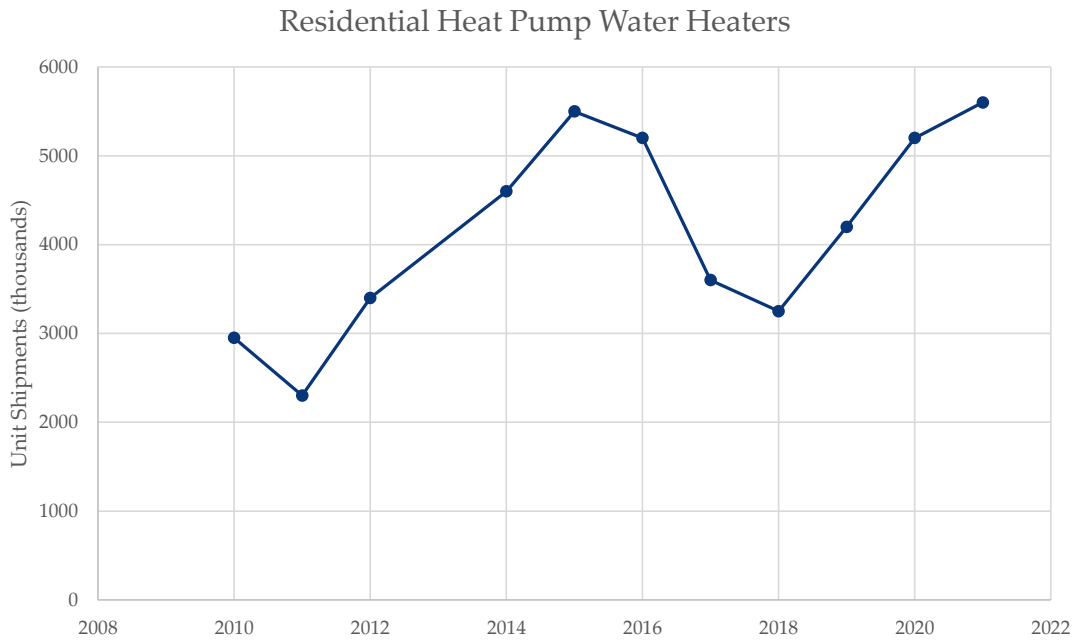
Shipments make up a small portion of electric resistance heaters, with a peak of only about 5,500 units, occurring in both 2015 and 2021.



Source: *ENERGY STAR*

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Residential Solar Water Heaters

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Same as Reference Case

DATA	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	ENERGY STAR V. 4.0	Typical	Typical	Typical	Typical
Typical Capacity (ft^2)[1]	42	42	40	40	40	40	40
	65	65	54.4	54.4	54.4	54.4	54.4
Solar Uniform Energy Factor (SUEF)[2]	3.0	3.0	3.0	99.0	99.0	99.0	99.0
Average Life (y)	15	15	15	15	15	15	15
	30	30	30	30	30	30	30
Retail Equipment Cost (2022$)	7,710	7,710	6,430	6,430	6,430	6,430	6,430
Total Installed Cost (2022$)	10,650	10,650	8,060	8,060	8,060	8,060	8,060
Annual Maintenance Cost (2022$)[3]	80	80	80	80	80	80	80

1. Capacity selections are based on the range observed from medium draw units in the ENERGY STAR database. Medium draw represented the largest portion of units.
2. An SUEF of 3.0 is the required threshold for ENERGY STAR certification, yet a value of 99 was the most common observed SUEF among medium draw units. Note that an SUEF of 99 indicates that no backup heating was required for the applicable draw pattern, and all energy was provided by the solar collector. Since SUEF is a measure of hot water energy out divided by electrical or gas backup energy in, it will be infinite for cases where the collector provides all the hot water needed for the draw pattern – the Solar Rating and Certification Corporation's (SRCC's) OG-300 software is written to assign an SUEF of 99 to this case.
3. Annual maintenance is expected to be 0.5% to 1% of the total installation for 2022, 2030, 2040, and 2050.

Note:
ENERGY STAR V. 4.0 went into effect January 5, 2022.

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Residential Solar Water Heaters

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- Solar water heaters are not subject to federal energy conservation standards. The ENERGY STAR requirements are:

Applicable Products	Backup Fuel	ENERGY STAR Requirement	Test Method
Whole-home solar units	Gas	SUEF ≥ 3.0	ICC 900/SRCC 300-2020 Solar Thermal System Standard, Appendix A: Solar Uniform Energy Factor Procedure for Solar Water Heating Systems
	Electric	SEF ≥ 1.8	

- Solar water heaters can be either active or passive. An active system uses an electric pump to circulate the heat transfer fluid; a passive system has no pump. Most solar water heaters in the U.S. are the active type.
- Solar water heaters are also characterized as open loop (also called "direct") or closed loop (also called "indirect"). An open-loop system circulates household (potable) water through the collector. A closed-loop system uses a heat transfer fluid (water or diluted antifreeze, for example) to collect heat and a heat exchanger to transfer the heat to household water. Direct systems were observed as the most common product type and subject of this analysis.
- In 2020, stakeholders from the solar thermal industry developed the Solar Uniform Energy Factor (SUEF) Specification for solar water heaters to align with the UEF metric used by DOE for other water heating technologies.
- SUEF is also the metric used by the current ENERGY STAR Specification, and it replaced the Solar Energy Factor (SEF) metric.
- Over two-third of the current solar water heater market is in the southern or western U.S. (including Hawaii). A collector area of 42 square feet (ft^2) would be typical for these areas. Colder areas of the U.S. would require a larger collector (e.g., 65 ft^2).
- Installed costs are higher for colder areas where larger collectors are required. Costs also vary widely depending on collector quality, type of system, and site-specific characteristics.

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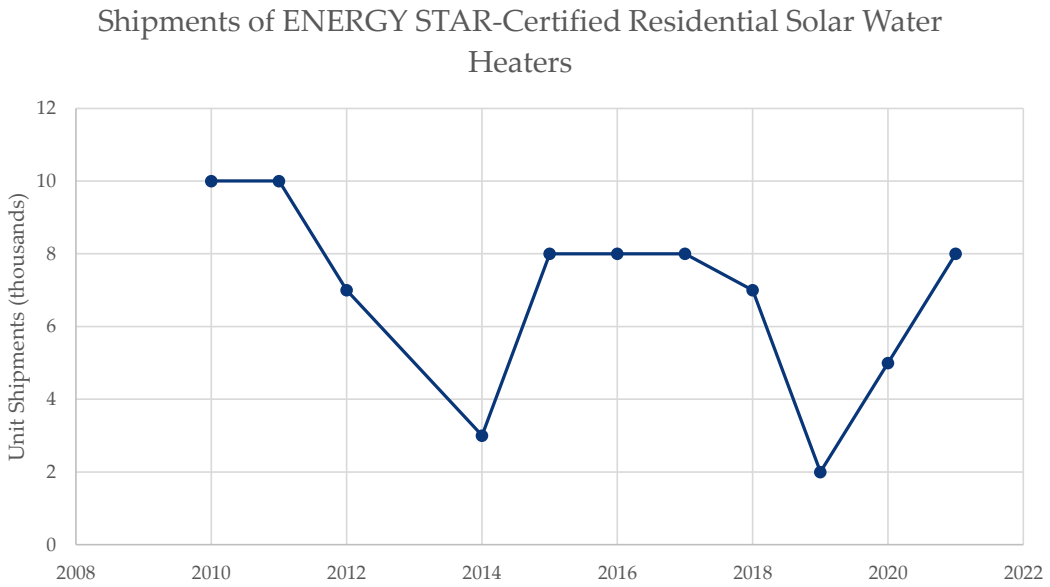
The shipments data below only represents ENERGY STAR-certified solar water heaters, as ENERGY STAR did not provide a market penetration rate. Solar water heaters have a small market share, with only 10,000 shipments at the peak in 2010 and 2011.



Source: *ENERGY STAR*

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Residential Gas-Fired Instantaneous Water Heaters

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Higher typical efficiency product with the same costs as ref. case despite increased efficiency

DATA	2015	2020	2022				2023	2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.0	High	ENERGY STAR V. 5.0	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	199	199	199	199	199	199	199	199	199	199	199	199	199
Uniform Energy Factor (UEF)[1]	0.81	0.89	0.81	0.92	0.87	0.97	0.95	0.96	0.97	0.96	0.97	0.96	0.97
Average Life (y)	19	19	20	20	20	20	20	20	20	20	20	20	20
Retail Equipment Cost (2022$)	1,410	1,180	430	580	580	610	610	580	610	580	610	580	610
	1,760	1,410	1,020	1,360	1,350	1,430	1,430	1,360	1,430	1,360	1,430	1,360	1,430
Total Installed Cost (2022$)	2,590	1,760	920	1,070	950	1,090	1,090	1,070	1,090	1,070	1,090	1,070	1,090
	3,820	3,350	2,860	3,160	3,140	3,230	3,220	3,160	3,230	3,160	3,230	3,160	3,230
Annual Maintenance Cost (2022$)[2]	90	90	90	90	90	90	90	90	90	90	90	90	90

1. Analysis is based on an average of low, medium, and high draw pattern units, as this is most reflective of the market.
2. Annual maintenance includes deliming to minimize deposition of sediment in the heat exchanger, maintain operating efficiency and prolong product life. Also includes additional tasks, including inspection of the ignition device, gas valve, controls, thermostat, and venting.

Note:
Current standards went into effect April 16, 2015.
ENERGY STAR V. 4.0 went into effect January 5, 2022.
ENERGY STAR V. 5.0 will go into effect April 18, 2023.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (21.3, 1.76, 1).

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Residential Gas-Fired Instantaneous Water Heaters

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- The equations for Federal Standards and the voluntary ENERGY STAR requirements, if applicable, are:

Volume Range	Draw Pattern	Federal standard[1]	Federal minimum UEF for typical sizes	ENERGY STAR
<2 gal and >50,000 Btu/h	Very Small	UEF=0.80	No models on the market	0.87
	Low	UEF=0.81	No models on the market	0.87
	Medium	UEF=0.81	0.81	0.87
	High	UEF=0.81	0.81	0.87

- The ENERGY STAR levels require the use of condensing technology.
- All of the major water heater manufacturers now offer an instantaneous water heater model.
- The maintenance costs include cleaning the water inlet filter and the heat exchanger of mineral deposits and replacing the water valve approximately once every five years for all instantaneous water heaters.
- When replacing a storage water heater with an instantaneous water heater, there are significant additional costs to upsize the gas supply line to ¾ inch from the typical ½ inch and change the venting.
- Advanced Case: Increased market incentives are expected to drive further adoption of condensing products, thereby raising the typical efficiency, while increased R&D is expected to improve cost.

[1]Energy Conservation Standards for Residential Water Heaters. 10 CFR 430.32(d).

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Residential Gas-Fired Instantaneous Water Heaters

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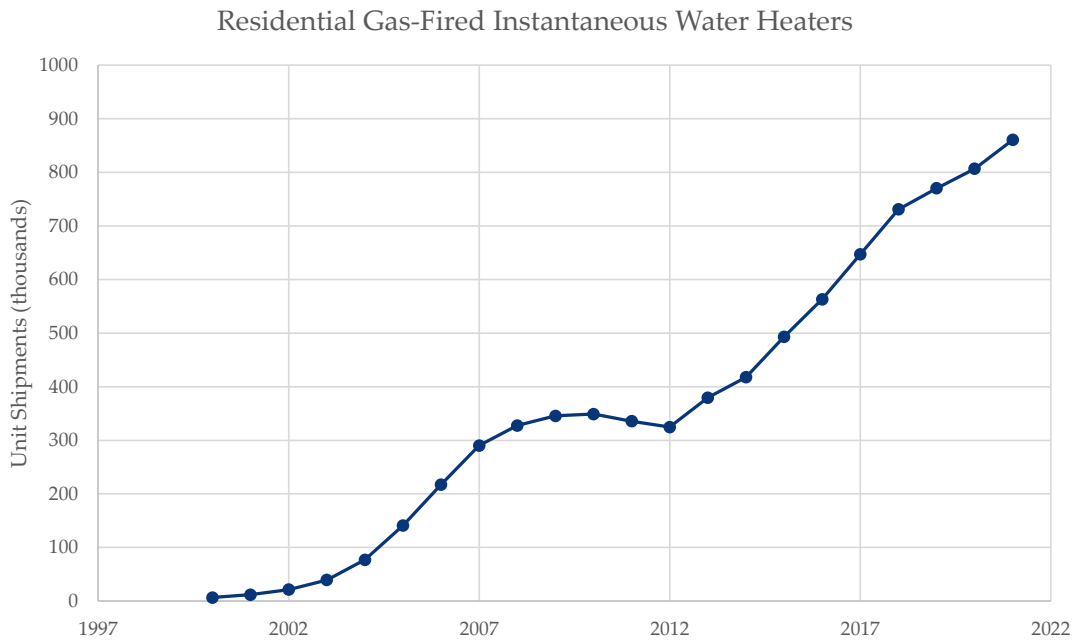
Shipments for Gas-Fired Instantaneous Water Heaters have grown steadily with nearly no shipments in 2000 and a peak of about 850,000 units in 2021.



Source: *CWH EERE 2022 Preliminary Analysis*

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Residential Electric Instantaneous Water Heaters

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Same as Reference Case

DATA	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Representative Input Rate (kW)	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Uniform Energy Factor (UEF)[1]	0.96	0.96	0.91	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98
Average Life (y)	20	20	20	20	20	20	20	20	20	20	20
Retail Equipment Cost (2022$)	260	260	260	260	260	260	260	260	260	260	260
Total Installed Cost (2022$)	520	520	520	520	520	520	520	520	520	520	520
Annual Maintenance Cost (2022$)[2]	90	90	90	90	90	90	90	90	90	90	90

1. Analysis is based on an average of low, medium, and very small draw pattern units, as this is most reflective of the market.
2. Annual maintenance costs not provided in CWH EERE 2022 Preliminary Analysis. Maintenance costs determined from the following calculation: GIWH - (GSWH - ESWH) - i.e., the difference factor in maintenance between gas and electric storage heat pumps applied to gas instantaneous heat pumps.

Note:
Current standards went into effect April 16, 2015.
Assume same lifetime as gas-fired instantaneous water heaters.

Residential Electric Instantaneous Water Heaters

- The Federal standards are:

Volume Range	Draw Pattern	Federal standard[1]	Federal minimum UEF for typical sizes
<2 gal	Very Small	UEF=0.91	0.91
	Low	UEF=0.91	0.91
	Medium	UEF=0.91	No models on the market
	High	UEF=0.92	No models on the market

- Electric instantaneous water heaters use electric resistance heating elements to heat water when there is a demand. Resistive heating elements are virtually 100% efficient, and the small storage capacities of these products means that they do not lose significant amounts of heat to the environment.
- The federal standards for these products require UEFs of 0.91 for very small, low, and medium draw pattern models and 0.92 for high draw pattern models.
- Most products currently on the market are in the very small draw pattern or the low draw pattern because electric resistance elements can only supply a limited quantity of heat on an instantaneous basis due to circuit amperage limitations.
- Many products are designed for point-of-use applications, such that the water heater only supplies water to one faucet or showerhead.

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Residential Appliances

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Residential Refrigerator-Freezers (Top)

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Higher typical efficiencies with same costs as reference case despite increased efficiency

DATA[1]	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)[2]	19	19	19	19	19	19	19	19	19	19	19	19
Energy Consumption (kWh/y)[3]	512	401	411	401	370	358	370	358	370	358	370	358
Average Life (y)	15	15	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)	670	750	740	750	760	760	750	760	750	760	750	760
Total Installed Cost (2022$)	670	750	740	750	760	760	750	760	750	760	750	760
Annual Maintenance Cost (2022$)[4]	10	10	10	10	10	10	10	10	10	10	10	10

1. Product Class 3 is used for this analysis (Refrigerator-freezers—automatic defrost with top-mounted freezer without through-the-door ice service and all-refrigerator—automatic defrost).
2. The volume shown here is the nominal total volume, not the adjusted volume, which is used to determine compliance with standards. The adjusted volume is equal to the fresh food internal volume plus the freezer internal volume times an adjustment factor, which depends on the product type.
3. The 2015 installed base energy consumption value is based on an adjusted volume of 21 cubic feet (ft^3). Energy consumption values for the 2020 installed base and 2022 and beyond are based on an adjusted volume of 22 ft^3, representing the current market.
4. Maintenance costs include cost of repairing integral components (e.g., compressor, evaporator fan, electronics, ice maker), not replaceable components (e.g., water filters).

Note:
Current standard went into effect in September 2014.
ENERGY STAR V. 5.1 went into effect in September 2014.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (10.26, 1.28, 5.13).

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Residential Refrigerator-Freezers (Side)

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Higher typical efficiencies with same costs as reference case despite increased efficiency

DATA[1]	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)[2]	26	26	25	25	25	25	25	25	25	25	25	25
Energy Consumption (kWh/y)[3]	893	693	705	693	635	610	635	610	635	610	635	610
Average Life (y)	15	15	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)	1,400	1,130	1,130	1,130	1,160	1,470	1,130	1,470	1,130	1,470	1,130	1,470
Total Installed Cost (2022$)	1,400	1,130	1,130	1,130	1,160	1,470	1,130	1,470	1,130	1,470	1,130	1,470
Annual Maintenance Cost (2022$)[4]	30	20	20	20	20	30	20	30	20	30	20	30

1. Product Class 7 is used for this analysis (Refrigerator-freezers—automatic defrost with side-mounted freezer with through-the-door ice service).
2. The volume shown here is the nominal total volume, not the adjusted volume, which is used to determine compliance with standards. The adjusted volume is equal to the fresh food internal volume plus the freezer internal volume times an adjustment factor, which depends on the product type.
3. Based on an adjusted volume of 32 ft^3 for all analysis years.
4. Maintenance costs include cost of repairing integral components (e.g., compressor, evaporator fan, electronics, ice maker), not replaceable components (e.g., water filters).

Note:
Current standard went into effect in September 2014.
ENERGY STAR V. 5.1 went into effect in September 2014.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (10.26, 1.28, 5.13).

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Residential Refrigerator-Freezers (Bottom)

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Higher typical efficiencies with same costs as reference case despite increased efficiency

DATA[1]	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)[2]	19	19	19	19	19	19	19	19	19	19	19	19
Energy Consumption (kWh/y)[3]	547	473	521	473	469	430	469	430	469	430	469	430
Average Life (y)	15	15	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)	1,190	920	920	920	920	930	920	930	920	930	920	930
Total Installed Cost (2022$)	1,190	920	920	920	920	930	920	930	920	930	920	930
Annual Maintenance Cost (2022$)[4]	30	20	20	20	20	20	20	20	20	20	20	20

1. Product Class 5 is used for this analysis (Refrigerator-freezers—automatic defrost with bottom-mounted freezer without through-the-door ice service).
2. The volume shown here is the nominal total volume, not the adjusted volume, which is used to determine compliance with standards. The adjusted volume is equal to the fresh food internal volume plus the freezer internal volume times an adjustment factor, which depends on the product type.
3. Based on an adjusted volume of 23 ft^3 for all analysis years.
4. Maintenance costs include cost of repairing integral components (e.g., compressor, evaporator fan, electronics, ice maker), not replaceable components (e.g., water filters).

Note:
Current standard went into effect in September 2014.
ENERGY STAR V. 5.1 went into effect in September 2014.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (10.26, 1.28, 5.13).

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Residential Refrigerator-Freezers

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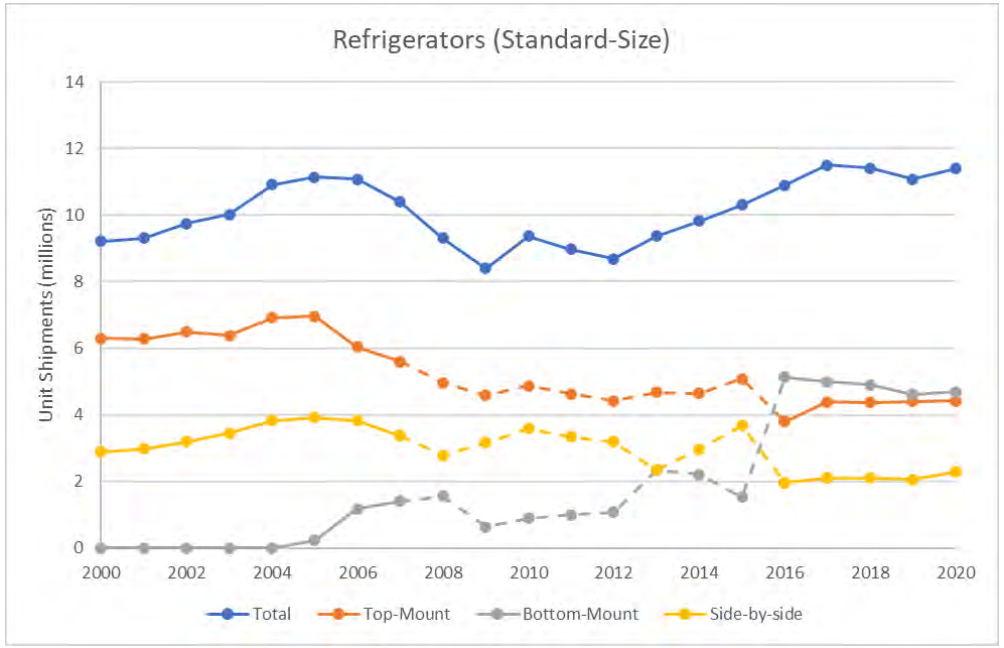
- Current Federal standards[1]:
  - Compliance required beginning September 15, 2014
  - Models divided into 32 product classes based on size (standard or compact), location of freezer (top, bottom, or side), type of defrost (automatic or manual), installation configuration (freestanding or built-in), and presence and configuration (through-the-door or inside cabinet) of automatic icemaker
  - Limits on annual electricity consumption expressed as functions of adjusted volume[2]
  - New product classes for built-in units
  - Amount by which standards are tightened varies by product class
- ENERGY STAR criteria limit annual electricity consumption to 10% less than the Federal standard
- Energy efficiency opportunities for refrigerators include:
  - More efficient compressor, including variable speed compressors
  - Brushless direct current (DC) fan motor (also known as ECM motor)
  - Variable defrost
  - Larger condenser
  - Dual evaporators
  - Vacuum-insulated panels
  - Refrigerants (Isobutane vs. R134a)
- Advanced Case: Increased market incentives will push product sales towards the ENERGY STAR level, but the technologies used to meet ENERGY STAR are already well-known and prices will likely not rise as manufacturing volumes increase at higher efficiencies.

[1]Energy Conservation Standards for Residential Refrigerators, Refrigerator-Freezers, and Freezers. 10 CFR 430.32(a).
[2]Adjusted Volume (AV) = (Fresh Volume) + 1.76 × (Freezer Volume)

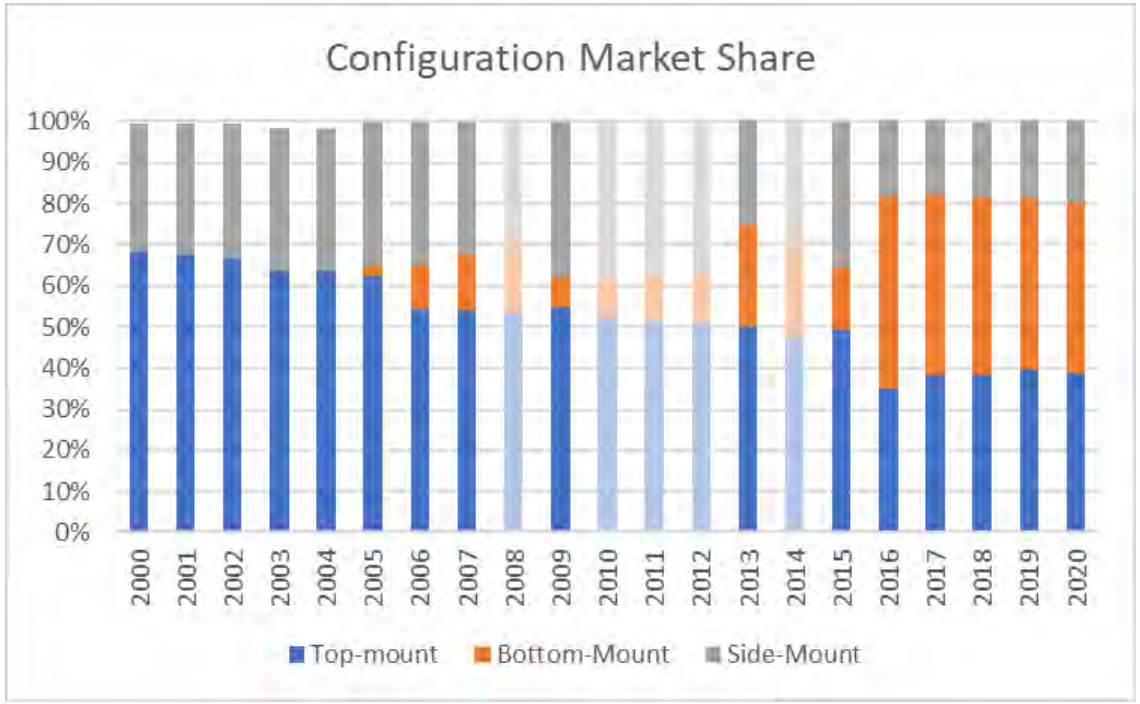
Annual shipment volumes have rebounded from a sharp decline between 2006 and 2009, reaching approximately 11.4 million units in 2020.



Source: *Appliance Magazine; DOE's CCD, as of December 2017; ENERGY STAR Unit Shipment Data (2017-2020); Guidehouse analysis.* Dashed lines are a combination of interpolated and available data.

Residential Refrigerator-Freezers

Bottom-mount units have gained market share, surpassing top-mount units since 2016.



Sources: *RF EERE 2021 Preliminary Analysis; DOE's CCD, as of December 2017; Guidehouse analysis.* Lightly shaded bars indicate interpolated data.

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Residential Freezers (Chest)

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Same as Reference Case

DATA[1]	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)[2]	16	15	15	15	15	15	15	15	15	15	15
Energy Consumption (kWh/y)[3]	360	297	297	297	287	297	287	297	287	297	287
Average Life (y)	21	21	21	21	21	21	21	21	21	21	21
Retail Equipment Cost (2022$)	510	590	680	680	690	680	690	680	690	680	690
Total Installed Cost (2022$)	510	590	680	680	690	680	690	680	690	680	690
Annual Maintenance Cost (2022$)[4]	10	10	10	10	10	10	10	10	10	10	10

1. Product Class 10 is used for this analysis (Chest freezers and all other freezers except compact freezers).
2. The volume shown here is the nominal volume, not the adjusted volume, which is used to determine compliance with standards. The adjusted volume is equal to the fresh food internal volume (zero for freezers) plus the freezer internal volume times an adjustment factor, which depends on the product type.
3. Based on an adjusted volume of 26 ft^3, which is the average adjusted volume for units with a rounded total refrigerated volume of 15 ft^3 per the DOE CCD.
4. Maintenance costs include cost of repairing integral components (e.g., compressor, evaporator fan, electronics)

Note:
Current standard went into effect in September 2014.
ENERGY STAR excluded as no products at the typical capacity are ENERGY STAR compliant.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (21.96, 1.83, 1).

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Residential Freezers (Upright)

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Higher typical efficiencies with same costs as reference case despite increased efficiency

DATA[1]	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)[2]	17	17	18	18	18	18	18	18	18	18	18	18
Energy Consumption (kWh/y)[3]	615	446	497	493	448	441	448	441	448	441	448	441
Average Life (y)	21	21	21	21	21	21	21	21	21	21	21	21
Retail Equipment Cost (2022$)	690	880	830	830	830	830	830	830	830	830	830	830
Total Installed Cost (2022$)	690	880	830	830	830	830	830	830	830	830	830	830
Annual Maintenance Cost (2022$)[4]	10	10	10	10	10	10	10	10	10	10	10	10

1. Product Class 9 is used for this analysis (Upright freezers with automatic defrost).
2. The volume shown here is the nominal volume, not the adjusted volume, which is used to determine compliance with standards. The adjusted volume is equal to the fresh food internal volume (zero for freezers) plus the freezer internal volume times an adjustment factor, which depends on the product type.
3. Based on an adjusted volume of 31 ft^3, which is the average adjusted volume for units with a rounded total refrigerated volume of 18 ft^3 per the DOE CCD.
4. Maintenance costs include cost of repairing integral components (e.g., compressor, evaporator fan electronics).

Note:
Current standard went into effect in September 2014.
ENERGY STAR V. 5.1 went into effect September 2014.
Assume same lifetime as chest freezers.

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Residential Freezers

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- Current Federal standards[1]:
  - Compliance required beginning September 15, 2014
  - Models divided into 10 product classes based on size (standard or compact), orientation (chest or upright), type of defrost (automatic or manual), installation configuration (freestanding or built-in), and presence of automatic icemaker
    - Current analysis focuses on the two representative product classes analyzed in the recent rulemaking, chest and upright freezers.
  - Limits on annual electricity consumption expressed as functions of adjusted volume[2]
    - Chest freezers and all other freezers except compact freezers (PC 9): 9.88AV + 143.7
    - Upright freezers with automatic defrost (PC 10): 12.43AV + 326.1
- ENERGY STAR criteria limit annual electricity consumption to 10% less than the Federal standard
  - No ENERGY STAR compliant products at the typical capacity for chest freezers
- Energy efficiency opportunities for freezers include:
  - Higher efficiency and/or variable-speed compressor systems
  - Larger heat exchangers
  - Permanent-magnet fan motor systems (vs. shaded pole motor (SPM) and PSC fan motors)
  - Demand defrost systems
  - Vacuum-insulated panels
  - Thicker insulation (though at a loss of consumer utility)
  - Refrigerants (Isobutane vs. R134a)
  - Variable anti-sweat heating
  - Use of forced convection condenser (for upright freezers)
- Advanced Case: Increased market incentives will push product sales of upright freezers towards the ENERGY STAR level, but the technologies used to meet ENERGY STAR are already well-known and prices will likely not rise as manufacturing volumes increase at higher efficiencies. Unlikely to occur for chest freezers due to such a low existing market penetration of ENERGY STAR products.

[1]Energy Conservation Standards for Residential Refrigerators, Refrigerator-Freezers, and Freezers. 10 CFR 430.32(a).
[2]Adjusted Volume (AV) = (Fresh Volume) + 1.76 × (Freezer Volume).

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Residential Freezers

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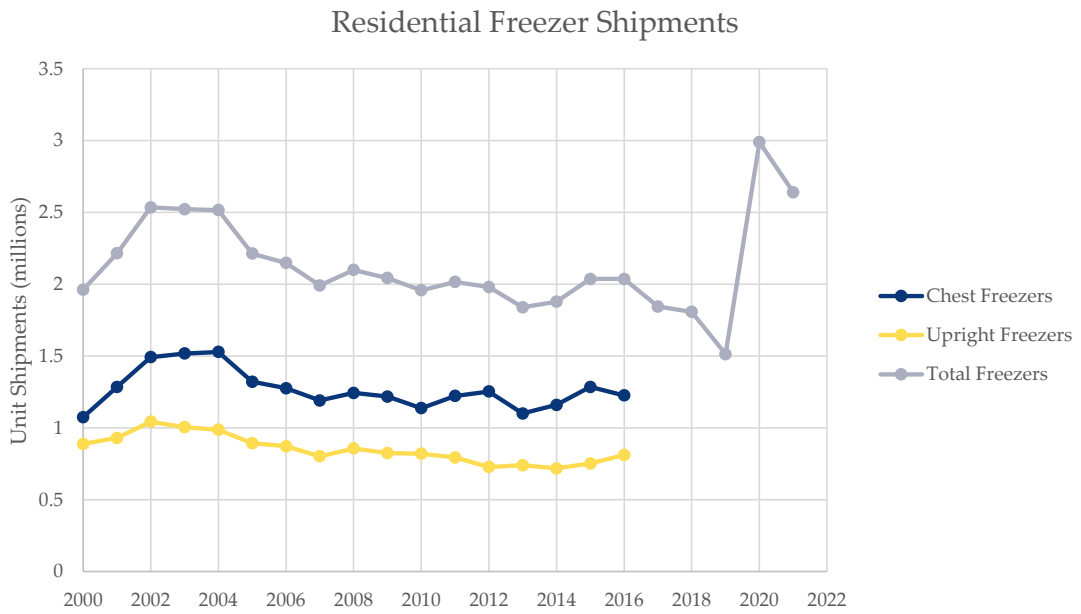
Shipment volumes held steady between 2007 to 2016 at about 2 million units per year. Shipments jumped to 3 million units in 2020. Chest freezers represent about 60% of the market.



Sources: *Appliance Magazine* from 2000 to 2016; *ENERGY STAR from 2017 to 2021*

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Residential Natural Gas Cooktops

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Same as Reference Case

DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	9	9	9	9	9	9	9	9	9	9
	23	23	23	23	23	23	23	23	23	23
Integrated Annual Energy Consumption (kBtu/y)[1]	1,061	914	914	730	914	730	914	730	914	730
Cooking Efficiency (%)	40	45	45	52	45	52	45	52	45	52
Average Life (y)	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)[2]	290	310	310	330	310	330	310	330	310	330
Total Installed Cost (2022$)[2]	420	460	460	480	460	480	460	480	460	480
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-

1. Although there is no performance standard in effect, the test procedure metric has changed from Cooking Efficiency (%) to Integrated Annual Energy Consumption (IAEC) (kBtu/h). The Consumer Cooking Products EERE 2020 notice of proposed determination (NOPD) used for 2020 and beyond in this analysis also determined IAEC using a different test procedure than the Consumer Cooking Products EERE 2016 SNOPR.
2. Equipment and installed costs are for cooktops only (not combined range units).
3. Annual maintenance costs are negligible.

Note:
The range for typical capacity represents the span of typical values.
Average life is determined using a Weibull distribution characterized by the following scale (α) and shape (β) parameters: (14.56, 5.73).

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Residential Natural Gas Ovens

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Same as Reference Case

DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	16	16	16	16	16	16	16	16	16	16
	18	18	18	18	18	18	18	18	18	18
Typical Cavity Volume (ft^3)	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Integrated Annual Energy Consumption (kBtu/y)[1]	2,038	1,960	1,960	1,831	1,960	1,831	1,960	1,831	1,960	1,831
Cooking Efficiency (%)	6.6	6.9	6.9	7.3	6.9	7.3	6.9	7.3	6.9	7.3
Average Life (y)	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)[2]	740	770	770	810	770	810	770	810	770	810
Total Installed Cost (2022$)[2]	870	920	920	950	920	950	920	950	920	950
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-

1. Although there is no performance standard in effect, the test procedure metric has changed from Cooking Efficiency (%) to IAEC (kBtu/y). The 2015 IAEC value is reflective of freestanding standard gas ovens, which was previously determined to be the most representative product class. IAEC for 2020 and beyond is reflective of freestanding self-clean gas ovens, which is the product class that makes up the majority of historical and projected gas oven shipments.
2. Equipment and installed costs are for ovens only (not combined ranges). Costs are reflective of freestanding self-clean oven units with single oven component, which represent the majority of the market.
3. Maintenance costs are negligible.

Note:
Ranges represent the span of typical values for a given parameter.
Average life is determined using a Weibull distribution characterized by the following scale (α) and shape (β) parameters: (14.56, 5.73).

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Residential Natural Gas Ranges

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Same as Reference Case

DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity of Cooktop Component (kBtu/h)	9	9	9	9	9	9	9	9	9	9
	23	23	23	23	23	23	23	23	23	23
Typical Capacity of Oven Component (kBtu/h)	16	16	16	16	16	16	16	16	16	16
	18	18	18	18	18	18	18	18	18	18
Typical Cavity Volume of Oven Component (ft^3)	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Integrated Annual Energy Consumption (kBtu/y)[1]	3,099	2,874	2,874	2,561	2,874	2,561	2,874	2,561	2,874	2,561
Average Life (y)	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$) [2]	750	770	770	850	770	850	770	850	770	850
Total Installed Cost (2022$) [2]	900	920	920	1,000	920	1,000	920	1,000	920	1,000
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-

1. IAEC of a natural gas range is calculated as the sum of the IAEC for a natural gas cooktop and natural gas oven. IAEC of the oven component is reflective of freestanding self-clean gas ovens, which represent the majority of the market. The 2015 IAEC value of the oven component is reflective of freestanding standard gas ovens, which was previously determined to be the most representative product class.
2. Retail and installed cost are reflective of a typical unit with standard 30-inch width and 4 to 5 cooking top heating elements. Based on data from DOE rulemakings, Gordian's RSMeans Data – Building Construction Costs 2023, and distributors, total installed cost is estimated to be around $150 more than retail equipment cost.
3. Maintenance costs are negligible.

Note:
Ranges represent the span of typical values for a given parameter.
Average life is determined using a Weibull distribution characterized by the following scale (α) and shape (β) parameters: (14.56, 5.73).

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Residential Natural Gas Cooktops, Ovens, and Ranges

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- DOE analyzes cooktops and ovens separately, although they are often sold together in a single unit that combines both a cooktop and an oven into a product referred to as a range.
- Since January 1, 1990, gas cooking products with an electrical supply cord have been required to not be equipped with a constant burning pilot light. This requirement extended to gas cooking products without an electrical supply cord, as of April 9, 2012.
- DOE published a final rule in 2009[1] in which it determined that no standard for cooking efficiency would be cost-justified.
- DOE initiated a standards rulemaking in 2014 to consider amended standards for cooking products, including gas cooktops and ovens[2].
- On September 2, 2016, DOE proposed performance-based standards for gas cooktops and ovens that would take effect in 2020, if adopted.
- DOE established the new IAEC metric, in kBtu/y, to replace cooking efficiency (%).
- On December 14, 2020, DOE initially determined that amended energy conservation standards for consumer conventional cooking products would not be economically justified and would not result in significant conservation of energy[3].
- On February 2, 2023, DOE proposed new and amended energy conservation standards for consumer conventional cooking products[4].
- The IAEC of a range is calculated as the sum of the IAECs for cooktops and ovens. However, retail and installation costs for a range are similar to the cost of an oven.

[1]Energy Conservation Standards for Certain Consumer Products (Dishwashers, Dehumidifiers, Microwave Ovens, and Electric and Gas Kitchen Ranges and Ovens) and for Certain Commercial and Industrial Equipment (Commercial Clothes Washers); Final Rule. 74 FR 16040.
[2]Energy Conservation Standards for Residential Conventional Cooking Products; Supplemental notice of proposed rulemaking (SNOPR). 81 FR 60784.
[3]Energy Conservation Standards for Consumer Conventional Cooking Products; Notice of proposed determination (NOPD). 85 FR 80982.
[4]Energy Conservation Standards for Consumer Conventional Cooking Products; SNOPR. 88 FR 6818.

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Residential Natural Gas Cooktops, Ovens, and Ranges

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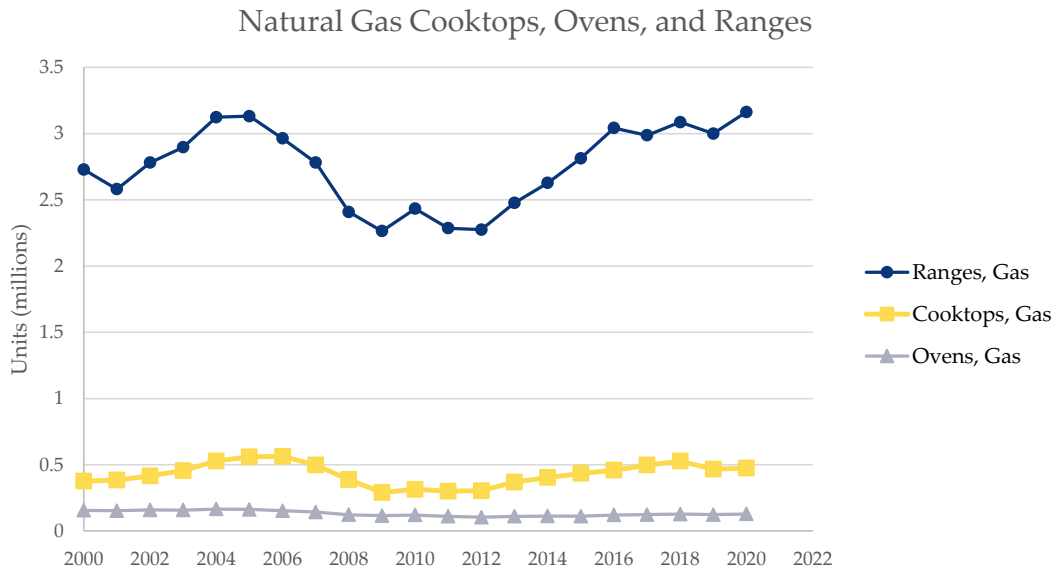
Shipments have been rising since 2012. In 2020, gas range shipments surpassed the peak reached in 2005.



Source: *Appliance Magazine and Consumer Cooking Products EERE 2022 SNOPR*

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Residential Electric Cooktops

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DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (W)	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700
Integrated Annual Energy Consumption (kWh/y)[1]	155	155	155	119	155	119	155	119	155	119
Average Life (y)	17	17	17	17	17	17	17	17	17	17
Retail Equipment Cost (2022$)[2]	470	470	470	810	470	810	470	810	470	810
Total Installed Cost (2022$)[2]	620	620	620	1,230	620	1,230	620	1,230	620	1,230
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-

1. Although there is no performance standard in effect, the test procedure metric has changed from Cooking Efficiency (%) to IAEC (kBtu/y). IAEC was determined using DOE rulemaking data for the most representative product class, electric smooth element cooking tops, which covers cooking tops with electric resistance heating elements and cooking tops with induction heating elements.
2. Equipment and installed costs are for cooktops only (not combined range units). Costs were determined using DOE rulemaking data for the most representative product class, electric smooth cooking tops, which includes cooking tops with electric resistance heating elements and cooking tops with induction heating elements. A high-end unit with induction technology is expected to have a greater retail equipment cost and greater installation cost in order to implement this technology.
3. Maintenance costs are negligible.

Note:
The range for typical capacity represents the span of typical values.
Average life is determined using a Weibull distribution characterized by the following scale (α) and shape (β) parameters: (16.88, 6.99).

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Residential Electric Ovens

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Same as Reference Case

DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (W)	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400
Typical Cavity Volume (ft^3)	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Integrated Annual Energy Consumption (kWh/y)[1]	355	355	355	278	355	278	355	278	355	278
Average Life (y)	17	17	17	17	17	17	17	17	17	17
Retail Equipment Cost (2022$)[2]	630	630	630	730	630	730	630	730	630	730
Total Installed Cost (2022$)[2]	770	770	770	870	770	870	770	870	770	870
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-

1. Although there is no performance standard in effect, the test procedure metric has changed from Cooking Efficiency (%) to IAEC (kBtu/y). IAEC was determined using DOE rulemaking data for freestanding electric self-clean ovens, which represent the majority of the market.
2. Equipment and installed costs are for ovens only (not combined ranges). Costs are reflective of freestanding self-clean oven units with single oven component, which represent the majority of the market.
3. Maintenance costs are negligible.

Note:
Ranges represent the span of typical values for a given parameter.
Average life is determined using a Weibull distribution characterized by the following scale (α) and shape (β) parameters: (16.88, 6.99).

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Residential Electric Ranges

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Same as Reference Case

DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity of Cooktop Component (W)	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700
Typical Capacity of Oven Component (W)	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400
Typical Cavity Volume of Oven Component (ft^3)	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Integrated Annual Energy Consumption (kWh/y)[1]	510	510	510	397	510	397	510	397	510	397
Average Life (y)	17	17	17	17	17	17	17	17	17	17
Retail Equipment Cost (2022$) [2]	630	630	630	900	630	900	630	900	630	900
Total Installed Cost (2022$) [2]	770	770	770	1,050	770	1,050	770	1,050	770	1,050
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-

1. IAEC of an electric range is calculated as the sum of the IAEC for an electric cooktop and an electric oven. IAEC of the electric cooktop component was determined using DOE rulemaking data for the most representative product class, electric smooth element cooking tops, which covers cooking tops with electric resistance heating elements and cooking tops with induction heating elements. IAEC of the electric oven component was determined using DOE rulemaking data for freestanding electric self-clean ovens, which represent the majority of the market.
2. Retail and installed cost are reflective of standard units that are 30-inch wide and have 4 to 5 cooking top heating elements. Based on data from DOE rulemakings, Gordian's RSMeans Data – Building Construction Costs 2023, and distributors, total installed cost is estimated to be around $140 more than retail equipment cost for a typical unit, and $150 more than retail equipment cost for a high-end unit. A high-end unit with an induction cooking top component is expected to have a greater retail equipment cost and greater installation cost in order to implement this technology.
3. Maintenance costs are negligible.

Note:
Ranges represent the span of typical values for a given parameter.
Average life is determined using a Weibull distribution characterized by the following scale (α) and shape (β) parameters: (16.88, 6.99).

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Residential Electric Cooktops, Ovens, and Ranges

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- DOE analyzes cooktops and ovens separately, although they are often sold together in a single unit that combines both a cooktop and an oven into a product referred to as a range.
- DOE initiated a standards rulemaking in 2014 to consider amended standards for cooking products, including electric cooktops and ovens[1].
- On September 2, 2016, DOE proposed performance-based standards for electric cooktops and ovens that would take effect in 2020 if adopted.
- DOE established the new IAEC metric, in kWh/y, to replace cooking efficiency (%).
- On December 14, 2020, DOE initially determined that amended energy conservation standards for consumer conventional cooking products would not be economically justified and would not result in a significant conservation of energy[2].
- On February 2, 2023, DOE proposed new and amended energy conservation standards for consumer conventional cooking products[3].
- The IAEC of a range is calculated as the sum of the IAECs for cooktops and ovens. However, retail and installation costs for a range are similar to the cost of an oven.

[1]Energy Conservation Standards for Residential Conventional Cooking Products; Supplemental notice of proposed rulemaking (SNOPR). 81 FR 60784.
[2]Energy Conservation Standards for Consumer Conventional Cooking Products; Notice of proposed determination (NOPD). 85 FR 80982.
[3]Energy Conservation Standards for Consumer Conventional Cooking Products; SNOPR. 88 FR 6818.

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Residential Electric Cooktops, Ovens, and Ranges

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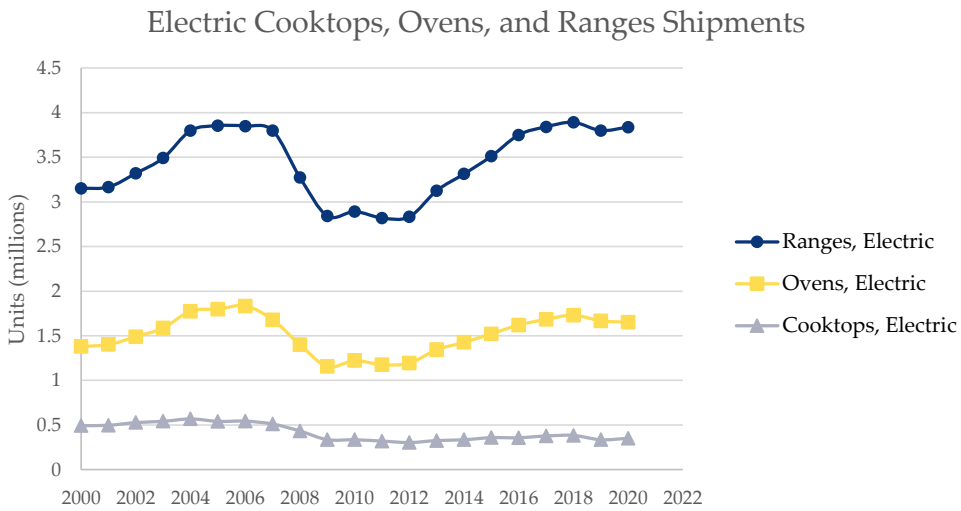
Shipments of electric cooking products reached a peak in 2006. Shipments of ranges and ovens have been rising again since 2012. In 2018, electric range shipments surpassed the peak reached in 2006.



Source: *Consumer Cooking Products EERE 2022 SNOPR*

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Residential Clothes Dryers (Electric)

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Higher typical efficiency product with the same costs as ref. case despite increased efficiency.

DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 1.1[1]	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	7.4	7.4	7.4	7.4	7.4	4.5	7.4	4.5	7.4	4.5	7.4	4.5
Combined Energy Factor, D1 (lb/kWh)[2]	3.59	3.73	3.73	3.73	NA	3.93	3.73	3.93	3.73	3.93	3.73	3.93
Combined Energy Factor, D2 (lb/kWh)[2]	3.59	3.93	3.73	3.93	3.93	11.00	5.34	11.00	6.48	11.00	7.38	11.00
Average Life (y)	8	8	8	8	8	8	8	8	8	8	8	8
	18	18	18	18	18	18	18	18	18	18	18	18
Retail Equipment Cost (2022$)	580	580	580	580	580	980	580	980	580	980	580	980
Total Installed Cost (2022$)	710	710	710	710	710	1,110	710	1,110	710	1,110	710	1,110
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-	-	-

1. ENERGY STAR V. 1.1 applies to vented and ventless standard electric clothes dryers.
2. The efficiency metric changed from EF to combined energy factor (CEF) in 2015. The 2015 Installed Base CEF data accounts for units tested to appendix D1 and appendix D2, because data specific to each appendix is not available for that year.
3. Maintenance costs are negligible. DOE estimated that on average 2.7 percent of electric and 3.3 percent of gas residential clothes dryers are repaired each year. (EERE 2014)

Note:
DOE test procedures for consumer clothes dryers appear at title 10 of the Code of Federal Regulations part 430, subpart B, appendix D1 and appendix D2. The second test method, appendix D2, was finalized in a final rule published by DOE on August 14, 2013. For current standard testing, units must be tested according to either the appendix D1 or the appendix D2 test method. ENERGY STAR V. 1.1 requires certified units to be tested according to the appendix D2 test method. The appendix D1 and appendix D2 test methods determine CEF differently.
The current standard went into effect in January 2015.
ENERGY STAR V. 1.1 went into effect in May 2017.
The range for average life represents the span of typical values.

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Residential Clothes Dryers (Gas)

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DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 1.1[1]	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Combined Energy Factor, D1 (lb/kWh)[2]	3.18	3.30	3.30	3.30	NA	3.48	3.30	3.48	3.30	3.48	3.30	3.48
Combined Energy Factor, D2 (lb/kWh)[2]	3.18	3.48	3.30	3.48	3.48	3.50	3.48	3.50	3.48	3.50	3.48	3.50
Average Life (y)	8	8	8	8	8	8	8	8	8	8	8	8
	18	18	18	18	18	18	18	18	18	18	18	18
Retail Equipment Cost (2022$)	660	670	660	670	670	670	670	670	670	670	670	670
Total Installed Cost (2022$)	860	870	870	870	870	870	870	870	870	870	870	870
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-	-	-

1. ENERGY STAR V. 1.1 applies to vented and ventless standard electric clothes dryers.
2. The efficiency metric changed from EF to CEF in 2015. The 2015 Installed Base CEF data accounts for units tested to appendix D1 and appendix D2, because data specific to each appendix is not available for that year.
3. Maintenance costs are negligible. DOE estimated that on average 2.7 percent of electric and 3.3 percent of gas residential clothes dryers are repaired each year. (EERE 2014)

Note:
DOE test procedures for consumer clothes dryers appear at title 10 of the Code of Federal Regulations part 430, subpart B, appendix D1 and appendix D2. The second test method, appendix D2, was finalized in a final rule published by DOE on August 14, 2013. For current standard testing, units must be tested according to either the appendix D1 or the appendix D2 test method. ENERGY STAR V. 1.1 requires certified units to be tested according to the appendix D2 test method. The appendix D1 and appendix D2 test methods determine CEF differently.
The current standard went into effect in January 2015.
ENERGY STAR V. 1.1 went into effect in May 2017.
The range for average life represents the span of typical values.

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- Current standards[1] in effect since 2015:
  - For standard-size electric units : CEF ≥ 3.73 pound per kilowatt hours (lb/kWh)
  - For gas units: CEF ≥ 2.30 lb/kWh
  - Units may be tested according to the test method in appendix D1 or appendix D2, which was finalized in 2013.
- The main differences between appendix D1 and appendix D2 are:
  - Appendix D2 includes test methods that more accurately measure the effects of automatic cycle termination and that may result in differences in the total measured energy consumption of the test cycle as compared to the test methods in appendix D1.
  - Appendix D2 contains instructions for the testing of timer dryers, which include a lower final moisture content (FMC) of the test load as compared to the version of appendix D1 used for the 2011 rulemaking analysis.
- Efficiency improvement technologies for clothes dryers include:
  - Multi-step or modulating heat
  - Higher efficiency drum motors
  - Inlet air pre-heat
  - Better control systems for cycle termination
  - Heat pump (for electric clothes dryers)
- EPA developed ENERGY STAR V. 1.1, which became effective in 2017 and requires units to be tested according to the test method in appendix D2.
- Standard-size heat pump clothes dryers with CEF values up to 11.0 are currently available in the U.S. market. High initial cost has limited market penetration, but some utilities are offering rebates to support market penetration.
- Advanced Case: Due to increases in market incentives, the residential electric clothes dryers market will see an increase in adoption of heat pump dryers that improve the typical efficiency products.

[1]Energy Conservation Standards for Consumer Clothes Dryers. 10 CFR 430.32(h).

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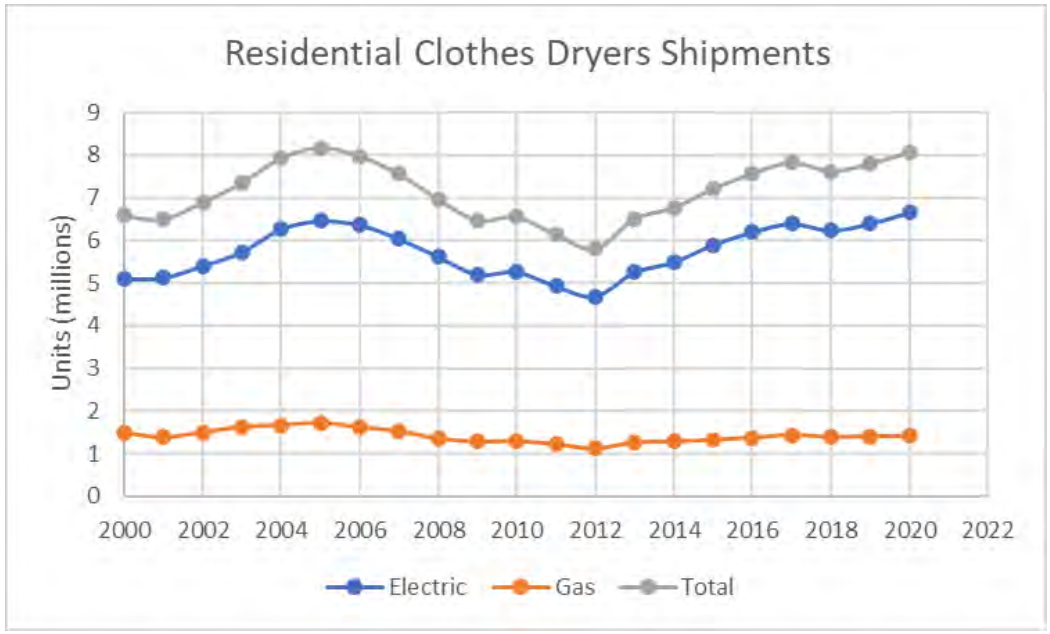
Shipment volumes have been on the rise since 2012. Gas dryers continue to account for about one-fifth of the market.



Source: *Consumer Clothes Dryers EERE 2022 NOPR*

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Residential Clothes Washers (Front)

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Same as Reference Case

DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 8.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	3.7	4.1	3.4	4.5	4.5	5.0	4.5	5.0	4.5	5.0	4.5	5.0
Integrated Modified Energy Factor (ft^3/kWh/cycle)[1]	2.16	2.76	1.84	2.76	2.76	3.10	2.76	3.10	2.76	3.10	2.76	3.10
Integrated Water Factor (gal/cycle/ft^3)[2]	4.7	3.2	4.7	3.2	3.2	2.7	3.2	2.7	3.2	2.7	3.2	2.7
Average Life (y)	6	6	6	6	6	6	6	6	6	6	6	6
	17	17	17	17	17	17	17	17	17	17	17	17
Water Consumption (gal/cycle)	17	14	16	14	14	14	14	14	14	14	14	14
Hot Water Energy (kWh/cycle)	0.21	0.17	0.36	0.12	0.12	0.13	0.12	0.13	0.12	0.13	0.12	0.13
Machine Energy (kWh/cycle)	0.17	0.14	0.15	0.12	0.12	0.17	0.12	0.17	0.12	0.17	0.12	0.17
Dryer Energy (kWh/cycle)	1.31	1.24	1.34	1.17	1.17	1.56	1.17	1.56	1.17	1.56	1.17	1.56
Retail Equipment Cost (2022$)	735	1,000	705	930	930	950	930	950	930	950	930	950
Total Installed Cost (2022$)	915	1,175	880	1,130	1,130	1,150	1,130	1,150	1,130	1,150	1,130	1,150
Annual Maintenance Cost (2022$)	15	15	15	15	15	15	15	15	15	15	15	15

1. The efficiency metric changed from Modified Energy Factor to Integrated Modified Energy Factor (IMEF) in 2015.
2. The efficiency metric changed from Water Factor to Integrated Water Factor (IWF) in 2015.

Note:
The current standard went into effect in January 2018.
ENERGY STAR V. 8.1 went into effect in February 2018.
The range for average life represents the span of typical values.

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Residential Clothes Washers (Top)

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Same as Reference Case

DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 8.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	3.3	3.4	3.5	3.5	4.4	5.5	3.5	5.5	3.5	5.5	3.5	5.5
Integrated Modified Energy Factor (ft^3/kWh/cycle)[1]	1.14	1.57	1.57	1.57	2.06	2.76	1.57	2.76	1.57	2.76	1.57	2.76
Integrated Water Factor (gal/cycle/ft^3)[2]	9.2	6.5	6.5	6.5	4.3	3.2	6.5	3.2	6.5	3.2	6.5	3.2
Average Life (y)	6	6	6	6	6	6	6	6	6	6	6	6
	17	17	17	17	17	17	17	17	17	17	17	17
Water Consumption (gal/cycle)	30	22	23	23	19	18	23	18	23	18	23	18
Hot Water Energy (kWh/cycle)	0.90	0.39	0.41	0.41	0.38	0.24	0.41	0.24	0.41	0.24	0.41	0.24
Machine Energy (kWh/cycle)	0.25	0.13	0.14	0.14	0.12	0.13	0.14	0.13	0.14	0.13	0.14	0.13
Dryer Energy (kWh/cycle)	1.73	1.63	1.68	1.68	1.64	1.61	1.68	1.61	1.68	1.61	1.68	1.61
Retail Equipment Cost (2022$)	590	590	520	520	640	725	520	725	520	725	520	725
Total Installed Cost (2022$)	765	765	715	715	840	920	715	920	715	920	715	920
Annual Maintenance Cost (2022$)	15	15	15	15	15	15	15	15	15	15	15	15

1. The efficiency metric changed from Modified Energy Factor to IMEF in 2015.
2. The efficiency metric changed from Water Factor to IWF in 2015.

Note:
The current standard went into effect in January 2018.
ENERGY STAR V. 8.1 went into effect in February 2018.
The range for average life represents the span of typical values.

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Residential Clothes Washers

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- The analysis treats front- and top-loading models separately due to their different energy use characteristics.
- Federal standards[1] for standard-capacity clothes washers (≥ 1.6 ft^3):

	Integrated Modified Energy Factor		Integrated Water Factor	
	Top-Loading	Front-Loading	Top-Loading	Front-Loading
Current DOE Standard (effective 1/1/2018)	≥ 1.57	≥ 1.84	≤ 6.5	≤ 4.7
Current ENERGY STAR V. 8.1 (effective 4/22/2021)	≥ 2.06	≥ 2.76	≤ 4.3	≤ 3.2

- In 2020, about 40% of top-loading models and almost all front-loading models achieved the ENERGY STAR level.
- Energy efficiency improvement technologies for clothes washers include:
  - Higher efficiency motors and higher spin speeds
  - Better load sensing for adaptive water fill control
  - Reduced water temperature and quantity, while providing equivalent cleaning and rinsing performance
- Maintenance costs include replacement or repair of the drain pump, control board, motor, rubber gaskets, or control panel knobs.
- The products on the market with the highest IMEF have significantly larger capacity and therefore use more energy per cycle than typical, smaller capacity products but still perform more efficiently on a per volume basis.

[1]Energy Conservation Standards for Consumer Clothes Washers. 10 CFR 430.32(g).

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Residential Clothes Washers

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Shipments have been on the rise since 2012 and reached a peak of about 10 million in 2020. Since 2012, top-loading and front-loading units represent approximately 75% and 25% of shipments, respectively.

Source: *AHAM Shipment Data; RCW EERE 2021 Preliminary Analysis*

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Residential Dishwashers

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DATA	2015	2020	2022				2023	2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 6.0	High	ENERGY STAR V. 7.0	Typical	High	Typical	High	Typical	High
Typical Annual Energy Use (kWh/y)	295	270	307	270	270	225	240	240	225	240	225	240	225
Water Consumption (gal/cycle)	4.25	3.50	5.00	3.50	3.50	2.40	3.20	3.20	2.40	3.20	2.40	3.20	2.40
Water Heating Energy Use (kWh/y)[1]	154	125	176	123	123	84	112	123	84	123	84	123	84
Average Life (y)	15	15	15	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)	440	380	310	340	340	500	430	340	500	340	500	340	500
Total Installed Cost (2022$)	840	570	490	520	520	690	610	520	690	520	690	520	690
Annual Maintenance Cost (2022$)[2]	-	-	-	-	-	-		-	-	-	-	-	-

1. Refers to that portion of "Typical Annual Energy Use" that is the energy used to heat water in a separate water heater before it enters the dishwasher. The energy used to heat water inside the dishwasher cannot be disaggregated from the total.
2. Maintenance costs are negligible.

Note:
All values in table reflect 215 cycles/year according to the current test procedure at 10 CFR 430 Appendix C1.
The current standard went into effect in May 2013.
ENERGY STAR V. 6.0 went into effect in January 2016.
ENERGY STAR V. 7.0 will go into effect in July 2023.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (15.9, 1.8, 1).

Residential Dishwashers

- Performance criteria for standard-capacity dishwashers (assumes 215 cycles/year):
  - Federal Standards:
    - May 30, 2013: ≤ 307 kWh/y, ≤ 5.0 gal/cycle (DOE Direct Final Rule, published May 2012)
  - ENERGY STAR Criteria:
    - Jan. 29, 2016: ≤ 270 kWh/y (5% allowance for connected), ≤ 3.5 gal/cycle (V. 6.0)
    - July 19, 2023: ≤ 240 kWh/y, ≤ 3.2 gal/cycle (V. 7.0, effective August 2023)
- ENERGY STAR has maintained a very high market share for several years (93% in 2021), so sales-weighted average efficiency has tracked ENERGY STAR levels.
  - Due to the historically high market penetration of ENERGY STAR products, it is expected that manufacturers will make the necessary adjustments so ENERGY STAR V. 7.0 levels will be typical in future projections.
- Test procedures:
  - Accounts for motor, dryer, booster heater (if present), and hot water from separate water heater, as well as standby and off-mode energy.
  - ENERGY STAR established a cleaning performance test method. While cleaning performance reporting is currently optional, V. 7.0 requires a cleaning index of 65 or higher for ENERGY STAR certification.
  - In January 2023, DOE established a test procedure at Appendix C2, which would go into effect at the time of any amended energy conservation standards. Appendix C2 establishes a minimum cleaning index threshold of 70 as a condition for a valid test cycle. The cleaning index threshold of 70 established by DOE is equivalent to the cleaning index threshold of 65 specified in ENERGY STAR V. 7.0.
- Efficiency improvement technologies for dishwashers include:
  - Better soil sensing
  - Control strategies
  - Water distribution (small pipes, fine filter, small sump, multiple spray arms, alternating water use) and controls (flow meter, temperature sensor)
  - Inline water heater (to minimize sump volume)
  - Separate drain pump, high-efficiency, variable-speed circulation pump motor
  - Condensation drying (rather than power dry)

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Residential Dishwashers

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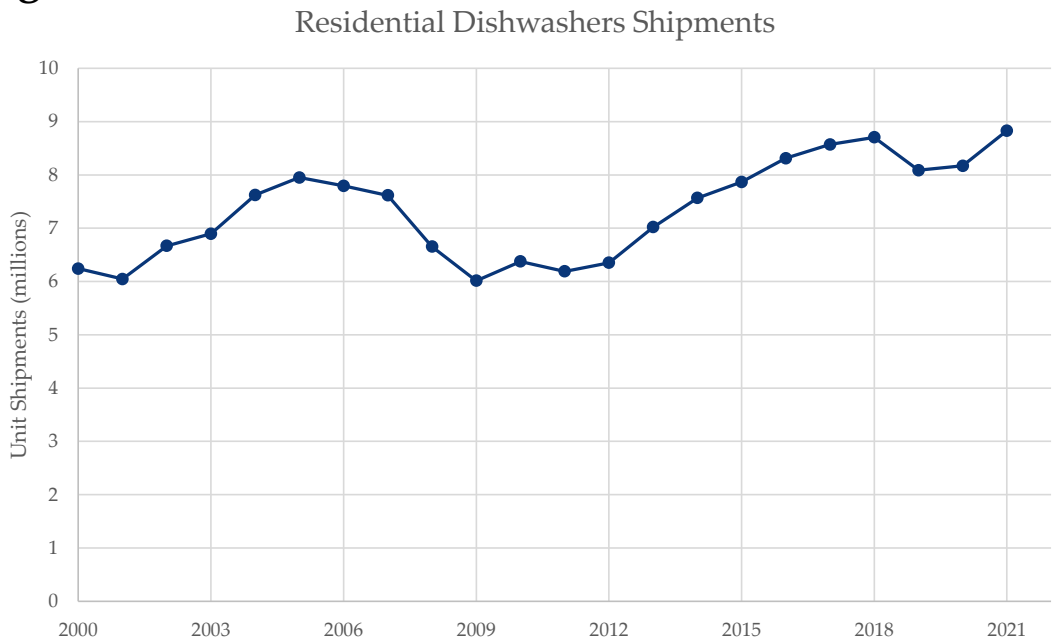
Shipments increased steadily from the early 1990s until the 2008-2009 recession. Shipments have resumed similar growth since then.



Source: *DW EERE 2022 Preliminary Analysis*

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Commercial Space Heating and Cooling

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Commercial Gas-Fired Furnaces

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High thermal efficiency increase is possible with increased costs.

DATA	2012	2018	2022			2023[1]		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	High	New Standard	Typical	Typical	Typical	Typical
Typical Input Capacity (kBtu/h)[2]	400	400	250	250	250	250	250	250	250	250
Thermal Efficiency (%)[3]	80	80	80	81	81	81	81	95	81	95
Typical Output Capacity (kBtu/h)	320	320	200	203	203	203	203	238	203	238
Average Life (y)	23	23	23	23	23	23	23	23	23	23
Retail Equipment Cost (2022$)	1,230	1,230	1,230	1,260	1,260	1,260	1,260	3,340	1,260	3,340
Total Installed Cost (2022$)	2,540	2,540	2,540	2,580	2,580	2,580	2,580	5,230	2,580	5,230
Total Installed Cost (2022$/kBtu/h)	6	6	10	10	10	10	10	21	10	21
Annual Maintenance Cost (2022$)	200	200	200	200	200	200	200	210	200	210
Annual Maintenance Cost (2022$/kBtu/h)	1	1	1	1	1	1	1	1	1	1

1. In 2023, the new Energy Conservation Standards for Commercial Warm Air Furnaces (CWAF) took effect. These projections reflect the 2023 minimum thermal efficiency requirement for gas-fired furnaces, 81%.
2. When this analysis was previously conducted in EIA Technology Forecast Updates (2018), a typical input capacity of 400 kBtu/h was listed. An updated typical input capacity value of 250 kBtu/h was determined through an evaluation of the units in the DOE CCD as of August 2022. CWAF EERE 2015 also listed a representative input capacity of 250 kBtu/h.
3. DOE's efficiency metric for commercial furnaces accounts only for flue losses, not jacket losses.

Note:
The previous standard went into effect in January 1994. The current standard went into effect in January 2023.

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Commercial Gas-Fired Furnaces

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- Until 2022, the Federal standard required minimum 80% thermal efficiency. This metric, more commonly called "combustion efficiency" in other contexts, accounts only for flue losses, not jacket losses.
  - The Federal standard applied to all units manufactured on or after January 1, 1994, with maximum rated heat input ≥ 225,000 Btu per hour.
  - On January 1, 2023, the minimum Federal standard increased to 81% thermal efficiency.
- ASHRAE Standard 90.1, which is used as a commercial building code in many states, stipulates that furnaces that are not within the conditioned space shall not have jacket losses exceeding 0.75% of the input rating.
- Commercial furnaces are typically non-condensing with thermal efficiencies ranging from 80% to 81%. Condensing commercial furnaces, which can achieve up to 95% thermal efficiency, were previously introduced to the market but are not currently available due to cost and reliability concerns. The highest thermal efficiency included in DOE's CCD at this time is 81%.
- Besides capacity, commercial units can differ from residential furnaces in terms of the control system (i.e., integration with a Building Management System, twinning, or other staging strategies). Commercial systems may also use a heat recovery system to pre-heat inlet air.
- Advanced Case: Increased high efficiencies are feasible due to market incentives to re-introduce condensing commercial gas-fired furnaces through additional investment, research, and development. No significant changes otherwise.

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Commercial Gas-Fired Furnaces

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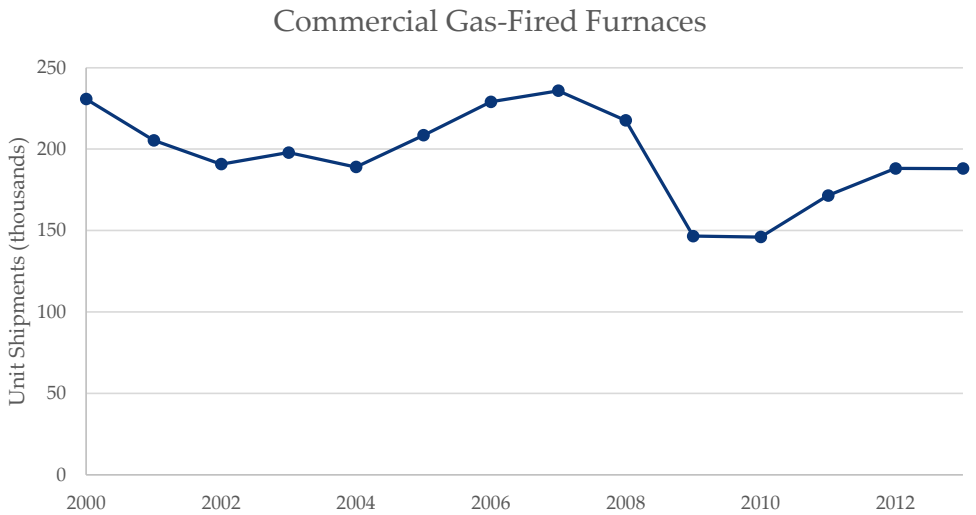
Annual shipments reached a peak of 235.9 thousand units in 2007. Following a decline in shipments after 2007, shipments increased to 188.1 thousand units in 2013. Shipment data after 2013 is not available.



Source: *AHRI*

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Commercial Oil-Fired Furnaces

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Same as Reference Case

DATA	2012	2018	2022			2023[1]	2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	New Standard	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	400	400	250	250	250	250	250	250	250	250	250	250
Thermal Efficiency (%)[2]	81	82	81	82	85	82	82	85	82	85	82	85
Typical Output Capacity (kBtu/h)	324	328	203	205	213	205	205	213	205	213	205	213
Average Life (y)	23	23	23	23	23	23	23	23	23	23	23	23
Retail Equipment Cost (2022$)	5,500	5,560	5,500	5,560	6,020	5,560	5,560	6,020	5,560	6,020	5,560	6,020
Total Installed Cost (2022$)	7,740	7,810	7,740	7,810	8,380	7,810	7,810	8,380	7,810	8,380	7,810	8,380
Total Installed Cost (2022$/kBtu/h)	24	24	38	38	39	38	38	39	38	39	38	39
Annual Maintenance Cost (2022$)	360	360	360	360	370	360	360	370	360	370	360	370
Annual Maintenance Cost (2022$/kBtu/h)	1	1	2	2	2	2	2	2	2	2	2	2

1. In 2023, the new Energy Conservation Standards for CWAF took effect. These projections reflect the 2023 minimum thermal efficiency requirement for oil-fired furnaces, 82%.
2. DOE's efficiency metric for commercial furnaces accounts only for flue losses, not jacket losses.

Note:
The previous standard went into effect in January 1994. The current standard went into effect in January 2023.

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Commercial Oil-Fired Furnaces

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- Until 2022, the Federal standard required minimum 81% thermal efficiency. This metric, more commonly called "combustion efficiency" in other contexts, accounts only for flue losses, not jacket losses.
  - The Federal standard applied to all units manufactured on or after January 1, 1994, with maximum rated heat input ≥ 225,000 Btu per hour.
  - On January 1, 2023, the minimum Federal standard increased to 82% thermal efficiency.
- ASHRAE Standard 90.1, which is used as a commercial building code in many states, stipulates that furnaces that are not within the conditioned space shall not have jacket losses exceeding 0.75% of the input rating.
- Commercial oil-fired furnaces have thermal efficiencies ranging from 81% to 85% and are non-condensing (i.e., not designed for condensation of flue gases).
- Besides capacity, commercial units can differ in terms of the control system (i.e., integration with a Building Management System, twinning, or other staging strategies). Commercial systems may also use a heat recovery system to pre-heat inlet air.
- The maintenance cost estimate assumes two cleanings per year.

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Commercial Oil-Fired Furnaces

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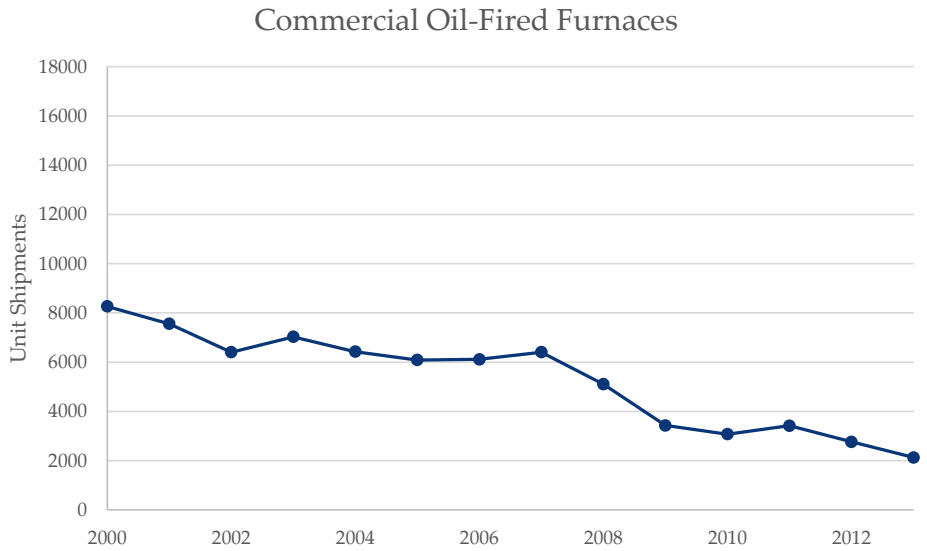
Annual shipments for commercial oil-fired furnaces have steadily decreased over time to 2,127 units in 2013. Shipment data after 2013 is not available.



Source: *AHRI*

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Commercial Electric Resistance Heaters

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Same as Reference Case

DATA	2012		2018		2022		2030		2040		2050	
	Installed Base: Small	Installed Base: Large	Installed Base: Small	Installed Base: Large	Small	Large	Small	Large	Small	Large	Small	Large
Typical Capacity (kBtu/h)[1]	17	170	17	170	17	170	17	170	17	170	17	170
Efficiency (%)	100	100	100	100	100	100	100	100	100	100	100	100
Average Life (y)	18	18	18	18	18	18	18	18	18	18	18	18
Retail Equipment Cost (2022$)	1,000	6,320	1,000	6,320	500	4,630	500	4,630	500	4,630	500	4,630
Total Installed Cost (2022$)	1,240	7,470	1,240	7,470	660	5,470	660	5,470	660	5,470	660	5,470
Total Installed Cost (2022$/kBtu/h)	73	44	73	44	39	32	39	32	39	32	39	32
Annual Maintenance Cost (2022$)[2]	-	-	-	-	-	-	-	-	-	-	-	-
Annual Maintenance Cost (2022$/kBtu/h)	-	-	-	-	-	-	-	-	-	-	-	-

1. Capacity is output.
2. Annual Maintenance Cost is negligible.

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Commercial Electric Resistance Heaters

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- This analysis examined standard suspended electric wall and ceiling unit heaters, which are more common in commercial settings than baseboard electric heaters that were considered for the residential analysis.
- Electric unit heaters range in capacity from 2 to 100 kW (7 to 340 kBtu/h), with 5 to 50 kW (17 to 170 kBtu/h) being the most typical units on the market.
- Electric resistance heaters are considered near 100% efficient because there is no heat loss through ducts or combustion.
- Installation time and costs are estimated to be minimal.

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Commercial Electric Boilers

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DATA	2012	2018	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical	Typical	Typical
Typical Capacity (kW)[1]	165	165	165	165	165	165
Efficiency (%)	98	98	98	98	98	98
Average Life (y)	15	15	15	15	15	15
Retail Equipment Cost (2022$)[2]	11,620	11,590	9,790	9,790	9,790	9,790
Total Installed Cost (2022$)[2]	17,500	13,820	11,950	11,950	11,950	11,950
Total Installed Cost (2022$/kBtu/h)	31	25	21	21	21	21
Annual Maintenance Cost (2022$)[2]	170	130	130	130	130	130
Annual Maintenance Cost (2022$/kBtu/h)	-	-	-	-	-	-

1. Capacity is output.
2. Retail and installed costs for 2022 and forecasts for 2030 and beyond are based on Gordian's RSMeans Data – Building Construction Costs 2023. Maintenance costs are same as EIA Technology Forecast Updates (2018), updated to reflect 2022$. The costs shown are for one 165kW unit, which would equate to a steady load of approximately 550,000 Btu/h. Annual maintenance in a typical application would include draining the unit for removal of any accumulated scale or sludge buildup.

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Commercial Electric Boilers

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- There are currently no federal standards associated with electric boilers.
- The costs shown are for one 165kW unit, which would equate to a steady load of approximately 550,000 Btu/h.
- Service life is determined mainly by water quality. Water conditioning (e.g., filters, softeners, de-alkalizers, chemical feeders) may be necessary for a given application.
- Annual maintenance in a typical application would include draining the unit for removal of any accumulated scale or sludge buildup.
- Minor end-use inefficiencies for electric boilers result from heat loss through the boiler (jacket losses).

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Commercial Gas-Fired Boilers

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Higher typical efficiencies with corresponding cost increases

DATA	2012	2018	2022			2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard[1]	Typical	High	New Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	800	800	800	800	800	800	800	800	800	800	800	800	800	800
Thermal Efficiency (%)[2]	77	85	80	85	99	84	85	99	93	99	95	99	95	99
Average Life (y)	30	25	25	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)	15,530	25,910	19,150	25,910	42,670	24,320	25,910	42,670	37,860	42,670	38,950	42,670	38,950	42,670
Total Installed Cost (2022$)	24,600	38,330	30,470	38,330	55,230	35,650	38,330	55,230	50,410	55,230	51,510	55,230	51,510	55,230
Total Installed Cost (2022$/kBtu/h)	40	56	48	56	70	53	56	70	68	70	68	70	68	70
Annual Maintenance Cost (2022$)[3]	1,710	2,100	2,100	2,100	2,140	2,100	2,100	2,140	2,140	2,140	2,140	2,140	2,140	2,140
Annual Maintenance Cost (2022$/kBtu/h)	3	3	3	3	3	3	3	3	3	3	3	3	3	3

1. The standard level shown here is for small (300 kBtu/h to 2500 kBtu/h) gas-fired hot water commercial packaged boilers, which are the most common type of boilers available on the market.
2. DOE's efficiency metric for most boiler types accounts for both flue and jacket losses; previously it did not. DOE continues to uses a combustion efficiency metric instead, for hot water boilers with heat input > 2,500,000 Btu/h.
3. Maintenance costs for 2018 and post-2018 are based on Commercial Packaged Boilers EERE 2020. The annualized maintenance costs estimated in the final rule differ for condensing vs. non-condensing boilers. Appendix 8E of the Commercial Packaged Boilers EERE 2020 TSD provides additional information on how the values are calculated.

Note:
The previous standard went into effect in March 2012.
The current standard went into effect in January 2023.
In December 2016, DOE issued a final rule titled Energy Conservation Program: Energy Conservation Standards for Commercial Packaged Boilers. This rule published in January 2020 with an effective date for January 2023.

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Commercial Gas-Fired Boilers

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- Commercial packaged gas-fired boilers are classified by:
  - Heat input capacity
  - Produce steam or hot water
  - Draft type (natural draft or not) – for steam boilers
- The most common type of commercial gas-fired boilers are small gas-fired hot water boilers with 300,000-2,500,000 Btu/h rated heat input.
- Similar technologies to those used in the residential gas-fired boilers market can be leveraged in the commercial arena. The higher efficiency units typically include electronic ignition, power burners, and improved heat exchangers. Some gas-fired boilers also condense water vapor from the flue gases to improve heating efficiency.
- DOE published a final rule for commercial packaged boilers in January 2020 that updated the efficiency ratings of gas-fired commercial packaged boilers beginning January 2023.
- Advanced Case: Condensing gas-fired boilers are expected to dominate the market by 2030, with corresponding price increases.

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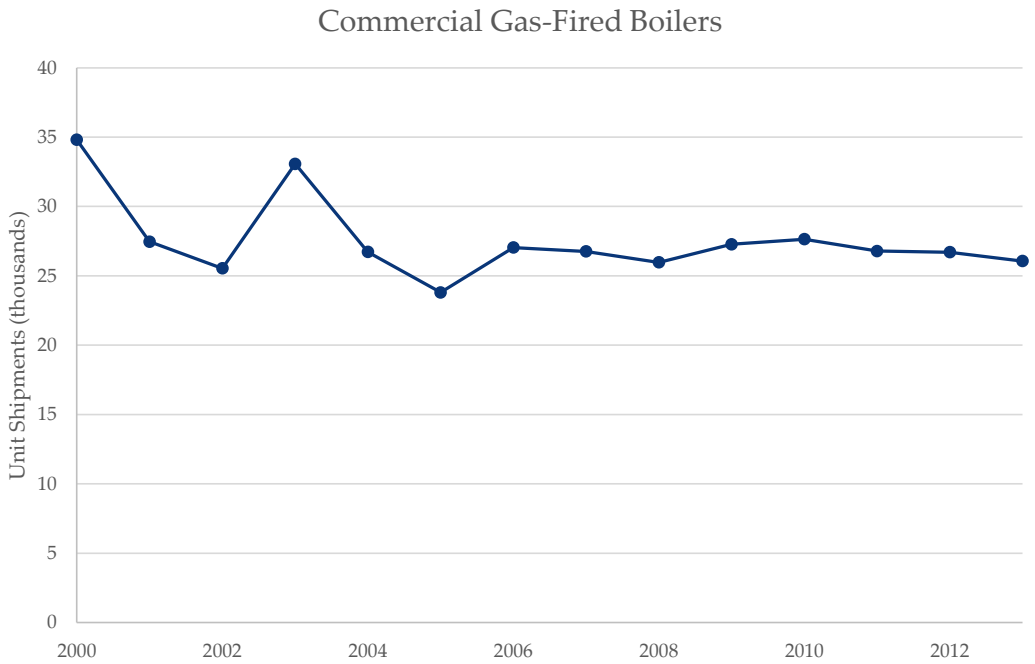
Shipments of commercial gas-fired boilers peaked in 2000 and have been steadily declining since 2010. Shipment data after 2013 is not available.



Source: *Commercial Packaged Boilers EERE 2020*

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Commercial Oil-Fired Boilers

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Higher typical efficiencies with same costs as reference case despite increased efficiency

DATA	2012	2018	2022			2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard[1]	Typical	High	New Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	1,200	800	800	800	800	800	800	800	800	800	800	800	800	800
Thermal Efficiency (%)[2]	81	85	82	85	97	87	87	97	92	97	92	97	92	97
Average Life (y)	30	25	25	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)	16,830	26,810	23,190	26,810	51,480	29,730	29,730	51,480	29,730	51,480	29,730	51,480	29,730	51,480
Total Installed Cost (2022$)	22,000	37,240	33,100	37,240	62,910	40,160	40,160	62,910	40,160	62,910	40,160	62,910	40,160	62,910
Total Installed Cost (2022$/kBtu/h)	23	55	50	55	81	58	58	81	55	81	55	81	55	81
Annual Maintenance Cost (2022$)[3]	1,710	2,690	2,690	2,690	2,690	2,690	2,690	2,690	2,690	2,690	2,690	2,690	2,690	2,690
Annual Maintenance Cost (2022$/kBtu/h)	2	4	4	4	3	4	4	3	4	3	4	3	4	3

1. The standard level shown here is for small (300 kBtu/h to 2500 kBtu/h) oil-fired hot water commercial packaged boilers, which are the most common type of boilers available on the market.
2. DOE's efficiency metric for most boiler types accounts for both flue and jacket losses; previously it did not. DOE continues to uses a combustion efficiency metric instead, for hot water boilers with heat input > 2,500,000 Btu/h.
3. Maintenance costs for 2018 and post-2018 are based on Commercial Packaged Boilers EERE 2020. The annualized maintenance costs estimated in the final rule differ for condensing vs. non-condensing boilers. Appendix 8E of the Commercial Packaged Boilers EERE 2020 TSD provides additional information on how the values are calculated.

Note:
The previous standard went into effect in March 2012.
The current standard went into effect in January 2023.
In December 2016, DOE issued a final rule titled Energy Conservation Program: Energy Conservation Standards for Commercial Packaged Boilers. This rule published in January 2020 with an effective date for January 2023.

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Commercial Oil-Fired Boilers

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- Commercial packaged oil-fired boilers are classified by:
  - Heat input capacity
  - Produce steam or hot water
- The most common type of commercial oil-fired boilers are small hot water boilers with 300,000-2,500,000 Btu/h rated heat input.
- The higher efficiency units typically include improved heat exchangers, and multi-step or variable-output power burners.
- DOE published a final rule for commercial packaged boilers in January 2020 that updated the efficiency ratings of oil-fired commercial packaged boilers beginning January 2023.
- Advanced Case: Increased adoption of condensing oil-fired boilers by 2030. However, due to low demand and a shrinking market, costs are expected to remain the same.

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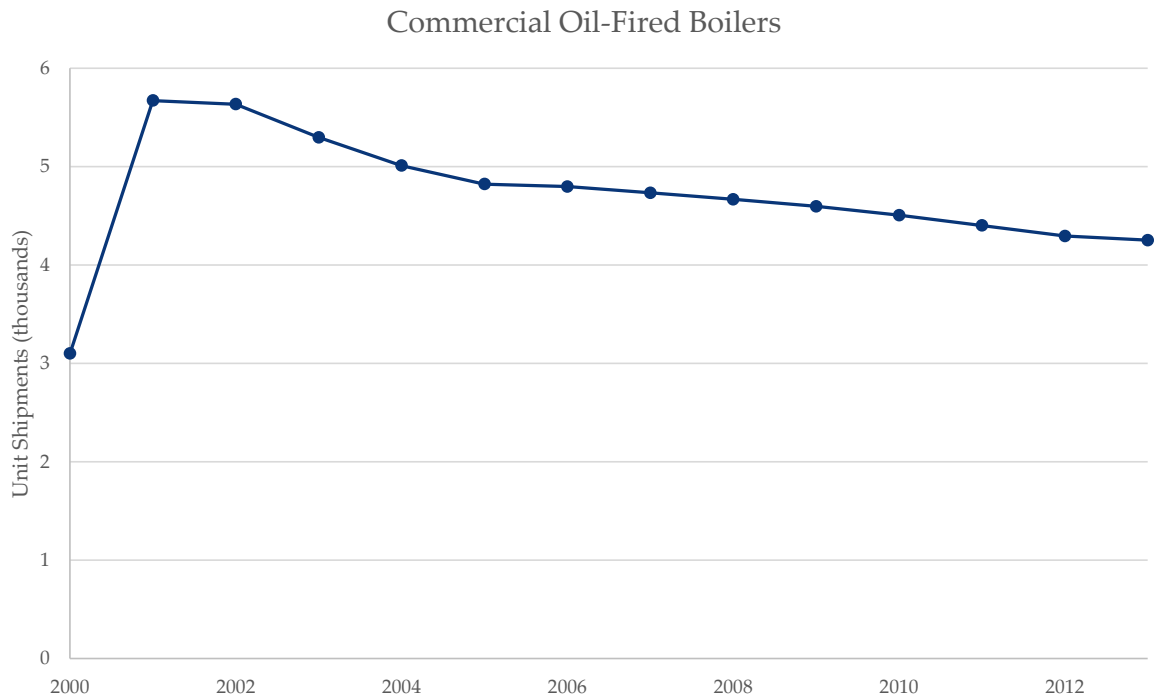
Shipments of commercial oil-fired boilers peaked in 2001 and have been decreasing since then.



Source: *Commercial Packaged Boilers EERE 2020*

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Commercial Centrifugal Chillers (Water-Cooled)

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Higher typical efficiencies with same costs as reference case despite increased efficiency

DATA	2012	2018	2022[2]			2030		2040		2050	
	Installed Base	Installed Base	ASHRAE 90.1-2019	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (tons)[1]	400	400	400	400	400	400	400	400	400	400	400
	600	600	600	600	600	600	600	600	600	600	600
Efficiency [full-load] (kW/ton)	0.66	0.53	0.56	0.52	0.45	0.48	0.42	0.45	0.41	0.44	0.40
Efficiency [IPLV] (kW/ton)	0.61	0.37	0.50	0.31	0.30	0.30	0.28	0.29	0.26	0.28	0.25
COP [full-load]	5.4	6.6	6.3	6.8	7.8	7.3	8.4	7.8	8.6	8.0	8.8
COP [IPLV]	5.9	9.5	7.0	11.3	11.7	11.7	12.6	12.1	13.5	12.6	14.1
Average Life (y)	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$/ton)	380	500	480	500	680	590	760	660	780	690	810
Total Installed Cost (2022$/ton)	440	560	480	560	740	640	820	720	840	740	870
	500	590	540	590	760	670	830	740	860	760	880
Total Installed Cost (2022$/kBtu/h)	39	48	43	48	63	55	69	61	71	63	73
Annual Maintenance Cost (2022$/ton)	30	30	30	30	30	30	30	30	30	30	30
	40	40	40	40	40	40	40	40	40	40	40
Annual Maintenance Cost (2022$/kBtu/h)	3	3	3	3	3	3	3	3	3	3	3

1. Capacity is output.
2. ASHRAE 90.1 data are for units larger than 400 tons and for full-load optimized applications (Path A in ASHRAE 90.1-2019). Typical and high efficiency levels are determined based on the range of products currently available on the market.

Note:

For most chillers (including those in single-chiller applications and for peaking units in multi-chiller applications), the seasonal performance (represented by the integrated part-load value (IPLV)) is more indicative of annual expected performance than the full-load performance; performance of baseload chillers in multi-chiller applications, which typically operate at full-load, are well represented by the full-load efficiency value.

ASHRAE 90.1 went into effect in October 2019.

Ranges represent the span of typical values for a given parameter.

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Commercial Centrifugal Chillers (Water-Cooled)

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- ASHRAE 90.1-2019 stipulates minimum efficiencies for centrifugal chillers separately from positive displacement water-cooled chillers. They are separated into 5 size categories, with categories divided at: 150, 300, 400, and 600 tons; ASHRAE 90.1-2019 also distinguishes between whether the unit will be optimized for full-load (Path A) or part-load operation (Path B). Data here are for Path A; a Path B chiller may have slightly high full-load consumption in exchange for much lower part-load consumption. For example, for a 600-ton unit:
  - Path A: ≥ 0.56 kW/ton full-load and ≥ 0.50 kW/ton IPLV
  - Path B: ≥ 0.585 kW/ton full-load and ≥ 38 kW/ton IPLV
- Federal Energy Management Program (FEMP) recommendations, last updated in 2020, match ASHRAE 90.1-2019.
- The highest efficiency centrifugal chillers incorporate some of the following:
  - Variable speed drive (VSD) compressors
  - Dedicated heat recovery (heat pump chiller)
  - Magnetic bearing technology (oil-free operation)
  - Greater heat exchanger surface areas; enhanced tube configurations (counterflow)
  - Optimized fluid flow velocities
  - High efficiency electric motors
  - Improved turbomachinery design, resulting in higher compressor efficiency
  - Better piping and valving, including electronic expansion valves
  - Evaporative condenser for the heat rejection equipment
- Installed costs vary widely depending on equipment needed for installation (e.g., crane) and size of system. This is a mature market with centrifugal chillers representing 75% of commercial chiller sales larger than 200 tons.
- Water-cooled chiller ratings do not include energy consumption of the cooling tower and therefore are not directly comparable to rating for air-cooled chillers. Water-cooled centrifugal chillers were selected for analysis due to a higher model share on the AHRI directory in comparison to air-cooled chillers.
- Advanced Case: Due to increases in R&D, improvements in current technology are expected to increase efficiency without substantially increasing costs.

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Commercial Reciprocating Chillers (Air-Cooled Only)

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Same as Reference Case

DATA	2012	2018	2022[2]			2030		2040		2050	
	Installed Base	Installed Base	ASHRAE 90.1-2019	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (tons)[1]	100	100	100	100	100	100	100	100	100	100	100
	200	200	200	200	200	200	200	200	200	200	200
Efficiency [full-load] (kW/ton)	1.26	1.19	1.19	1.15	1.00	1.15	1.00	1.15	1.00	1.15	1.00
Efficiency [IPLV] (kW/ton)	1.13	0.86	0.86	0.86	0.80	0.80	0.79	0.80	0.79	0.80	0.79
COP [full-load]	2.8	3.0	3.0	3.0	3.5	3.1	3.5	3.1	3.5	3.1	3.5
COP [IPLV]	3.1	4.1	4.1	4.1	4.5	4.4	4.5	4.4	4.5	4.4	4.5
Average Life (y)	20	20	20	20	20	20	20	20	20	20	20
Retail Equipment Cost (2022$/ton)	725	820	820	820	1,030	820	1,030	820	1,030	820	1,030
	600	730	730	730	880	730	880	730	880	730	880
Total Installed Cost (2022$/ton)	800	880	880	880	1,180	880	1,180	880	1,180	880	1,180
	700	760	760	760	1,090	760	1,090	760	1,090	760	1,090
Total Installed Cost (2022$/kBtu/h)	63	68	68	68	95	68	95	68	95	68	95
Annual Maintenance Cost (2022$/ton)	45	45	50	50	50	45	50	45	50	45	50
	25	25	30	30	30	25	30	25	30	25	30
Annual Maintenance Cost (2022$/kBtu/h)	3	3	3	3	3	3	3	3	3	3	3

1. Capacity is output.
2. ASHRAE 90.1 data are for units larger than 150 tons and for full-load optimized applications (Path A in ASHRAE 90.1-2019). Typical and high efficiency levels are determined based on the range of products currently available on the market.

Note:

This analysis covers air-cooled chillers only.

For most chillers (including those in single-chiller applications and for peaking units in multi-chiller applications), the seasonal performance (represented by the IPLV) is more indicative of annual expected performance than the full-load performance; performance of baseload chillers in multi-chiller applications, which typically operate at full-load, are well represented by the full-load efficiency value.

ASHRAE 90.1 went into effect in October 2019.

Ranges represent the span of typical values for a given parameter.

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Commercial Reciprocating Chillers (Air-Cooled Only)

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- Reciprocating chillers are most cost effective for small loads (30 to 150-ton range). However, reciprocating chiller market share continues to be supplanted by screw and scroll chillers. This trend has accelerated with the phase out of R-22, which was the refrigerant of choice for reciprocating products, which has in turn driven major manufacturers to replace their reciprocating product lines with scroll products (rather than redesign reciprocating products for new refrigerants). As a result, product options are very limited.
- Reciprocating chillers can be used in either air-cooled or water-cooled applications. Reciprocating chillers shown in the data are air-cooled. Air-cooled chillers are less efficient than the water-cooled models. Listed efficiencies include matched condensers and their associated energy use.
- ASHRAE 90.1-2019 stipulates minimum efficiencies for all air-cooled chillers together, including reciprocating chillers, while water-cooled chillers are separated by positive displacement (e.g., reciprocating) versus centrifugal models. Air-cooled chiller efficiencies are further split by size for more and less than 150 tons. ASHRAE 90.1-2019 also distinguishes between whether the unit will be optimized for full-load (Path A) or part-load operation (Path B). Data here are for Path A; a Path B chiller may have slightly lower full-load efficiency in exchange for much higher part-load efficiency. For example, for a 100-ton unit:
  - Path A: ≥ 10.1 EER full-load and ≥ 13.7 IPLV EER
  - Path B: ≥ 9.7 EER full-load and ≥ 15.8 IPLV EER
- FEMP (2022) recommendations for air-cooled chillers are:
  - Path A (<150 tons): ≥ 10.89 EER full-load and ≥ 13.7 IPLV EER
  - Path B (<150 tons): ≥ 9.7 EER full-load and ≥ 16.86 IPLV EER (same as 90.1-2019)
- The highest efficiency reciprocating chillers incorporate some of the following:
  - Multiple compressors for staged capacity control
  - Improved heat-exchangers

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Commercial Screw Chillers (Air-Cooled Only)

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Higher typical efficiencies with same costs as reference case despite increased efficiency

DATA	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	ASHRAE 90.1-2019[1]	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (tons)	100	100	100	100	100	100	100	100	100	100	100
	300	300	300	300	300	300	300	300	300	300	300
Efficiency [full-load] (kW/ton)	1.26	1.18	1.19	1.15	0.92	1.11	0.91	0.99	0.86	0.93	0.77
Efficiency [IPLV] (kW/ton)	1.13	0.84	0.86	0.81	0.55	0.77	0.53	0.65	0.49	0.61	0.43
COP [full-load]	2.8	3.0	3.0	3.1	3.8	3.2	3.9	3.6	4.1	3.8	4.6
COP [IPLV]	3.1	4.2	4.1	4.4	6.4	4.5	6.6	5.4	7.2	5.7	8.2
Average Life (y)	20	20	20	20	20	20	20	20	20	20	20
Retail Equipment Cost (2022$/ton)	760	970	1,130	1,130	1,230	1,140	1,230	1,180	1,250	1,200	1,270
	620	850	770	770	870	780	870	820	890	840	910
Total Installed Cost (2022$/ton)	910	1,150	1,250	1,250	1,350	1,260	1,350	1,300	1,370	1,320	1,390
	850	940	820	820	920	830	920	870	940	890	960
Total Installed Cost (2022$/kBtu/h)	73	87	86	86	95	87	95	90	96	92	98
Annual Maintenance Cost (2022$/ton)	50	50	50	50	50	50	50	50	50	50	50
	20	20	20	20	20	20	20	20	20	20	20
Annual Maintenance Cost (2022$/kBtu/h)	3	3	3	3	3	3	3	3	3	3	3

1. ASHRAE 90.1 data for units larger than 150 tons and for full-load optimized applications (Path A in ASHRAE 90.1-2019).

Note:
For most chillers (including those in single-chiller applications and for peaking units in multi-chiller applications), the seasonal performance (represented by the IPLV) is more indicative of annual expected performance than the full-load performance; performance of baseload chillers in multi-chiller applications, which typically operate at full-load, are well represented by the full-load efficiency value.
ASHRAE 90.1 went into effect in October 2019.
Ranges represent the span of typical values for a given parameter.

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Commercial Screw Chillers (Air-Cooled Only)

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- Screw chillers are common in 150 to 500-ton capacities but are most cost effective for small (<300 tons) loads; screw chillers dominate the current market for small to mid-size chillers.
- Screw chillers can be used in either air-cooled or water-cooled applications. Screw chillers shown in the data are air-cooled. Air-cooled chillers are less efficient than the water-cooled models. Listed efficiencies include matched condensers and their associated energy use.
- ASHRAE 90.1-2019 stipulates minimum efficiencies for all air-cooled chillers together, including screw chillers, while water-cooled chillers are separated by positive displacement (e.g., screw) versus centrifugal models. Air-cooled chiller efficiencies are further split by size for more and less than 150 tons. ASHRAE 90.1-2019 also distinguishes between whether the unit will be optimized for full-load (Path A) or part-load operation (Path B). Data here are for Path A; a Path B chiller may have slightly lower full-load efficiency in exchange for much higher part-load efficiency. For example, for a ≥ 150-ton unit:
  - Path A: ≥ 10.1 EER full-load and ≥ 14.0 IPLV EER
  - Path B: ≥ 9.7 EER full-load and ≥ 16.1 IPLV EER
- FEMP recommendations for air-cooled chillers (updated June 2020) are:
  - Path A (≥ 150 tons): ≥ 10.7 EER full-load and ≥ 14.0 IPLV EER
  - Path B (≥ 150 tons): ≥ 9.7 EER full-load and ≥ 16.4 IPLV EER
- The highest efficiency screw chillers incorporate some of the following:
  - Variable speed compressors and/or multiple compressors
  - Economizers
  - Improved heat-exchangers
- Advanced Case: Due to increases in R&D, improvements in current technology are expected to increase efficiency without substantially increasing costs.

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Commercial Scroll Chillers (Air-Cooled Only)

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Higher typical efficiencies with same costs as reference case despite increased efficiency

DATA	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	ASHRAE 90.1-2019[1]	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (tons)	50	50	50	50	50	50	50	50	50	50	50
	140	140	140	140	140	140	140	140	140	140	140
Efficiency [full-load] (kW/ton)	1.23	1.16	1.19	1.15	1.07	1.08	1.03	1.04	0.99	0.99	0.94
Efficiency [IPLV] (kW/ton)	0.99	0.77	0.88	0.77	0.70	0.71	0.66	0.69	0.63	0.67	0.60
COP [full-load]	2.9	3.0	3.0	3.1	3.3	3.3	3.4	3.4	3.6	3.6	3.7
COP [IPLV]	3.7	4.6	4.0	4.6	5.0	5.0	5.3	5.1	5.6	5.3	5.8
Average Life (y)	20	20	20	20	20	20	20	20	20	20	20
Retail Equipment Cost (2022$/ton)	680	1,000	1,060	1,060	1,160	1,120	1,160	1,150	1,200	1,200	1,240
	560	820	530	530	630	590	630	620	670	670	710
Total Installed Cost (2022$/ton)	970	1,210	1,170	1,170	1,270	1,230	1,270	1,260	1,310	1,310	1,350
	850	970	860	860	960	920	960	950	1,000	1,000	1,040
Total Installed Cost (2022$/kBtu/h)	76	91	85	85	93	90	93	92	96	96	100
Annual Maintenance Cost (2022$/ton)	60	60	60	60	60	60	60	60	60	60	60
	40	40	40	40	40	40	40	40	40	40	40
Annual Maintenance Cost (2022$/kBtu/h)	4	4	4	4	4	4	4	4	4	4	4

1. ASHRAE 90.1 data for units less than 150 tons and for full-load optimized applications (Path A in ASHRAE 90.1-2019).

Note:
For most chillers (including those in single-chiller applications and for peaking units in multi-chiller applications), the seasonal performance (represented by the IPLV) is more indicative of annual expected performance than the full-load performance; performance of baseload chillers in multi-chiller applications, which typically operate at full-load, are well represented by the full-load efficiency value.
ASHRAE 90.1 went into effect in October 2019.
Ranges represent the span of typical values for a given parameter.

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Commercial Scroll Chillers (Air-Cooled Only)

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- Scroll chillers range in size from ~20 tons to ~200 tons and can be used in either air-cooled or water-cooled applications. They are the most common type of chiller for small chiller plants. The scroll chillers shown in the data are air-cooled, which is most common. Air-cooled chillers are less efficient than the water-cooled models. Listed efficiencies include matched condensers and their associated energy use.
- ASHRAE 90.1-2019 stipulates minimum efficiencies for all air-cooled chillers together, including scroll chillers, while water-cooled chillers are separated by positive displacement (e.g., scroll) versus centrifugal models. Air-cooled chiller efficiencies are distinct for more and less than 150 tons. ASHRAE 90.1-2019 also distinguishes between whether the unit will be optimized for full-load (Path A) or part-load operation (Path B). Data here are for Path A; a Path B chiller may have slightly lower full-load efficiency in exchange for much higher part-load efficiency. For example, for a 100-ton unit:
  - Path A: ≥ 10.1 EER full-load and ≥ 13.7 IPLV EER
  - Path B: ≥ 9.7 EER full-load and ≥ 15.8 IPLV EER
- FEMP recommendations for air-cooled chillers (updated June 2020) are:
  - Path A (< 150 tons): ≥ 10.7 EER full-load and ≥ 13.7 IPLV EER
  - Path B (< 150 tons): ≥ 9.7 EER full-load and ≥ 15.9 IPLV EER
- The highest efficiency scroll chillers incorporate some of the following:
  - Multiple compressors for staged capacity control
  - Improved heat-exchangers
  - Variable speed compressor (or other modulation controls)
- With the phase out of R-22, manufacturers have replaced many of their small reciprocating chiller products with equivalent scroll products, making them a primary choice for small tonnage applications.
- Advanced Case: Due to increases in R&D, improvements in current technology are expected to increase efficiency without substantially increasing costs.

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Commercial Gas-Fired Chillers (Water-Cooled, Direct-Fired Only)

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Same as Reference Case

DATA	2012		2018		2022				2030		2040		2050	
	Installed Base: Absorption	Installed Base: Engine-Driven	Installed Base: Absorption	Installed Base: Engine-Driven	ASHRAE 90.1-2019 Absorption	CA Title 24 – Engine-Driven	Absorption	Engine-Driven	Absorption	Engine-Driven	Absorption	Engine-Driven	Absorption	Engine-Driven
Typical Capacity (tons)[1]	150	150	150	150	150	150	150	150	150	150	150	150	150	150
	1,500	400	1,500	400	1,500	400	1,500	400	1,500	400	1,500	400	1,500	400
COP [full-load]	1.1	1.7	1.2	1.7	1.0	1.2	1.2	1.7	1.3	1.8	1.4	1.8	1.4	1.8
COP [IPLV]	NA	NA	1.6	2.6	1.0	2.0	1.6	2.6	1.6	2.6	1.6	2.6	1.6	2.6
Average Life (y)	23	25	23	25	23	25	23	25	23	25	23	25	23	25
Retail Equipment Cost (2022$/ton)	1,060	1,000	1,060	1,000	1,200	1,000	1,200	1,000	1,200	1,000	1,200	1,000	1,200	1,000
	880	880	880	880	870	880	870	880	870	880	870	880	870	880
Total Installed Cost (2022$/ton)	1,290	1,240	1,180	1,240	1,110	1,240	1,110	1,240	1,110	1,240	1,110	1,240	1,110	1,240
	1,000	1,000	1,000	1,000	850	1,000	850	1,000	850	1,000	850	1,000	850	1,000
Total Installed Cost (2022$/kBtu/h)	95	93	91	93	82	93	82	93	82	93	82	93	82	93
Annual Maintenance Cost (2022$/ton)	40	60	40	60	40	60	40	60	40	60	40	60	40	60
	20	40	20	40	20	40	20	40	20	40	20	40	20	40
Annual Maintenance Cost (2022$/kBtu/h)	3	4	3	4	3	4	3	4	3	4	3	4	3	4

1. Capacity is output.

Note:
This analysis assumes a water-cooled chiller; both gas-fired chiller types (absorption and engine-driven) are shown. COP values for double-effect absorption chillers are shown.
For most chillers (including those in single-chiller applications and for peaking units in multi-chiller applications), the seasonal performance (represented by the IPLV) is more indicative of annual expected performance than the full-load performance; performance of baseload chillers in multi-chiller applications, which typically operate at full-load, are well represented by the full-load efficiency value.
ASHRAE 90.1 went into effect in October 2019.
CA Title 24 went into effect in January 2020.
Ranges represent the span of typical values for a given parameter.

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Commercial Gas-Fired Chillers (Water-Cooled, Direct-Fired Only)

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- Gas-fired chillers are available as either air-cooled (~25-50 tons) or water-cooled (150+ tons). This analysis covers only water-cooled chillers of two varieties: absorption and engine-driven vapor compression (direct-fired only; indirect steam or hot water driven units are excluded).
- Direct gas firing provides high enough temperatures to operate double effect absorption chillers, which operate at a 50-60% higher COP than single effect systems. Triple effect chillers, though not commercially available, can boost cooling COP 30-50% beyond double effect chillers. Some companies have worked on prototype direct-fired triple effect absorption chillers, but prohibitively high cost of advanced high heat/corrosion-resistant materials required for triple effect absorption chillers suggests that this technology will not likely have an impact on the market in the near-term.
- Gas-fired engine-driven chillers pair conventional vapor compression systems (typically screw or centrifugal compressors) with natural gas powered-reciprocating engines. They exhibit higher peak cooling COP than absorbers, and engine modulation results in better part-load performance. Future efficiency improvements for engine-driven chillers are not anticipated. Engine-driven chillers allow the opportunity to recover waste heat for useful purposes.
- Maintenance costs for engine-driven chillers are higher than for other chillers because they include all the typical components of a vapor compression chiller in addition to an engine; the engine maintenance costs vary depending on the annual run hours of the unit.
- Limited sales data suggest that the U.S. market for gas-fired chillers is very limited and is mostly for replacement units, not for new installations. Recent increases in electric chiller efficiency have narrowed the operating cost differential with gas chillers. Asia has the majority of the global gas-fired chiller market.
- Gas-fired chiller installations are particularly valuable in locations where electric rates are high and gas prices are low (i.e., low spark spread), where digester or landfill gas sources are available, or where waste heat sources are available (e.g., an industrial process or microturbine CHP system) that could be used with a hybrid direct/indirect-fired absorption chiller to offset the use of natural gas.

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Commercial Rooftop Air Conditioners

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Higher efficiencies with same costs as reference case despite increased efficiency

DATA	2012	2018	2022[4]				2023				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.1	High	New Standard	Typical	ENERGY STAR V. 4.0	High	Typical	High	Typical	High	Typical	High
Typical Output Capacity (kBtu/h)	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Part Load Efficiency (IEER)[1]	12.4	12.9	12.9	12.9	14.0	23.3	14.8	14.8	18.0	23.3	16.0	23.3	16.5	23.3	17.5	23.3
Efficiency (EER)[2]	10.6	11.5	11.5	11.5	12.2	12.8	12.2	12.2	12.7	12.8	12.6	12.8	12.6	12.8	12.7	12.8
Efficiency Conversion	3.6	3.8	3.8	3.8	4.1	6.8	4.3	4.3	5.3	6.8	4.7	6.8	4.8	6.8	5.1	6.8
Average Life (y)	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Retail Equipment Cost (2022$)	7,760	8,280	8,280	8,280	9,090	12,210	9,490	9,490	10,340	12,210	9,590	12,210	9,590	12,210	9,590	12,210
Total Installed Cost (2022$)	10,350	11,870	11,870	11,870	13,020	17,600	13,560	13,560	14,970	17,600	13,720	17,600	13,720	17,600	13,720	17,600
Total Installed Cost (2022$/kBtu/h)	115	132	132	132	145	196	151	151	166	196	152	196	152	196	152	196
Annual Maintenance Cost (2022$)[3]	370	370	370	370	370	370	370	370	370	370	370	370	370	370	370	370
Annual Maintenance Cost (2022$/kBtu/h)	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4

1. Values shown are for air-cooled small commercial packaged air conditioners with either electric resistance heating or no heating within the same enclosure. DOE published a direct final rule for commercial packaged air conditioners and heat pumps in January 2016 with initial standards becoming effective in 2018 and additional standards becoming effective in 2023. As part of this rulemaking, DOE changed the regulated metric from EER to integrated energy efficiency ratio (IEER).
2. DOE investigated the relationship between IEER and EER. Because the relationship between IEER and EER is weak, this analysis estimates EER values based on the average of the values seen at a given IEER.
3. Examples of annual maintenance services include, check tensions, condition, and alignment of belts and adjust as necessary; lubricate shaft and motor bearings; replace air filters; clean coils, drain pan and piping, blowers, fan motors as required; check refrigerant pressure and compressor oil level; etc.
4. The 2022 typical efficiency is based on the average IEER from DOE's CCD. The 2022 high efficiency is based on the most-efficient model in DOE's CCD, but costs are estimated based on the most efficient unit analyzed in CUAC EERE 2016, which had an IEER of 21.5.

Note:
EER is the ratio of the cooling capacity (in Btu/h) to the power input (in watts) and provides a measure of the efficiency of equipment operating at full load (i.e., 100 percent cooling capacity) in high-ambient-temperature conditions (i.e., 95 °F). IEER is a single number part-load efficiency based on weighting of EER at various load capacities. Efficiency Conversion is the conversion of IEER from a [(Btu/h)/W] metric to a metric in the same units.
The previous standard went into effect in January 2018. The current standard went into effect in January 2023.
ENERGY STAR V. 3.1 went into effect in January 2018. ENERGY STAR V. 4.0 went into effect in January 2023.

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Commercial Rooftop Air Conditioners

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- Air-Cooled Commercial Packaged Air Conditioners

Cooling Capacity (kBtu/h)	Heating Type	Federal Standard Effective 1/1/2018 Min. IEER	Federal Standard Effective 1/1/2023 Min. IEER
Small (≥ 65 and < 135)	Electric resistance or none	12.9	14.8
	Any other type	12.7	14.6
Large (≥ 135 and < 240)	Electric resistance or none	12.4	14.2
	Any other type	12.2	14.0

- This analysis focused on small air-cooled commercial packaged rooftop air conditioners (90 kBtu/h or 7.5 tons), though there are also standards for many other types of commercial air conditioners.
- Amended standards in terms of IEER for all equipment classes took effect in January 2018. More stringent standards in terms of IEER for all equipment classes took effect in January 2023.
- Advanced Case: Due to increases in R&D, improvements in current technology (e.g., more cost-effective variable speed technology) are expected to increase efficiency without substantially increasing costs.

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Commercial Gas-Fired Engine-Drive Rooftop Air Conditioners

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Same as Reference Case

DATA	2012[1]	2018	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical	Typical	Typical
Typical Capacity (tons)	18	11	11	11	11	11
Heating COP	1.4	1.4	1.4	1.4	1.4	1.4
Cooling COP	0.9	1.2	1.2	1.2	1.2	1.2
Average Life (y)	15	15	15	15	15	15
Retail Equipment Cost ($/ton)	3,350	2,820	3,710	3,710	3,710	3,710
Total Installed Cost ($/ton)	3,820	3,290	4,110	4,110	4,110	4,110
Total Installed Cost ($/kBtu/h)	318	274	343	343	343	343
Annual Maintenance Cost (2022$)	70	70	70	70	70	70
Annual Maintenance Cost (2022$/kBtu/h)	6	6	6	6	6	6

1. The 2012 typical capacity and cooling COP were estimated as a simple average between obsolete pre-2003 units and 2013 units, which first became available in 2010; this assumes that each vintage represents about half of the installed base.

Note:
Only one product was available in 2012; the market has grown slightly in years since. Typical capacity and COP for 2018 and later are averages of units available as of 2017.

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Commercial Gas-Fired Engine-Drive Rooftop Air Conditioners

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- There are only a few gas-fired engine-driven rooftop units currently available in the U.S. market. The first unit was introduced in 2010. It is an 11-ton packaged heat pump with dual scroll compressors, variable refrigerant flow, and a variable speed supply fan. Engine coolant heat recovery improves the heating mode COP.
- There are currently no Federal requirements on gas-fired engine-driven rooftop air conditioners or heat pumps.
- Annual sales of the engine-driven rooftop heat pump are estimated at less than 5,000 units per year.

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Commercial Rooftop Heat Pumps

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Higher efficiencies with same costs as reference case despite increased efficiency

DATA	2012	2018	2022				2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.1	High	New Standard	ENERGY STAR V. 4.0	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Part Load Efficiency (IEER)[1]	12.0	11.3	12.2	14.3	12.8	20.3	14.1	15.3	20.3	14.4	20.3	15.3	20.3	15.3	20.3
EER	10.2	11.2	11.3	11.5	11.8	13.0	12.0	11.8	13.0	11.7	13.1	11.7	13.1	11.7	13.1
COP (Heating)	3.3	3.3	3.3	3.4	3.4	3.7	3.4	3.5	3.7	3.4	3.7	3.5	3.7	3.5	3.7
Average Life (y)	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Retail Equipment Cost (2022$)	7,490	7,490	9,000	10,250	9,370	12,920	10,160	10,600	12,920	10,290	12,920	10,600	12,920	10,600	12,920
Total Installed Cost (2022$)	9,340	9,340	12,900	14,940	13,530	18,860	14,810	15,510	18,860	15,000	18,860	15,510	18,860	15,510	18,860
Total Installed Cost (2022$/kBtu/h)	104	104	143	166	150	210	165	172	210	167	210	172	210	172	210
Annual Maintenance Cost (2022$)	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380
Annual Maintenance Cost (2022$/kBtu/h)	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4

1. Values shown are for air-cooled small commercial packaged heat pumps with either electric resistance heating or no heating within the same enclosure. DOE published a direct final rule for commercial packaged air conditioners and heat pumps in January 2016 with initial standards becoming effective in 2018 and additional standards becoming effective in 2023. As part of this rulemaking, DOE changed the regulated metric from EER to IEER.

Note:
The previous standard went into effect in January 2018. The current standard went into effect in January 2023.
ENERGY STAR V. 3.1 went into effect in January 2018. ENERGY STAR V. 4.0 went into effect in January 2023.

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Commercial Rooftop Heat Pumps

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- Air-Cooled Commercial Packaged Heat Pumps

Cooling Capacity (kBtu/h)	Heating Type	Federal Standard Effective 1/1/2018 Min. IEER	Federal Standard Effective 1/1/2023 Min. IEER
Small (≥ 65 and < 135)	Electric resistance or none	12.2	14.1
	Any other type	12.0	13.9
Large (≥ 135 and < 240)	Electric resistance or none	11.6	13.5
	Any other type	11.4	13.3

- This analysis focused on small air-cooled commercial packaged rooftop heat pumps (90 kBtu/h or 7.5 tons), though there are also standards for many other types of commercial heat pumps.
- Amended standards in terms of IEER for all equipment classes took effect in 2018. More stringent standards in terms of IEER for all equipment classes took effect in 2023.
- Advanced Case: Due to increases in R&D, improvements in current technology (e.g., more cost-effective variable speed technology) are expected to increase efficiency without substantially increasing costs.

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Commercial Ground-Source Heat Pumps

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Same efficiencies with lower costs than reference case despite same efficiency

DATA	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	48	48	48	48	48	48	48	48	48	48	48
COP (Heating)[1]	3.1	3.7	3.2	3.5	3.6	3.5	3.6	3.5	3.6	3.5	3.6
EER (Cooling)[2]	12.7	17.4	14.1	17.0	21.6	17.0	21.6	17.0	21.6	17.0	21.6
Average Life (y)	8	8	8	8	8	8	8	8	8	8	8
	21	21	21	21	21	21	21	21	21	21	21
Retail Equipment Cost (2022$)	10,470	6,470	5,590	6,470	7,880	6,470	7,880	6,470	7,880	6,470	7,880
Total Installed Cost (2022$)	19,760	18,230	17,350	18,230	19,650	16,410	17,690	16,410	17,690	16,410	16,410
	44,820	26,520	25,580	26,520	27,880	23,870	25,090	23,870	25,090	23,870	23,870
Total Installed Cost (2022$/kBtu/h)	673	466	447	466	495	420	446	420	446	420	420
Annual Maintenance Cost (2022$)	180	180	180	180	180	180	180	180	180	180	180
Annual Maintenance Cost (2022$/kBtu/h)	4	4	4	4	4	4	4	4	4	4	4

1. COP values listed are assessed at a "ground loop" test condition, which is representative of closed loop GSHP operating conditions. However, DOE sets standards at a "water loop" test condition. The AHRI directory lists COP ratings at both sets of test conditions and is used to convert between them where necessary.
2. EER values listed are assessed at a full-load "ground loop" test condition, which is representative of closed loop GSHP operating conditions. However, DOE sets standards at a full-load "water loop" test condition. The AHRI directory lists EER ratings at all sets of test conditions and is used to convert between them where necessary.

Note:
Residential and commercial GSHPs are very similar - the main difference in data presented is the different capacity (3-ton vs. 4-ton) and slightly higher installation costs for commercial GSHP. DOE does not distinguish between residential and commercial units in its regulations.

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Commercial Ground-Source Heat Pumps

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- The most common commercial ground-source heat pump systems are closed-loop in which water or anti-freeze solution is circulated through plastic pipes buried underground. Commercial water-to-air heat pumps (WAHPs) range in size from 1 ton or less to over 500 tons depending on whether a distributed or centralized architecture is used. Distributed systems are more prevalent.
- Most geothermal WAHPs are rated for capacity and efficiency based on the ISO 13256-1 standard. Heating and cooling efficiency measurements under this standard include input energy for fans and pumps on a proportional basis that only includes that power required to transport air and liquid through the heat pump. The reason for this method is to simplify comparisons between heat pumps and to allow equipment to be optimized for real world conditions without suffering rating penalties. Real world energy use will exceed ratings predictions as a result of higher fluid static pressure requirements.
- ISO 13256-1 cooling rating conditions require 77 °F entering water temperature and 80.6 °F entering air temperature. More typical peak design criteria would be 80-90 °F entering water temperature and 75 °F entering air temperature. As a result, ISO 13256-1 rated cooling efficiency would be higher than typical design peak operation.
- Some WAHPs include efficiency data for a part-load operating condition as allowed by ISO 13256-1 for multiple stage or variable speed compressors. No seasonal energy efficiency metric (analogous to SEER or IEER) currently applies to WAHPs. The annual performance of a geothermal WAHP system can vary more widely than for other system types due to the large influence of ground loop design and characteristics.
- The ENERGY STAR criteria for ground-source heat pumps apply only to residential applications.
- Installation cost is for a closed loop system and includes necessary accessories. The ground loop heat exchanger and distribution pumping systems represent a majority of the installation cost.
- Low end WAHPs utilize single stage compressors. Higher efficiency units incorporate multiple stage or variable speed compressor controls to improve efficiency as well as humidity and temperature control. Variable speed ECM fan motors also improve overall energy efficiency.
- Advanced Case: Ground-source heat pumps are already highly efficient and have not changed much in terms of efficiency in recent years. With increased R&D, it is anticipated that the equipment and installation costs will be reduced over time, but efficiency will likely stay the same.

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Packaged Terminal Air Conditioners

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DATA	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High[2]	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)[1]	9	9	9	9	9	9	9	9	9	9	9
Efficiency (EER)	11.3	11.3	11.3	11.3	13.1	11.3	13.1	11.3	13.1	11.3	13.1
Efficiency	3.3	3.3	3.3	3.3	3.8	3.3	3.8	3.3	3.8	3.3	3.8
Average Life (y)	8	8	8	8	8	8	8	8	8	8	8
Retail Equipment Cost (2022$)	1,460	1,460	1,460	1,460	1,560	1,460	1,560	1,460	1,560	1,460	1,560
Total Installed Cost (2022$)	1,740	1,740	1,740	1,740	1,840	1,740	1,840	1,740	1,840	1,740	1,840
Total Installed Cost (2022$/kBtu/h)	193	193	193	193	204	193	204	193	204	193	204
Annual Maintenance Cost (2022$)	70	70	70	70	70	70	70	70	70	70	70
Annual Maintenance Cost (2022$/kBtu/h)	8	8	8	8	8	8	8	8	8	8	8

1. Typical capacity is representative of units with the most shipments. It was also the representative cooling capacity for DOE's analysis in packaged terminal air conditioners (PTAC) and packaged terminal heat pumps (PTHP) EERE 2022 NOPD.
2. High values for 2022 and beyond are based on the max-tech level from PTAC & PTHP EERE 2022 NOPD.

Note:
The current standard went into effect in January 2017.

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Packaged Terminal Air Conditioners

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- PTAC are a self-contained, ductless air conditioning system used for commercial applications.
- Analysis was conducted for the standard equipment class at the representative cooling capacity of 9000 Btu/h.

Cooling Capacity (kBtu/h)	Equipment Size	Equipment Class	Federal Standard EER
PTAC	Standard	< 7000	11.9
		≥7,000 Btu/h and ≤15,000 Btu/h	14.0 – (0.3 x Cap)
		> 15,000 Btu/h	9.5

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Packaged Terminal Heat Pumps

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Higher efficiencies with the same costs as ref. case despite increased efficiency

DATA	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical[2]	High[3]	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)[1]	9	9	9	9	9	9	9	9	9	9	9
Efficiency (EER)	11.3	11.3	11.3	11.3	13.1	11.5	13.1	12.0	13.1	12.4	13.1
Efficiency	3.3	3.3	3.3	3.3	3.8	3.4	3.8	3.5	3.8	3.6	3.8
COP (Heating)	3.2	3.2	3.2	3.2	3.6	3.3	3.6	3.4	3.6	3.5	3.6
Average Life (y)	8	8	8	8	8	8	8	8	8	8	8
Retail Equipment Cost (2022$)	1,620	1,620	1,620	1,620	1,720	1,630	1,720	1,630	1,720	1,630	1,720
Total Installed Cost (2022$)	1,910	1,910	1,910	1,910	2,010	1,910	2,010	1,910	2,010	1,910	2,010
Total Installed Cost (2022$/kBtu/h)	212	212	212	212	223	212	223	212	223	212	223
Annual Maintenance Cost (2022$)	70	70	70	70	70	70	70	70	70	70	70
Annual Maintenance Cost (2022$/kBtu/h)	8	8	8	8	8	8	8	8	8	8	8

1. Typical capacity is representative of units with the most shipments. It was also the representative cooling capacity for DOE's analysis in PTAC & PTHP EERE 2022 NOPD.
2. Typical values for 2022 and beyond are based on the efficiency level that has the largest market share per PTAC & PTHP EERE 2022 NOPD.
3. High values for 2022 and beyond are based on the max-tech level from PTAC & PTHP EERE 2022 NOPD.

Note:
The current standard went into effect in October 2012.

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Packaged Terminal Heat Pumps

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- PTHP are self-contained heat pumps primarily used for commercial applications.
- Analysis was conducted for the standard equipment class at the representative cooling capacity of 9000 Btu/h.

Cooling Capacity (kBtu/h)	Equipment Size	Equipment Class	Federal Standard EER	Federal Standard COP
PTHP	Standard	< 7000	11.9	3.3
		≥7,000 Btu/h and ≤15,000 Btu/h	14.0 – (0.3 x Cap)	3.7 – (0.052 x Cap)
		> 15,000 Btu/h	9.5	2.9
PTHP	Non-Standard	< 7000	9.3	2.7
		≥7,000 Btu/h and ≤15,000 Btu/h	10.8 – (0.213 x Cap)	2.9 – (0.026 x Cap)
		> 15,000 Btu/h	7.6	2.5

- Advanced Case: Due to increases in R&D, improvements in current technology (e.g., more cost-effective variable speed technology) are expected to increase efficiency without substantially increasing costs.

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Commercial Water Heating

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Commercial Gas-Fired Storage Water Heaters

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Same as Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 2.0	High	Typical	High	Typical	High	Typical	High
Typical Storage Capacity (gal)	100	100	100	100	100	100	100	100	100	100	100	100
Typical Input Capacity (kBtu/h)	199	199	199	199	199	199	199	199	199	199	199	199
Thermal Efficiency (%)[1]	81	82	80	82	94	99	95	99	95	99	95	99
Average Life (y)	13	10	10	10	10	10	10	10	10	10	10	10
Retail Equipment Cost (2022$)	3,870	3,890	3,850	3,890	4,180	4,290	4,200	4,290	4,200	4,290	4,200	4,290
	5,170	5,200	5,140	5,200	5,530	5,650	5,550	5,650	5,550	5,650	5,550	5,650
Total Installed Cost (2022$)	5,170	5,190	5,140	5,190	6,630	6,730	6,640	6,730	6,640	6,730	6,640	6,730
	8,440	8,460	8,410	8,460	8,590	8,710	8,610	8,710	8,610	8,710	8,610	8,710
Total Installed Cost (2022$/kBtu/h)	42	42	43	42	41	39	40	39	40	39	40	39
Annual Maintenance Cost (2022$)[2]	320	320	320	320	330	330	330	330	330	330	330	330
Annual Maintenance Cost (2022$/kBtu/h)	2	2	2	2	2	2	2	2	2	2	2	2

1. Different levels of standby loss were not included in this analysis.
2. Maintenance consists of sediment and scale removal once or twice per year and replacement of miscellaneous components such as gaskets and sealants. Condensing units have an additional cost for replacement of condensate neutralizer media every two years.

Note:
The current standard went into effect in October 2015.
ENERGY STAR V. 2.0 went into effect in October 2018.
The range of retail and installed costs represent the range from replacement market to new construction market.

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Commercial Gas-Fired Storage Water Heaters

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- Input capacity > 155 kBtu/h and storage capacity ≤ 140 gal
- Federal standard:
  - Minimum thermal efficiency: 80%
  - Maximum standby loss (Btu/h) : Input Rate/800 + 110 × (Rated Volume)$^{1/2}$
- ENERGY STAR requirements:
  - Minimum thermal efficiency: 94%
  - Maximum standby loss (Btu/h): 0.84 × [(Input Rate/800) + 110 × (Rated Volume)$^{1/2}$]
- Baseline units are typically constructed similarly to residential units, though with higher input capacities (and often higher storage volumes).
- High-efficiency units include condensing heat exchangers (typically stainless or enameled steel) to extract additional heat by condensing water vapor in flue gases. Condensing units also include an inducer fan system or power burner. The heat exchanger is typically contained within the tank, but some designs consist of an external heating module attached to a storage tank. Condensing units are expected to be the majority market share by 2030.
- Maintenance consists of sediment and scale removal once or twice per year and replacement of miscellaneous components such as gaskets and sealants. Condensing units have an additional cost for replacement of condensate neutralizer media every two years.

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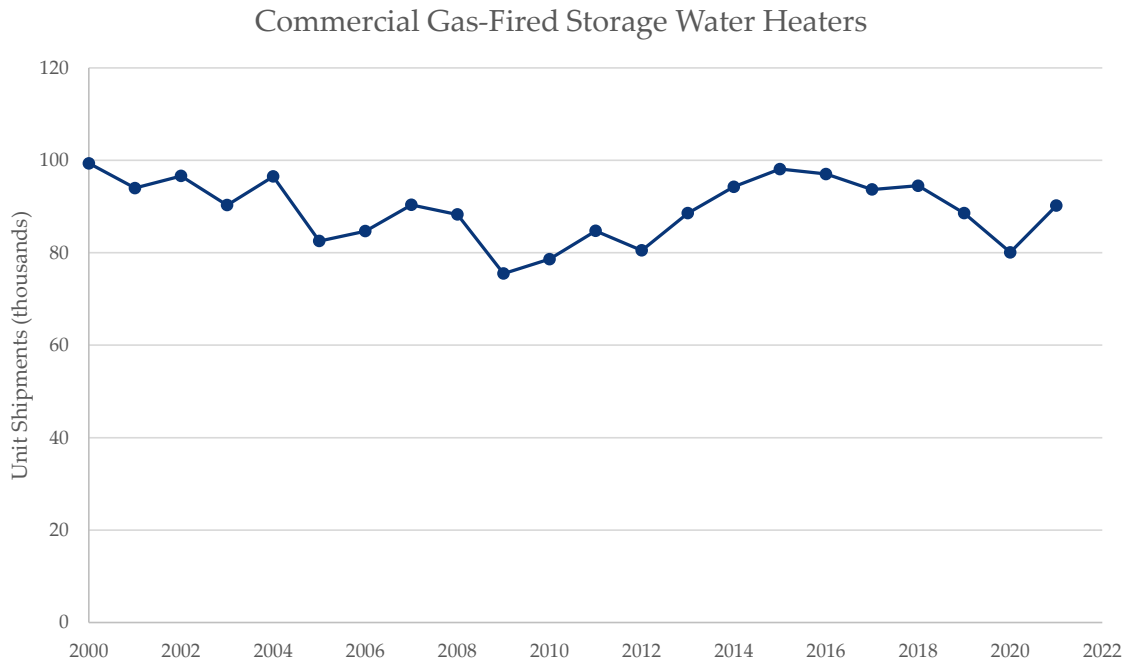
Annual shipments have fluctuated from 99,000 units in 2000 to 75,000 units in 2009, back to 99,000 units in 2015 and gradually decreasing since then until 2020.



Source: CWH EERE 2022 NOPR and AHRI

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Commercial Electric Resistance Storage Water Heaters

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Same as Reference Case

DATA	2012	2018	2022		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	Typical	Typical	Typical
Typical Storage Capacity (gal)	119	119	119	119	119	119	119
Typical Input Capacity (kW)[1]	18	18	18	18	18	18	18
Typical Input Capacity (kBtu/h)	60	60	60	60	60	60	60
Thermal Efficiency (%)	98	98	98	98	98	98	98
Average Life (y)	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)	3,180	3,180	3,180	3,180	3,180	3,180	3,180
	3,750	3,750	3,750	3,750	3,750	3,750	3,750
Total Installed Cost (2022$)	4,460	4,460	4,460	4,460	4,460	4,460	4,460
	4,690	4,690	4,690	4,690	4,690	4,690	4,690
Total Installed Cost (2022$/kBtu/h)	76	76	76	76	76	76	76
Annual Maintenance Cost (2022$)	50	50	50	50	50	50	50
Annual Maintenance Cost (2022$/kBtu/h)	1	1	1	1	1	1	1

1. Different levels of standby loss were not included in this analysis.

Note:
No new standards rulemaking has been initiated for commercial electric resistance water heaters since CWH EERE 2016 NOPR. Accordingly, the results are the same as EIA Technology Forecast Updates (2018), updated to 2022$.
The range of retail equipment and installed costs represents the range from replacement market to new construction market.

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Commercial Electric Resistance Storage Water Heaters

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- Federal standard:
  - Maximum standby loss (%/h) : 0.30 + 27/Measured Storage Volume
  - Minimum thermal efficiency: no standard, but all units have an efficiency ≥ 98%
- Storage capacity: typically, 50 to 120 gallons, though smaller and larger units exist for specialized applications
- Commercial units are typically constructed similar to residential units, though with higher input capacities (and often higher storage volumes).
- There is very little variation in thermal efficiency on the market; variation in standby loss is typically due to tank design and insulation thickness.
- Maintenance consists of sediment and scale removal once or twice per year.

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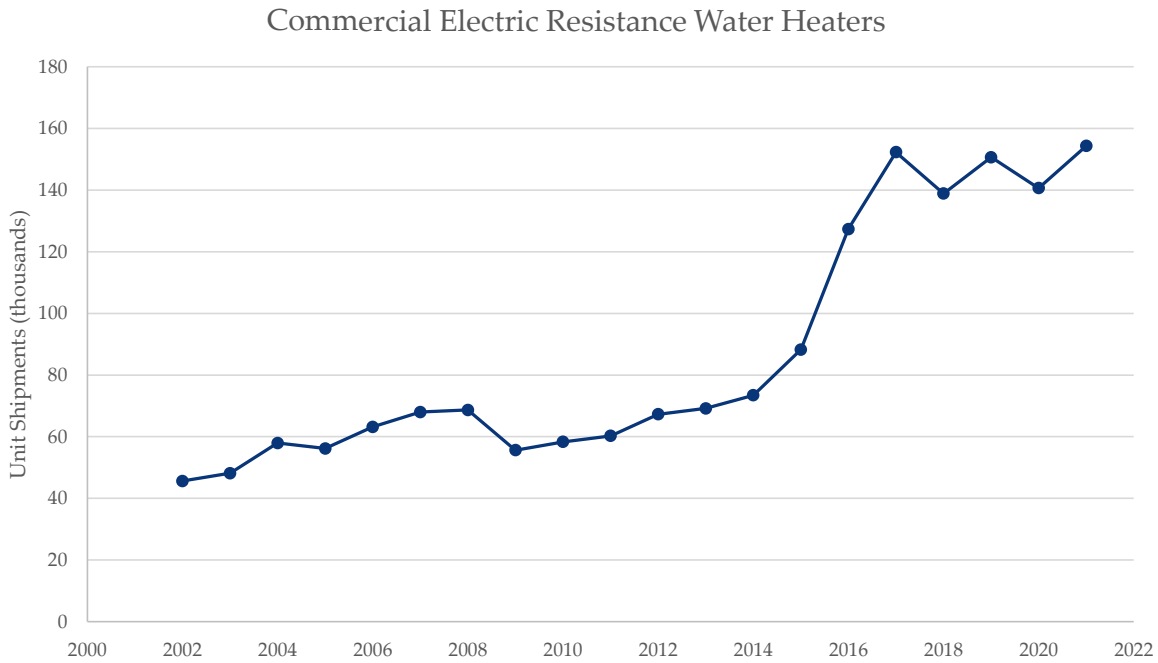
Annual shipments increased by almost 50% between 2002 and 2008. After a small dip in shipments in 2009, annual shipments have increased by about 173% between 2009 and 2017, stabilizing between 140-150 thousand shipments per year since then.



Source: AHRI

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Commercial Heat Pump Water Heaters

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Higher typical efficiencies with the same costs as reference case despite increased efficiency

DATA	2012	2018	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	ENERGY STAR V. 2.0	Typical	Typical	Typical
Water Flow Rate (gal/min)[1]	34	34	34	34	34	34	34
Typical Output Capacity (kW)[1]	50	50	50	50	50	50	50
Typical Output Capacity (kBtu/h)	171	171	171	171	171	171	171
Coefficient of Performance (COP_h)	3.9	3.9	3.9	3.0	4	4.2	4.4
Average Life (y)	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)[2]	55,406	55,406	55,406	55,406	55,406	55,406	55,406
Total Installed Cost (2022$)[2]	59,935	59,935	59,935	59,935	59,935	59,935	59,935
Total Installed Cost (2022$/kBtu/h)	350	350	350	350	350	350	350
Annual Maintenance Cost (2022$)[2]	120	120	120	120	120	120	120
Annual Maintenance Cost (2022$/kBtu/h)	1	1	1	1	1	1	1

1. Water flow rate scales with typical capacity. The storage tanks must be purchased and installed separately from the HP unit. The typical output and flow rate provided are near the median of the products available on the market currently.
2. Costs are same as EIA Technology Forecast Updates (2018), updated to 2022$. Updated representative costs for commercial heat pump water heaters are not available due to the extremely small market for these products.

Note:
ENERGY STAR V. 2.0 went into effect in October 2018.

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Commercial Heat Pump Water Heaters

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- Typical commercial HPWHs (CHPWHs) are add-on units designed to be used with a storage tank(s); integrated CHPWHs have emerged on the market (i.e., heat pump module and storage tank combined in one unit) in recent years.
- CHPWHs serve only a small portion of the commercial water heating (CWH) market, with the ENERGY STAR database listing only two manufacturers, each with one basic model listed.
- CHPWHs can extract heat from either air or water for heating potable water ("air-source" or "water-source"). The capacity of air-source CHPWHs falls at lower ambient air temperatures.
- Air-source CHPWHs cool the surrounding air, which can be desirable when installed indoors in applications with a year-round cooling load (e.g., a commercial kitchen).
- Output capacities for CHPWHs range from 17 kW to over 70 kW for air-source units and over 600 kW for water-source units.
- Some commercial applications require water as hot as 180 °F, such as dishwashing; however, most CHPWHs cannot deliver hot water at temperatures higher than 150 °F.
- There are no current Federal standards for CHPWHs, but DOE prescribes a test procedure for determining COP_h for CHPWHs.
- The most recent ENERGY STAR V. 2.0 specification for CWH equipment went into effect in October 2018. It specifies a COP_h level of 3.0 for CHPWHs.
- Advanced Case: Due to increases in R&D, improvements in current technology (e.g., more cost-effective variable speed technology) are expected to increase efficiency without substantially increasing costs.

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Commercial Oil-Fired Storage Water Heaters

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Same as Reference Case

DATA	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Storage Capacity (gal)	70	85	85	85	85	85	85	85	85	85	85
Typical Input Capacity (kBtu/h)	300	300	300	300	300	300	300	300	300	300	300
Thermal Efficiency (%)[1]	79	81	80	81	82	81	82	81	82	81	82
Average Life (y)	13	13	13	13	13	13	13	13	13	13	13
Retail Equipment Cost (2022$)	5,470	5,470	5,470	5,470	5,470	5,470	5,470	5,470	5,470	5,470	5,470
Total Installed Cost (2022$)	6,120	6,120	6,120	6,120	6,120	6,120	6,120	6,120	6,120	6,120	6,120
Total Installed Cost (2022$/kBtu/h)	26	25	26	25	25	25	25	25	25	25	25
Annual Maintenance Cost (2022$)	200	200	200	200	200	200	200	210	210	210	210
Annual Maintenance Cost (2022$/kBtu/h)	1	1	1	1	1	1	1	1	1	1	1

1. Different levels of standby loss were not included in this analysis.

Note:
The commercial oil-fired water heaters market is very small; currently, there are only 4 basic models in DOE's CCD. DOE's rulemaking analysis for oil-fired water heaters has not been updated since 2001. The retail, installed, and maintenance costs have been updated from EIA Technology Forecast Updates (2018) to 2022$.
The current standard went into effect in October 2015.

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Commercial Oil-Fired Storage Water Heaters

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- Input capacity > 155 kBtu/h and storage capacity ≤ 140 gal
- Federal standard:
  - Minimum thermal efficiency: 80%
  - Maximum standby loss (Btu/h) : Input Rate/800 + 110 × (Rated Volume)$^{1/2}$
- Condensing units do not exist, thus the highest thermal efficiency on the market is 82%.
- Commercial units are typically constructed similar to residential units, though with higher input capacities (and often higher storage volumes).
- Maintenance costs include sediment and scale removal once or twice per year.
- The market for commercial oil-fired storage water heaters is very small; shipments are approximately 3% of shipments for commercial gas-fired storage water heaters.

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Commercial Electric Booster Water Heaters

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Same as Reference Case

DATA	2012	2018	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical	Typical	Typical
Typical Capacity (gal)	6	6	6	6	6	6
	16	16	16	16	16	16
Typical Output Capacity (kBtu/h)	1,374	1,374	1,374	1,374	1,374	1,374
Thermal Efficiency (%)	98	98	98	98	98	98
Average Life (y)	3	3	3	3	3	3
	10	10	10	10	10	10
Retail Equipment Cost (2022$)[1]	1,530	1,530	1,920	1,920	1,920	1,920
	3,290	3,530	4,560	4,560	4,560	4,560
Total Installed Cost (2022$) [1]	1,730	1,730	2,120	2,120	2,120	2,120
	3,490	3,730	4,760	4,760	4,760	4,760
Total Installed Cost (2022$/kBtu/h)	2	2	3	3	3	3
Annual Maintenance Cost (2022$)[2]	-	-	-	-	-	-
Annual Maintenance Cost (2022$/kBtu/h)	-	-	-	-	-	-

1. The 2012 and 2018 installed base costs are the same as EIA Technology Forecast Updates (2018), updated to 2022$. Retail costs for 2022 and later are based on the range of costs for products on the market today. Installed costs assume a $200 installation price.
2. Maintenance costs are negligible.

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Commercial Gas-Fired Booster Water Heaters

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Higher efficiencies with corresponding cost increases

DATA	2012	2018	2022		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	Typical	Typical	Typical
Typical Capacity (gal)	3	3	3	3	3	3	3
	5	5	5	5	5	5	5
Typical Output Capacity (kBtu/h)	500	500	500	500	500	500	500
Thermal Efficiency (%)[1]	80	80	80	80	80	91	80
Average Life (y)	5	5	5	5	5	5	5
	10	10	10	10	10	10	10
Retail Equipment Cost (2022$)[2]	5,530	5,760	7,130	7,130	7,130	9,500	7,130
	8,000	9,060	11,120	11,120	11,120	12,500	11,120
Total Installed Cost (2022$)[2]	5,830	6,060	7,430	7,430	7,430	9,800	7,430
	8,300	9,360	11,420	11,420	11,420	12,800	11,420
Total Installed Cost (2022$/kBtu/h)	14	15	19	19	19	23	19
Annual Maintenance Cost (2022$)	160	160	160	160	160	160	160
Annual Maintenance Cost (2022$/kBtu/h)	0	0	0	0	0	0	0

1. While EIA Technology Forecast Updates (2018) included high values reflecting condensing models, models currently available in the market do not exceed 80% efficiency.
2. The 2012 and 2018 installed base costs are the same as EIA Technology Forecast Updates (2018), updated to 2022$. Retail costs for 2022 and later are based on the range of costs for products on the market today. Installed costs assume a $300 installation price.

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Commercial Booster Water Heaters

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- Booster water heaters are installed, often at the point of use, in series with the main service water heating system to boost service water temperatures. The main service water heating system may provide 110-140 °F water, and the booster water heater may increase that temperature to 180-195 °F. Typical commercial applications for booster water heaters include commercial dishwashers, laundromats, hospitals, and car washes.
- Commercial booster water heaters are regulated by DOE as either storage or instantaneous water heaters, depending on the ratio of input capacity to storage volume. Units with input capacity < 4,000 Btu/h per gallon of stored water are storage water heaters; all other units are instantaneous water heaters.
- DOE's regulations do not currently include standards for electric instantaneous water heaters, but standards are included for electric storage water heaters, gas-fired instantaneous water heaters, and gas-fired storage water heaters.
- Condensing gas-fired booster water heaters, those with an efficiency of 90% of more, were analyzed previously. There are no condensing units currently on the market. Condensing gas-fired booster water heaters can only operate if the incoming water temperature is below 130 °F so there is enough heat transfer to condense.
- Booster water heaters typically have short lifetimes because of high usage and extreme temperatures.
- Shipments are small due to the limited number of applications.
- Advanced Case: increased high efficiencies are possible due to market incentives to re-introduce condensing commercial gas-fired booster water heaters through additional investment, research, and development. No significant changes otherwise.

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Commercial Gas-Fired Instantaneous Water Heaters

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Same as Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 2.0	High[2]	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	250	250	250	250	250	250	250	250	250	250	250	250
	399	399	399	399	399	399	399	399	399	399	399	399
Thermal Efficiency (%)	80	92	80	92	94	99	96	99	96	99	96	99
Average Life (y)	17	17	17	17	17	17	17	17	17	17	17	17
	25	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)[1]	1,630	1,840	1,630	1,840	1,880	7,990	1,930	7,990	1,930	7,990	1,930	7,990
	4,400	8,610	4,400	8,610	9,000	9,990	9,400	9,990	9,400	9,990	9,400	9,990
Total Installed Cost (2022$)[1]	2,430	3,980	2,430	3,980	4,010	13,000	4,070	13,000	4,070	13,000	4,070	13,000
	10,380	13,560	10,380	13,560	13,950	14,950	14,350	14,950	14,350	14,950	14,350	14,950
Total Installed Cost (2022$/kBtu/h)	25	29	25	29	29	44	30	44	30	44	30	44
Annual Maintenance Cost (2022$)[3]	90	100	90	100	100	820	100	820	100	820	100	820
	760	820	760	820	820	830	830	830	830	830	830	830
Annual Maintenance Cost (2022$/kBtu/h)	2	2	2	2	2	3	1	3	1	3	1	3

1. Commercial gas-fired instantaneous water heaters are categorized into two groups: tankless water heater and hot water supply boiler. Tankless units are similar in design to residential tankless units. The hot water supply boiler has a much higher input and is similar in design to boilers. The large variation of total input capacity and design causes a large range of costs. The range of retail, installed, and maintenance costs represent the differences in design, as well as the cost ranges arising from replacement versus new construction markets.
2. High efficiency was determined based on DOE's CCD. The most efficient tankless water heater has a thermal efficiency of 96%. The most efficient hot water supply boiler has a thermal efficiency of 99%.
3. Maintenance consists replacement of miscellaneous components such as gaskets and sealants. Condensing units have an additional cost for replacement of condensate neutralizer media every two years.

Note:
For the installed base, current standard, and typical costs, low values represent costs for tankless water heaters in the replacement market while high values represent costs for hot water supply boilers in the new construction market. The range of costs for the High values are estimated costs for hot water supply boilers in the replacement and new construction market.
ENERGY STAR V. 2.0 went into effect in October 2018.

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Commercial Gas-Fired Instantaneous Water Heaters

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- Storage Capacity < 10 gallons and ≥ 10 gallons
- Federal standard:
  - Minimum thermal efficiency: 80%
  - Maximum standby loss (Btu/h): Input Rate/800 + 110 x (Rated Volume)$^{1/2}$
- ENERGY STAR requirements:
  - Minimum thermal efficiency: 94%
- Wall-mounted ("tankless") units typically do not exceed ~400,000 Btu/h and are similar in design to residential tankless units. Floor-mounted units ("circulating" or "volume" water heaters) are similar in design to boilers and can have input capacities in the millions of Btu/h. Floor-mounted units are typically installed with a storage tank.
- Despite high available input capacities, some installations use multiple units staged together, which may have reliability and/or efficiency benefits.
- Similar to storage water heaters, higher efficiencies are achieved with condensing operation, which requires a condensing heat exchanger and inducer fan or power burner. Some units include both non-condensing and condensing heat exchangers, while others include a single condensing heat exchanger.
- When replacing a storage water heater with an instantaneous water heater, there may be significant additional costs to upsize the gas supply line and change the venting.

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Commercial Gas-Fired Instantaneous Water Heaters

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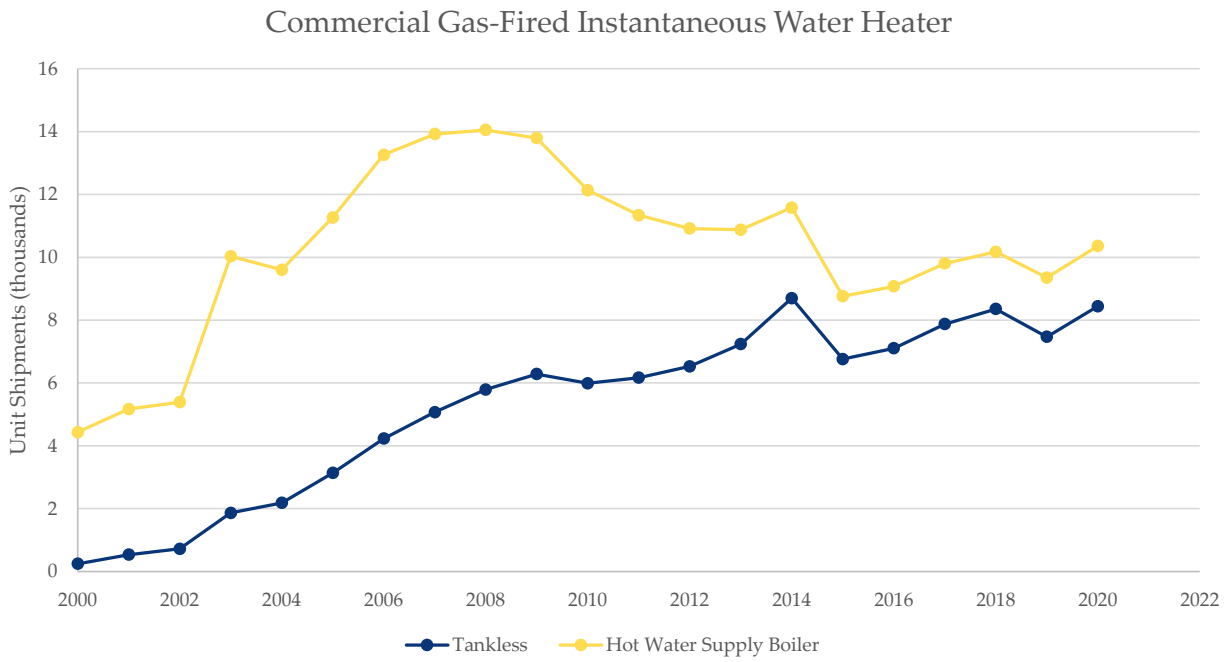
Annual shipments for gas-fired instantaneous tankless water heaters have gradually increased since 2000 while those for gas-fired instantaneous hot water supply boiler water heaters peaked in 2008 and have been decreasing since then, recently stabilizing around 10,000 annual shipments.



Source: CWH EERE 2022 NOPR

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Commercial Solar Water Heaters

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DATA	2012	2018	2022		2023	2030	2040	2050
	Installed Base	Installed Base	Typical	ENERGY STAR V. 4.0	ENERGY STAR V. 5.0	Typical	Typical	Typical
Typical Capacity (sq. ft.)[1]	85	85	85	85	85	85	85	85
Typical Capacity (m^2)	7.90	7.90	7.90	7.90	7.90	7.90	7.90	7.90
Typical Capacity (Input) (kBtu/h) – North	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05
Typical Capacity (Input) (kBtu/h) – South	6.74	6.74	6.74	6.74	6.74	6.74	6.74	6.74
Solar Uniform Energy Factor (SUEF)[2]	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Average Life (y)	20	20	20	20	20	20	20	20
Retail Equipment Cost (2022$)[3]	10,470	10,470	10,280	10,280	10,280	10,280	10,280	10,280
Total Installed Cost (2022$)[3]	14,180	14,180	12,640	12,640	12,640	12,640	12,640	12,640
Total Installed Cost (2022$/kBtu/h) – North	936	936	834	834	834	834	834	834
Total Installed Cost (2022$/kBtu/h) – South	702	702	626	626	626	626	626	626
Annual Maintenance Cost (2022$)[4]	100	100	100	100	100	100	100	100
Annual Maintenance Cost (2022$/kBtu/h) - North	7	7	7	7	7	7	7	7
Annual Maintenance Cost (2022$/kBtu/h) - South	5	5	5	5	5	5	5	5

1. Typical capacity refers to the solar collector panel area. It was determined using the SRCC database as the average value of the largest bin (in terms of capacity) with the greatest number of units.
2. In 2020, the efficiency metric for solar water heaters changed from SEF to SUEF. There is no equation or scaling factor readily available to translate SEF to SUEF. Accordingly, for the 2012 and 2018 installed base, SUEF was determined using the 2020 ENERGY STAR data set assuming the typical SEF/SUEF value was similar between 2012-2020. For 2022 and beyond, due to lack of SUEF data, it is assumed that a typical electric backup unit would meet the ENERGY STAR criteria. ENERGY STAR specifies a minimum SUEF of 3.0 for electric backup units and 1.8 for gas backup units.
3. Costs are for an indirect (active closed loop) system, including tank and backup heater. Smaller capacity/cost systems are typical for southern & western states (>two-third of the current market). Higher capacity/cost systems are required in colder/cloudier regions. The 2012 and 2018 installed base costs are updated from EIA Technology Forecast Updates (2018) to 2022$.
4. Annual maintenance is expected to be 0.5% to 1% of the total installation.

Note:
ENERGY STAR V. 4.0 went into effect in January 2022. ENERGY STAR V. 5.0 will go into effect in April 2023 but the ENERGY STAR criteria for solar water heaters will remain the same in ENERGY STAR V. 5.0.

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- In 2020, a diverse group of stakeholders from the solar thermal industry developed the SUEF Specification for solar water heaters. The goal of this specification is to align with the UEF metric used by DOE for other water heating technologies.
- SUEF is also the metric used by the current ENERGY STAR Specification, and it replaced the SEF metric.
- EIA Technology Forecast Updates (2018) presented results using SEF and solar fraction (SF). SEF is currently not used in either the ENERGY STAR or SRCC databases; accordingly, this report presents results according to SUEF. SF is the portion of the total conventional hot water heating load (delivered energy and tank standby losses). SF varies from 0 to 1.0. Typical solar fraction values are 0.5–0.75.
- There is no equation or scaling factor readily available to translate SEF to SUEF. Accordingly, for the 2012 and 2018 installed base, SUEF was determined using the 2020 ENERGY STAR data set assuming the typical SEF/SUEF value was similar between 2012-2020. For 2022 and beyond, SUEF is the average SUEF for solar water heaters with a "high-usage" draw pattern from the current ENERGY STAR qualified product list.
- Commercial solar water heaters are typically custom designed for a specific installation.
- Commercial solar water heaters may include backup heating, from sources such as electric resistance or hydronic heat (supplied from a gas-fired boiler or geothermal heat pump).
- Storage volumes of tanks for commercial solar water heaters can span from 140 gallons to over 2,000 gallons.
- SRCC's OG-300 can be used to certify commercial systems, but most commercial systems are larger and unique; this certification program is mostly used for residential solar water heaters.
  - Many incentive programs require that solar collectors for commercial systems be certified to SRCC's certification program for collectors, OG-100.

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Commercial Cooking Products

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Commercial Natural Gas Range with Griddle and Oven

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Higher typical efficiencies with the same costs as ref. case despite increased efficiency

DATA	2012	2018	2022			2023	2030		2040		2050	
	Installed Base	Installed Base	Typical	ENERGY STAR V. 2.2[1]	High	ENERGY STAR V. 3.0[2]	Typical	High	Typical	High	Typical	High
Griddle - Cooking Energy Efficiency (%)	30	30	40	38	69	NA	42	69	44	69	46	69
Oven - Cooking Energy Efficiency (%)	35	35	35	46	69	49	39	69	42	69	47	69
Range - Cooking Energy Efficiency (%)	30	30	30	NA	40	NA	33	40	36	40	39	40
Combined Energy Efficiency (%)[3]	31	31	35	NA	58	NA	38	58	41	58	44	58
Griddle - Normalized Idle Energy Rate (Btu/h/ft^2)	3,000	3,000	3,000	2,650	1,724	NA	2,700	1,724	2,450	1,724	2,200	1,724
Oven - Idle Energy Rate (Btu/h)	18,000	18,000	18,000	12,000	3,516	9,500	16,200	3,516	14,600	3,516	13,150	3,516
Range - Idle Energy Rate (Btu/h)	3,600	3,600	3,600	NA	1,900	NA	3,250	1,900	2,950	1,900	2,650	1,900
Combined Idle Energy Rate (Btu/h)[3]	10,350	10,350	10,350	NA	4,178	NA	9,319	4,178	8,431	4,178	7,581	4,178
Average Life (y)	12	12	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)[4]	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760
Total Installed Cost (2022$)	8,940	8,940	8,940	8,940	8,940	8,940	8,940	8,940	8,940	8,940	8,940	8,940
Total Installed Cost (2022$/kBtu/h)	864	864	864	NA	2,140	NA	959	2,140	1,060	2,140	1,179	2,140
Annual Maintenance Cost (2022$)[5]	–	–	–	–	–	–	–	–	–	–	–	–
Annual Maintenance Cost (2022$/kBtu/h)	–	–	–	–	–	–	–	–	–	–	–	–

1. ENERGY STAR does not cover combination products that include griddles, ranges, and ovens in one single package. The ENERGY STAR levels provided here reflect specifications for individual products. Range tops are not covered by ENERGY STAR.
2. ENERGY STAR V. 3.0 updated the requirements for commercial ovens from V. 2.2, effective January 2023. Data shown is reflective of a standard full-size convection oven that holds 5 or more pans.
3. Combined energy efficiency and combined idle energy rate are calculated as a weighted average of each component using typical daily operating hours sourced from Food Service Technology Center (FSTC). Typical daily operating hours are assumed to be 12 hours for the griddle component, 8 hours for the oven component, and 12 hours for the range component.
4. Products in the commercial cooking market generally do not scale in price with relation to cooking efficiency. Distributors also do not provide this information.
5. Maintenance costs are negligible.

Note:
ENERGY STAR V. 2.2 went into effect in October 2015. ENERGY STAR V. 3.0 went into effect in January 2023.

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Commercial Electric Range with Griddle and Oven

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Higher typical efficiencies with the same costs as ref. case despite increased efficiency

DATA	2012	2018	2022			2023	2030		2040		2050	
	Installed Base	Installed Base	Typical	ENERGY STAR V. 2.2[1]	High	ENERGY STAR V. 3.0[2]	Typical	High	Typical	High	Typical	High
Griddle - Cooking Energy Efficiency (%)	65	70	72	70	91	NA	74	91	76	91	78	91
Oven - Cooking Energy Efficiency (%)	65	65	65	71	86	76	67	86	69	86	71	86
Range - Cooking Energy Efficiency (%)	75	75	75	NA	87	NA	77	87	80	87	81	87
Combined Energy Efficiency (%)[3]	69	71	71	NA	88	NA	73	88	76	88	77	88
Griddle - Normalized Idle Energy Rate (kW/ft^2)	0.44	0.34	0.30	0.32	0.21	NA	0.29	0.21	0.28	0.21	0.27	0.21
Oven - Idle Energy Rate (kW)	1.5	1.5	1.5	1.6	0.6	1.4	1.4	0.6	1.3	0.6	1.2	0.6
Range - Idle Energy Rate (kW)[4]	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Combined Idle Energy Rate (kW)[3]	1.7	1.4	1.3	1.4	0.8	NA	1.3	0.8	1.2	0.8	1.1	0.8
Average Life (y)	12	12	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)[5]	11,230	11,230	11,230	11,230	11,230	11,230	11,230	11,230	11,230	11,230	11,230	11,230
Total Installed Cost (2022$)	11,410	11,410	11,410	11,410	11,410	11,410	11,410	11,410	11,410	11,410	11,410	11,410
Total Installed Cost (2022$/kBtu/h)	2,019	2,362	2,533	2,375	4,423	NA	2,662	4,423	2,805	4,423	2,964	4,423
Annual Maintenance Cost (2022$)[6]	–	–	–	–	–	–	–	–	–	–	–	–
Annual Maintenance Cost (2022$/kBtu/h)	–	–	–	–	–	–	–	–	–	–	–	–

1. ENERGY STAR does not cover combination products that include griddles, ranges, and ovens in one single package. The ENERGY STAR levels provided here reflect specifications for individual products. Range tops are not covered by ENERGY STAR.
2. ENERGY STAR V. 3.0 updates the requirements for commercial ovens from V. 2.2, effective January 12, 2023. Data shown is reflective of a standard full-size convection oven that holds 5 or more pans.
3. Combined energy efficiency and combined idle energy rate are calculated as a weighted average of each component using typical daily operating hours sourced from FSTC. Typical daily operating hours are assumed to be 12 hours for the griddle component, 8 hours for the oven component, and 12 hours for the range component.
4. No data on electric range top idle energy rates.
5. Products in the commercial cooking market generally do not scale in price with relation to cooking efficiency. Distributors also do not provide this information.
6. Maintenance costs are negligible.

Note:
ENERGY STAR V. 2.2 went into effect in October 2015. ENERGY STAR V. 3.0 goes into effect in January 2023.

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Commercial Ranges with Griddle and Oven

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- Combined product that typically includes 2-6 range tops, a 24 in. x 24 in. griddle surface, and one or two half- or full-size ovens.
- Combined product is not covered by ENERGY STAR. However, the individual product ENERGY STAR V. 2.2 specifications are provided below.

Product	ENERGY STAR V. 2.2 Requirements	Gas	Electric
Griddle	Cooking Energy Efficiency	≥ 38%	≥ 70%
	Normalized Idle Energy Rate	≤ 2,650 Btu/h per ft^2	≤ 0.320 kW per ft^2
Oven	Cooking Energy Efficiency	≥ 46%	≥ 71%
	Idle Energy Rate	≤ 12,000 Btu/h	Half size: ≤1.00 kW Full size: ≤1.60 kW

- ENERGY STAR does not provide certification for range tops.
- There are no Federal standards for commercial cooking products.
- Product pricing in this market do not scale with efficiency, but rather depend on a number of other factors such as brand name, aesthetics, and additional features.

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Commercial Ranges with Griddle and Oven

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- ENERGY STAR V. 3.0 requirements for commercial ovens went into effect in January 2023:

Product	ENERGY STAR Requirements	Gas	Electric
Oven	Cooking Energy Efficiency	≥ 49%	Half size: ≥ 71% Full size: ≥ 76%
	Idle Energy Rate	≤ 9,500 Btu/h	Half size: ≤1.00 kW Full size ≥ 5 Pans: ≤1.40 kW Full size ≤ 5 Pans: ≤1.00 kW

- Advanced Case: Increased market incentives are expected to drive efficiency improvements. However, because cost does not scale with efficiency, there is no significant expected change in cost.

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Commercial Ranges with Griddle and Oven

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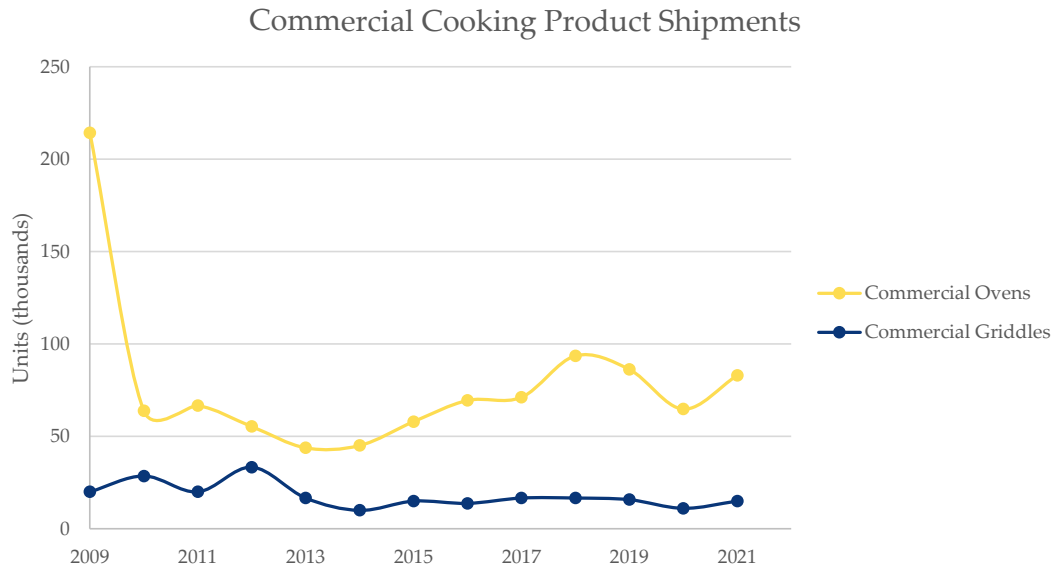
Commercial oven shipments have gradually increased since 2013, following a peak in 2009. Commercial griddle shipments have remained steady since 2014.



Source: *ENERGY STAR (Unit Shipment Data)*

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Commercial Hot Food Holding Cabinets – Small

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Higher typical efficiencies with the same costs as ref. case despite increased efficiency

DATA	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	State Standards	Typical	ENERGY STAR V. 2.0	High	Typical	High	Typical	High	Typical	High
Interior Volume (ft^3)[1]	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Maximum Idle Energy Rate (W)[2]	312	312	312	312	168	168	250	168	200	168	200	168
Annual Energy Use (kWh/y)[3]	1,025	1,025	1,025	1,025	552	552	820	552	656	552	656	552
Average Life (y)	12	12	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)[4]	3,200	3,200	3,200	3,200	3,800	3,800	3,200	3,800	3,200	3,800	3,200	3,800
Total Installed Cost (2022$)[5]	3,200	3,200	3,200	3,200	3,800	3,800	3,200	3,800	3,200	3,800	3,200	3,800
Total Installed Cost (2022$/kBtu/h)	8,016	8,016	8,016	8,016	17,677	17,677	10,020	17,677	12,524	17,677	12,524	17,677
Annual Maintenance Cost (2022$) [5]	–	–	–	–	–	–	–	–	–	–	–	–
Annual Maintenance Cost (2022$/kBtu/h)	–	–	–	–	–	–	–	–	–	–	–	–

1. Interior volume is characterized by the product size classes reported by ENERGY STAR. The small size class covers units with interior volume less than 13 ft^3. Interior volume for the small size class was determined based on the units in the ENERGY STAR database, accessed February 2023.
2. Maximum idle energy rate is a function of interior volume. For the small size class, ENERGY STAR and high values were determined for a representative 7.8 ft^3 using the ENERGY STAR database, accessed February 2023. The typical value was assumed to be equivalent to the state standard for a representative 7.8 ft^3 unit.
3. Annual energy use is determined using the latest FEMP data from December 2021, which assumes that a typical 22.4 ft^3 commercial hot food holding cabinet uses an average of 9 hours per day and 365 days per year. The small size class is assumed to use the same number of annual usage hours as the medium size class.
4. Retail equipment costs were determined using distributor information for undercounter, half-size, and full-size hot food holding cabinets.
5. Additional installation costs and maintenance costs are negligible.

Note:
ENERGY STAR V. 2.0 went into effect in October 2011 and was revised in December 2022. Massachusetts, Nevada, and Rhode Island state standards have adopted the ENERGY STAR V. 2.0 criteria that went into effect in October 2011. The majority of state standards (California, Colorado, Connecticut, DC, Maryland, New Hampshire, Oregon, Rhode Island, Vermont, and Washington) implement the ENERGY STAR V. 1.0 specification that went into effect in August 2003, which is recorded in the table. ENERGY STAR V. 1.0 specifies a maximum idle energy rate of 40 W per cubic foot of interior volume.

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Commercial Hot Food Holding Cabinets – Medium

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Higher typical efficiencies with the same costs as ref. case despite increased efficiency

DATA	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	State Standards	Typical	ENERGY STAR V. 2.0	High	Typical	High	Typical	High	Typical	High
Interior Volume (ft^3)[1]	21.4	21.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4
Maximum Idle Energy Rate (W)[2]	900	856	896	896	299	298	717	298	573	298	459	298
Annual Energy Use (kWh/y)[3]	2,957	2,812	2,943	2,943	982	979	2,355	979	1,884	979	1,507	979
Average Life (y)	12	12	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)[4]	2,940	4,530	4,600	4,600	5,000	5,000	4,600	5,000	4,600	5,000	4,600	5,000
Total Installed Cost (2022$)[5]	2,940	4,530	4,600	4,600	5,000	5,000	4,600	5,000	4,600	5,000	4,600	5,000
Total Installed Cost (2022$/kBtu/h)	2,553	4,136	4,012	4,012	13,078	13,113	5,015	13,113	6,269	13,113	7,836	13,113
Annual Maintenance Cost (2022$)[5]	–	–	–	–	–	–	–	–	–	–	–	–
Annual Maintenance Cost (2022$/kBtu/h)	–	–	–	–	–	–	–	–	–	–	–	–

1. Interior volume is characterized by the product size classes reported by ENERGY STAR. The medium size class covers units with interior volume between 13 ft^3 to 28 ft^3. For the medium size class, the interior volume increase from 21.4 ft^3 to 22.4 ft^3 in 2022 reflects the current representative product volume reported by FEMP, last updated December 2021.
2. Maximum idle energy rate is a function of interior volume. For the medium size class, the maximum idle energy rate for 2022 onward is reflective of a representative 22.4 ft^3 unit, using the latest FEMP data from December 2021.
3. Annual energy use is determined using the latest FEMP data from December 2021, which assumes that a typical 22.4 ft^3 commercial hot food holding cabinet uses an average of 9 hours per day and 365 days per year.
4. Retail equipment costs were determined using distributor information for undercounter, half-size, and full-size hot food holding cabinets.
5. Additional installation costs and maintenance costs are negligible.

Note:
ENERGY STAR V. 2.0 went into effect in October 2011 and was revised in December 2022. Massachusetts, Nevada, and Rhode Island state standards have adopted the ENERGY STAR V. 2.0 criteria that went into effect in October 2011. The majority of state standards (California, Colorado, Connecticut, DC, Maryland, New Hampshire, Oregon, Rhode Island, Vermont, and Washington) implement the ENERGY STAR V. 1.0 specification that went into effect in August 2003, which is recorded in the table. ENERGY STAR V. 1.0 specifies a maximum idle energy rate of 40 W per cubic foot of interior volume.

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Commercial Hot Food Holding Cabinets – Large

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Higher typical efficiencies with the same costs as ref. case despite increased efficiency

DATA	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	State Standards	Typical	ENERGY STAR V. 2.0	High	Typical	High	Typical	High	Typical	High
Interior Volume (ft^3)[1]	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0
Maximum Idle Energy Rate (W)[2]	1,333	1,333	1,760	1,333	400	310	1,067	310	853	310	683	310
Annual Energy Use (kWh/y)[3]	4,380	4,380	5,782	4,380	1,314	1,018	3,504	1,018	2,803	1,018	2,243	1,018
Average Life (y)	12	12	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)[4]	5,500	5,500	5,500	5,500	6,000	6,000	5,500	6,000	5,500	6,000	5,500	6,000
Total Installed Cost (2022$)[5]	5,500	5,500	5,500	5,500	6,000	6,000	5,500	6,000	5,500	6,000	5,500	6,000
Total Installed Cost (2022$/kBtu/h)	3,224	3,224	2,442	3,224	11,723	15,126	4,030	15,126	5,037	15,126	6,296	15,126
Annual Maintenance Cost (2022$)[5]	–	–	–	–	–	–	–	–	–	–	–	–
Annual Maintenance Cost (2022$/kBtu/h)	–	–	–	–	–	–	–	–	–	–	–	–

1. Interior volume is characterized by the product size classes reported by ENERGY STAR. The large size class covers units with interior volume greater than or equal to 28 ft^3. Interior volume for the large size class was determined based on the units in the ENERGY STAR database, accessed February 1, 2023.
2. Maximum idle energy rate is a function of interior volume. For the large size class, ENERGY STAR and high values were determined using the ENERGY STAR database, and the typical value uses the assumption that ENERGY STAR units are reported to be 70% more efficient than typical units.
3. Annual energy use is determined using the latest FEMP data from December 2021, which assumes that a typical 22.4 ft^3 commercial hot food holding cabinet uses an average of 9 hours per day and 365 days per year. The large size class is assumed to use the same number of annual usage hours as the medium size class.
4. Retail equipment costs were determined using distributor information for undercounter, half-size, and full-size hot food holding cabinets.
5. Additional installation costs and maintenance costs are negligible.

Note:
ENERGY STAR V. 2.0 went into effect in October 2011 and was revised in December 2022. Massachusetts, Nevada, and Rhode Island state standards have adopted the ENERGY STAR V. 2.0 criteria that went into effect in October 2011. The majority of state standards (California, Colorado, Connecticut, DC, Maryland, New Hampshire, Oregon, Rhode Island, Vermont, and Washington) implement the ENERGY STAR V. 1.0 specification that went into effect in August 2003, which is recorded in the table. ENERGY STAR V. 1.0 specifies a maximum idle energy rate of 40 W per cubic foot of interior volume.

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Commercial Hot Food Holding Cabinets

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- Hot food holding cabinets are used in commercial kitchens to keep food warm until it is served.
- While available in many shapes and sizes, interior volumes around 21.4 ft^3 were reported as typical in many settings in EIA Technology Forecast Updates (2018). FEMP currently lists 22.4 ft^3 as a representative unit size.
- Annual unit energy consumption can range from < 1,000 to > 30,000 kWh/y, depending on size, efficiency, and usage.
- Energy performance metric is "Idle Energy Consumption Rate" in Watts, measured using ASTM Standard F2140-11.
- There are no Federal standards for hot food holding cabinets, but seven States have identical standards.
  - The first State standard took effect in California in 2006; this standard is now considered the typical or "baseline" product. It is also equivalent to the ENERGY STAR V. 1.0 Specification that went into effect in August 2003.
  - ENERGY STAR V. 2.0 went into effect in October 2011.
- Maximum Idle Energy Consumption Rate for products $12 \leq V < 28$:
  - State standards: $\leq 40 \times V$ (baseline)
  - ENERGY STAR V. 2.0: $\leq 2.0 \times V + 254$ (about 65% below baseline)

  where V is interior volume in ft^3.
- The most efficient products are about 80% below baseline.
- Energy savings achieved with insulation, automatic door closers, magnetic door gaskets, and Dutch doors (half-doors).
- Advanced Case: Increased market incentives are expected to drive efficiency improvements. However, because cost does not scale with efficiency, there is no significant expected change in cost.

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Commercial Hot Food Holding Cabinets

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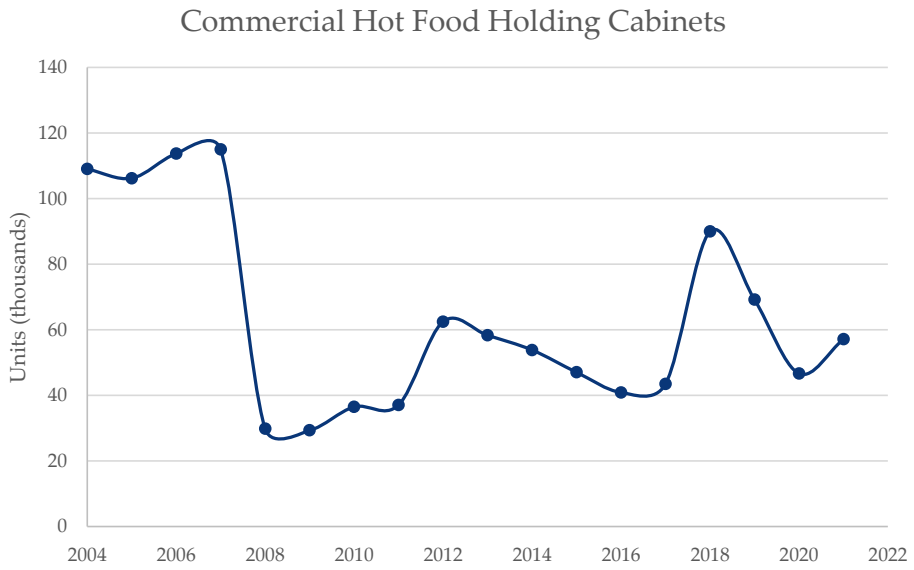
Commercial hot food holding cabinet shipments peaked in 2007 at 115,000 units, followed by a peak of 90,000 units in 2019.



Source: *ENERGY STAR (Unit Shipment Data)*

Appendix A
Data Sources

Guidehouse
1676 International Drive
McLean, VA 22102

And

Leidos
11951 Freedom Drive
Reston, VA 20190

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Residential Space Heating and Cooling

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Residential Gas-Fired Furnaces (North)

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR (North) V. 4.1	High	Typical / High		
Typical Input Capacity (kBtu/h)	Residential Furnaces EERE 2022 NOPR								
AFUE (%)	CFR			DOE CCD	ENERGY STAR V. 4.1	DOE CCD	Residential Furnaces EERE 2022 NOPR		
Electric Consumption (kWh/y)	Residential Furnaces EERE 2016	Residential Furnaces EERE 2022 NOPR							
Average Life (y)	Residential Furnaces EERE 2022 NOPR								
Retail Equipment Cost (2022$)	Residential Furnaces EERE 2016	Residential Furnaces EERE 2022 NOPR							
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)									

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Residential Gas-Fired Furnaces (Rest of Country)

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR (ROC) V. 4.1	High	Typical / High		
Typical Input Capacity (kBtu/h)	Residential Furnaces EERE 2022 NOPR								
AFUE (%)	CFR			DOE CCD	ENERGY STAR V. 4.1	DOE CCD	Residential Furnaces EERE 2022 NOPR		
Electric Consumption (kWh/y)	Residential Furnaces EERE 2016		Residential Furnaces EERE 2022 NOPR						
Average Life (y)	Residential Furnaces EERE 2022 NOPR								
Retail Equipment Cost (2022$)	Residential Furnaces EERE 2016		Residential Furnaces EERE 2022 NOPR						
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)									

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Residential Oil-Fired Furnaces

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.1	High	Typical / High		
Typical Input Capacity (kBtu/h)	Residential Furnaces EERE 2011								
AFUE (%)	CFR			DOE CCD	ENERGY STAR V. 4.1	DOE CCD			
Electric Consumption (kWh/y)	Residential Furnaces EERE 2011								
Average Life (y)									
Retail Equipment Cost (2022$)									
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)									

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Residential Gas-Fired Boilers

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.0	High	Typical / High		
Typical Input Capacity (kBtu/h)	Boilers EERE 2016	Boilers EERE 2022 Preliminary Analysis							
AFUE (%)		Boilers EERE 2022 Preliminary Analysis		DOE CCD	ENERGY STAR V. 3.0	Boilers EERE 2022 Preliminary Analysis			
Electric Consumption (kWh/y)		Boilers EERE 2022 Preliminary Analysis							
Average Life (y)									
Retail Equipment Cost (2022$)									
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)									

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Residential Oil-Fired Boilers

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.0	High	Typical / High		
Typical Input Capacity (kBtu/h)	Boilers EERE 2016	Boilers EERE 2022 Preliminary Analysis					Guidehouse		
AFUE (%)		Boilers EERE 2022 Preliminary Analysis	DOE CCD		ENERGY STAR V. 3.0	Boilers EERE 2022 Preliminary Analysis			
Electric Consumption (kWh/y)		Boilers EERE 2022 Preliminary Analysis							
Average Life (y)									
Retail Equipment Cost (2022$)									
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)									

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Residential Electric Resistance Furnaces

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	Typical		
Typical Input Capacity (kBtu/h)	Distributors				Guidehouse		
AFUE (%)	DOE / ASHRAE						
Average Life (y)	Distributors						
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)	Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse					
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse						

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Residential Electric Resistance Unit Heaters

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SOURCES	2015	2020	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical		
Typical Capacity (kBtu/h)	Distributors		Utilities/Distributors	Guidehouse		
Efficiency (%)	DOE		DOE			
Average Life (y)	Guidehouse		Guidehouse			
Retail Equipment Cost (2022$)			Distributors			
Total Installed Cost (2022$)			Home Remodeling Service			
Annual Maintenance Cost (2022$)			Guidehouse			

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Residential Central Air Conditioners – North (Not Hot-Dry or Hot-Humid)

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SOURCES	2015	2020	2022				2023			2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.0	High	New Standard	ENERGY STAR V. 6.1	High	Typical / High		
Typical Input Capacity (kBtu/h)	CAC and HP EERE 2016									Guidehouse		
SEER	CAC and HP EERE 2016 / Guidehouse		CFR	DOE CCD	ENERGY STAR V. 5.0	CAC and HP EERE 2016	RESNET		CAC and HP EERE 2016			
SSER2	RESNET						CAC and HP EERE 2016	ENERGY STAR V. 6.1	RESNET			
Average Life (y)	CAC and HP EERE 2016											
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)	CAC and HP EERE 2016 / Less (2021)											
Annual Maintenance Cost (2022$)	CAC and HP EERE 2016											

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Residential Central Air Conditioners – South (Hot-Dry and Hot-Humid)

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SOURCES	2015	2020	2022				2023			2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.0	High	New Standard	ENERGY STAR V. 6.1	High	Typical / High		
Typical Input Capacity (kBtu/h)	CAC and HP EERE 2016									Guidehouse		
SEER	CAC and HP EERE 2016 / Guidehouse		CFR	DOE CCD	ENERGY STAR V. 5.0	CAC and HP EERE 2016	RESNET		CAC and HP EERE 2016			
SSER2	RESNET						CAC and HP EERE 2016	ENERGY STAR V. 6.1	RESNET			
Average Life (y)	CAC and HP EERE 2016											
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)	CAC and HP EERE 2016 / Less (2021)											
Annual Maintenance Cost (2022$)	CAC and HP EERE 2016											

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Residential Room Air Conditioners

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SOURCES	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.2	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	Distributors		RAC EERE 2022 NOPR									
CEER (Btu/Wh)	Guidehouse		CFR	DOE CCD	ENERGY STAR V. 4.2	DOE CCD	Guidehouse					
Average Life (y)	RAC EERE 2011	RAC EERE 2022 NOPR										
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Annual Maintenance Cost (2022$)												

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Residential Portable Air Conditioners

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SOURCES	2015	2020	2022		2025		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	New Standard	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	PAC EERE 2020/Guidehouse						Guidehouse					
CEER												
Average Life (y)												
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Annual Maintenance Cost (2022$)												

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Residential Swamp Coolers

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SOURCES	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
CFM	Product Literature / Guidehouse				Guidehouse					
Power (Hp)										
Average Life (y)	TLC Plumbing / Guidehouse									
Retail Equipment Cost (2022$)	Product Literature / Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse									
Total Installed Cost (2022$)										
Annual Maintenance Cost (2022$)										

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Residential Air-Source Heat Pumps

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SOURCES	2015	2020	2022				2023				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.0	High	New Standard	ENERGY STAR V. 6.1	ENERGY STAR Cold Climate Criteria	High	Typical/High		
Typical Capacity (kBtu/h)	CACs and HPs EERE 2016 Direct Final Rule												
SEER (Cooling)	CACs and HPs EERE 2016 Direct Final Rule/ Guidehouse		CFR	DOE CCD/ Guidehouse	ENERGY STAR V. 5.0	CACs and HPs EERE 2016 Direct Final Rule	CACs and HPs EERE 2016 Direct Final Rule/ Guidehouse	ENERGY STAR V. 6.1	ENERGY STAR V. 6.1	CACs and HPs EERE 2016 Direct Final Rule	CACs and HPs EERE 2016 Direct Final Rule/Guidehouse		
HSPF (Heating)													
Average Life (y)	CACs and HPs EERE 2016 Direct Final Rule										Guidehouse		
Retail Equipment Cost (2022$)													
Total Installed Cost (2022$)													
Annual Maintenance Cost (2022$)													

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Residential Ductless Mini-Split Air-Source Heat Pumps

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SOURCES	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	AHRI/Guidehouse				Guidehouse					
SEER										
EER										
HSPF										
Average Life (y)	CACs and HPs EERE 2016 Direct Final Rule									
Retail Equipment Cost (2022$)	Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse									
Total Installed Cost (2022$)										
Annual Maintenance Cost (2022$)	CACs and HPs EERE 2016 Direct Final Rule									

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Residential Ground-Source Heat Pumps

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SOURCES	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.2	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	Water-Source Unitary Heat Pumps EERE 2015 Final Rule / DOE CCD		Guidehouse									
COP (Heating)	AHRI Database	AHRI Database / DOE CCD										
EER (Cooling)												
Average Life (y)	Guidehouse / Water-Source Unitary Heat Pumps EERE 2015 Final Rule											
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Annual Maintenance Cost (2022$)												

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Residential Natural Gas Heat Pumps

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SOURCES	2015	2020	2022	2030	2040	2050
	Installed Base		Typical			
Typical Capacity (kBtu/h)	Manufacturer		Guidehouse			
COP (Heating)	Product Literature					
COP (Cooling)						
Annual Electric Use (kWh/y)						
Average Life (y)	Guidehouse					
Retail Equipment Cost (2022$)	PERC					
Total Installed Cost (2022$)	Guidehouse					
Annual Maintenance Cost (2022$)						

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Residential Cordwood Stoves

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SOURCES	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	Distributors / Product Literature				Guidehouse					
Efficiency (Non-Catalytic) (HHV)	Guidehouse / Literature	EPA Certified Wood Stove Database (Room Heaters)								
Efficiency (Catalytic) (HHV)										
Average Life (y)	Guidehouse									
Retail Equipment Cost (2022$)	Product Literature/Dealers									
Total Installed Cost (2022$)	Dealers	Dealers/Guidehouse								
Annual Maintenance Cost (2022$)	Dealers/Guidehouse									

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Residential Wood Pellet Stoves

Final

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SOURCES	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	Distributors / Product Literature				Guidehouse					
Efficiency (HHV)	EPA Default/ Literature/ Guidehouse	EPA Certified Wood Stove Database (Room Heaters)								
Average Life (y)	Guidehouse									
Retail Equipment Cost (2022$)	Product Literature/ Dealers									
Total Installed Cost (2022$)	Dealers/Guidehouse									
Annual Maintenance Cost (2022$)										

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Residential Water Heating

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Residential Gas-Fired Storage Water Heaters

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SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.0	High	ENERGY STAR V. 5.0	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	Guidehouse	CWH EERE 2010 Final Rule /AHRI	CWH EERE 2022 Preliminary Analysis					Guidehouse					
Uniform Energy Factor		DOE CCD	CWH EERE 2022 Preliminary Analysis		ENERGY STAR	CWH EERE 2022 Preliminary Analysis	ENERGY STAR						
Average Life (y)	CWH EERE 2010 Final Rule		CWH EERE 2022 Preliminary Analysis										
Retail Equipment Cost (2022$)	Distributors	CWH EERE 2010 Final Rule											
Total Installed Cost (2022$)	EIA Technology Forecast Updates (2018)	CWH EERE 2010 Final Rule											
Annual Maintenance Cost (2022$)	CWH EERE 2010 Final Rule												

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Residential Oil-Fired Water Heaters

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SOURCES	2015	2020	2022			2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	High	Typical / High		
Typical Capacity (gal)	AHRI	CWH EERE 2010 Final Rule/AHRI	CWH EERE 2022 Preliminary Analysis			Guidehouse		
Uniform Energy Factor	Guidehouse	AHRI/DOE CCD						
Average Life (y)	CWH EERE 2010 Final Rule							
Retail Equipment Cost (2022$)								
Total Installed Cost (2022$)								
Annual Maintenance Cost (2022$)								

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Residential Electric Resistance Storage Water Heaters

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SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	AHRI	CWH EERE 2010 Final Rule/AHRI	CWH EERE 2022 Preliminary Analysis			Guidehouse					
Uniform Energy Factor	Guidehouse	AHRI/ DOE CCD									
Average Life (y)	CWH EERE 2010 Final Rule										
Retail Equipment Cost (2022$)											
Total Installed Cost (2022$)											
Annual Maintenance Cost (2022$)											

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Residential Heat Pump Water Heaters

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SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Typical	ENERGY STAR V. 4.0	High	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	Guidehouse	AHRI	CWH EERE 2022 Preliminary Analysis			Guidehouse					
Uniform Energy Factor		DOE CCD	CWH EERE 2022 Preliminary Analysis	ENERGY STAR	CWH EERE 2022 Preliminary Analysis						
Average Life (y)	CWH EERE 2010 Final Rule		CWH EERE 2022 Preliminary Analysis								
Retail Equipment Cost (2022$)	CWH EERE 2010 Final Rule	Distributors									
Total Installed Cost (2022$)	CWH EERE 2010 Final Rule										
Annual Maintenance Cost (2022$)											

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Residential Solar Water Heaters

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	ENERGY STAR V. 4.0	Typical	Typical	Typical	Typical
Typical Capacity (sq. ft.)	SRCC / Guidehouse		ENERGY STAR		Guidehouse		
Solar Uniform Energy Factor (SUEF)			DOE				
Average Life (y)	DOE / Guidehouse						
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)		Gordian's RSMeans Data – Building Construction Costs 2023				
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse		DOE				

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Residential Gas-Fired Instantaneous Water Heaters

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SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.0	High	ENERGY STAR V. 5.0	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	AHRI	CWH EERE 2010 Final Rule /AHRI	CWH EERE 2022 Preliminary Analysis					Guidehouse					
Uniform Energy Factor	Guidehouse	DOE CCD	CWH EERE 2022 Preliminary Analysis		ENERGY STAR	CWH EERE 2022 Preliminary Analysis	ENERGY STAR						
Average Life (y)	CWH EERE 2010 Final Rule		CWH EERE 2022 Preliminary Analysis										
Retail Equipment Cost (2022$)													
Total Installed Cost (2022$)													
Annual Maintenance Cost (2022$)													

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Residential Electric Instantaneous Water Heaters

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SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	Guidehouse		CWH EERE 2022 Preliminary Analysis			Guidehouse					
Uniform Energy Factor			CWH EERE 2022 Preliminary Analysis/DOE CCD								
Average Life (y)			Gordian's RSMeans Data – Building Construction Costs 2023								
Retail Equipment Cost (2022$)											
Total Installed Cost (2022$)											
Annual Maintenance Cost (2022$)			Guidehouse								

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Residential Appliances

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Residential Refrigerator-Freezers (Top)

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SOURCES	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	RF EERE 2011 / Guidehouse	RF EERE 2021 Preliminary Analysis / Guidehouse					Guidehouse					
Energy Consumption (kWh/y)		DOE CCD/ Guidehouse	CFR	DOE CCD	ENERGY STAR	DOE CCD						
Average Life (y)		RF EERE 2021 Preliminary Analysis / Guidehouse										
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Annual Maintenance Cost (2022$)												

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Residential Refrigerator-Freezers (Side)

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SOURCES	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	RF EERE 2011 / Guidehouse	RF EERE 2021 Preliminary Analysis / Guidehouse					Guidehouse					
Energy Consumption (kWh/y)		DOE CCD/ Guidehouse	CFR	DOE CCD	ENERGY STAR	DOE CCD						
Average Life (y)		RF EERE 2021 Preliminary Analysis / Guidehouse										
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Annual Maintenance Cost (2022$)												

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Residential Refrigerator-Freezers (Bottom)

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SOURCES	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	RF EERE 2011 / Guidehouse	RF EERE 2021 Preliminary Analysis / Guidehouse					Guidehouse					
Energy Consumption (kWh/y)		DOE CCD/ Guidehouse	CFR	DOE CCD	ENERGY STAR	DOE CCD						
Average Life (y)		RF EERE 2021 Preliminary Analysis / Guidehouse										
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Annual Maintenance Cost (2022$)												

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Residential Freezers (Chest)

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SOURCES	2015	2020	2022			2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	High	Typical / High		
Typical Capacity (ft^3)	RF EERE 2011 / Guidehouse		RF EERE Preliminary Analysis 2021/DOE CCD			Guidehouse		
Energy Consumption (kWh/y)	Guidehouse		RF EERE Preliminary Analysis 2021	RF EERE Preliminary Analysis 2021/DOE CCD	DOE CCD			
Average Life (y)	RF EERE 2011 / Guidehouse		RF EERE Preliminary Analysis 2021		RF EERE Preliminary Analysis 2021			
Retail Equipment Cost (2022$)					RF EERE Preliminary Analysis 2021/DOE CCD			
Total Installed Cost (2022$)								
Annual Maintenance Cost (2022$)								

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Residential Freezers (Upright)

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SOURCES	2015	2022	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical / High		
Typical Capacity (ft^3)	RF EERE 2011/ Guidehouse		RF EERE Preliminary Analysis 2021/ DOE CCD				Guidehouse		
Energy Consumption (kWh/y)	Guidehouse		RF EERE Preliminary Analysis 2021	RF EERE Preliminary Analysis 2021/ DOE CCD	ENERGY STAR	DOE CCD			
Average Life (y)	RF EERE 2011 / Guidehouse		RF EERE Preliminary Analysis 2021			RF EERE Preliminary Analysis 2021			
Retail Equipment Cost (2022$)						RF EERE Preliminary Analysis 2021/ DOE CCD			
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)									

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Residential Natural Gas Cooktops

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	High	Typical / High		
Typical Capacity (kBtu/h)	Distributors / Product Literature				Guidehouse		
Integrated Annual Energy Consumption (kBtu/y)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						
Cooking Efficiency (%)	Guidehouse						
Average Life (y)	Consumer Cooking Products EERE 2020 NOPD						
Retail Equipment Cost (2022$)	Consumer Cooking Products EERE 2016 SNOPR / Consumer Cooking Products EERE 2020 NOPD						
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						

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Residential Natural Gas Ovens

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	High	Typical / High		
Typical Capacity (kBtu/h)	Consumer Cooking Products EERE 2016 SNOPR / Product Literature				Guidehouse		
Typical Cavity Volume (ft^3)	Consumer Cooking Products EERE 2016 SNOPR	Consumer Cooking Products EERE 2020 NOPD					
Integrated Annual Energy Consumption (kBtu/y)							
Cooking Efficiency (%)	Guidehouse						
Average Life (y)	Consumer Cooking Products EERE 2020 NOPD	Consumer Cooking Products EERE 2020 NOPD					
Retail Equipment Cost (2022$)	Consumer Cooking Products EERE 2016 SNOPR						
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						

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Residential Natural Gas Ranges

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	High	Typical / High		
Typical Capacity of Cooktop Component (kBtu/h)	Distributors / Product Literature				Guidehouse		
Typical Capacity of Oven Component (kBtu/h)	Consumer Cooking Products EERE 2016 SNOPR / Product Literature						
Typical Cavity Volume of Oven Component (ft^3)	Consumer Cooking Products EERE 2020 NOPD	Consumer Cooking Products EERE 2020 NOPD					
Integrated Annual Energy Consumption (kBtu/y)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						
Average Life (y)	Consumer Cooking Products EERE 2020 NOPD						
Retail Equipment Cost (2022$)	Guidehouse / Distributors / Gordian's RSMeans Data – Building Construction Costs 2023						
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						

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Residential Electric Cooktops

Final

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	High	Typical / High		
Typical Capacity (W)	Consumer Cooking Products EERE 2016 SNOPR / Distributors				Guidehouse		
Integrated Annual Energy Consumption (kWh/y)	Consumer Cooking Products EERE 2020 NOPD						
Average Life (y)							
Retail Equipment Cost (2022$)							
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						

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Residential Electric Ovens

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	High	Typical / High		
Typical Capacity (W)	Consumer Cooking Products EERE 2016 SNOPR / Distributors				Guidehouse		
Typical Cavity Volume (ft^3)	Consumer Cooking Products EERE 2016 SNOPR	Consumer Cooking Products EERE 2020 NOPD					
Integrated Annual Energy Consumption (kWh/y)							
Average Life (y)	Consumer Cooking Products EERE 2020 NOPD						
Retail Equipment Cost (2022$)	Consumer Cooking Products EERE 2020 NOPD						
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						

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Residential Electric Ranges

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	High	Typical / High		
Typical Capacity of Cooktop Component (W)	Consumer Cooking Products EERE 2016 SNOPR / Distributors				Guidehouse		
Typical Capacity of Oven Component (W)							
Typical Cavity Volume of Oven Component (ft^3)	Consumer Cooking Products EERE 2016 SNOPR	Consumer Cooking Products EERE 2020 NOPD					
Integrated Annual Energy Consumption (kWh/y)							
Average Life (y)	Consumer Cooking Products EERE 2020 NOPD						
Retail Equipment Cost (2022$)	Consumer Cooking Products EERE 2020 NOPD						
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						

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Residential Electric Clothes Dryers

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SOURCES	2015	2020	2022				2030	2040	2040
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 1.1	High	Typical / High		
Typical Capacity (ft^3)	DOE CCD					Guidehouse / DOE CCD / ENERGY STAR	Guidehouse		
CEF, D1 (lb/kWh)	Consumer Clothes Dryers EERE 2022 NOPR / Guidehouse	DOE CCD	Consumer Clothes Dryers EERE 2022 NOPR	DOE CCD	ENERGY STAR V. 1.1	DOE CCD			
CEF, D2 (lb/kWh)						ENERGY STAR			
Average Life (y)	Consumer Clothes Dryers EERE 2022 NOPR								
Retail Equipment Cost (2022$)	Consumer Clothes Dryers EERE 2022 NOPR / Guidehouse								
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)	Consumer Clothes Dryers EERE 2022 NOPR								

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Residential Natural Gas Clothes Dryers

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 1.1	High	Typical / High		
Typical Capacity (ft^3)	DOE CCD						Guidehouse		
CEF, D1 (lb/kWh)	Consumer Clothes Dryers EERE 2022 NOPR / Guidehouse	DOE CCD	Consumer Clothes Dryers EERE 2022 NOPR	DOE CCD	ENERGY STAR V. 1.1	DOE CCD			
CEF2, D2 (lb/kWh)									
Average Life (y)	Consumer Clothes Dryers EERE 2022 NOPR								
Retail Equipment Cost (2022$)	Consumer Clothes Dryers EERE 2022 NOPR / Guidehouse								
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)	Consumer Clothes Dryers EERE 2022 NOPR								

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Residential Clothes Washers (Front)

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 8.1	High	Typical / High		
Typical Capacity (ft^3)	Guidehouse	DOE CCD / Guidehouse	DOE CCD	DOE CCD	DOE CCD	DOE CCD	Guidehouse		
Integrated Modified Energy Factor (ft^3/kWh/cycle)	AHAM / Guidehouse		RCW EERE 2021 Preliminary Analysis		ENERGY STAR V. 8.1				
Integrated Water Factor (gal/cycle/ft^3)									
Average Life (y)	RCW EERE 2021 Preliminary Analysis								
Water Consumption (gal/cycle)	Guidehouse / RCW EERE 2021 Preliminary Analysis								
Hot Water Energy (kWh/cycle)									
Machine Energy (kWh/cycle)									
Dryer Energy (kWh/cycle)									
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)	RCW EERE 2021 Preliminary Analysis/ Distributors							
Total Installed Cost (2022$)		RCW EERE 2021 Preliminary Analysis/ Guidehouse							
Annual Maintenance Cost (2022$)	RCW EERE 2021 Preliminary Analysis / Guidehouse								

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Residential Clothes Washers (Top)

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 8.1	High	Typical / High		
Typical Capacity (ft^3)	Guidehouse	Guidehouse	DOE CCD	DOE CCD	DOE CCD	DOE CCD	Guidehouse		
Integrated Modified Energy Factor (ft^3/kWh/cycle)	AHAM / Guidehouse	RCW EERE 2021 Preliminary Analysis			ENERGY STAR V. 8.1	DOE CCD			
Integrated Water Factor (gal/cycle/ft^3)									
Average Life (y)	RCW EERE 2021 Preliminary Analysis								
Water Consumption (gal/cycle)	RCW EERE 2021 Preliminary Analysis / Guidehouse								
Hot Water Energy (kWh/cycle)	Guidehouse	RCW EERE 2021 Preliminary Analysis / Guidehouse							
Machine Energy (kWh/cycle)									
Dryer Energy (kWh/cycle)									
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)								
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)	RCW EERE 2021 Preliminary Analysis / Guidehouse								

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Residential Dishwashers

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SOURCES	2015	2020	2022				2023	2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 6.0	High	ENERGY STAR V. 7.0	Typical / High		
Typical Annual Energy Use (kWh/y)	AHAM 2014 / DW EERE 2012 Final Rule	Guidehouse / DOE CCD / ENERGY STAR	CFR	Guidehouse / DOE CCD / ENERGY STAR	ENERGY STAR	DW EERE 2022 Preliminary Analysis	ENERGY STAR	Guidehouse		
Water Consumption (gal/cycle)										
Water Heating Energy Use (kWh/y)	AHAM 2014 / DW EERE 2012 Final Rule	DW EERE 2016 Direct Final Rule	DW EERE 2022 Preliminary Analysis							
Average Life (y)	DW EERE 2016 Direct Final Rule/Guidehouse									
Retail Equipment Cost (2022$)	DW EERE 2012 Final Rule	DW EERE 2016 Direct Final Rule								
Total Installed Cost (2022$)										

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Commercial Space Heating and Cooling

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Commercial Gas-Fired Furnaces

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SOURCES	2012	2018	2022			2023			2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	High	New Standard	Typical	High	Typical/High		
Typical Input Capacity (kBtu/h)	AHRI	CWAF EERE 2015	DOE CCD						Guidehouse		
Thermal Efficiency (%)		DOE CCD	CFR	DOE CCD		CFR					
Typical Output Capacity (kBtu/h)	Guidehouse										
Average Life (y)	CWAF EERE 2015										
Retail Equipment Cost (2022$)											
Total Installed Cost (2022$)											
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$)											
Annual Maintenance Cost (2022$/kBtu/h)											

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Commercial Oil-Fired Furnaces

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SOURCES	2012	2018	2022			2023		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	High	New Standard	Typical	Typical/High		
Typical Input Capacity (kBtu/h)	AHRI	DOE CCD	DOE CCD				Guidehouse	Guidehouse		
Thermal Efficiency (%)			10 CFR 431.77	DOE CCD		10 CFR 431.77				
Typical Output Capacity (kBtu/h)	Guidehouse									
Average Life (y)	CWAF EERE 2015									
Retail Equipment Cost (2022$)										
Total Installed Cost (2022$)										
Total Installed Cost (2022$/kBtu/h)										
Annual Maintenance Cost (2022$)										
Annual Maintenance Cost (2022$/kBtu/h)										

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Commercial Electric Resistance Heaters

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SOURCES	2012		2018		2022		2030		2040		2050	
	Small	Large	Small	Large	Small	Large	Small	Large	Small	Large	Small	Large
Typical Capacity (kBtu/h)	Distributors/Guidehouse						Guidehouse					
Efficiency (%)	Guidehouse/DOE											
Average Life (y)	Technology Cost and Performance File for Commercial Model for AEO2010											
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)				Gordian's RSMeans Data – Building Construction Costs 2023							
Total Installed Cost (2022$)												
Total Installed Cost (2022$/kBtu/h)												
Annual Maintenance Cost (2022$)	Guidehouse											
Annual Maintenance Cost (2022$/kBtu/h)												

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Commercial Electric Boilers

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SOURCES	2012	2018	2022	2030	2040	2050
	Installed Base	Installed Base	Typical			
Typical Capacity (kW)	BSRIA		Guidehouse			
Efficiency (%)	EERE / Guidehouse					
Average Life (y)	ASHRAE 2007 HVAC Applications	ASHRAE 2015 HVAC Applications	ASHRAE 2019 HVAC Applications			
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)		Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse			
Total Installed Cost (2022$)			Gordian's RSMeans Data – Building Construction Costs 2023			
Total Installed Cost (2022$/kBtu/h)						
Annual Maintenance Cost (2022$)			EIA Technology Forecast Updates (2018)			
Annual Maintenance Cost (2022$/kBtu/h)						

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Commercial Gas-Fired Boilers

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SOURCES	2012	2018	2022			2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	New Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	Guidehouse	Comm. Packaged Boilers EERE 2020												
Thermal Efficiency (%)	ASHRAE Standard 90.1-2004 / Guidehouse	Comm. Packaged Boilers EERE 2020 / Guidehouse	DOE CCD			Comm. Packaged Boilers EERE 2020/Guidehouse								
Average Life (y)	Comm. Heating, AC, WH EERE 2009	Comm. Packaged Boilers EERE 2020												
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)													
Total Installed Cost (2022$)														
Total Installed Cost (2022$/kBtu/h)														
Annual Maintenance Cost (2022$)	Comm. Heating, AC, WH EERE 2009													
Annual Maintenance Cost (2022$/kBtu/h)														

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Commercial Oil-Fired Boilers

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SOURCES	2012	2018	2022			2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	New Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	Guidehouse	Comm. Packaged Boilers EERE 2020												
Thermal Efficiency (%)	ASHRAE Standard 90.1-2004 / Guidehouse	Comm. Packaged Boilers EERE 2020 / Guidehouse	DOE CCD			Comm. Packaged Boilers EERE 2020/Guidehouse								
Average Life (y)	Comm. Heating, AC, WH EERE 2009	Comm. Packaged Boilers EERE 2020												
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)													
Total Installed Cost (2022$)														
Total Installed Cost (2022$/kBtu/h)														
Annual Maintenance Cost (2022$)	Comm. Heating, AC, WH EERE 2009													
Annual Maintenance Cost (2022$/kBtu/h)														

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Commercial Centrifugal Chillers (Water-Cooled)

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SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	ASHRAE 90.1-2019	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (tons)	IPCC/ARB/TEAP/Guidehouse					Guidehouse					
Efficiency (kW/ton)	ASHRAE 90.1-2010/FEMP/ eSource/ Product Literature	ASHRAE 90.1-2019/Product Lit									
COP											
Average Life (y)	2007 ASHRAE Applications Handbook	2015 ASHRAE Applications Handbook A37 Table 4									
Retail Equipment Cost (2022$/ton)	EIA Technology Forecast Updates (2018)	Gordian's RSMeans Data – Building Construction Costs 2023									
Total Installed Cost (2022$/ton)											
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$/ton)	Guidehouse/Alabama Power										
Annual Maitnenance Cost (2022$/kBtu/h)											

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Commercial Reciprocating Chillers (Air-Cooled Only)

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SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	ASHRAE 90.1-2019	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (tons)	BSRIA/DEER		Guidehouse			Guidehouse					
Efficiency (kW/ton)	ASHRAE 90.1-2010/DEER/ FEMP/Product Literature	ASHRAE 90.1-2016 (>150 TR)	ASHRAE 90.1-2019		Product Lit						
COP	ASHRAE 90.1-2010/DEER/ FEMP/Product Literature	ASHRAE 90.1-2016 (>150 TR)									
Average Life (y)	Manufacturers	2015 ASHRAE Applications Handbook A37 Table 4									
Retail Equipment Cost (2022$/ton)	EIA Technology Forecast Updates (2018)		Gordian's RSMeans Data – Building Construction Costs 2023								
Total Installed Cost (2022$/ton)											
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$/ton)	Guidehouse/Alabama Power										
Annual Maintenance Cost (2022$/kBtu/h)											

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Commercial Screw Chillers (Air-Cooled Only)

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SOURCES	2012	2018	2022			2030	2040	2050
	Installed Base	Installed Base	ASHRAE 90.1-2019	Typical	High	Typical/High		
Typical Capacity (tons)	Guidehouse					Guidehouse		
Efficiency (kW/ton)	Guidehouse	ASHRAE 90.1-2016 (>150 TR)	ASHRAE 90.1-2019 (>150 TR)	ASHRAE 90.1-2019 (>150 TR)/Product Lit	Product Lit			
COP								
Average Life (y)	Manufacturers	FacilitiesNet						
Retail Equipment Cost (2022$/ton)	EIA Technology Forecast Updates (2018)		Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse					
Total Installed Cost (2022$/ton)								
Total Installed Cost (2022$/kBtu/h)								
Annual Maintenance Cost (2022$/ton)	Guidehouse/Alabama Power							
Annual Maintenance Cost (2022$/kBtu/h)								

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Commercial Scroll Chillers (Air-Cooled Only)

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SOURCE	2012	2018	2022			2030	2040	2050
	Installed Base	Installed Base	ASHRAE 90.1-2019	Typical	High	Typical / High		
Typical Capacity (tons)	Guidehouse/Manufacturers					Guidehouse		
Efficiency [full-load/IPLV] (kW/ton)	Guidehouse	Product Lit/ Guidehouse	ASHRAE 90.1-2019 (>150 TR)	Product Lit/ Guidehouse	Product Lit			
COP [full-load/IPLV]								
Average Life (y)	Manufacturers							
Retail Equipment Cost (2022$/ton)	EIA Technology Forecast Updates (2018)		Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse					
Total Installed Cost (2022$/ton)								
Total Installed Cost (2022$/kBtu/h)								
Annual Maintenance Cost (2022$/ton)	Guidehouse/Alabama Power							
Annual Maintenance Cost (2022$/kBtu/h)								

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Commercial Gas-Fired Chillers (Water-Cooled, Direct-Fired Only)

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SOURCES	2012		2018		2022				2030	2040	2050
	Installed Base: Absorption	Installed Base: Engine-Driven	Installed Base: Absorption	Installed Base: Engine-Driven	ASHRAE 90.1-2019 Absorption	CA Title 24 – Engine-Driven	Absorption	Engine-Driven	Absorption/Engine-Driven		
Typical Capacity (tons)	BSRIA/Distributors								Guidehouse		
COP [full-load]	Product Literature/ Guidehouse		Product Lit		ASHRAE 90.1-2019 Direct-fired Double Effect	CA Title 24 Gas Engine Standard	Product Lit				
COP [IPLV]											
Average Life (y)	2007 ASHRAE Applications Handbook/ Distributors		2015 ASHRAE Applications Handbook A37 Table 4								
Retail Equipment Cost (2022$/ton)	EIA Technology Forecast Updates (2018)				Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse						
Total Installed Cost (2022$/ton)											
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$/ton)	Guidehouse/Alabama Power										
Annual Maintenance Cost (2022$/kBtu/h)											

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Commercial Rooftop Air Conditioners

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SOURCES	2012	2018	2022				2023				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.1	High	New Standard	Typical	ENERGY STAR V. 4.0	High	Typical	High	Typical	High	Typical	High
Typical Output Capacity (kBtu/h)	AHRI / Guidehouse	CUAC EERE 2016									CUAC EERE 2016 / Guidehouse					
Part Load Efficiency (IEER)	CUAC EERE 2016				ENERGY STAR	CUAC EERE 2016			ENERGY STAR	CUAC EERE 2016						
Efficiency (EER)	CUAC EERE 2016 / Guidehouse															
Efficiency Conversion	Calculated															
Average Life (y)	CUAC EERE 2016															
Retail Equipment Cost (2022$)	Distributors / Guidehouse / DEER, 2008	CUAC EERE 2016														
Total Installed Cost (2022$)																
Total Installed Cost (2022$/kBtu/h)	Calculated															
Annual Maintenance Cost (2022$)	CUAC EERE 2016															
Annual Maintenance Cost (2022$/kBtu/h)	Calculated															

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Commercial Gas-Fired Engine-Drive Rooftop Air Conditioners

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SOURCES	2012	2018	2022	2030	2040	2050
	Installed Base		Typical			
Typical Capacity (tons)	EIA Technology Forecast Updates (2018)		Guidehouse			
Heating COP						
Cooling COP						
Average Life (y)						
Retail Equipment Cost ($/ton)			Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse			
Total Installed Cost ($/ton)						
Total Installed Cost ($/kBtu/h)						
Annual Maintenance Cost (2022$)						
Annual Maintenance Cost (2022$/kBtu/h)						

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Commercial Rooftop Heat Pumps

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SOURCES	2012	2018	2022				2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.1	High	New Standard	ENERGY STAR V. 4.0	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	CUHP EERE 2016									CUHP EERE 2016 / Guidehouse					
Part Load Efficiency (IEER)	CUHP EERE 2016 / Guidehouse				ENERGY STAR	CUHP EERE 2016		ENERGY STAR	CUHP EERE 2016						
COP (Heating)															
Average Life (y)	EIA Technology Forecast Updates (2018)	CUHP EERE 2016													
Retail Equipment Cost (2022$)															
Total Installed Cost (2022$)															
Total Installed Cost (2022$/kBtu/h)															
Annual Maintenance Cost (2022$)															
Annual Maintenance Cost (2022$/kBtu/h)															

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Commercial Ground-Source Heat Pumps

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SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	U.S. DOE/EIA	Water-Source Unitary Heat Pumps EERE 2015 Final Rule				Guidehouse					
COP (Heating)	Guidehouse	AHRI Database									
EER (Cooling)											
Average Life (y)	Guidehouse / Water-Source Unitary Heat Pumps EERE 2015 Final Rule										
Retail Equipment Cost (2022$)	Distributors/Guidehouse	Water-Source Unitary Heat Pumps 2015 EERE Final Rule / Guidehouse									
Total Installed Cost (2022$)	U.S. DOD/IGSHPA/MA DOER/CEFIA/ ASHRAE										
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$)	Geothermal Heat Pump Consortium, Inc. (U.S. DOE Contract DE-FG07-95ID13347)										
Annual Maintenance Cost (2022$/kBtu/h)											

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Packaged Terminal Air Conditioners

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SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	PTAC & PTHP EERE 2022 NOPD					PTAC & PTHP EERE 2022 NOPD / Guidehouse					
Efficiency (EER)											
Efficiency											
Average Life (y)											
Retail Equipment Cost (2022$)											
Total Installed Cost (2022$)											
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$)											
Annual Maintenance Cost (2022$/kBtu/h)											

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Packaged Terminal Heat Pumps

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SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	PTAC & PTHP EERE 2022 NOPD					PTAC & PTHP EERE 2022 NOPD / Guidehouse					
Efficiency (EER)											
Efficiency											
COP (Heating)											
Average Life (y)											
Retail Equipment Cost (2022$)											
Total Installed Cost (2022$)											
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$)											
Annual Maintenance Cost (2022$/kBtu/h)											

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Commercial Water Heating

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Commercial Gas-Fired Storage Water Heaters

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SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 2.0	High	Typical	High	Typical	High	Typical	High
Typical Storage Capacity (gal)	EIA Technology Forecast Updates (2018)	CWH EERE 2022 NOPR										
Typical Input Capacity (kBtu/h)												
Thermal Efficiency (%)		DOE CCD / Guidehouse	CFR	DOE CCD / Guidehouse	ENERGY STAR	DOE CCD	CWH EERE 2022 NOPR / Guidehouse					
Average Life (y)		CWH EERE 2022 NOPR										
Retail Equipment Cost (2022$)	CWH EERE 2022 NOPR											
Total Installed Cost (2022$/kBtu/h)												
Annual Maintenance Cost (2022$)												
Annual Maintenance Cost (2022$/kBtu/h)												
Annual Maintenance Cost (2022$/kBtu/h)												

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Commercial Electric Resistance Storage Water Heaters

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SOURCES	2012	2018	2022		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	Typical		
Typical Storage Capacity (gal)	Product Literature / Guidehouse	CWH EERE 2016 NOPR			Guidehouse		
Typical Input Capacity (kW)	Product Literature						
Typical Input Capacity (kBtu/h)							
Thermal Efficiency (%)	Guidehouse						
Average Life (y)	CWH EERE 2016 NOPR						
Retail Equipment Cost (2022$)	CWH EERE 2016 NOPR / Guidehouse	CWH EERE 2016 NOPR					
Total Installed Cost (2022$)							
Total Installed Cost (2022$/kBtu/h)							
Annual Maintenance Cost (2022$)							
Annual Maintenance Cost (2022$/kBtu/h)							

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Commercial Heat Pump Water Heaters

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SOURCES	2012	2018	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	ENERGY STAR V. 2.0	Typical	Typical	Typical
Water Flow Rate (gal/min)	Distributors/Guidehouse		Guidehouse				
Typical Output Capacity (kW)							
Typical Output Capacity (kBtu/h)							
Coefficient of Performance (COP_h)							
Average Life (y)	EERE/Guidehouse						
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)						
Total Installed Cost (2022$)							
Total Installed Cost (2022$/kBtu/h)							
Annual Maintenance Cost (2022$)	Guidehouse						
Annual Maintenance Cost (2022$/kBtu/h)							

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Commercial Oil-Fired Storage Water Heaters

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Return to Table of Contents

SOURCES	2012	2018	2022			2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	High	Typical/High		
Typical Storage Capacity (gal)	AHRI / Guidehouse	DOE CCD/Guidehouse				Guidehouse		
Typical Input Capacity (kBtu/h)								
Thermal Efficiency (%)	Guidehouse		CFR	DOE CCD				
Average Life (y)	Commercial Heating, Air Conditioning and Water Heating Equipment EERE 2001							
Retail Equipment Cost (2022$)	Distributors / Guidehouse							
Total Installed Cost (2022$)								
Total Installed Cost (2022$/kBtu/h)								
Annual Maintenance Cost (2022$)								
Annual Maintenance Cost (2022$/kBtu/h)								

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Commercial Electric Booster Water Heaters

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SOURCES	2012	2018	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical	Typical	Typical
Typical Capacity (gal)	Product Literature / Guidehouse					
Typical Output Capacity (kBtu/h)						
Thermal Efficiency (%)						
Average Life (y)						
Retail Equipment Cost (2022$)						
Total Installed Cost (2022$)						
Total Installed Cost (2022$/kBtu/h)						
Annual Maintenance Cost (2022$)						
Annual Maintenance Cost (2022$/kBtu/h)						

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Commercial Gas-Fired Booster Water Heaters

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SOURCES	2012	2018	2022		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	Typical	Typical	Typical
Typical Capacity (gal)	Product Literature / Guidehouse				Guidehouse		
Typical Output Capacity (kBtu/h)							
Thermal Efficiency (%)							
Average Life (y)							
Retail Equipment Cost (2022$)							
Total Installed Cost (2022$)							
Total Installed Cost (2022$/kBtu/h)							
Annual Maintenance Cost (2022$)							
Annual Maintenance Cost (2022$/kBtu/h)							

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Commercial Gas-Fired Instantaneous Water Heaters

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SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 2.0	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	DOE CCD						DOE CCD / Guidehouse					
Thermal Efficiency (%)	Guidehouse/DOE CCD		DOE CCD		ENERGY STAR	DOE CCD						
Average Life (y)	CWH EERE 2022 NOPR											
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Total Installed Cost (2022$/kBtu/h)												
Annual Maintenance Cost (2022$)												
Annual Maintenance Cost (2022$/kBtu/h)												

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Commercial Solar Water Heaters

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SOURCES	2012	2018	2022		2023	2030	2040	2050
	Installed Base	Installed Base	Typical	ENERGY STAR V. 4.0	ENERGY STAR V. 5.0	Typical	Typical	Typical
Typical Capacity (sq. ft.)	SRCC / Guidehouse					Guidehouse		
Typical Capacity (m^2)								
Typical Capacity (Input) (kBtu/h) - North								
Typical Capacity (Input) (kBtu/h) - South								
Solar Uniform Energy Factor (SUEF)	ENERGY STAR / Guidehouse							
Average Life (y)	SRCC / Guidehouse							
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)		Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse					
Total Installed Cost (2022$)								
Total Installed Cost (2022$/kBtu/h) - North	Guidehouse							
Total Installed Cost (2022$/kBtu/h) - South								
Annual Maintenance Cost (2022$)	DOE / Guidehouse							
Annual Maintenance Cost (2022$/kBtu/h) - North								
Annual Maintenance Cost (2022$/kBtu/h) - South								

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Commercial Cooking Products

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Commercial Natural Gas Range with Griddle and Oven

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SOURCES	2012	2018	2022			2023	2030	2040	2050
	Installed Base	Installed Base	Typical	ENERGY STAR V. 2.2	High	ENERGY STAR V. 3.0	Typical/High		
Griddle - Cooking Energy Efficiency (%)	Guidehouse	FSTC	ENERGY STAR / FSTC	ENERGY STAR	ENERGY STAR	NA	Guidehouse		
Oven - Cooking Energy Efficiency (%)						ENERGY STAR			
Range - Cooking Energy Efficiency (%)			FEMP / CEC	NA	FEMP / CEC	NA			
Combined Energy Efficiency (%)	Guidehouse / FSTC								
Griddle - Normalized Idle Energy Rate (Btu/h/ft^2)	Guidehouse	FSTC	ENERGY STAR / FSTC	ENERGY STAR	ENERGY STAR	NA			
Oven - Idle Energy Rate (Btu/h)	FEMP		ENERGY STAR			ENERGY STAR			
Range - Idle Energy Rate (Btu/h)	FSTC			NA	FSTC	NA			
Combined Idle Energy Rate (Btu/h)	Guidehouse / FSTC / Distributors								
Average Life (y)	FSTC								
Retail Equipment Cost (2022$)	Distributors								
Total Installed Cost (2022$)	FSTC / Guidehouse								
Total Installed Cost (2022$/kBtu/h)									
Annual Maintenance Cost (2022$)	FSTC								
Annual Maintenance Cost (2022$/kBtu/h)									

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Commercial Electric Range with Griddle and Oven

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SOURCES	2012	2018	2022			2023	2030	2040	2050
	Installed Base	Installed Base	Typical	ENERGY STAR V. 2.2	High	ENERGY STAR V. 3.0	Typical/High		
Griddle - Cooking Energy Efficiency (%)	Guidehouse	FSTC	FSTC / ENERGY STAR / Guidehouse	ENERGY STAR	ENERGY STAR	NA	Guidehouse		
Oven - Cooking Energy Efficiency (%)						ENERGY STAR			
Range - Cooking Energy Efficiency (%)				NA	CEC	NA			
Combined Energy Efficiency (%)	Guidehouse / FSTC								
Griddle - Normalized Idle Energy Rate (kW/ft²)	Guidehouse	FSTC	FSTC / ENERGY STAR / Guidehouse	ENERGY STAR	ENERGY STAR	NA			
Oven - Idle Energy Rate (kW)						ENERGY STAR			
Range - Idle Energy Rate (kW)	NA								
Combined Idle Energy Rate (kW)	Guidehouse / FSTC / Distributors								
Average Life (y)	FSTC								
Retail Equipment Cost (2022$)	Distributors								
Total Installed Cost (2022$)	FSTC / Guidehouse								
Total Installed Cost (2022$/kBtu/h)									
Annual Maintenance Cost (2022$)	FSTC								
Annual Maintenance Cost (2022$/kBtu/h)									

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Commercial Hot Food Holding Cabinets – Small

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SOURCES	2012	2018	2022				2030	2040
	Installed Base	Installed Base	State Standards	Typical	ENERGY STAR V. 2.0	High	Typical/High	
Interior Volume (ft^3)	FEMP / ENERGY STAR						Guidehouse	
Maximum Idle Energy Rate (W)	CEE / Guidehouse	FEMP	ASAP	ASAP / ENERGY STAR	ENERGY STAR V. 2.0	FEMP / ENERGY STAR		
Annual Energy Use (kWh/y)	FEMP							
Average Life (y)								
Retail Equipment Cost (2022$)	Distributors / ENERGY STAR Savings Calculator / Guidehouse							
Total Installed Cost (2022$)	Guidehouse							
Total Installed Cost (2022$/kBtu/h)								
Annual Maintenance Cost (2022$)	FSTC							
Annual Maintenance Cost (2022$/kBtu/h)								

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Commercial Hot Food Holding Cabinets – Medium

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SOURCES	2012	2018	2022				2030	2040
	Installed Base	Installed Base	State Standards	Typical	ENERGY STAR V. 2.0	High	Typical/High	
Interior Volume (ft^3)	FEMP / ENERGY STAR						Guidehouse	
Maximum Idle Energy Rate (W)	CEE / Guidehouse	FEMP	ASAP	ASAP / ENERGY STAR	ENERGY STAR V. 2.0	FEMP / ENERGY STAR		
Annual Energy Use (kWh/y)	FEMP							
Average Life (y)								
Retail Equipment Cost (2022$)	Distributors / ENERGY STAR Savings Calculator / Guidehouse							
Total Installed Cost (2022$)	Guidehouse							
Total Installed Cost (2022$/kBtu/h)								
Annual Maintenance Cost (2022$)	FSTC							
Annual Maintenance Cost (2022$/kBtu/h)								

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Commercial Hot Food Holding Cabinets – Large

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SOURCES	2012	2018	2022				2030	2040
	Installed Base	Installed Base	State Standards	Typical	ENERGY STAR V. 2.0	High	Typical/High	
Interior Volume (ft^3)	FEMP / ENERGY STAR						Guidehouse	
Maximum Idle Energy Rate (W)	CEE / Guidehouse	FEMP	ASAP	ASAP / ENERGY STAR	ENERGY STAR V. 2.0	FEMP / ENERGY STAR		
Annual Energy Use (kWh/y)	FEMP							
Average Life (y)								
Retail Equipment Cost (2022$)	Distributors / ENERGY STAR Savings Calculator / Guidehouse							
Total Installed Cost (2022$)	Guidehouse							
Total Installed Cost (2022$/kBtu/h)								
Annual Maintenance Cost (2022$)	FSTC							
Annual Maintenance Cost (2022$/kBtu/h)								

Appendix B
References

Guidehouse
1676 International Drive
McLean, VA 22102

And

Leidos
11951 Freedom Drive
Reston, VA 20190

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APPENDIX C

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Final

EIA - Technology Forecast Updates – Residential and Commercial Building Technologies – Reference Case

Presented to:

U.S. Energy Information Administration

Prepared by:

Guidehouse
1200 19th Street, NW, Suite 700
Washington, D.C. 20036

And

Leidos
11951 Freedom Drive
Reston, VA 20190

October 14, 2022

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Objective

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The objective of this study is to develop baseline and projected performance and cost characteristics for residential and commercial end-use equipment.

- Examine 2012 and 2018 (commercial) and 2015 and 2020 (residential) baselines, as well as this year's baseline (2022).
  - Review literature, standards, installed base, contractor, and manufacturer information.
  - Provide a relative comparison and characterization of the cost and efficiency of a generic product.
- Forecast technology improvements that are projected to be available through 2050.
  - Review trends in standards, product enhancements, and research and development (R&D).
  - Project impact of product improvements and technology enhancement.

The performance and cost characterization of end-use equipment developed in this study will assist EIA in projecting national primary energy consumption.

Methodology

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Input from industry stakeholders, including government, R&D organizations, and manufacturers, was used to project product enhancements concerning equipment performance and cost attributes.

- Technology forecasting involves many uncertainties.
- Technology developments affect performance and cost forecasts.
- Varied sources ensure a balanced view of technology progress and the probable timing of commercial availability.

Definitions

Final

The following tables represent the current and projected efficiencies for residential and commercial building equipment ranging from the installed base in 2012 and 2018 (for commercial products) and 2015 and 2020 (for residential) to the highest efficiency equipment that is expected to be commercially available by 2050, assuming incremental adoption. Below are definitions for the terms used in characterizing the status of each technology.

- **Installed Stock Average**: the installed and *in use* equipment for that year. Represents the installed stock of equipment, but does *not* represent sales.
- **Current Standard**: the minimum efficiency (or maximum energy use) required (allowed) by current U.S. Department of Energy (DOE) standards, when applicable. For lighting, if no product exists at the standard efficiency level, a hypothetical wattage and lumen output is given for the standard's efficiency level.
- **ENERGY STAR®**: the minimum efficiency required (or maximum energy use allowed) to meet the ENERGY STAR® criteria, when applicable. Presented performance data represents certified products just meeting current ENERGY STAR specifications. For lighting, if no products exist at the ENERGY STAR efficiency level, a hypothetical wattage and lumen output is given for the ENERGY STAR efficiency level.
- **Low**: The minimum efficiency product or product mix available on the market. This rating typically reflects minimal compliance with DOE standards.
- **Typical**: the average, or typical, product being sold in the particular timeframe.
- **High**: the product with the highest efficiency available in the particular timeframe.
- **Lumens (lm):** the unit for luminous flux used in the SI unit system. This unit is used to indicate a light source's light output. All reported lumens are initial lumens. 1 kilolumen (klm) = 1,000 lumens.
- **Correlated Color Temperature (CCT)**: a specification of the color appearance of the light emitted by a lamp. Note: CCT is not a performance metric.
- **Color Rendering Index (CRI)**: a scale from 0 to 100 percent indicating how accurate a given light source is at rendering color when compared to a reference light source. The higher the CRI, the better the color rendering ability.
- **British thermal unit (Btu)**: a measure of the heat content of fuels or energy sources. It is the quantity of heat required to raise the temperature of one pound of liquid water by 1°F at the temperature that water has its greatest density (approximately 39 °F). 1 kBtu = 1,000 Btu.
- **Cubic Feet per Minute (CFM)**: a measure of airflow volume equal to the number of cubic feet of air flowing through a two-dimensional plane in one minute.
- **Not Available (N/A)**: data is not available where indicated.

Calculations

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The following metrics are commonly referred to throughout the tables to follow. Below are the calculations for each metric

— **Lighting**

- **System Wattage** = (Lamp Wattage * Ballast Factor) / Ballast Efficiency
- **System Lumens** = Lamp Lumens * Ballast Factor
- **Lamp Efficacy** = Lamp Lumens / Lamp Wattage
- **System Efficacy** = System Lumens / System Wattage
- **Lamp Cost ($/klm)** = Lamp Cost / (Lamp Lumens / 1,000)
- **Total Equipment Cost** = Lamp Cost + Fixture (including ballast) Cost
- **System Cost ($/klm)** = Total Equipment Cost / (System Lumens / 1,000). l/b/f denotes that the cost includes the luminaire, the ballast, and the fixture.
- **Total Installed Cost** = Total Equipment Cost + Labor Installation Cost
- **Ballast Luminous Efficiency (BLE)** = A/(1+B*Avg Total Lamp Arc Power^(-C)) where A, B, and C are pre-defined constants by DOE Energy Conservation Standards for Fluorescent Lamp Ballasts.

— **Commercial Refrigeration**

- **Nominal Capacity over Average Input (Btu in / Btu out)** = (Cooling or Heat Rejection Capacity)*24*365/(Annual Energy Consumption * 3,412)
- **Total Installed Cost** = Retail Equipment Cost + Labor Installation Cost
- **Total Installed Cost ($/kBtu/hour)** = Total Installed Cost*1,000 / (Cooling or Heat Rejection Capacity). h used as an abbreviation for hour throughout
- **Annual Maintenance Cost ($/kBtu/h)** = Annual Maintenance Cost * 1,000 / (Cooling or Heat Rejection Capacity)

— **Ventilation**

- **CFM out / Btu in / h** = System Airflow / (System Fan Power * 3,412)
- **Total Installed Cost ($/1,000 CFM)** = Total Installed Cost * 1,000 / System Airflow
- **Annual Maintenance Cost ($/1,000 CFM)** = Annual Maintenance Cost * 1,000 / System Fan Power

Market Transformation

The market for the reviewed products has changed since this analysis was performed in 2015. These changes are noted and reflected in the efficiency and cost characteristics.

- DOE issued federal minimum efficiency standards that have gone into effect for General Service Fluorescent Lamps (2012), Incandescent Reflector Lamps (2012), and Fluorescent Lamp Ballasts (2019).

- In April 2022, DOE codified into the Code of Federal Regulations the 45 lumens per watt (lm/W) backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act (10 CFR 430, 87 FR 27439). This action also amended the definition of general service lamps to include previously exempted product classes, such as reflector lamps. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

- DOE published a Final Rule updating energy conservation standards for Refrigerated Beverage Vending Machines at the end of 2015, effective in 2018. DOE also issued federal minimum efficiency standards that have or will soon go into effect for Refrigerated Beverage Vending Machines (2012), Automatic Commercial Ice Makers (2018), Walk-In Coolers and Freezers (2017), and Commercial Refrigeration Equipment (2017).

Residential Lighting

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Performance and Cost Characteristics » Residential General Service Lamps

Final

The residential general service lamps characterized in this report are a 60-watt and a 75-watt medium screw-based (E26) A-type incandescent lamp and their halogen, CFL, and LED equivalents. A standard 60-watt incandescent lamp produces approximately 800 – 850 lumens. A standard 75-watt incandescent lamp produces approximately 1,100 lumens.

Performance:

- A majority of residential lamps have a nominal CCT rating of 2,700K and give off a warm, yellowish white color, but products with CCTs of 3,000K, 3,500K, 4,100K (neutral white), 5,000K (daylight), and 6,500K (blueish white) are also available. Traditional incandescent light bulbs have a nominal CCT of about 2,700K. When replacing a light bulb, it is advised to chose a product with a similar CCT value in order to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100. However, CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination. High CRI products are preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these specific retail and display applications.

Cost:

- Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy. Therefore, typical lamp prices in 2022 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Fixture prices and installation costs are not included for the residential sector. Labor costs are assumed to be negligible because homeowners likely replaces lamps themselves as they burn out. Therefore, total installed cost is the price of a lamp, and annual maintenance costs are the cost of replacing the lamps, which is a function of lamp life, lamp price, and the annual operating hours.
- Disposal costs are not characterized for residential lighting in this analysis. In residential cases, disposal is done by the occupant. Lamp and product burnout are assumed to result in no "added" cost aside from the work performed to install the replacement.

Legislation:

- The Energy Independence and Security Act of 2007 (EISA 2007) established standards for 60-watt general service lamps, effective in 2014, and 75-watt lamps, effective in 2013. These standards cannot be achieved by incandescent bulbs, but can be by halogen, CFL, and LED technologies.
- In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. This action also amended the definition of general service lamps to include previously exempted product classes, such as reflector lamps. These standards can not be achieved by traditional incandescent or halogen technologies currently on the market, and given current and projected trends in industry, they will likely not be met. It is currently assumed that industry will increase its investment in LED technology at the expense of incandescent, halogen, and CFL technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

ENERGY STAR:

- For ENERGY STAR qualification, general service omnidirectional lamps must have a minimum lamp efficacy of 70 lm/W for products with CRI ≥ 90 and 80 lm/W for lamps with CRI < 90. Additionally, the lamps must have a CRI ≥ 80, nominal CCT of 2,700, 3,000, 3,500, 4,000/4,100, 5,000, or 6,000 K, and rated lifetime ≥ 10,000 hours (ENERGY STAR).

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Performance and Cost Characteristics » Residential General Service Lamps

Final

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent, halogen, and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050:

Technology	Efficacy	Lifetime	Price	Potential for Improvements
Incandescent	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
Halogen	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements as of 2022.
CFL	+0.5%	0%	-0.5%	Improvements in efficacy can be made by using more rare-earth phosphors in compact fluorescent lamps.

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Performance and Cost Characteristics » Residential General Service Incandescent Lamps (60 W)

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DATA	2015[1]	2020[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	60.0	60.0	N/A	N/A	N/A	N/A	18.9	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	850	850	N/A	N/A	N/A	N/A	850	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	14.2	14.2	N/A	N/A	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,700	2,700	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	1.0	1.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	511	511	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$0.30	$0.30	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$0.34	$0.34	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$0.30	$0.30	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$0.15	$0.15	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$0.35	$0.35	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$0.18	$0.18	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. The Energy Independence and Security Act of 2007 (EISA 2007) prescribes standards for 60 watt incandescent lamps as of January 1, 2014. Despite the phase out of incandescent lamps, these products remain in the installed stock.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. These standards cannot be met with incandescent technologies.

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Performance and Cost Characteristics » Residential General Service Incandescent Lamps (75 W)

Final

DATA	2015[1]	2020[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	75.0	75.0	N/A	N/A	N/A	N/A	26.0	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	1,170	1,170	N/A	N/A	N/A	N/A	1,170	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	15.6	15.6	N/A	N/A	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,700	2,700	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	0.8	0.8	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	511	511	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$0.44	$0.44	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$0.38	$0.38	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$0.44	$0.44	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$0.30	$0.30	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$0.38	$0.38	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$0.26	$0.26	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. The Energy Independence and Security Act of 2007 (EISA 2007) prescribes standards for 75 watt incandescent lamps as of January 1, 2013. Despite the phase out of incandescent lamps, these products remain in the installed stock.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. These standards cannot be met with incandescent technologies.

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Performance and Cost Characteristics » Residential General Service Halogen Lamps (60 W Incandescent Equivalent)

Final

DATA	2015[1]	2020[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	43.1	43.1	N/A	43.0	N/A	N/A	16.7	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	750	750	N/A	750	N/A	N/A	750	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	17.4	17.4	N/A	17.4	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,850	2,850	N/A	2,700	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	1.0	1.0	N/A	1.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	621	621	N/A	621	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$2.36	$4.90	N/A	$5.92	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$3.15	$6.54	N/A	$7.89	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$2.36	$4.90	N/A	$5.92	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$1.47	$3.04	N/A	$3.68	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$3.15	$6.54	N/A	$7.89	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$1.95	$4.06	N/A	$4.90	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. The Energy Independence and Security Act of 2007 (EISA 2007) prescribes standards for 60 watt incandescent lamps as of January 1, 2014. Starting in 2014, 60 watt incandescent lamps were replaced by halogen lamps.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. These standards cannot be met with existing halogen lamp technologies.

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Performance and Cost Characteristics » Residential General Service Halogen Lamps (75 W Incandescent Equivalent)

Final

DATA	2015[1]	2020[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	53.0	53.0	N/A	53.0	N/A	N/A	19.8	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	1,050	936	N/A	890	N/A	N/A	890	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	19.8	17.7	N/A	16.8	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,850	2,950	N/A	2,950	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	1.0	1.0	N/A	1.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	621	621	N/A	621	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$2.37	$3.58	N/A	$4.06	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$2.26	$3.82	N/A	$4.56	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$2.37	$3.58	N/A	$4.06	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$1.47	$2.22	N/A	$2.52	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$2.26	$3.82	N/A	$4.56	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$1.40	$2.37	N/A	$2.83	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. The Energy Independence and Security Act of 2007 prescribes standards for current 75 watt incandescent lamps as of January 1, 2013. Starting in 2013, 75 watt incandescent lamps were replaced by halogen lamps.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. These standards cannot be met with existing halogen lamp technologies.

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Performance and Cost Characteristics » Residential General Service Compact Fluorescent Lamps (60 W Incandescent Equivalent)

Final

DATA	2015[1]	2020[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[4]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	13.0	13.1	14.0	13.0	13.0	13.8	20.0	12.5	12.5	11.9	11.9	11.3	11.3
Lamp Lumens	825	900	900	900	925	800	900	900	925	900	925	900	925
Lamp Efficacy (lm/W)[3]	63.5	68.5	64.3	69.2	71.2	80.0	45.0	72.0	74.1	75.7	77.8	79.6	81.8
CRI	82	82	82	82	82	80	N/A	82	82	82	82	82	82
Correlated Color Temperature (CCT)	2,700	2,700	2,700	2,700	2,700	2,700	N/A	2,700	2,700	2,700	2,700	2,700	2,700
Average Lamp Life (thousand hours)	10.0	10.0	10.0	10.0	12.0	10.0	N/A	10.0	12.0	10.0	12.0	10.0	12.0
Annual Operating Hours (h/y)	767	767	767	767	767	N/A	N/A	767	767	767	767	767	767
Lamp Price (2022$)	$2.55	$5.40	$1.50	$5.35	$4.63	N/A	N/A	$5.14	$4.45	$4.89	$4.23	$4.65	$4.02
Lamp Cost (2022$/klm)[3]	$3.10	$6.00	$1.67	$5.94	$5.01	N/A	N/A	$5.71	$4.81	$5.43	$4.57	$5.17	$4.35
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0	0	0	0	0	N/A	N/A	0	0	0	0	0	0
Total Installed Cost (2022$)	$2.55	$5.40	$1.50	$5.35	$4.63	N/A	N/A	$5.14	$4.45	$4.89	$4.23	$4.65	$4.02
Annual Maintenance Cost (2022$)	$0.20	$0.41	$0.12	$0.41	$0.30	N/A	N/A	$0.39	$0.28	$0.37	$0.27	$0.36	$0.26
Total Installed Cost (2022$/klm)	$3.09	$6.00	$1.67	$5.94	$5.01	N/A	N/A	$5.71	$4.81	$5.43	$4.57	$5.17	$4.35
Annual Maintenance Cost (2022$/klm)	$0.24	$0.46	$0.13	$0.46	$0.32	N/A	N/A	$0.44	$0.31	$0.42	$0.29	$0.40	$0.28

1. 2020 data back calculated based on 2022 data and the following assumptions: Efficacy +0.5%/y, Cost -0.5%/y (NCI, 2019)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. These standards can be met with existing CFL products.
3. Year-to-year price and performance assumptions for incumbent technologies from 2022 to 2050: Efficacy +0.5%/y, Cost -0.5%/y (NCI, 2019)
4. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)

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Performance and Cost Characteristics » Residential General Service LED Lamps (60 W Incandescent Equivalent)

Final

DATA	2015	2020	2022				2023[2]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[1]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	8.7	9.2	10.0	8.9	8.0	10.0	17.8	7.3	6.6	5.8	5.2	5.0	4.5
Lamp Lumens	656	803	800	800	800	800	800	800	800	800	800	800	800
Lamp Efficacy (lm/W)	75.5	87.1	80.0	90.0	100.0	80.0	45.0	108.9	120.9	138.6	154.0	160.7	178.6
CRI	81	85	80	81	90	80	N/A	81	90	81	90	81	90
Correlated Color Temperature (CCT)	2,700	2,700	2,700	2,700	2,700	2,700	N/A	2,700	2,700	2,700	2,700	2,700	2,700
Average Lamp Life (thousand hours)	25	21	15	14	18	15.0	N/A	14	18	14	18	14	18
Annual Operating Hours (h/y)	657	657	657	657	657	657	N/A	657	657	657	657	657	657
Lamp Price (2022$)	$13.53	$4.56	$6.20	$3.92	$5.32	$6.20	N/A	$3.23	$4.39	$2.84	$3.86	$2.46	$3.33
Lamp Cost (2022$/klm)	$20.63	$5.68	$7.75	$4.90	$6.65	$7.75	N/A	$4.04	$5.49	$3.56	$4.83	$3.07	$4.17
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0.0	0.0	0.0	0.0	0.0	0.0	N/A	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$13.53	$4.56	$6.20	$3.92	$5.32	$6.20	N/A	$3.23	$4.39	$2.84	$3.86	$2.46	$3.33
Annual Maintenance Cost (2022$)	$0.35	$0.15	$0.27	$0.18	$0.19	$0.27	N/A	$0.15	$0.16	$0.13	$0.14	$0.11	$0.12
Total Installed Cost (2022$/klm)	$20.63	$5.68	$7.75	$4.90	$6.65	$7.75	N/A	$4.04	$5.49	$3.56	$4.83	$3.07	$4.17
Annual Maintenance Cost (2022$/klm)	$0.54	$0.18	$0.34	$0.22	$0.24	$0.34	N/A	$0.18	$0.20	$0.16	$0.17	$0.14	$0.15

1. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. All LED lighting products exceed the new minimum efficacy standards.

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Performance and Cost Characteristics » Residential General Service Filament-LED Lamps (60 W Incandescent Equivalent)

Final

DATA	2015	2020	2022				2023[2]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[1]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	9.7	7.1	5.5	6.9	8.0	13.8	17.8	7.0	6.6	5.5	5.2	4.7	4.5
Lamp Lumens	457	650	450	650	800	800	800	800	800	800	800	800	800
Lamp Efficacy (lm/W)	47.1	91.7	81.8	94.8	100.0	80.0	45.0	114.6	120.9	146.0	154.0	169.3	178.6
CRI	82	84	90	84	80	80	N/A	81	90	81	90	81	90
Correlated Color Temperature (CCT)	2,700	2,700	2,700	2,700	2,700	2,700	N/A	2,700	2,700	2,700	2,700	2,700	2,700
Average Lamp Life (thousand hours)	23	21	15	15	15	15	N/A	15	15	15	15	15	15
Annual Operating Hours (h/y)	657	657	657	657	657	N/A	N/A	657	657	657	657	657	657
Lamp Price (2022$)	$15.17	$6.88	$6.25	$5.91	$7.75	N/A	N/A	$4.87	$6.39	$4.29	$5.62	$3.70	$4.86
Lamp Cost (2022$/klm)	$33.20	$10.58	$13.89	$9.09	$9.69	N/A	N/A	$6.09	$7.99	$5.36	$7.03	$4.63	$6.07
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0.0	0.0	0.0	0.0	0.0	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$15.17	$6.88	$6.25	$5.91	$7.75	N/A	N/A	$4.87	$6.39	$4.29	$5.62	$3.70	$4.86
Annual Maintenance Cost (2022$)	$0.43	$0.21	$0.27	$0.26	$0.34	N/A	N/A	$0.21	$0.28	$0.19	$0.25	$0.16	$0.21
Total Installed Cost (2022$/klm)	$33.20	$10.58	$13.89	$9.09	$9.69	N/A	N/A	$6.09	$7.99	$5.36	$7.03	$4.63	$6.07
Annual Maintenance Cost (2022$/klm)	$0.93	$0.33	$0.61	$0.40	$0.42	N/A	N/A	$0.27	$0.35	$0.23	$0.31	$0.20	$0.27

1. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. All LED lighting products exceed the new minimum efficacy standards.

Performance and Cost Characteristics » Residential Reflector Lamps

Final

The residential reflector lamps characterized in this report are directional lamps that emit approximately 550 – 850 lumens (except for LED PAR38s which have outputs up to 1,700 lumens). Multiple baseline reflector lamps were analyzed, including 65W Incandescent BR30, Halogen PAR30, Halogen Infrared Reflector (HIR) PAR30, CFL BR30, LED BR30, and LED PAR38.

Performance:

- A majority of residential lamps have a nominal CCT rating of 2,700K and give off a warm, yellowish white color, but products with CCTs of 3,000K, 3,500K, 4,100K (neutral white), 5,000K (daylight), and 6,500K (blueish white) are also available. Traditional incandescent light bulbs have a nominal CCT of about 2,700K. When replacing a light bulb, it is advised to chose a product with a similar CCT value in order to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100, but for CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination, with high CRI products being preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these very specific retail and display applications.

Cost:

- Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy.
- Fixture prices and installation costs are not included for the residential sector. Labor costs are assumed to be negligible because homeowners likely replaces lamps themselves as they burn out. Therefore, total installed cost is the price of a lamp, and annual maintenance costs are the cost of replacing the lamps, which is a function of lamp life, lamp price, and the annual operating hours.
- Disposal costs are not characterized for residential lighting in this analysis. In residential cases, disposal is done by the occupant. Lamp and product burnout are assumed to result in no "added" cost aside from the work performed to install the replacement.

Legislation:

- EPAct92 established minimum performance standards for some reflector lamps and provided exemptions for certain specialty applications (e.g., ER/BR, vibration service, more than 5% neodymium oxide, impact resistant, infrared heat, colored). EPAct92 effectively phased-out R-shaped tungsten filament incandescent reflector lamps at certain wattages and bulb diameters, replacing them with more efficient and cost effective tungsten-halogen parabolic aluminized reflector (PAR) lamps. EISA 2007 took away certain exemptions from EPACT 1992, requiring certain previously exempted lamps to meet EPAct92 minimum performance standards by January 1, 2008. The 65W BR30, a large majority of the incandescent reflector lamp market, was still exempted until 2022.
- In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. **This action also amended the definition of general service lamps to include previously exempted product classes, such as reflector lamps.** These standards can not be achieved by traditional incandescent or halogen technologies currently on the market, and given current and projected trends in industry, they will likely not be met. It is currently assumed that industry will increase its investment in LED technology at the expense of incandescent, halogen, and CFL technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

Performance and Cost Characteristics » Residential Reflector Lamps

Final

ENERGY STAR:

- For ENERGY STAR qualification, general service, reflector lamps must have a minimum lamp efficacy of 61 lm/W for products with CRI ≥ 90 and 70 lm/W for lamps with CRI < 90, respectively. Additionally, the lamps must have a CRI ≥ 80, nominal CCT of 2,700, 3,000, 3,500, 4,000/4,100, 5,000, or 6,000 K, and rated lifetime ≥ 10,000 hours (ENERGY STAR).

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

Technology	Efficacy	Lifetime	Price	Potential for Improvements
Incandescent	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
Halogen	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements as of 2022.
CFL	+0.5%	0%	-0.5%	In addition to higher efficiency reflector coatings, improvements in efficacy can be made by using more rare-earth phosphors in compact fluorescent lamps. Lifetime improvements can be made by improving the compact fluorescent lamp electrodes.

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Performance and Cost Characteristics » Residential Reflector Lamps (65W BR30 Incandescent)

Final

DATA	2015[1]	2020[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	65.0	65.0	N/A	65.0	N/A	N/A	13.3	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	637	637	N/A	602	N/A	N/A	600	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	9.8	9.8	N/A	9.3	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,700	2,700	N/A	2,700	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	2.0	2.0	N/A	2.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	621	621	N/A	621	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$4.00	$4.00	N/A	$3.70	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$6.28	$6.28	N/A	$6.15	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$4.00	$4.00	N/A	$3.70	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$1.24	$1.24	N/A	$1.15	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$6.28	$6.28	N/A	$6.15	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$1.95	$1.95	N/A	$1.91	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. Incandescent BR30 lamps were previously exempted from DOE Incandescent Reflector Lamp standards and the EISA 2007 general service lamp definition until DOE's new final rule in 2022. The new definitions go into effect in 2023.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. These standards cannot be met with incandescent technologies.

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Performance and Cost Characteristics » Residential Reflector Lamps (PAR30 Halogen)

Final

DATA	2015[1]	2020[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	47.1	38.8	N/A	38.8	N/A	N/A	12.0	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	660	576	N/A	542	N/A	N/A	542	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	14.0	14.0	N/A	14.0	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,850	2,850	N/A	2,850	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	1.5	1.5	N/A	1.5	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	876	876	N/A	876	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$6.77	$8.13	N/A	$8.67	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$10.26	$14.12	N/A	$16.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$6.77	$8.13	N/A	$8.67	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$3.96	$4.75	N/A	$5.06	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$10.26	$14.12	N/A	$16.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$5.99	$8.25	N/A	$9.34	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. Halogen PAR30 lamps were previously exempted from the EISA 2007 GSL definition until DOE's new final rule in 2022. The new definitions go into effect in 2023. Note: product offerings are very limited in 2022.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. These standards cannot be met with halogen technologies.

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Performance and Cost Characteristics » Residential Reflector Lamps (PAR30 Halogen Infrared Reflector (HIR))

Final

DATA	2015[1]	2020[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	38.9	45.5	N/A	48.0	N/A	N/A	18.7	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	650	786	N/A	840	N/A	N/A	840	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	16.7	17.3	N/A	17.5	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,850	2,850	N/A	2,700	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	4.0	4.0	N/A	4.2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	876	876	N/A	876	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$14.69	$25.62	N/A	$29.99	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$22.59	$32.60	N/A	$35.70	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$14.69	$25.62	N/A	$29.99	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$3.22	$5.61	N/A	$6.26	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$22.59	$32.60	N/A	$35.70	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$4.95	$7.14	N/A	$7.45	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. Halogen PAR30 lamps were previously exempted from the EISA 2007 GSL definition until DOE's new final rule in 2022. The new definitions go into effect in 2023. Note: product offerings are very limited in 2022.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. These standards cannot be met with halogen technologies.

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Performance and Cost Characteristics » Residential Reflector Lamps (BR30 CFL)

Final

DATA	2015[1]	2020[1]	2022[2]				2023[3]	2030[3]		2040[3]		2050[3]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[4]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	15.5	15.1	N/A	N/A	N/A	N/A	16.7	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	750	750	N/A	N/A	N/A	N/A	750	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	48.3	49.5	N/A	N/A	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	82	82	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,700	2,700	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	8.2	8.5	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	913	913	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$6.76	$6.59	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$9.01	$8.79	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$6.76	$6.59	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$0.75	$0.71	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$9.01	$8.79	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$1.00	$0.95	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. 2015 and 2020 data calculated based on 2009 installed stock data and the following assumptions: Efficacy +0.5%/y, Cost -0.5%/y (NCI, 2019)
2. Virtually all manufacturers have discontinued manufacturing of CFL reflector lamps in favor of LEDs. Distributor offerings for CFL reflectors have been eliminated.
3. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. Although these standards can be met with CFL technology, manufacturers have discontinued manufacturing CFL reflector lamps in favor of LEDs.
4. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)

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Performance and Cost Characteristics » Residential Reflector LED BR30

Final

DATA	2015	2020	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[1]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	14.2	10.9	11.0	8.8	7.2	10.7	14.4	7.1	6.2	6.2	5.4	5.5	4.8
Lamp Lumens	706	781	800	683	650	650	650	650	650	650	650	650	650
Lamp Efficacy (lm/W)	49.8	71.5	72.7	78.6	90.3	61.0	45.0	91.7	105.4	104.9	120.5	118.0	135.6
CRI	82	85	92	87	90	80	N/A	87	90	87	90	87	90
Correlated Color Temperature (CCT)	2,700	2,700	2,700	2,700	2,700	2,700	N/A	2,700	2,700	2,700	2,700	2,700	2,700
Average Lamp Life (thousand hours)	25	25	25	19	18	15	N/A	19	18	19	18	19	18
Annual Operating Hours (h/y)	730	730	730	730	730	N/A	N/A	730	730	730	730	730	730
Lamp Price (2022$)	$21.40	$15.36	$4.09	$5.01	$5.96	N/A	N/A	$4.11	$4.89	$3.62	$4.31	$3.14	$3.74
Lamp Cost (2022$/klm)	$30.31	$19.66	$5.11	$7.33	$9.17	N/A	N/A	$6.32	$7.53	$5.57	$6.64	$4.83	$5.75
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0.0	0.0	0.0	0.0	0.0	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$21.40	$15.36	$4.09	$5.01	$5.96	N/A	N/A	$4.11	$4.89	$3.62	$4.31	$3.14	$3.74
Annual Maintenance Cost (2022$)	$0.63	$0.45	$0.12	$0.20	$0.24	N/A	N/A	$0.16	$0.19	$0.14	$0.17	$0.12	$0.15
Total Installed Cost (2022$/klm)	$30.31	$19.66	$5.11	$7.33	$9.17	N/A	N/A	$6.32	$7.53	$5.57	$6.64	$4.83	$5.75
Annual Maintenance Cost (2022$/klm)	$0.89	$0.57	$0.15	$0.29	$0.37	N/A	N/A	$0.25	$0.30	$0.22	$0.26	$0.19	$0.23

1. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. All LED lighting products exceed the new minimum efficacy standards.

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Performance and Cost Characteristics » Residential Reflector LED PAR38

Final

DATA	2015	2020	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[1]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	19.2	15.5	17.0	16.4	17.0	22.0	29.9	14.0	14.6	12.3	12.7	10.9	11.3
Lamp Lumens	1,202	1,211	1,200	1,344	1,700	1,344	1,344	1,344	1,700	1,344	1,700	1,344	1,700
Lamp Efficacy (lm/W)	62.7	77.9	70.6	82.0	100.0	61.0	45.0	95.7	116.7	109.5	133.5	123.2	150.2
CRI	83	86	82	86	82	80	N/A	86	86	86	86	86	86
Correlated Color Temperature (CCT)	3,000	3,000	2,700	3,000	3,000	3,000	N/A	3,000	3,000	3,000	3,000	3,000	3,000
Average Lamp Life (thousand hours)	24	27	25	27	25	15	N/A	27	25	27	25	27	25
Annual Operating Hours (h/y)	730	730	730	730	730	N/A	N/A	730	730	730	730	730	730
Lamp Price (2022$)	$35.23	$22.44	$23.71	$23.09	$15.69	N/A	N/A	$19.40	$13.18	$17.36	$11.79	$15.37	$10.45
Lamp Cost (2022$/klm)	$29.31	$18.54	$19.76	$17.18	$9.23	N/A	N/A	$14.43	$7.75	$12.91	$6.94	$11.44	$6.14
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0.0	0.0	0.0	0.0	0.0	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$35.23	$22.44	$23.71	$23.09	$15.69	N/A	N/A	$19.40	$13.18	$17.36	$11.79	$15.37	$10.45
Annual Maintenance Cost (2022$)	$1.07	$0.60	$0.69	$0.62	$0.46	N/A	N/A	$0.52	$0.38	$0.46	$0.34	$0.41	$0.31
Total Installed Cost (2022$/klm)	$29.31	$18.54	$19.76	$17.18	$9.23	N/A	N/A	$14.43	$7.75	$12.91	$6.94	$11.44	$6.14
Annual Maintenance Cost (2022$/klm)	$0.89	$0.49	$0.58	$0.46	$0.27	N/A	N/A	$0.39	$0.23	$0.35	$0.20	$0.31	$0.18

1. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. All LED lighting products exceed the new minimum efficacy standards.

Performance and Cost Characteristics » Residential 4-foot Linear 2-Lamp Lighting Systems

Final

This section characterizes commercial linear fixtures that house two 4ft long linear lamps and their integrated luminaire equivalents. The technologies available for this system are linear fluorescent and LED.

- T5 lamps are approximately 40% narrower than T8 lamps and almost 60% narrower than T12 lamps. This narrowness allows T5 lamps to be coated with higher quality, more efficient phosphor blends than larger diameter lamps, resulting in a more efficacious lamp. The compact size of T5 lamps also permits greater flexibility in lighting design and construction.
- LED options for linear fixtures include replacement lamps that can fit directly into an existing fixture and fully integrated luminaires that can be used to replace existing fixtures. LED replacement lamps are also known as TLEDs. Type A TLEDs can be installed with existing ballasts and Type B and C TLEDs require the ballast to be disconnected. Replacement lamps are only sold to go into existing fixtures. If a new fixture is to be installed, a fully integrated LED luminaire is a more cost effective and efficient option. Because LED luminaires are fully integrated, they do not have lamp or fixture efficiency losses associated with ballasts and fixture optics.

Performance:

- Residential linear lamps often have a nominal CCT rating of 3,500K, but products with CCTs of 3,000K, 4,000K, and 4,100K (neutral white) are also common. 5,000K (daylight) lamps are available as well. When replacing a light bulb, it is important to choose a product with a similar CCT value to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100, but for CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination, with high CRI products being preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these very specific retail and display applications.

Cost:

- Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy. Therefore, typical lamp prices in 2022 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- The total installed cost is the price of a lamp, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED replacement lamps, which are sold only as a replacement for use in an existing fixture. The LED luminaire is more efficient and cost effective for new installations or fixture retrofits.
- Labor costs for lamp changes are assumed to be negligible because homeowners likely replace lamps themselves as they burn out. Therefore, annual maintenance costs are the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours for residential linear systems.
- Disposal costs are not characterized for residential lighting in this analysis. In residential cases, disposal is done by the occupant. Lamp and product burnout are assumed to result in no "added" cost aside from the work performed to install the replacement.

Legislation:

- Beginning July 14, 2012 (or July 14, 2014, for T8 700-series phosphor lamps), DOE fluorescent lamp standards required a minimum efficacy of 89 lm/W. Although the amended performance-based standards do not explicitly prohibit T12 lamps, no T12 lamps met the standard at the time of its announcement. Since then, however, T12 lamps meeting the standard have entered the market.
- Beginning November 14, 2014, DOE standards required that the characterized residential ballasts have a minimum BLE = 0.993 / (1 + 0.41 * Avg Total Lamp Arc power ^ (- 0.25)). Residential ballasts also must have a minimum power factor of 0.5.
- California's Title 24 mandates the use of electronic ballasts with high efficacy luminaires (including fluorescent) of 13 W or higher (CEC, 2005).

ENERGY STAR:

- ENERGY STAR does not cover linear lamps. (ENERGY STAR, 2020)

Performance and Cost Characteristics » Residential 4-foot Linear 2-Lamp Lighting Systems

Final

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050:

Technology	Efficacy	Lifetime	Price	Potential for Improvements
T12	0%	0%	-0.5%	Limited because the technology is mature.
T8	0%	0%	-0.5%	Limited because the technology is mature.
T5	0%	0%	-0.5%	Limited because the technology is mature.

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Performance and Cost Characteristics » Residential Linear Fluorescent Lamp T12

Final

DATA	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	40.0	40.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	2,860	2,860	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	72	72	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	70.0	82.8	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Lumens	3,890	5,148	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Efficacy (lm/W)	56	62	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Ballast Efficiency (BLE)	78%	87%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	70	70	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	4,100	4,100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	15	15	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	694	694	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$1.10	$1.10	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Ballast Price (2022$)	$13.31	$13.31	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$34.67	$34.67	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$0.38	$0.38	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (lamp, ballast, and fixture (l/b/f)) Cost (2022$/klm)	$12.90	$12.90	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$77.22	$77.22	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor System Installation (hours)	0.5	0.5	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Change (hours)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$39.71	$39.71	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$1.84	$1.84	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$10.21	$10.21	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$0.47	$0.47	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Note: Assume no labor is associated with lamp replacement in the residential sector because residents likely replace the lamps themselves.
Assume real cost has not changed since 2009 because this product has been phased out.

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Performance and Cost Characteristics » Residential Linear Fluorescent Lamp T8

Final

DATA	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	30.8	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0
Lamp Lumens	2,770	2,855	2,450	2,855	3,100	2,855	3,100	2,855	3,100	2,855	3,100
Lamp Efficacy (lm/W)[1]	90	89	77	89	97	89	97	89	97	89	97
System Wattage	62.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1
System Lumens	4,875	5,082	4,361	5,082	5,518	5,082	5,518	5,082	5,518	5,082	5,518
System Efficacy (lm/W)	78	81	69	81	87	81	87	81	87	81	87
Ballast Efficiency (BLE)	87%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
CRI	85	87	90	87	85	87	85	87	85	87	85
Correlated Color Temperature (CCT)	4,100	4,100	5,000	4,100	3,500	4,100	3,500	4,100	3,500	4,100	3,500
Average Lamp Life (thousand hours)	21	31	23	31	40	31	40	31	40	31	40
Annual Operating Hours (h/y)	767	767	767	767	767	767	767	767	767	767	767
Lamp Price (2022$)	$6.54	$4.12	$3.36	$4.08	$4.32	$3.92	$4.15	$3.73	$3.95	$3.55	$3.75
Ballast Price (2022$)[2]	$19.10	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$29.23	$76.29	$75.53	$75.53	$75.53	$72.56	$72.56	$69.01	$69.01	$65.64	$65.64
Lamp Cost (2022$/klm)	$2.36	$1.44	$1.37	$1.43	$1.39	$1.37	$1.34	$1.31	$1.27	$1.24	$1.21
System (l/b/f) Cost (2022$/klm)	$12.59	$29.61	$33.57	$29.31	$27.15	$27.19	$25.18	$25.86	$23.95	$24.60	$22.78
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Labor Lamp Change (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$100.01	$189.07	$179.41	$181.97	$182.82	$171.18	$171.97	$164.42	$165.18	$158.00	$158.71
Annual Maintenance Cost (2022$)	$0.48	$0.21	$0.22	$0.20	$0.17	$0.19	$0.16	$0.18	$0.15	$0.18	$0.14
Total Installed Cost (2022$/klm)	$20.51	$37.20	$41.14	$35.81	$33.13	$33.68	$31.17	$32.35	$29.93	$31.09	$28.76
Annual Maintenance Cost (2022$/klm)	$0.10	$0.04	$0.05	$0.04	$0.03	$0.04	$0.03	$0.04	$0.03	$0.03	$0.03

1. Data and assumptions taken from the 2018 SSL Forecast. The report states that efficacy improvements for T8 lamps are not expected in the future, and that the cost for all commercial fixtures is expected to decrease between 0.1%-0.6% per year. We use 0.5% per year here.
2. From 2020 to 2050, fixture (and fixture price) includes ballast.

Note: Assume no labor is associated with lamp replacement in the residential sector because residents likely replace lamps themselves.

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Performance and Cost Characteristics » Residential Linear Fluorescent Lamp T5

Final

DATA	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	27.0	27.5	28.0	27.5	26.0	27.5	26.0	27.5	26.0	27.5	26.0
Lamp Lumens	2,697	2,732	2,530	2,732	2,900	2,732	2,900	2,732	2,900	2,732	2,900
Lamp Efficacy (lm/W)[1]	100	99	90	99	112	99	112	99	112	99	112
System Wattage	51.5	61.7	62.9	61.7	58.4	61.7	58.4	61.7	58.4	61.7	58.4
System Lumens	4,747	5,464	5,060	5,464	5,800	5,464	5,800	5,464	5,800	5,464	5,800
System Efficacy (lm/W)	92	89	81	89	99	89	99	89	99	89	99
Ballast Efficiency (BLE)	92%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%
CRI	85	85	85	85	85	85	85	85	85	85	85
Correlated Color Temperature (CCT)	4,100	4,100	5,000	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
Average Lamp Life (thousand hours)	30	29	36	29	30	29	30	29	30	29	30
Annual Operating Hours (h/y)	949	949	949	949	949	949	949	949	949	949	949
Lamp Price (2022$)	$7.05	$9.54	$13.76	$9.45	$21.28	$9.08	$20.44	$8.63	$19.44	$8.21	$18.49
Ballast Price (2022$)[2]	$31.17	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$109.93	$170.87	$170.87	$170.87	$170.87	$164.15	$164.15	$156.13	$156.13	$148.50	$148.50
Lamp Cost (2022$/klm)	$2.61	$3.49	$5.44	$3.46	$7.34	$3.32	$7.05	$3.16	$6.70	$3.01	$6.38
System (l/b/f) Cost (2022$/klm)	$32.69	$34.77	$39.21	$34.73	$36.80	$33.37	$35.35	$31.73	$33.62	$30.18	$31.98
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Labor Lamp Change (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$193.80	$228.57	$231.39	$222.77	$246.43	$215.31	$238.04	$206.40	$228.02	$197.92	$218.48
Annual Maintenance Cost (2022$)	$0.45	$0.62	$0.73	$0.62	$1.35	$0.59	$1.29	$0.57	$1.23	$0.54	$1.17
Total Installed Cost (2022$/klm)	$40.83	$41.83	$45.73	$40.77	$42.49	$39.41	$41.04	$37.77	$39.31	$36.22	$37.67
Annual Maintenance Cost (2022$/klm)	$0.09	$0.11	$0.14	$0.11	$0.23	$0.11	$0.22	$0.10	$0.21	$0.10	$0.20

1. Year-to-year price and performance assumptions for incumbent technologies 2030–2050: Efficacy +0.5%/yr, Life +0.5%/yr, Cost -0.5%/yr (SSL Forecast 2018). 2020 data back calculated using the 2022 data and these assumptions
2. From 2020 to 2050, fixture (and fixture price) includes ballast.

Note: Assume no labor is associated with lamp replacement in the residential sector because residents likely replace lamps themselves.

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Performance and Cost Characteristics » Residential Linear LED Replacement Lamp 2-Lamp System

Final

DATA	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	18.5	16.3	16.0	13.7	11.0	11.6	9.3	10.0	8.0	8.8	7.2
Lamp Lumens	2,013	2,130	1,800	1,920	1,800	1,920	1,800	1,920	1,800	1,920	1,800
Lamp Efficacy (lm/W)	111.0	130.7	112.5	140.1	163.6	166.2	194.1	192.2	224.4	218.0	250.0
System Wattage	36.9	32.6	32.0	27.4	22.0	23.1	18.6	20.0	16.0	17.6	14.4
System Lumens	3,583	4,004	3,384	3,686	3,456	3,686	3,456	3,686	3,456	3,686	3,456
System Efficacy (lm/W)	97.0	122.8	105.8	134.5	157.1	159.6	186.3	184.5	215.4	209.3	240.0
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	83	82	82	81	80	81	80	81	80	81	80
Correlated Color Temperature (CCT)	4,100	3,500	4,100	4,100	5,000	4,100	5,000	4,100	5,000	4,100	5,000
Average Lamp Life (thousand hours)	55	50	50	54	50	54	50	54	50	54	50
Annual Operating Hours (h/y)	730	730	730	730	730	730	730	730	730	730	730
Lamp Price (2022$)	$27.00	$12.89	$14.63	$11.11	$4.28	$9.97	$3.84	$9.87	$3.80	$9.77	$3.77
Ballast Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$13.41	$6.05	$8.13	$5.79	$2.38	$5.19	$2.13	$5.14	$2.11	$5.09	$2.09
System (l/b/f) Cost (2022$/klm)	N/A	$6.44	$8.65	$6.03	$2.48	$5.41	$2.22	$5.35	$2.20	$5.30	$2.18
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor System Installation (hours)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Change (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$54.00	$25.78	$29.26	$22.22	$8.56	$19.95	$7.68	$19.74	$7.60	$19.55	$7.53
Annual Maintenance Cost (2022$)	$0.72	$0.38	$0.43	$0.30	$0.12	$0.27	$0.11	$0.27	$0.11	$0.26	$0.11
Total Installed Cost (2022$/klm)	$15.07	$6.44	$8.65	$6.03	$2.48	$5.41	$2.22	$5.35	$2.20	$5.30	$2.18
Annual Maintenance Cost (2022$/klm)	$0.20	$0.09	$0.13	$0.08	$0.04	$0.07	$0.03	$0.07	$0.03	$0.07	$0.03

1. N/A because a fixture and an LED replacement lamp would not be purchased separately for a new installation or retrofit when there are integrated LED luminaires that are more efficient and cost effective. These lamps are sold only as replacements to go into existing fixtures.

Note: Assume no labor is associated with lamp replacement in the residential sector because residents likely replace lamps themselves.

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Performance and Cost Characteristics » Residential Linear LED Luminaire

Final

DATA	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	50.0	43.1	49.0	44.0	35.0	35.6	28.3	29.9	23.8	25.8	20.5
System Lumens	4,615	4,945	5,024	5,302	4,800	5,302	4,800	5,302	4,800	5,302	4,800
System Efficacy (lm/W)	92.3	114.7	102.5	120.5	137.1	148.8	169.3	177.2	201.7	205.5	233.9
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	83	82	80	79	80	79	80	79	80	79	80
Correlated Color Temperature (CCT)	3,838	3,000	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
Average Lamp Life (thousand hours)	56	58	54	53	50	53	50	53	50	53	50
Annual Operating Hours (h/y)	584	584	584	584	584	584	584	584	584	584	584
Lamp or Luminaire Price (2022$)	$181.60	$158.60	$144.85	$152.54	$207.80	$121.11	$164.98	$105.34	$143.50	$90.11	$122.76
Ballast Price (2022$) [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$78.70	$64.15	$57.66	$57.54	$86.58	$45.68	$68.74	$39.74	$59.79	$33.99	$51.15
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Labor Lamp Change (hours)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$401.81	$355.81	$322.70	$338.08	$448.60	$275.22	$362.97	$243.68	$320.01	$213.23	$278.52
Annual Maintenance Cost (2022$)	$2.30	$1.97	$1.92	$2.04	$2.81	$1.70	$2.31	$1.52	$2.06	$1.36	$1.82
Total Installed Cost (2022$/klm)	$87.07	$71.95	$64.23	$63.76	$93.46	$51.91	$75.62	$45.96	$66.67	$40.22	$58.03
Annual Maintenance Cost (2022$/klm)	$0.50	$0.40	$0.38	$0.39	$0.59	$0.32	$0.48	$0.29	$0.43	$0.26	$0.38

1. N/A because the lamp and fixture are both included in the luminaire.

Performance and Cost Characteristics » Residential Outdoor Lamps

Final

- The residential outdoor lamps characterized in this report include reflector and general service lamps used for security and/or porch lighting that can be switched on from inside the home (i.e. parking lot/garage and outdoor common area lighting at multifamily buildings are excluded) with lumen outputs of approximately 1,000 – 1,400 lumens. Multiple baseline lamps were analyzed according to estimates of installed base average lumens by lamp type, including:

Security (Reflector Lamps)	Porch (General Service Lamps)
Incandescent BR30	Incandescent A-Type
Halogen PAR38	Halogen A-Type
Halogen Infrared Reflector (HIR) PAR38	CFL Bare Spiral
CFL PAR38	LED A-Type Lamp
LED PAR38	

Performance:

- 65W BR30 is the only viable incandescent reflector lamp due to exemption from EISA 2007. The lumen output of this lamp type is well below other reflector lamp technologies characterized for residential outdoor spaces, thus its use is limited for this application. This product is, as of 2022, expected to be eliminated by DOE's 45 lm/W backstop requirement.
- A majority of residential lamps have a nominal CCT rating of 2,700K and give off a warm, yellowish white color, but products with CCTs of 3,000K, 3,500K, 4,100K (neutral white), 5,000K (daylight), and 6,500K (blueish white) are also available. Traditional incandescent light bulbs have a nominal CCT of about 2,700K. When replacing a light bulb, it is advised to chose a product with a similar CCT value in order to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100. However, CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination. High CRI products are preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these specific retail and display applications.

Cost:

- Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy. Therefore, typical lamp prices in 2015 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Fixture prices and installation costs are not included for the residential sector. Labor costs are assumed to be negligible because homeowners likely replaces lamps themselves as they burn out. Therefore, total installed cost is the price of a lamp, and annual maintenance costs are the cost of replacing the lamps, which is a function of lamp life, lamp price, and the annual operating hours for residential reflector lamps.
- Disposal costs are not characterized for residential lighting in this analysis. In residential cases, disposal is done by the occupant. Lamp and product burnout are assumed to result in no "added" cost aside from the work performed to install the replacement.

Performance and Cost Characteristics » Residential Outdoor Lamps

Final

Legislation:

- In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. **This action also amended the definition of general service lamps to include previously exempted product classes, such as reflector lamps.** These standards can not be achieved by traditional incandescent or halogen technologies currently on the market, and given current and projected trends in industry, they will likely not be met. It is currently assumed that industry will increase its investment in LED technology at the expense of incandescent, halogen, and CFL technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

ENERGY STAR:

- For ENERGY STAR qualification, general service omnidirectional lamps must have a minimum lamp efficacy of 70 lm/W for products with CRI ≥ 90 and 80 lm/W for lamps with CRI < 90.
- For ENERGY STAR qualification, general service reflector lamps must have a minimum lamp efficacy of 61 lm/W for products with CRI ≥ 90 and 70 lm/W for lamps with CRI < 90.
- Additionally, the lamps must have a CRI ≥ 80, nominal CCT of 2,700, 3,000, 3,500, 4,000/4,100, 5,000, or 6,000 K, and rated lifetime ≥ 10,000 hours (ENERGY STAR).

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

Technology	Efficacy	Lifetime	Price	Potential for Improvements
Incandescent Omnidirectional	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
Incandescent Directional	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
Halogen	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
CFL	+0.5%	0%	-0.5%	In addition to benefiting from higher efficiency reflector coatings, improvements in efficacy can be made by using more rare-earth phosphors in compact fluorescent lamps. Lifetime improvements can be made by improving the compact fluorescent lamp electrodes.

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Performance and Cost Characteristics » Residential Outdoor Lamps (Security: Incandescent BR30)

Final

DATA	2015[1]	2020[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	65.0	65.0	N/A	65.0	N/A	N/A	13.3	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	637	637	N/A	602	N/A	N/A	600	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	9.8	9.8	N/A	9.3	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,700	2,700	N/A	2,700	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	2.0	2.0	N/A	2.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	621	621	N/A	621	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$4.00	$4.00	N/A	$3.70	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$6.28	$6.28	N/A	$6.15	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$4.00	$4.00	N/A	$3.70	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$1.24	$1.24	N/A	$1.15	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$6.28	$6.28	N/A	$6.15	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$1.95	$1.95	N/A	$1.91	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. Incandescent BR30 lamps were previously exempted from DOE Incandescent Reflector Lamp standards and the EISA 2007 general service lamp definition until DOE's new final rule in 2022. The new definitions go into effect in 2023.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. These standards cannot be met with incandescent technologies.

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Performance and Cost Characteristics » Residential Outdoor Lamps (Security: Halogen PAR38)

Final

DATA	2015	2020	2022				2023[1]	2030[1]		2040[1]		2050[1]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	88.7	78.7	N/A	70.0	N/A	N/A	29.1	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	1,323	1,316	N/A	1,308	N/A	N/A	1,308	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	14.9	16.9	N/A	18.7	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,900	2,900	N/A	2,900	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	2.4	2.4	N/A	1.4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	876	876	N/A	876	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$6.24	$9.15	N/A	$10.32	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$4.71	$6.96	N/A	$7.89	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$6.24	$9.15	N/A	$10.32	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$2.28	$3.34	N/A	$6.62	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$4.71	$6.96	N/A	$7.89	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$1.72	$2.54	N/A	$5.06	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. These standards cannot be met with halogen technologies.

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Performance and Cost Characteristics » Residential Outdoor Lamps (Security: HIR PAR38)

Final

DATA	2015	2020	2022				2023[1]	2030[1]		2040[1]		2050[1]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	70.0	70.0	N/A	70.0	N/A	N/A	28.0	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	1,407	1,334	N/A	1,260	N/A	N/A	1,260	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	20.1	19.1	N/A	18.0	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,850	2,850	N/A	2,900	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	3.6	3.6	N/A	3.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	876	876	N/A	876	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$21.85	$27.31	N/A	$29.49	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$15.53	$20.48	N/A	$23.40	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$21.85	$27.31	N/A	$29.49	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$5.32	$6.64	N/A	$8.61	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$15.53	$20.48	N/A	$23.40	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$3.78	$4.98	N/A	$6.83	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. These standards cannot be met with halogen technologies.

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Performance and Cost Characteristics » Residential Outdoor Lamps (Security: CFL PAR38)

Final

DATA	2015[1]	2020[1]	2022[2]				2023[3]	2030[3]		2040[3]		2050[3]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	23.0	22.4	N/A	N/A	N/A	N/A	28.9	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	1,300	1,300	N/A	N/A	N/A	N/A	1,300	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	56.5	57.9	N/A	N/A	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	82	82	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,700	2,700	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	10.0	10.3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	913	913	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$8.52	$8.31	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$6.55	$6.39	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$8.52	$8.31	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$0.78	$0.74	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$6.55	$6.39	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$0.60	$0.57	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. 2015 and 2020 data calculated based on 2009 installed stock data and the following assumptions: Efficacy +0.5%/y, Cost -0.5%/y (NCI, 2019)
2. Virtually all manufacturers have discontinued manufacturing of CFL reflector lamps in favor of LEDs. Distributor offerings for CFL reflectors have been eliminated.
3. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. Although these standards can be met with CFL technology, manufacturers have discontinued manufacturing CFL reflector lamps in favor of LEDs.

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Performance and Cost Characteristics » Residential Outdoor Lamps (Security: LED PAR38)

Final

DATA	2015	2020	2022				2023[1]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[2]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	19.2	15.5	17.0	16.4	17.0	22.0	29.9	14.0	14.6	12.3	12.7	10.9	11.3
Lamp Lumens	1,202	1,211	1,200	1,344	1,700	1,344	1,344	1,344	1,700	1,344	1,700	1,344	1,700
Lamp Efficacy (lm/W)	62.7	77.9	70.6	82.0	100.0	61.0	45.0	95.7	116.7	109.5	133.5	123.2	150.2
CRI	83	86	82	86	82	80	N/A	86	86	86	86	86	86
Correlated Color Temperature (CCT)	3,000	3,000	2,700	3,000	3,000	3,000	N/A	3,000	3,000	3,000	3,000	3,000	3,000
Average Lamp Life (thousand hours)	24	27	25	27	25	15	N/A	27	25	27	25	27	25
Annual Operating Hours (h/y)	730	730	730	730	730	N/A	N/A	730	730	730	730	730	730
Lamp Price (2022$)	$35.23	$22.44	$23.71	$23.09	$15.69	N/A	N/A	$19.40	$13.18	$17.36	$11.79	$15.37	$10.45
Lamp Cost (2022$/klm)	$29.31	$18.54	$19.76	$17.18	$9.23	N/A	N/A	$14.43	$7.75	$12.91	$6.94	$11.44	$6.14
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0.0	0.0	0.0	0.0	0.0	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$35.23	$22.44	$23.71	$23.09	$15.69	N/A	N/A	$19.40	$13.18	$17.36	$11.79	$15.37	$10.45
Annual Maintenance Cost (2022$)	$1.07	$0.60	$0.69	$0.62	$0.46	N/A	N/A	$0.52	$0.38	$0.46	$0.34	$0.41	$0.31
Total Installed Cost (2022$/klm)	$29.31	$18.54	$19.76	$17.18	$9.23	N/A	N/A	$14.43	$7.75	$12.91	$6.94	$11.44	$6.14
Annual Maintenance Cost (2022$/klm)	$0.89	$0.49	$0.58	$0.46	$0.27	N/A	N/A	$0.39	$0.23	$0.35	$0.20	$0.31	$0.18

1. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. All LED lighting products exceed the new minimum efficacy standards.
2. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)

Performance and Cost Characteristics » Residential Outdoor Lamps (Porch: Incandescent A19)

Final

DATA	2015[1]	2020[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	75.0	75.0	N/A	N/A	N/A	N/A	26.0	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	1,170	1,170	N/A	N/A	N/A	N/A	1,170	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	15.6	15.6	N/A	N/A	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,700	2,700	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	0.8	0.8	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	511	511	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$0.44	$0.44	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$0.38	$0.38	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$0.44	$0.44	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$0.30	$0.30	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$0.38	$0.38	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$0.26	$0.26	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. The Energy Independence and Security Act of 2007 (EISA 2007) prescribes standards for 75 watt incandescent lamps as of January 1, 2013. Despite the phase out of incandescent lamps, these products remain in the installed stock.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. These standards cannot be met with incandescent technologies.

Performance and Cost Characteristics » Residential Outdoor Lamps (Porch: Halogen A19)

Final

DATA	2015[1]	2020[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	53.0	53.0	N/A	53.0	N/A	N/A	19.8	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	1050	936	N/A	890	N/A	N/A	890	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	19.8	17.7	N/A	16.8	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,850	2,950	N/A	2,950	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	1.0	1.0	N/A	1.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	621	621	N/A	621	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$2.37	$3.58	N/A	$4.06	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$2.26	$3.82	N/A	$4.56	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Installation (hours)	0	0	N/A	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$2.37	$3.58	N/A	$4.06	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$1.47	$2.22	N/A	$2.52	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$2.26	$3.82	N/A	$4.56	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$1.40	$2.37	N/A	$2.83	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. The Energy Independence and Security Act of 2007 prescribes standards for current 75 watt incandescent lamps as of January 1, 2013. Starting in 2013, 75 watt incandescent lamps were replaced by halogen lamps.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. These standards cannot be met with existing halogen lamp technologies.

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Performance and Cost Characteristics » Residential Outdoor Lamps (Porch: CFL Bare Spiral)

Final

DATA	2015	2020[1]	2022				2023[3]	2030[4]		2040[4]		2050[4]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[2]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	18.6	14.6	20.0	18.8	18.0	13.8	26.0	13.9	12.8	13.2	12.2	12.5	11.6
Lamp Lumens	1,216	900	1,100	1,171	1,250	800	1,171	900	925	900	925	900	925
Lamp Efficacy (lm/W)	65.4	61.8	55.0	62.4	69.4	80.0	45.0	65.0	72.3	68.3	76.0	71.8	79.9
CRI	82	82	85	83	82	80	N/A	83	82	83	82	83	82
Correlated Color Temperature (CCT)	2,700	2,700	5,000	2,700	2,700	2,700	N/A	2,700	2,700	2,700	2,700	2,700	2,700
Average Lamp Life (thousand hours)	10.0	10.0	12.0	10.4	10.0	10.0	N/A	10.4	10.0	10.4	10.0	10.4	10.0
Annual Operating Hours (h/y)	767	767	767	767	767	N/A	N/A	767	767	767	767	767	767
Lamp Price (2022$)	$3.82	$5.33	$9.00	$5.28	$5.91	N/A	N/A	$5.07	$5.67	$4.82	$5.40	$4.59	$5.13
Lamp Cost (2022$/klm)	$3.14	$5.92	$8.18	$4.51	$4.72	N/A	N/A	$5.63	$6.13	$5.36	$5.83	$5.10	$5.55
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0	0	0	0	0	N/A	N/A	0	0	0	0	0	0
Total Installed Cost (2022$)	$3.82	$5.33	$9.00	$5.28	$5.91	N/A	N/A	$5.07	$5.67	$4.82	$5.40	$4.59	$5.13
Annual Maintenance Cost (2022$)	$0.29	$0.41	$0.58	$0.39	$0.45	N/A	N/A	$0.37	$0.44	$0.36	$0.41	$0.34	$0.39
Total Installed Cost (2022$/klm)	$3.14	$5.92	$8.18	$4.51	$4.72	N/A	N/A	$5.63	$6.13	$5.36	$5.83	$5.10	$5.55
Annual Maintenance Cost (2022$/klm)	$0.24	$0.45	$0.52	$0.33	$0.36	N/A	N/A	$0.42	$0.47	$0.40	$0.45	$0.38	$0.43

1. 2020 data back calculated based on 2022 data and the following assumptions: Efficacy +0.5%/y, Cost -0.5%/y (NCI, 2019)
2. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
3. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. CFL products exceed the new minimum efficacy standards.
4. The market for 75W equivalent bare spiral CFLs is very limited because almost all product lines are discontinued. This trend is expected to continue until no products are offered at this level by 2030.

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Performance and Cost Characteristics » Residential Outdoor Lamps (Porch: LED A-Type)

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DATA	2015	2020	2022				2023[1]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[2]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	12.9	11.8	13.5	11.9	11.0	13.6	24.4	9.9	9.1	7.7	7.1	6.7	6.2
Lamp Lumens	1,073	1,102	1,100	1,089	1,100	1,089	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Lamp Efficacy (lm/W)	83.1	93.5	81.5	92.2	100.0	80	45.0	111.5	120.9	142.0	154.0	164.6	178.6
CRI	81	85	80	86	80	80	N/A	86	80	86	80	86	80
Correlated Color Temperature (CCT)	2,700	2,700	3,000	2,700	2,700	2,700	N/A	2,700	2,700	2,700	2,700	2,700	2,700
Average Lamp Life (thousand hours)	25	21	25	18	25	15	N/A	18	25	18	25	18	25
Annual Operating Hours (h/y)	657	657	657	657	657	N/A	N/A	657	657	657	657	657	657
Lamp Price (2022$)	$18.13	$8.48	$4.39	$3.92	$5.29	N/A	N/A	$3.23	$4.36	$2.84	$3.84	$2.46	$3.31
Lamp Cost (2022$/klm)	$16.90	$7.70	$3.99	$3.60	$4.81	N/A	N/A	$7.02	$7.02	$3.57	$3.57	$2.38	$2.38
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0.0	0.0	0.0	0.0	0.0	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$18.13	$8.48	$4.39	$3.92	$5.29	N/A	N/A	$3.23	$4.36	$2.84	$3.84	$2.46	$3.31
Annual Maintenance Cost (2022$)	$0.49	$0.27	$0.12	$0.14	$0.14	N/A	N/A	$0.12	$0.11	$0.10	$0.10	$0.09	$0.09
Total Installed Cost (2022$/klm)	$16.90	$7.70	$3.99	$3.60	$4.81	N/A	N/A	$2.94	$3.97	$2.59	$3.49	$2.23	$3.01
Annual Maintenance Cost (2022$/klm)	$0.45	$0.24	$0.10	$0.13	$0.13	N/A	N/A	$0.11	$0.10	$0.09	$0.09	$0.08	$0.08

1. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. All LED lighting products exceed the new minimum efficacy standards.
2. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)

Commercial Lighting

Performance and Cost Characteristics » Commercial General Service Lamps in Recessed Can Fixtures

Final

This section characterizes commercial omnidirectional incandescent, halogen, CFL, and LED screw-based general service lamps emitting approximately 1,600 lumens (equivalent to a 100W incandescent lamp) used in recessed can fixtures. A recessed can is a directional fixture set into the ceiling, in which all of the light is directed downwards from the opening. Therefore, an omnidirectional lamp is not well suited for use in such fixtures because light that emits upwards and out of the sides must be reflected downwards and out of the fixture and some light is absorbed in the process. A fixture efficiency of 61% is used to characterize these lumen losses for all omnidirectional lamps. For all lamp technologies, an annual fixture renovation rate of 10% (i.e., 10-year fixture service life) is used to reflect the proportion of equipment that retires each year.

Performance:

- A majority of general service lamps have a nominal CCT rating of 2,700K and give off a warm, yellowish white color, but products with CCTs of 3,000K, 3,500K, 4,100K (neutral white), 5,000K (daylight), and 6,500K (blueish white) are also available. Traditional incandescent light bulbs have a nominal CCT of about 2,700K. When replacing a light bulb, it is advised to chose a product with a similar CCT value in order to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100. However, CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination. High CRI products are preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these specific retail and display applications.

Cost:

- The total installed cost is the price of a lamp, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED replacement lamps which are sold only as a replacement for use in an existing fixture. There are integrated LED luminaires that are more efficient and cost effective for new installations or fixture retrofits. Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy. Therefore typical lamp prices in 2015 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Annual maintenance costs are the cost of labor for replacing the lamps and the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours for commercial general service lamps (DOE SSL Program, 2012a).
- Commercial lighting disposal costs are estimated to be $0.12 per linear foot of fluorescent lamps, $1.50 per lamp for high intensity discharge (HID) lamps, and $0.50 for CFLs (EPA, 2022).

Legislation:

- The Energy Independence and Security Act of 2007 (EISA 2007) established standards for 100W lamps effective in 2012. These standards cannot be achieved by incandescent bulbs, but they can be met by halogen, CFL, and LED technologies from 2012 to 2023.
- In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. This action also amended the definition of general service lamps to include previously exempted product classes, such as reflector lamps. These standards can not be achieved by traditional incandescent or halogen technologies currently on the market, and given current and projected trends in industry, they will likely not be met. It is currently assumed that industry will increase its investment in LED technology at the expense of incandescent, halogen, and CFL technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

ENERGY STAR:

- For ENERGY STAR qualification, general service omnidirectional lamps must have a minimum lamp efficacy of 70 lm/W for products with CRI ≥ 90 and 80 lm/W for lamps with CRI < 90. Additionally, the lamps must have a CRI ≥ 80, nominal CCT of 2,700, 3,000, 3,500, 4,000/4,100, 5,000, or 6,000 K, and rated lifetime ≥ 10,000 hours (ENERGY STAR).

Performance and Cost Characteristics » Commercial General Service Lamps in Recessed Can Fixtures

Final

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus would be on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

Technology	Efficacy	Lifetime	Price	Potential for Improvements
Incandescent	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
Halogen	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements as of 2022
CFL	+0.5%	0%	-0.5%	Improvements in efficacy can be made by using more rare-earth phosphors in compact fluorescent lamps. Lifetime improvements can be made by improving the compact fluorescent lamp electrodes.

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Performance and Cost Characteristics » Commercial General Service 100W Incandescent Lamp in Recessed Can Fixture

Final

DATA	2012[1]	2018[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	100.0	100.0	N/A	N/A	N/A	N/A	36.0	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	1,620	1,620	N/A	N/A	N/A	N/A	1,620	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	16.2	16.2	N/A	N/A	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	100.0	100.0	N/A	N/A	N/A	N/A	36.0	N/A	N/A	N/A	N/A	N/A	N/A
System Lumens[3]	988	988	N/A	N/A	N/A	N/A	988	N/A	N/A	N/A	N/A	N/A	N/A
System Efficacy (lm/W)	9.9	9.9	N/A	N/A	N/A	N/A	27.5	N/A	N/A	N/A	N/A	N/A	N/A
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,700	2,700	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	0.8	0.8	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	4,015	4,015	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$0.67	$0.67	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$23.72	$23.72	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$0.41	$0.41	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$24.68	$24.68	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$77.22	$77.22	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor System Installation (hours)	1.0	1.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Change (hours)	0.05	0.05	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$101.61	$101.61	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$24.25	$24.25	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$102.83	$102.83	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$24.54	$24.54	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. The Energy Independence and Security Act of 2007 (EISA 2007) prescribes standards for 100 watt incandescent lamps as of January 1, 2012. Despite the phase out of incandescent lamps, these products remain in the installed stock.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. These standards cannot be met with incandescent technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. Note: the 45 lm/W backstop applies to the lamp, not the calculated fixture efficacy.
3. Based on a fixture efficiency of 61% for an omnidirectional lamp installed in a recessed can fixture.

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Performance and Cost Characteristics » Commercial General Service Halogen Lamp (100W Incandescent Equivalent) in Recessed Can Fixture

Final

DATA	2012[1]	2018[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	72.0	72.0	N/A	72.0	N/A	N/A	33.1	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	1,490	1,490	N/A	1,490	N/A	N/A	1,490	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	20.7	20.7	N/A	20.7	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	72.0	72.0	N/A	72.0	N/A	N/A	33.1	N/A	N/A	N/A	N/A	N/A	N/A
System Lumens[3]	909	909	N/A	909	N/A	N/A	909	N/A	N/A	N/A	N/A	N/A	N/A
System Efficacy (lm/W)	12.6	12.6	N/A	12.6	N/A	N/A	27.5	N/A	N/A	N/A	N/A	N/A	N/A
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,850	3,000	N/A	3,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	1.0	1.0	N/A	1.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	4,015	4,015	N/A	4,015	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$2.33	$5.16	N/A	$4.02	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$23.72	$26.38	N/A	$22.07	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$1.57	$3.46	N/A	$2.70	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$28.67	$34.71	N/A	$28.71	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$77.22	$77.22	N/A	$66.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor System Installation (hours)	1.0	1.0	N/A	1.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Change (hours)	0.05	0.05	N/A	0.05	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$103.28	$108.77	N/A	$92.09	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$24.87	$36.23	N/A	$29.39	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$113.63	$119.67	N/A	$101.32	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$27.36	$39.86	N/A	$32.34	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. The Energy Independence and Security Act of 2007 (EISA 2007) prescribes standards for 100 watt incandescent lamps as of January 1, 2012. Starting in 2012, 100 watt incandescent lamps were replaced by halogen lamps.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. These standards cannot be met with existing commercialized halogen lamp technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. Note: the 45 lm/W backstop applies to the lamp, not the calculated fixture efficacy.
3. Based on a fixture efficiency of 61% for an omnidirectional lamp installed in a recessed can fixture.

Additional note: No products are currently marketed specifically as 100W equivalent HIR general service lamps and no available data from manufacturers. It is assumed this market is the same as 100W equivalent halogen lamps.

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Performance and Cost Characteristics » Commercial General Service 100W Equivalent CFL Bare Spiral in Recessed Can Fixture

Final

DATA	2012	2018	2022				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[1]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	24.7	24.6	25.0	24.6	26.0	26.0	37.6	23.6	25.0	22.5	23.8	21.4	22.6
Lamp Lumens	1,680	1,680	1,600	1,694	1,835	1,600	1,694	1,694	1,835	1,694	1,835	1,694	1,835
Lamp Efficacy (lm/W)	68.1	68.2	64.0	68.9	70.6	80.0	45.0	71.7	73.4	75.3	77.2	79.2	81.2
System Wattage	24.7	24.6	25.0	24.6	26.0	26.0	37.6	23.6	25.0	22.5	23.8	21.4	22.6
System Lumens[3]	1,025	1,025	976	1,033	1,119	976	1,033	1,033	1,119	1,033	1,119	1,033	1,119
System Efficacy (lm/W)	41.6	41.6	39.0	42.0	43.1	37.5	27.5	43.7	44.8	46.0	47.1	48.3	49.5
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	82	82	82	82	82	82	N/A	82	82	82	82	82	82
Correlated Color Temperature (CCT)	3,000	3,000	2,700	3,000	5,000	3,000	N/A	3,000	3,000	3,000	3,000	3,000	3,000
Average Lamp Life (thousand hours)	10.0	10.0	10.0	10.0	10.0	10.0	N/A	10.0	10.0	10.0	10.0	10.0	10.0
Annual Operating Hours (h/y)	4,745	4,745	4,745	4,745	4,745	N/A	N/A	4,745	4,745	4,745	4,745	4,745	4,745
Lamp Price (2022$) [4]	$3.08	$6.40	$9.90	$8.62	$9.35	N/A	N/A	$8.28	$8.98	$7.87	$8.54	$7.49	$8.13
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$) [4]	$23.72	$26.38	$22.07	$22.07	$22.07	N/A	N/A	$21.20	$21.20	$20.17	$20.17	$19.18	$19.18
Disposal Cost (2022$)	$0.50	$0.50	$0.50	$0.50	$0.50	N/A	N/A	$0.50	$0.50	$0.50	$0.50	$0.50	$0.50
Lamp Cost (2022$/klm)	$1.84	$3.81	$6.19	$5.09	$5.10	N/A	N/A	$4.89	$4.90	$4.65	$4.66	$4.42	$4.43
System (l/b/f) Cost (2022$/klm)	$26.15	$31.98	$32.76	$29.70	$28.07	N/A	N/A	$28.53	$26.97	$27.13	$25.65	$25.81	$24.39
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	N/A	N/A	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	1.0	1.0	1.0	1.0	1.0	N/A	N/A	1.0	1.0	1.0	1.0	1.0	1.0
Labor Lamp Change (hours)	0.05	0.05	0.05	0.05	0.05	N/A	N/A	0.05	0.05	0.05	0.05	0.05	0.05
Total Installed Cost (2022$)	$104.03	$110.01	$97.97	$96.69	$97.42	N/A	N/A	$95.48	$96.18	$94.04	$94.71	$92.67	$93.31
Annual Maintenance Cost (2022$)	$3.53	$5.11	$6.50	$5.89	$6.24	N/A	N/A	$5.73	$6.07	$5.54	$5.86	$5.36	$5.66
Total Installed Cost (2022$/klm)	$101.48	$107.32	$100.38	$93.57	$87.03	N/A	N/A	$92.40	$85.93	$91.00	$84.61	$89.68	$83.36
Annual Maintenance Cost (2022$/klm)	$3.45	$4.98	$6.66	$5.70	$5.57	N/A	N/A	$5.55	$5.42	$5.36	$5.23	$5.18	$5.06

1. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. These standards can be met with existing CFL products. Note: the 45 lm/W backstop applies to the lamp, not the calculated fixture efficacy.
3. Based on a fixture efficiency of 61% for an omnidirectional lamp installed in a recessed can fixture.
4. Year-to-year price and performance assumptions 2022 – 2050: Efficacy +0.5%, Equipment Cost -0.5%

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Performance and Cost Characteristics » Commercial General Service 100W Equivalent LED Replacement Lamp in Recessed Can Fixture

Final

DATA	2012	2018	2022				2023[2]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[1]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	26.7	14.5	16.0	14.8	13.0	20.0	34.8	12.2	10.8	9.6	8.4	8.3	7.3
Lamp Lumens	1,600	1,528	1,600	1,567	1,600	1,600	1,567	1,567	1,600	1,567	1,600	1,567	1,600
Lamp Efficacy (lm/W)	60.0	105.1	100.0	106.0	123.1	80.0	45.0	128.2	148.8	163.3	189.5	189.3	219.8
System Wattage	26.7	14.5	16.0	14.8	13.0	20.0	34.8	12.2	10.8	9.6	8.4	8.3	7.3
System Lumens[3]	976	932	976	956	976	976	956	956	976	956	976	956	976
System Efficacy (lm/W)	36.6	64.1	61.0	64.7	75.1	48.8	27.5	78.2	90.8	99.6	115.6	115.5	134.1
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	80	80	90	84.8	84	80	N/A	84.8	84.8	84.8	84.8	84.8	84.8
Correlated Color Temperature (CCT)	3,000	3,000	2,700	2,700	5,000	N/A	N/A	2,700	2,700	2,700	2,700	2,700	2,700
Average Lamp Life (thousand hours)	22.0	17.9	25.0	16.9	25.0	15.0	N/A	16.9	25.0	16.9	25.0	16.9	25.0
Annual Operating Hours (h/y)	4,928	4,928	4,928	4,928	4,928	N/A	N/A	4,928	4,928	4,928	4,928	4,928	4,928
Lamp Price (2022$)	$47.45	$11.28	$5.62	$7.04	$3.39	N/A	N/A	$5.81	$2.80	$5.11	$2.46	$4.41	$2.12
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$23.72	$26.38	$22.07	$22.07	$22.07	N/A	N/A	$21.20	$21.20	$20.17	$20.17	$19.18	$19.18
Lamp Cost (2022$/klm)	$25.00	$7.38	$3.51	$4.49	$2.12	N/A	N/A	$3.71	$1.75	$3.26	$1.54	$2.82	$1.33
System (l/b/f) Cost (2022$/klm)	$72.92	$40.40	$28.37	$30.46	$26.09	N/A	N/A	$28.26	$24.59	$26.45	$23.18	$24.68	$21.83
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	N/A	N/A	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	1.0	1.0	1.0	1.0	1.0	N/A	N/A	1.0	1.0	1.0	1.0	1.0	1.0
Labor Lamp Change (hours)	0.05	0.05	0.05	0.05	0.05	N/A	N/A	0.05	0.05	0.05	0.05	0.05	0.05
Total Installed Cost (2022$)	$148.39	$114.88	$93.69	$95.11	$91.46	N/A	N/A	$93.01	$90.00	$91.27	$88.63	$89.59	$87.30
Annual Maintenance Cost (2022$)	$11.49	$4.16	$1.76	$3.02	$1.32	N/A	N/A	$2.66	$1.20	$2.45	$1.14	$2.25	$1.07
Total Installed Cost (2022$/klm)	$152.04	$123.25	$95.99	$99.52	$93.71	N/A	N/A	$97.32	$92.21	$95.51	$90.81	$93.75	$89.45
Annual Maintenance Cost (2022$/klm)	$11.77	$4.46	$1.80	$3.16	$1.35	N/A	N/A	$2.78	$1.23	$2.57	$1.16	$2.35	$1.10

1. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. All LED lighting products exceed the new minimum efficacy standards. Note: the 45 lm/W backstop applies to the lamp, not the calculated fixture efficacy.
3. Based on a fixture efficiency of 61% for an omnidirectional lamp installed in a recessed can fixture.

Performance and Cost Characteristics » Commercial Reflector Lamps in Recessed Can Fixtures

Final

This section characterizes commercial halogen, halogen infrared reflector (HIR), and LED screw-based reflector lamps emitting approximately 1400 lumens used in recessed can fixtures.

- HIR lamps contain a tungsten halogen capsule with a film coating on the inside of the capsule. The coating reflects infrared radiation back into the lamp filament, which forces the filament to burn at a higher temperature. This design increases the efficacy of the lamp, without reducing operating life.
- A recessed can is a directional fixture set into the ceiling, in which all of the light is directed downwards from the opening. Therefore, a reflector lamp, which employs reflective coating to direct light out in only one direction, is well suited for use in such fixtures. However, some light is not able to escape the fixture, and a fixture efficiency of 93% is used to characterize these minimal lumen losses. For all lamp technologies, an annual fixture renovation rate of 10% (i.e., 10-year fixture service life) is used to reflect the proportion of equipment that retires each year.

Performance:

- A majority of reflector lamps have a nominal CCT rating of 2,700K and give off a warm, yellowish white color, but products with CCTs of 3,000K, 3,500K, 4,100K (neutral white), 5,000K (daylight), and 6,500K (blueish white) are also available. Traditional incandescent light bulbs have a nominal CCT of about 2,700K. When replacing a light bulb, it is advised to chose a product with a similar CCT value in order to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100. However, CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination. High CRI products are preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these specific retail and display applications.

Cost:

- The total installed cost is the price of a lamp, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED replacement lamps which are sold only as a replacement for use in an existing fixture. Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy.
- Annual maintenance costs are the cost of labor for replacing the lamps and the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours for commercial reflector lamps (DOE SSL Program, 2012a).
- Commercial lighting disposal costs are estimated to be $0.12 per linear foot of fluorescent lamps, $1.50 per lamp for HID lamps, and $0.50 for CFLs (EPA, 2022).

Legislation:

- EPAct92 established minimum performance standards for some reflector lamps and provided exemptions for certain specialty applications (e.g., ER/BR, vibration service, more than 5% neodymium oxide, impact resistant, infrared heat, colored). EPAct92 effectively phased-out R-shaped tungsten filament incandescent reflector lamps at certain wattages and bulb diameters, replacing them with more efficient and cost effective tungsten-halogen parabolic aluminized reflector (PAR) lamps. EISA2007 took away certain exemptions from EPACT 1992, requiring certain previously exempted lamps to meet EPAct92 minimum performance standards by January 1, 2008. In 2015, DOE issued a final rule that determined that amending the standards for incandescent reflector lamps could not be economically justified.
- In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. **This action also amended the definition of general service lamps to include previously exempted product classes, such as reflector lamps.** These standards can not be achieved by traditional incandescent or halogen technologies currently on the market, and given current and projected trends in industry, they will likely not be met. It is currently assumed that industry will increase its investment in LED technology at the expense of incandescent, halogen, and CFL technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

Performance and Cost Characteristics » Commercial Reflector Lamps in Recessed Can Fixtures

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ENERGY STAR:

- For ENERGY STAR qualification, general service reflector lamps must have a minimum lamp efficacy of 61 lm/W for products with CRI ≥ 90 and 70 lm/W for lamps with CRI < 90. Additionally, the lamps must have a CRI ≥ 80, nominal CCT of 2,700, 3,000, 3,500, 4,000/4,100, 5,000, or 6,000 K, and rated lifetime ≥ 10,000 hours (ENERGY STAR).

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus would be on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

Technology	Efficacy	Lifetime	Price	Potential for Improvements
Incandescent	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
Halogen	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements as of 2022
CFL	+0.5%	0%	-0.5%	In addition to higher efficiency reflector coatings, improvements in efficacy can be made by using more rare-earth phosphors in compact fluorescent lamps. Lifetime improvements can be made by improving the compact fluorescent lamp electrodes.

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Performance and Cost Characteristics » Commercial Halogen Reflector Lamp (PAR38) in Recessed Can Fixture

Final

DATA	2012	2018	2022				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	90.0	87.3	N/A	70.0	N/A	N/A	29.1	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	1,323	1,323	N/A	1,308	N/A	N/A	1,308	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	14.7	15.1	N/A	18.7	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	90.0	87.3	N/A	70.0	N/A	N/A	29.1	N/A	N/A	N/A	N/A	N/A	N/A
System Lumens[1]	1,230	1,230	N/A	1,217	N/A	N/A	1,217	N/A	N/A	N/A	N/A	N/A	N/A
System Efficacy (lm/W)	13.7	14.1	N/A	17.4	N/A	N/A	41.9	N/A	N/A	N/A	N/A	N/A	N/A
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,850	2,850	N/A	2,850	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	2.4	2.4	N/A	1.4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	4,052	4,052	N/A	4,052	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$4.49	$7.99	N/A	$10.32	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$23.72	$26.38	N/A	$22.07	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$3.39	$6.04	N/A	$7.89	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$22.93	$27.93	N/A	$26.62	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$77.22	$77.22	N/A	$66.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor System Installation (hours)	1.0	1.0	N/A	1.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Change (hours)	0.05	0.05	N/A	0.05	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$105.43	$111.59	N/A	$98.39	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$14.09	$20.00	N/A	$40.40	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$85.69	$90.70	N/A	$80.86	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$11.46	$16.26	N/A	$33.20	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. Based on a fixture efficiency of 93% for an directional reflector lamp installed in a recessed can fixture.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. These standards cannot be met with existing commercialized halogen lamp technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

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Performance and Cost Characteristics » Commercial Halogen Infrared Reflector Lamp (PAR38) in Recessed Can Fixture

Final

DATA	2012	2018	2022				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	70.0	70.0	N/A	70.0	N/A	N/A	28.0	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	1,407	1,407	N/A	1,260	N/A	N/A	1,260	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	20.1	20.1	N/A	18.0	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	70.0	70.0	N/A	70.0	N/A	N/A	28.0	N/A	N/A	N/A	N/A	N/A	N/A
System Lumens[1]	1,309	1,309	N/A	1,172	N/A	N/A	1,172	N/A	N/A	N/A	N/A	N/A	N/A
System Efficacy (lm/W)	18.7	18.7	N/A	16.7	N/A	N/A	41.9	N/A	N/A	N/A	N/A	N/A	N/A
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,850	2,850	N/A	2,850	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	3.6	3.6	N/A	3.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	4,052	4,052	N/A	4,052	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$18.58	$25.12	N/A	$29.49	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$23.72	$26.38	N/A	$22.07	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$13.20	$17.86	N/A	$23.40	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$32.33	$39.36	N/A	$44.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$77.22	$77.22	N/A	$66.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor System Installation (hours)	1.0	1.0	N/A	1.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Change (hours)	0.05	0.05	N/A	0.05	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$119.52	$128.73	N/A	$117.56	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$25.25	$32.62	N/A	$44.28	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$91.34	$98.38	N/A	$100.32	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$19.30	$24.93	N/A	$37.79	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. Based on a fixture efficiency of 93% for an directional reflector lamp installed in a recessed can fixture.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. These standards cannot be met with existing commercialized halogen lamp technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

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Performance and Cost Characteristics » Commercial LED Reflector Lighting (PAR38)

Final

DATA	2012	2018	2022				2023[2]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[3]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	17.2	16.6	17.0	16.4	17.0	22.0	29.9	14.0	14.6	12.3	12.7	10.9	11.3
Lamp Lumens	1,045	1,210	1,200	1,344	1,700	1,344	1,344	1,344	1,700	1,344	1,700	1,344	1,700
Lamp Efficacy (lm/W)	60.9	73.0	70.6	82.0	100.0	61.0	45.0	95.7	116.7	109.5	133.5	123.2	150.2
System Wattage	17.2	16.6	17.0	16.4	17.0	22.0	29.9	14.0	14.6	12.3	12.7	10.9	11.3
System Lumens[1]	972	1,125	1,116	1,250	1,581	1,250	1,250	1,250	1,581	1,250	1,581	1,250	1,581
System Efficacy (lm/W)	56.6	67.9	65.6	76.1	93.0	56.7	41.9	89.0	108.6	101.9	124.2	114.6	139.7
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	83	83	82	86	82	80	N/A	86	82	86	82	86	82
Correlated Color Temperature (CCT)	3,000	3,000	2,700	3,000	3,000	3,000	N/A	3,000	3,000	3,000	3,000	3,000	3,000
Average Lamp Life (thousand hours)	22	15	25	28	25	25	N/A	28	25	28	25	28	25
Annual Operating Hours (h/y)	4,928	4,928	4,928	4,928	4,928	N/A	N/A	4,928	4,928	4,928	4,928	4,928	4,928
Lamp Price (2022$)	$61.98	$28.10	$23.71	$23.09	$15.69	N/A	N/A	$19.40	$13.18	$17.36	$11.79	$15.37	$10.45
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$23.72	$26.38	$22.07	$22.07	$22.07	N/A	N/A	$21.20	$21.20	$20.17	$20.17	$19.18	$19.18
Lamp Cost (2022$/klm)	$59.31	$23.23	$19.76	$17.18	$9.23	N/A	N/A	$14.43	$7.75	$12.91	$6.94	$11.44	$6.14
System (l/b/f) Cost (2022$/klm)	$88.18	$48.42	$41.02	$36.13	$23.88	N/A	N/A	$32.48	$21.75	$30.02	$20.22	$27.64	$18.74
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	N/A	N/A	$91.40	$91.40	$91.40	$91.40	$91.40	$91.40
Labor System Installation (hours)	1.0	1.0	1.0	1.0	1.0	N/A	N/A	1.0	1.0	1.0	1.0	1.0	1.0
Labor Lamp Change (hours)	0.05	0.05	0.05	0.05	0.05	N/A	N/A	0.05	0.05	0.05	0.05	0.05	0.05
Total Installed Cost (2022$)	$162.93	$131.71	$111.78	$111.16	$103.76	N/A	N/A	$132.00	$125.78	$128.92	$123.36	$125.95	$121.02
Annual Maintenance Cost (2022$)	$14.75	$10.50	$5.32	$4.64	$3.74	N/A	N/A	$4.22	$3.50	$3.86	$3.23	$3.51	$2.96
Total Installed Cost (2022$/klm)	$167.64	$117.04	$100.16	$88.92	$65.63	N/A	N/A	$105.59	$79.56	$103.13	$78.02	$100.75	$76.55
Annual Maintenance Cost (2022$/klm)	$15.17	$9.33	$4.77	$3.72	$2.37	N/A	N/A	$3.37	$2.21	$3.09	$2.04	$2.81	$1.87

1. Based on a fixture efficiency of 93% for an omnidirectional lamp installed in a recessed can fixture.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. All LED lighting products exceed the new minimum efficacy standards.
3. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)

Performance and Cost Characteristics » Commercial 4-foot Linear 2-Lamp Lighting Systems

Final

This section characterizes commercial linear fixtures that house two 4ft long linear lamps and their integrated luminaire equivalents. The technologies available for this system are linear fluorescent and LED.

- Linear fluorescent options are T5, T8, and T12 lamps. T5 lamps are approximately 40% narrower than T8 lamps and almost 60% narrower than T12 lamps. This narrowness allows T5 lamps to be coated with higher quality, more efficient phosphor blends than larger diameter lamps, resulting in a more efficacious lamp. The compact size of T5 lamps also permits greater flexibility in lighting design and construction.
- LED options for linear fixtures include replacement lamps that can fit directly into an existing fixture and fully integrated luminaires that can be used to replace existing fixtures. LED replacement lamps are also known as TLEDs. Type A TLEDs can be installed with existing ballasts and Type B and C TLEDs require the ballast to be disconnected. Replacement lamps are only sold to go into existing fixtures. If a new fixture is to be installed, a fully integrated LED luminaire is a more cost effective and efficient option. Because LED luminaires are fully integrated, they do not have lamp or fixture efficiency losses associated with ballasts and fixture optics. For all lamp technologies, an annual fixture renovation rate of 10% (i.e., 10-year fixture service life) is used to reflect the proportion of equipment that retires each year.

Performance:

- Linear lamps often have a nominal CCT rating of 3,500K, but products with CCTs of 3,000K, 4,000K, and 4,100K (neutral white) are also common. 5,000K (daylight) lamps are available as well. When replacing a light bulb, it is important to choose a product with a similar CCT value to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100, but for CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination, with high CRI products being preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these very specific retail and display applications.

Cost:

- The total installed cost is the price of 2 lamps, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED replacement lamps, which are sold only as a replacement for use in an existing fixture. There are integrated LED luminaires that are more efficient and cost effective for new installations or fixture retrofits. Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy. Therefore typical lamp prices in 2022 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Annual maintenance costs are the cost of labor for replacing the lamps and the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours of 4055 hours/year for commercial 4ft linear systems (DOE SSL Program, 2012a).
- Commercial lighting disposal costs are estimated to be $0.12 per linear foot of fluorescent lamps, $1.50 per lamp for HID lamps, and $0.50 for CFLs (EPA, 2022).

Legislation:

- Beginning July 14, 2012 (or July 14, 2014, for T8 700-series phosphor lamps), DOE fluorescent lamp standards required a minimum efficacy of 89 lm/W. Although the amended performance-based standards do not explicitly prohibit T12 lamps, no T12 lamps met the standard at the time of its announcement. Since then, however, T12 lamps meeting the standard have entered the market.
- California's Title 24 mandates the use of electronic ballasts with high efficacy luminaires (including fluorescent) of 13 W or higher (CEC, 2005).

ENERGY STAR:

- ENERGY STAR does not cover commercial linear luminaires (ENERGY STAR, 2020).

Performance and Cost Characteristics » Commercial 4-foot Linear 2-Lamp Lighting Systems

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Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

Technology	Efficacy	Lifetime	Price	Potential for Improvements
T8 F32 Commodity	0%	0%	-0.5%	Limited because the technology is mature.
T8 F32 High Efficiency/High Output	0%	0%	-0.5%	Limited because the technology is mature.
T5 F28	0%	0%	-0.5%	Limited because the technology is mature.

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Performance and Cost Characteristics » Commercial 4-ft T8 F32 Commodity in 2-Lamp System

Final

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average[1]	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0
Lamp Lumens	2,725	2,855	2,450	2,855	3,100	2,855	3,100	2,855	3,100	2,855	3,100
Lamp Efficacy (lm/W)	85.2	89.0	76.6	89.2	96.9	89.2	96.9	89.2	96.9	89.2	96.9
System Wattage	61.8	62.5	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1
System Lumens	4,796	5,082	4,361	5,082	5,518	5,082	5,518	5,082	5,518	5,082	5,518
System Efficacy (lm/W)	77.7	81.4	69.1	80.6	87.5	80.6	87.5	80.6	87.5	80.6	87.5
Ballast Efficiency (BLE)	91%	91%	90%	90%	90%	90%	90%	90%	90%	90%	90%
CRI	83	87	90	87	85	87	85	87	85	87	85
Correlated Color Temperature (CCT)	4,100	4,100	5,000	4,100	3,500	4,100	3,500	4,100	3,500	4,100	3,500
Average Lamp Life (thousand hours)	24	31	23	31	40	31	40	31	40	31	40
Annual Operating Hours (h/y)	4,055	2,920	2,920	2,920	2,920	2,920	2,920	2,920	2,920	2,920	2,920
Lamp Price (2022$)	$7.81	$5.02	$3.36	$4.08	$4.32	$3.92	$4.15	$3.73	$3.95	$3.55	$3.75
Ballast Price (2022$)[2]	$19.56	$19.40	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$29.67	$77.61	$75.53	$75.53	$75.53	$72.56	$72.56	$69.01	$69.01	$65.64	$65.64
Disposal Costs (2022$)	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48
Lamp Cost (2022$/klm)	$2.86	$1.76	$1.37	$1.43	$1.39	$1.37	$1.34	$1.31	$1.27	$1.24	$1.21
System (l/b/f) Cost (2022$/klm)	$13.52	$21.07	$33.57	$29.31	$27.15	$15.91	$14.65	$15.05	$13.94	$14.31	$13.26
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Labor Lamp Change (hours)	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total Installed Cost (2022$)	$103.45	$145.67	$179.41	$181.97	$182.82	$113.86	$113.86	$109.47	$109.91	$105.73	$106.15
Annual Maintenance Cost (2022$)	$7.89	$3.88	$4.24	$3.28	$2.58	$3.25	$2.55	$3.21	$2.52	$3.18	$2.49
Total Installed Cost (2022$/klm)	$21.57	$28.66	$41.14	$35.81	$33.13	$22.41	$20.63	$21.54	$19.92	$20.81	$19.24
Annual Maintenance Cost (2022$/klm)	$1.65	$0.76	$0.97	$0.65	$0.47	$0.64	$0.46	$0.63	$0.46	$0.63	$0.45

1. Data and assumptions taken from the 2018 SSL Forecast. The report states that efficacy improvements for T8 lamps are not expected in the future and that cost for all commercial fixtures is expected to decrease between 0.1%-0.6% per year. We use 0.5% per year here.
2. From 2020 to 2050, fixture (and fixture price) includes ballast.

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Performance and Cost Characteristics » Commercial 4-ft T8 F28 High-efficiency and High-output in 2-Lamp System

Final

DATA[1]	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average[2]	Typical	Typical	Typical	Typical
Lamp Wattage	28.0	28.0	28.0	28.0	28.0	28.0
Lamp Lumens	2,560	2,682	2,682	2,682	2,682	2,682
Lamp Efficacy (lm/W)	91	96	96	96	96	96
System Wattage	55.4	55.4	55.4	55.4	55.4	55.4
System Lumens	4,557	4,774	4,774	4,774	4,774	4,774
System Efficacy (lm/W)	82	86	86	86	86	86
Ballast Efficiency (BLE)	90%	90%	90%	90%	90%	90%
CRI	85	84	84	84	84	84
Correlated Color Temperature (CCT)	4,100	3,500	3,500	3,500	3,500	3,500
Average Lamp Life (thousand hours)	24	48	48	48	48	48
Annual Operating Hours (h/y)	4,055	2,920	2,920	2,920	2,920	2,920
Lamp Price (2022$)	$11.17	$5.40	$5.29	$5.08	$4.84	$4.60
Ballast Price (2022$)[3]	$19.56	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$35.20	$77.05	$75.53	$72.56	$69.01	$65.64
Disposal Costs (2022$)	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48
Lamp Cost (2022$/klm)	$4.36	$2.01	$1.97	$1.90	$1.80	$1.71
System (l/b/f) Cost (2022$/klm)	$30.12	$32.75	$32.11	$30.85	$29.34	$27.90
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	0.5	0.5	0.5	0.5	0.5	0.5
Labor Lamp Change (hours)	0.4	0.4	0.4	0.4	0.4	0.4
Total Installed Cost (2022$)	$104.54	$121.06	$113.82	$110.64	$106.85	$103.24
Annual Maintenance Cost (2022$)	$9.03	$2.54	$2.26	$2.23	$2.20	$2.17
Total Installed Cost (2022$/klm)	$22.94	$25.36	$23.84	$23.18	$22.38	$21.63
Annual Maintenance Cost (2022$/klm)	$1.98	$0.53	$0.47	$0.47	$0.46	$0.46

1. Only a typical dataset because provided as these lamps all have similar efficacies.
2. Data and assumptions taken from the 2018 SSL Forecast. The report states that efficacy improvements for T8 lamps are not expected in the future and that cost for all commercial fixtures is expected to decrease between 0.1%-0.6% per year. We use 0.5% per year here.
3. From 2018 to 2050, fixture (and fixture price) includes ballast.

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Performance and Cost Characteristics » Commercial 4-ft T5 F28 in 2-Lamp System

Final

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	28.0	27.7	28.0	27.5	26.0	27.5	26.0	27.5	26.0	27.5	26.0
Lamp Lumens	2,697	2,732	2,530	2,732	2,900	2,732	2,900	2,732	2,900	2,732	2,900
Lamp Efficacy (lm/W)	96.3	98.5	90.4	99.3	111.5	99.3	111.5	99.3	111.5	99.3	111.5
System Wattage	62.9	62.3	62.9	61.7	58.4	61.7	58.4	61.7	58.4	61.7	58.4
System Lumens	5,394	5,464	5,060	5,464	5,800	5,464	5,800	5,464	5,800	5,464	5,800
System Efficacy (lm/W)	85.8	87.8	80.5	88.5	99.4	88.5	99.4	88.5	99.4	88.5	99.4
Ballast Efficiency (BLE)	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%
CRI	85	85	85	85	85	85	85	85	85	85	85
Correlated Color Temperature (CCT)	4,100	3,500	5,000	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
Average Lamp Life (thousand hours)	30	29	36	29	30	29	30	29	30	29	30
Annual Operating Hours (h/y)	4,055	3,176	3,176	3,176	3,176	3,176	3,176	3,176	3,176	3,176	3,176
Lamp Price (2022$)[1]	$6.54	$6.96	$13.76	$9.45	$21.28	$9.08	$20.44	$8.63	$19.44	$8.21	$18.49
Ballast Price (2022$)[2]	$31.94	$22.83	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$111.59	$83.32	$170.87	$170.87	$170.87	$164.15	$164.15	$156.13	$156.13	$148.50	$148.50
Disposal Costs (2022$)	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48
Lamp Cost (2022$/klm)	$2.42	$2.55	$5.44	$3.46	$7.34	$3.32	$7.05	$3.16	$6.70	$3.01	$6.38
System (l/b/f) Cost (2022$/klm)	$29.03	$21.97	$39.21	$34.73	$36.80	$37.53	$35.35	$31.73	$33.62	$30.18	$31.98
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Labor Lamp Change (hours)	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total Installed Cost (2022$)	$195.22	$158.68	$231.39	$222.77	$246.43	$238.04	$238.04	$206.40	$228.02	$197.92	$218.48
Annual Maintenance Cost (2022$)	$5.97	$4.93	$4.78	$4.99	$7.33	$4.91	$7.15	$4.81	$6.94	$4.72	$6.74
Total Installed Cost (2022$/klm)	$36.19	$29.04	$45.73	$40.77	$42.49	$43.57	$41.04	$37.77	$39.31	$36.22	$37.67
Annual Maintenance Cost (2022$/klm)	$1.11	$0.90	$0.94	$0.91	$1.26	$0.90	$1.23	$0.88	$1.20	$0.86	$1.16

1. Year-to-year price and performance assumptions for incumbent technologies 2030–2050: Efficacy +0%/y, Life +0%/y, Cost -0.5%/y (SSL Forecast 2018).
2. From 2020 to 2050, fixture (and fixture price) includes ballast.

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Performance and Cost Characteristics » Commercial 4-ft Linear LED Replacement Lamp in 2-Lamp System

Final

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	20.8	17.0	16.0	13.7	11.0	11.6	9.3	10.0	8.0	8.8	7.2
Lamp Lumens	2,091	2,003	1,800	1,920	1,800	1,920	1,800	1,920	1,800	1,920	1,800
Lamp Efficacy (lm/W)	100.5	117.8	112.5	140.1	163.6	166.2	194.1	192.2	224.4	218.0	250.0
System Wattage	41.6	34.0	32.0	27.4	22.0	23.1	18.6	20.0	16.0	17.6	14.4
System Lumens	3,555	3,565	3,456	3,686	3,456	3,686	3,456	3,686	3,456	3,686	3,456
System Efficacy (lm/W)	85.4	104.9	108.0	134.5	157.1	159.6	186.3	184.5	215.4	209.3	240.0
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	86	81	82	81	80	81	80	81	80	81	80
Correlated Color Temperature (CCT)	4,100	4,020	4,100	4,100	5,000	4,100	5,000	4,100	5,000	4,100	5,000
Average Lamp Life (thousand hours)	50	54	50	54	50	54	50	54	50	54	50
Annual Operating Hours (h/y)	4,055	3,541	3,541	3,541	3,541	3,541	3,541	3,541	3,541	3,541	3,541
Lamp Price (2022$)	$278.36	$35.06	$14.63	$11.11	$4.28	$9.88	$3.81	$9.66	$3.72	$9.44	$3.64
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$133.10	$17.50	$8.13	$5.79	$2.38	$5.15	$2.11	$5.03	$2.07	$4.92	$2.02
System (l/b/f) Cost (2022$/klm)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Change (hours)	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total Installed Cost (2022$)	$587.35	$70.12	$29.26	$22.22	$8.56	$19.76	$7.61	$19.31	$7.44	$18.89	$7.28
Annual Maintenance Cost (2022$)	$47.64	$6.61	$3.93	$3.17	$2.46	$3.01	$2.39	$2.98	$2.38	$2.95	$2.37
Total Installed Cost (2022$/klm)	$165.20	$19.67	$8.47	$6.03	$2.48	$5.36	$2.20	$5.24	$2.15	$5.12	$2.11
Annual Maintenance Cost (2022$/klm)	$13.40	$1.85	$1.14	$0.86	$0.71	$0.82	$0.69	$0.81	$0.69	$0.80	$0.69

1. N/A because a fixture and an LED replacement lamp would not be purchased separately for a new installation or retrofit when there are integrated LED luminaires that are more efficient and cost effective. These lamps are sold only as replacements to go into existing fixtures.

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Performance and Cost Characteristics » Commercial 4-ft Linear LED Luminaire to Replace 2-Lamp Systems

Final

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	51.5	50.0	49.0	44.0	35.0	35.6	28.3	29.9	23.8	25.8	20.5
System Lumens	4,818	4,673	5,024	5,302	4,800	5,302	4,800	5,302	4,800	5,302	4,800
System Efficacy (lm/W)	93.6	93.5	102.5	120.5	137.1	148.8	169.3	177.2	201.7	205.5	233.9
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	84	79	80	79	80	79	80	79	80	79	80
Correlated Color Temperature (CCT)	3,500	3,650	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
Average Lifetime (thousand hours)	67	53	54	53	50	53	50	53	50	53	50
Annual Operating Hours (h/y)	4,055	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431
Lamp or Luminaire Price (2022$)	$723.96	$188.00	$144.85	$152.54	$207.80	$127.58	$173.80	$118.37	$161.25	$109.57	$149.27
Ballast Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$150.25	$40.23	$57.66	$57.54	$86.58	$24.06	$36.21	$22.33	$33.59	$20.67	$31.10
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Labor Lamp Change (hours)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$762.57	$226.61	$322.70	$338.08	$448.60	$160.58	$206.80	$151.37	$194.25	$142.57	$182.27
Annual Maintenance Cost (2022$)	$46.16	$14.67	$11.30	$12.01	$16.52	$10.40	$14.19	$9.80	$13.33	$9.23	$12.51
Total Installed Cost (2022$/klm)	$158.27	$48.49	$64.23	$63.76	$93.46	$30.29	$43.08	$28.55	$40.47	$26.89	$37.97
Annual Maintenance Cost (2022$/klm)	$9.58	$3.14	$2.25	$2.27	$3.44	$1.96	$2.96	$1.85	$2.78	$1.74	$2.61

1. N/A because the lamp and fixture are both included in the luminaire.

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Performance and Cost Characteristics » Commercial 4-ft T8 F28 High-efficiency and High-output in 2-Lamp System with Occupancy Sensor

Final

DATA[1]	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average[2]	Typical	Typical	Typical	Typical
Lamp Wattage	28.0	28.0	28.0	28.0	28.0	28.0
Lamp Lumens	2,560	2,682	2,682	2,682	2,682	2,682
Lamp Efficacy (lm/W)	91	96	96	96	96	96
System Wattage	50.3	55.4	55.4	55.4	55.4	55.4
System Lumens	4,506	4,774	4,774	4,774	4,774	4,774
System Efficacy (lm/W)	90	86	86	86	86	86
Ballast Efficiency (BLE)	90%	90%	90%	90%	90%	90%
CRI	85	84	84	84	84	84
Correlated Color Temperature (CCT)	4,100	3,500	3,500	3,500	3,500	3,500
Average Lamp Life (thousand hours)	24	48	48	48	48	48
Annual Operating Hours (h/y)[3]	4,055	2,920	1,869	1,869	1,869	1,869
Lamp Price (2022$)	$11.17	$5.40	$5.29	$5.08	$4.84	$4.60
Ballast Price (2022$)	$19.56	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$35.20	$77.05	$75.53	$72.56	$69.01	$65.64
Occupancy Sensor Price (2022$)	N/A	N/A	$161.34	$161.34	$161.34	$161.34
Disposal Costs (2022$)	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48
Lamp Cost (2022$/klm)	$4.36	$2.01	$1.97	$1.90	$1.80	$1.71
System (l/b/f) Cost (2022$/klm)	$30.12	$32.75	$92.26	$91.00	$89.49	$88.06
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	0.5	0.5	0.5	0.5	0.5	0.5
Labor Lamp Change (hours)	0.4	0.4	0.4	0.4	0.4	0.4
Total Installed Cost (2022$)	$104.54	$121.06	$275.16	$271.98	$268.19	$264.58
Annual Maintenance Cost (2022$)	$9.03	$2.54	$1.44	$1.43	$1.41	$1.39
Total Installed Cost (2022$/klm)	$23.20	$25.36	$57.64	$56.97	$56.18	$55.42
Annual Maintenance Cost (2022$/klm)	$2.00	$0.53	$0.30	$0.30	$0.30	$0.29

1. Only a typical dataset is provided because these lamps all have similar efficacies.
2. Data and assumptions taken from the 2018 SSL Forecast. The report states that efficacy improvements for T8 lamps are not expected in the future and that cost for all commercial fixtures is expected to decrease between 0.1%-0.6% per year. We use 0.5% per year here.
3. Assumes occupancy sensor reduces hours of use by 36% (NCI, 2019)

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Performance and Cost Characteristics » Commercial 4-ft T8 F28 High-efficiency and High-output in 2-Lamp System with Specular Reflector

Final

DATA[1]	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average[2]	Typical	Typical	Typical	Typical
Lamp Wattage	28.0	28.0	28.0	28.0	28.0	28.0
Lamp Lumens	2,560	2,682	2,682	2,682	2,682	2,682
Lamp Efficacy (lm/W)	91.4	95.8	95.8	95.8	95.8	95.8
System Wattage	55.4	55.4	55.4	55.4	55.4	55.4
System Lumens[3]	4,506	4,774	5,347	5,347	5,347	5,347
System Efficacy (lm/W)	81	86	97	97	97	97
Ballast Efficiency (BLE)	90%	90%	90%	90%	90%	90%
CRI	85	84	84	84	84	84
Correlated Color Temperature (CCT)	4,100	3,500	3,500	3,500	3,500	3,500
Average Lamp Life (thousand hours)	24	48	48	48	48	48
Annual Operating Hours (h/y)	2,920	4,055	4,055	4,055	4,055	4,055
Lamp Price (2022$)	$11.17	$5.40	$5.29	$5.08	$4.84	$4.60
Ballast Price (2022$)	$19.56	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$35.20	$77.05	$75.53	$72.56	$69.01	$65.64
Reflector Price (2022$)	N/A	N/A	$44.53	$44.53	$44.53	$44.53
Disposal Costs (2022$)	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48
Lamp Cost (2022$/klm)	$4.36	$2.01	$1.97	$1.90	$1.80	$1.71
System (l/b/f) Cost (2022$/klm)	$30.12	$32.75	$48.71	$47.45	$45.94	$44.51
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	0.5	0.5	0.5	0.5	0.5	0.5
Labor Lamp Change (hours)	0.4	0.4	0.4	0.4	0.4	0.4
Total Installed Cost (2022$)	$104.54	$121.06	$158.35	$155.17	$151.38	$147.77
Annual Maintenance Cost (2022$)	$6.50	$3.53	$3.13	$3.10	$3.06	$3.02
Total Installed Cost (2022$/klm)	$23.20	$25.36	$29.62	$29.02	$28.31	$27.64
Annual Maintenance Cost (2022$/klm)	$1.44	$0.74	$0.59	$0.58	$0.57	$0.56

1. Only a typical dataset is provided because these lamps all have similar efficacies.
2. Data and assumptions taken from the 2018 SSL Forecast. The report states that efficacy improvements for T8 lamps are not expected in the future and that cost for all commercial fixtures is expected to decrease between 0.1%-0.6% per year. We use 0.5% per year here.
3. Specular reflector is expected to add 12% luminaire efficiency (LRC, 1992).

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Performance and Cost Characteristics » Commercial 4-ft T8 F28 High-efficiency and High-output in 2-Lamp System with Occupancy Sensor and Specular Reflector

Final

DATA[1]	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average[2]	Typical	Typical	Typical	Typical
Lamp Wattage	28.0	28.0	28.0	28.0	28.0	28.0
Lamp Lumens	2,560	2,682	2,682	2,682	2,682	2,682
Lamp Efficacy (lm/W)	91.4	95.8	95.8	95.8	95.8	95.8
System Wattage	50.3	55.4	55.4	55.4	55.4	55.4
System Lumens[3]	4,506	4,774	5,347	5,347	5,347	5,347
System Efficacy (lm/W)	89.6	86.2	96.6	96.6	96.6	96.6
Ballast Efficiency (BLE)	90%	90%	90%	90%	90%	90%
CRI	85	84	84	84	84	84
Correlated Color Temperature (CCT)	4,100	3,500	3,500	3,500	3,500	3,500
Average Lamp Life (thousand hours)	24	48	48	48	48	48
Annual Operating Hours (h/y)[3]	4,055	2,920	1,869	1,869	1,869	1,869
Lamp Price (2022$)	$11.17	$5.40	$5.29	$5.08	$4.84	$4.60
Ballast Price (2022$)	$19.56	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$35.20	$77.05	$75.53	$72.56	$69.01	$65.64
Reflector Price (2022$)	N/A	N/A	$44.53	$44.53	$44.53	$44.53
Occupancy Sensor Price (2022$)	N/A	N/A	$161.34	$161.34	$161.34	$161.34
Disposal Costs (2022$)	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48
Lamp Cost (2022$/klm)	$4.36	$2.01	$1.97	$1.90	$1.80	$1.71
System (l/b/f) Cost (2022$/klm)	$30.12	$32.75	$108.87	$107.61	$106.10	$104.66
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	0.5	0.5	0.5	0.5	0.5	0.5
Labor Lamp Change (hours)	0.4	0.4	0.4	0.4	0.4	0.4
Total Installed Cost (2022$)	$104.54	$121.06	$319.69	$316.51	$312.72	$309.11
Annual Maintenance Cost (2022$)	$9.03	$2.54	$1.44	$1.43	$1.41	$1.39
Total Installed Cost (2022$/klm)	$23.20	$25.36	$59.79	$59.20	$58.49	$57.81
Annual Maintenance Cost (2022$/klm)	$2.00	$0.53	$0.27	$0.27	$0.26	$0.26

1. Only a typical dataset is provided because these lamps all have similar efficacies.
2. Data and assumptions taken from the 2018 SSL Forecast. The report states that efficacy improvements for T8 lamps are not expected in the future and that cost for all commercial fixtures is expected to decrease between 0.1%-0.6% per year. We use 0.5% per year here.
3. Assumes occupancy sensor reduces hours of use by 36% (NCI, 2019). Specular reflector is expected to add 12% luminaire efficiency (LRC, 1992).

Performance and Cost Characteristics » Commercial 8-foot Linear 2-Lamp Lighting Systems

Final

This section characterizes commercial linear fixtures that house two 8ft long linear lamps and their integrated luminaire equivalents. The technologies available for this system are linear fluorescent and LED.

- Linear fluorescent options are T5, T8, and T12 lamps. T5 lamps are approximately 40% narrower than T8 lamps and almost 60% narrower than T12 lamps. This narrowness allows T5 lamps to be coated with higher quality, more efficient phosphor blends than larger diameter lamps, resulting in a more efficacious lamp. The compact size of T5 lamps also permits greater flexibility in lighting design and construction.
- LED options for linear fixtures include replacement lamps that can fit directly into an existing fixture and fully integrated luminaires that can be used to replace existing fixtures. LED replacement lamps are also known as TLEDs. Type A TLEDs can be installed with existing ballasts and Type B and C TLEDs require the ballast to be disconnected. Replacement lamps are only sold to go into existing fixtures. If a new fixture is to be installed, a fully integrated LED luminaire is a more cost effective and efficient option. Because LED luminaires are fully integrated, they do not have lamp or fixture efficiency losses associated with ballasts and fixture optics. For all lamp technologies, an annual fixture renovation rate of 10% (i.e., 10-year fixture service life) is used to reflect the proportion of equipment that retires each year.

Performance:

- Linear lamps often have a nominal CCT rating of 3,500K, but products with CCTs of 3,000K, 4,000K, and 4,100K (neutral white) are also common. 5,000K (daylight) lamps are available as well. When replacing a light bulb, it is important to choose a product with a similar CCT value to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100, but for CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination, with high CRI products being preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these very specific retail and display applications.

Cost:

- The total installed cost is the price of 2 lamps, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED replacement lamps which are sold only as a replacement for use in an existing fixture. There are integrated LED luminaires that are more efficient and cost effective for new installations or fixture retrofits. Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy. Therefore typical lamp prices in 2022 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Annual maintenance costs are the cost of labor for replacing the lamps and the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours of 4147 hours/year for commercial 8ft linear systems (DOE SSL Program, 2012a).
- Commercial lighting disposal costs are estimated to be $0.12 per linear foot of fluorescent lamps, $1.50 per lamp for HID lamps, and $0.50 for CFLs (EPA, 2022).

Legislation:

- Beginning July 14, 2012 (or July 14, 2014, for T8 700-series phosphor lamps), DOE fluorescent lamp standards required a minimum efficacy of 89 lm/W. Although the amended performance-based standards do not explicitly prohibit T12 lamps, no T12 lamps met the standard at the time of its announcement. Since then, however, T12 lamps meeting the standard have entered the market.
- California's Title 24 mandates the use of electronic ballasts with high efficacy luminaires (including fluorescent) of 13 W or higher (CEC, 2005).

ENERGY STAR:

- ENERGY STAR does not cover commercial linear luminaires (ENERGY STAR, 2020).

Performance and Cost Characteristics » Commercial 8-foot Linear 2-Lamp Lighting Systems

Final

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume the manufacturers will focus on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050:

Technology	Efficacy	Lifetime	Price	Potential for Improvements
T8 F59 Typical Efficiency	0%	0%	-0.5%	Limited because the technology is mature.
T8 F59 High Efficiency	0%	0%	-0.5%	Limited because the technology is mature.
T8 F96 High Output	0%	0%	-0.5%	Limited because the technology is mature.

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Performance and Cost Characteristics » Commercial 8-ft T8 F59 Typical Efficiency in a 2-Lamp System

Final

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0
Lamp Lumens	5,430	5,788	5,900	5,905	5,950	5,905	5,950	5,905	5,950	5,905	5,950
Lamp Efficacy (lm/W)	92.0	98.1	100.0	100.1	100.8	100.1	100.8	100.1	100.8	100.1	100.8
System Wattage	106.8	111.6	112.9	112.9	112.9	112.9	112.9	112.9	112.9	112.9	112.9
System Lumens	9,448	10,071	10,384	10,393	10,472	10,393	10,472	10,393	10,472	10,393	10,472
System Efficacy (lm/W)	88.5	90.3	92.0	92.1	92.8	92.1	92.8	92.1	92.8	92.1	92.8
Ballast Efficiency (BLE)	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%
CRI	82	84	85	84	85	84	85	84	85	84	85
Correlated Color Temperature (CCT)	4,100	4,100	3,500	4,100	3,500	4,100	3,500	4,100	3,500	4,100	3,500
Average Lamp Life (thousand hours)	24	21	24	21	24	21	24	21	24	21	24
Annual Operating Hours (h/y)	4,147	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066
Lamp Price (2022$)	$14.70	$21.80	$23.58	$21.37	$22.84	$20.53	$21.94	$19.53	$20.87	$18.57	$19.85
Ballast Price (2022$)	$23.26	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	$27.20	$117.38	$115.06	$115.06	$115.06	$110.54	$110.54	$105.13	$105.13	$99.99	$99.99
Disposal Costs (2022$)	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96
Lamp Cost (2022$/klm)	$2.28	$3.77	$4.00	$3.62	$3.84	$3.48	$3.69	$3.31	$3.51	$3.15	$3.34
System (l/b/f) Cost (2022$/klm)	$12.40	$15.99	$15.62	$15.18	$15.35	$14.59	$14.75	$13.87	$14.03	$13.20	$13.34
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	1.0	1.0	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Labor Lamp Change (hours)	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total Installed Cost (2022$)	$114.60	$238.20	$247.36	$242.94	$245.88	$236.74	$239.56	$229.33	$232.01	$222.28	$224.83
Annual Maintenance Cost (2022$)	$8.98	$9.66	$8.51	$9.08	$8.32	$8.83	$8.09	$8.54	$7.82	$8.26	$7.55
Total Installed Cost (2022$/klm)	$12.13	$23.65	$23.82	$23.38	$23.48	$22.78	$22.88	$22.07	$22.16	$21.39	$21.47
Annual Maintenance Cost (2022$/klm)	$0.95	$0.96	$0.82	$0.87	$0.79	$0.85	$0.77	$0.82	$0.75	$0.79	$0.72

1. From 2018 to 2050, fixture (and fixture price) includes ballast.

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Performance and Cost Characteristics » Commercial 8-ft T8 F96 High-Output in a 2-Lamp System

Final

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0
Lamp Lumens	7600	8134	7710	8134	8200	8134	8200	8134	8200	8134	8200
Lamp Efficacy (lm/W)	88.4	94.6	89.7	94.6	95.3	94.6	95.3	94.6	95.3	94.6	95.3
System Wattage	148.4	183.6	183.6	183.6	183.6	183.6	183.6	183.6	183.6	183.6	183.6
System Lumens	12,026	15,455	14,649	15,455	15,580	15,455	15,580	15,455	15,580	15,455	15,580
System Efficacy (lm/W)	81.0	84.2	79.8	84.2	84.9	84.2	84.9	84.2	84.9	84.2	84.9
Ballast Efficiency (BLE)	92%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%
CRI	78	85	85	85	85	85	85	85	85	85	85
Correlated Color Temperature (CCT)	4,100	4,100	3,500	4,100	4,100	4,100	4,100	4,100	4,100	4,100	4,100
Average Lamp Life (thousand hours)	18	22	18	22	30	22	30	22	30	22	30
Annual Operating Hours (h/y)	4,147	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066
Lamp Price (2022$)	$20.22	$30.62	$16.51	$30.02	$73.42	$28.84	$70.53	$27.43	$67.09	$26.09	$63.81
Ballast Price (2022$)	$18.55	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	$27.20	$117.38	$115.06	$115.06	$115.06	$110.54	$110.54	$105.13	$105.13	$99.99	$99.99
Disposal Costs (2022$)	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96
Lamp Cost (2022$/klm)	$2.24	$3.77	$2.14	$3.69	$8.95	$3.55	$8.60	$3.37	$8.18	$3.21	$7.78
System (l/b/f) Cost (2022$/klm)	$21.99	$11.56	$10.11	$11.33	$16.81	$10.88	$16.15	$10.35	$15.36	$9.85	$14.61
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	1.0	1.0	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Labor Lamp Change (hours)	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total Installed Cost (2022$)	$143.19	$255.85	$233.22	$260.24	$347.04	$253.36	$336.75	$245.13	$324.44	$237.31	$312.74
Annual Maintenance Cost (2022$)	$13.48	$11.68	$8.94	$11.08	$16.99	$10.75	$16.40	$10.35	$15.70	$9.98	$15.03
Total Installed Cost (2022$/klm)	$17.89	$16.55	$15.92	$16.84	$22.27	$16.39	$21.61	$15.86	$20.82	$15.36	$20.07
Annual Maintenance Cost (2022$/klm)	$1.12	$0.76	$0.61	$0.72	$1.09	$0.70	$1.05	$0.67	$1.01	$0.65	$0.96

1. From 2018 to 2050, fixture (and fixture price) includes ballast.

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Performance and Cost Characteristics » Commercial 8-ft Linear LED Replacement Lamp for a 2 Lamp System

Final

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A	35.7	34.0	39.0	40.0	32.9	33.7	28.4	29.2	25.1	25.7
Lamp Lumens	N/A	3,975	4,200	4,960	5,500	4,960	5,500	4,960	5,500	4,960	5,500
Lamp Efficacy (lm/W)	N/A	111.2	123.5	127.2	137.5	150.8	163.1	174.4	188.6	197.9	213.9
System Wattage	N/A	71.5	68.0	78.0	80.0	65.8	67.5	56.9	58.3	50.1	51.4
System Lumens	N/A	7,473	8,064	9,523	10,560	9,523	10,560	9,523	10,560	9,523	10,560
System Efficacy (lm/W)	N/A	104.5	118.6	122.1	132.0	144.8	156.5	167.4	181.0	189.9	205.4
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	N/A	80	82	81	82	81	82	81	82	81	82
Correlated Color Temperature (CCT)	N/A	5,000	4,000	4,000	5,000	4,000	5,000	4,000	5,000	4,000	5,000
Average Lamp Life (thousand hours)	N/A	50	50	50	50	50	50	50	50	50	50
Annual Operating Hours (h/y)	N/A	3,541	3,541	3,541	3,541	3,541	3,541	3,541	3,541	3,541	3,541
Lamp Price (2022$)	N/A	$89.59	$33.11	$37.22	$41.44	$32.35	$36.02	$31.71	$35.30	$31.11	$34.64
Ballast Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	N/A	$19.00	$7.88	$7.50	$7.53	$6.52	$6.55	$6.39	$6.42	$6.27	$6.30
System (l/b/f) Cost (2022$/klm)	N/A	$23.98	$8.21	$7.82	$7.85	$6.79	$6.82	$6.66	$6.69	$6.53	$6.56
Labor Cost (2022$/h)	N/A	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Change (hours)	N/A	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total Installed Cost (2022$)	N/A	$179.18	$66.22	$74.44	$82.88	$64.70	$72.04	$63.42	$70.61	$62.22	$69.28
Annual Maintenance Cost (2022$)	N/A	$14.22	$6.00	$6.58	$7.18	$5.89	$6.41	$5.80	$6.31	$5.71	$6.21
Total Installed Cost (2022$/klm)	N/A	$45.08	$8.21	$7.82	$7.85	$6.79	$6.82	$6.66	$6.69	$6.53	$6.56
Annual Maintenance Cost (2022$/klm)	N/A	$3.58	$0.74	$0.69	$0.68	$0.62	$0.61	$0.61	$0.60	$0.60	$0.59

1. N/A because a fixture and an LED replacement lamp would not be purchased separately for a new installation or retrofit when there are integrated LED luminaires that are more efficient and cost effective. These lamps are sold only as replacements to go into existing fixtures.

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Performance and Cost Characteristics » Commercial 8-ft Linear LED Luminaire Replacement for a 2-Lamp System

Final

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	N/A	73.0	90.0	78.0	72.0	64.6	59.6	55.2	50.9	48.1	44.4
System Lumens	N/A	8,000	8,200	9,465	10,400	9,465	10,400	9,465	10,400	9,465	10,400
System Efficacy (lm/W)	N/A	109.6	91.1	121.3	144.4	146.5	174.4	171.6	204.3	196.6	234.0
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	N/A	90	80	81	80	81	80	81	80	81	80
Correlated Color Temperature (CCT)	N/A	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000
Average Lifetime (thousand hours)	N/A	75	50	73	100	73	100	73	100	73	100
Annual Operating Hours (h/y)	N/A	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431
Lamp or Luminaire Price (2022$)	N/A	$759.16	$119.99	$142.48	$153.91	$109.90	$118.71	$96.00	$103.70	$82.68	$89.31
Ballast Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	N/A	$80.00	$14.63	$15.05	$14.80	$11.61	$11.41	$10.14	$9.97	$8.73	$8.59
Labor Cost (2022$/h)	N/A	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	N/A	1.0	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Labor Lamp Change (hours)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	N/A	$708.20	$206.52	$229.01	$240.44	$196.42	$205.24	$182.53	$190.23	$169.20	$175.83
Annual Maintenance Cost (2022$)	N/A	$39.16	$22.40	$17.46	$13.53	$14.40	$11.11	$13.09	$10.08	$11.84	$9.10
Total Installed Cost (2022$/klm)	N/A	$88.53	$25.18	$24.20	$23.12	$20.75	$19.73	$19.28	$18.29	$17.88	$16.91
Annual Maintenance Cost (2022$/klm)	N/A	$4.89	$2.73	$1.84	$1.30	$1.52	$1.07	$1.38	$0.97	$1.25	$0.87

1. N/A because the lamp and fixture are both included in the luminaire.

Performance and Cost Characteristics » Commercial Low-Bay Lighting Systems

Final

The commercial low bay lighting characterized in this report is a one-lamp and one-ballast system in a low/high bay fixture that emits between 6,000 and 10,000 system lumens. Low bay lighting is defined as "interior lighting where the roof trusses or ceiling height is less than 25ft. above the floor"(IESNA, 2000). For all lamp technologies, an annual fixture renovation rate of 10% (i.e., 10-year fixture service life) is used to reflect the proportion of equipment that retires each year.

Performance:

- Low bay conventional lighting technologies, such as metal halide and sodium vapor lamps, provide higher efficacy ranging from 80 lm/W to 100 lm/W. Older, mercury vapor lamps have much lower efficacy at approximately 40 lm/W.
- CCT and CRI values range broadly based on technology type for low bay products.

Cost:

- The total installed cost is the price of a lamp, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED luminaires, which are sold as one integrated system. Many factors influence the price of LED luminaires, including CRI, lifetime, dimming capabilities, and efficacy. Therefore, typical luminaire prices in 2022 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Annual maintenance costs are the cost of labor for replacing the lamps and the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours for commercial low-bay systems (DOE SSL Program, 2012a).
- Commercial lighting disposal costs are estimated to be $0.12 per linear foot of fluorescent lamps, $1.50 per lamp for HID lamps, and $0.50 for CFLs (EPA, 2022).

ENERGY STAR:

- ENERGY STAR does not cover low/high bay luminaires (ENERGY STAR, 2012).

Performance and Cost Characteristics » Commercial Low-Bay Lighting Systems

Final

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus would be on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- (Navigant, 2019). Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

	Efficacy	Lifetime	Price	Potential for Improvements
Mercury Vapor	0%	0%	-0.5%	Limited because the technology is mature.
Metal Halide	0%	0%	-0.5%	Limited because the technology is mature.
Sodium Vapor	0%	0%	-0.5%	Limited because the technology is mature.

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Performance and Cost Characteristics » Commercial Mercury Vapor Low-Bay

Final

DATA[1]	2012	2018	2022	2030[2]	2040[2]	2050[2]
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	175.0	175.0	175.0	N/A	N/A	N/A
Lamp Lumens	7,400	7,400	7,400	N/A	N/A	N/A
Lamp Efficacy (lm/W)	42.3	42.3	44.0	N/A	N/A	N/A
System Wattage	205.9	205.9	205.9	N/A	N/A	N/A
System Lumens	7,400	7,400	7,400	N/A	N/A	N/A
System Efficacy (lm/W)	35.9	35.9	35.9	N/A	N/A	N/A
Ballast Efficiency	85%	85%	85%	N/A	N/A	N/A
CRI	33	33	33	N/A	N/A	N/A
Correlated Color Temperature (CCT)	3,700	3,700	3,700	N/A	N/A	N/A
Average Lamp Life (thousand hours)	24	24	24	N/A	N/A	N/A
Annual Operating Hours (h/y)	3,687	3,687	3,687	N/A	N/A	N/A
Lamp Price (2022$)	$13.96	$13.55	$13.80	N/A	N/A	N/A
Ballast Price (2022$)	$51.91	$50.37	$49.48	N/A	N/A	N/A
Fixture Price (2022$)	$38.73	$37.58	$36.83	N/A	N/A	N/A
Disposal Cost (2022$)	$1.50	$1.50	$1.50	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$1.89	$1.83	$1.86	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$14.13	$13.72	$13.53	N/A	N/A	N/A
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	N/A	N/A	N/A
Labor System Installation (hours)	1.5	1.5	1.5	N/A	N/A	N/A
Labor Lamp Change (hours)	0.5	0.5	0.5	N/A	N/A	N/A
Total Installed Cost (2022$)	$220.43	$217.33	$199.11	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$8.31	$8.24	$7.42	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$29.79	$29.37	$26.91	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$1.12	$1.11	$1.00	N/A	N/A	N/A

1. Only a typical dataset is provided because these lamps all have similar efficacies.
2. EPAct 2005 limited the sale and production of mercury vapor ballasts since 2008, and by 2030 there is no expected market for these products.

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Performance and Cost Characteristics » Commercial Metal Halide Low-Bay

Final

DATA[1]	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	100.0	100.0	100.0	100.0	100.0	100.0
Lamp Lumens	8,084	8,331	8,500	8,500	8,500	8,500
Lamp Efficacy (lm/W)	80.8	83.3	85.0	85.0	85.0	85.0
System Wattage	113.6	113.6	113.6	113.6	113.6	113.6
System Lumens	7,400	7,400	7,400	7,400	7,400	7,400
System Efficacy (lm/W)	65.1	65.1	65.1	65.1	65.1	65.1
Ballast Efficiency	88%	88%	88%	88%	88%	88%
CRI	80	80	80	80	80	80
Correlated Color Temperature (CCT)	4,000	4,000	4,000	4,000	4,000	4,000
Average Lamp Life (thousand hours)	15	15	15	15	15	15
Annual Operating Hours (h/y)	3,760	3,760	3,760	3,760	3,760	3,760
Lamp Price (2022$)	$17.97	$17.44	$17.10	$16.43	$15.62	$14.86
Ballast Price (2022$)	$57.97	$56.26	$49.48	$47.54	$45.21	$43.00
Fixture Price (2022$)	$38.73	$37.58	$36.83	$35.39	$33.66	$32.01
Disposal Cost (2022$)	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50
Lamp Cost (2022$/klm)	$2.22	$2.09	$2.01	$1.93	$1.84	$1.75
System (l/b/f) Cost (2022$/klm)	$15.50	$15.04	$13.97	$13.43	$12.77	$12.14
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	1.5	1.5	1.5	1.5	1.5	1.5
Labor Lamp Change (hours)	0.5	0.5	0.5	0.5	0.5	0.5
Total Installed Cost (2022$)	$230.51	$227.11	$202.41	$198.35	$193.49	$188.87
Annual Maintenance Cost (2022$)	$14.56	$14.43	$12.93	$12.76	$12.56	$12.37
Total Installed Cost (2022$/klm)	$31.15	$30.69	$27.35	$26.80	$26.15	$25.52
Annual Maintenance Cost (2022$/klm)	$1.97	$1.95	$1.75	$1.72	$1.70	$1.67

1. Only a typical dataset is provided because these lamps all have similar efficacies.

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Performance and Cost Characteristics » Commercial Sodium Vapor Low-Bay

Final

DATA[1]	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	100.0	100.0	100.0	100.0	100.0	100.0
Lamp Lumens	8,550	8,550	9,300	9,300	9,300	9,300
Lamp Efficacy (lm/W)	85.5	85.5	93.0	93.0	93.0	93.0
System Wattage	128.0	128.0	128.0	128.0	128.0	128.0
System Lumens	8,550	8,550	9,300	9,300	9,300	9,300
System Efficacy (lm/W)	66.8	66.8	72.6	72.6	72.6	72.6
Ballast Efficiency	78%	78%	78%	78%	78%	78%
CRI	22	22	22	22	22	22
Correlated Color Temperature (CCT)	2,100	2,100	2,100	2,100	2,100	2,100
Average Lamp Life (thousand hours)	24	24	24	24	24	24
Annual Operating Hours (h/y)	3,614	3,614	3,614	3,614	3,614	3,614
Lamp Price (2022$)	$54.04	$52.44	$13.14	$12.62	$12.01	$11.42
Ballast Price (2022$)	$56.14	$54.48	$43.26	$41.56	$39.53	$37.60
Fixture Price (2022$)	$128.14	$124.35	$121.88	$117.09	$111.36	$105.92
Disposal Cost (2022$)	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50
Lamp Cost (2022$/klm)	$6.32	$6.13	$1.41	$1.36	$1.29	$1.23
System (l/b/f) Cost (2022$/klm)	$27.87	$27.05	$19.17	$18.42	$17.52	$16.66
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	1.5	1.5	1.5	1.5	1.5	1.5
Labor Lamp Change (hours)	0.5	0.5	0.5	0.5	0.5	0.5
Total Installed Cost (2022$)	$354.16	$347.10	$277.28	$270.27	$261.90	$253.93
Annual Maintenance Cost (2022$)	$14.18	$13.93	$7.17	$7.10	$7.00	$6.91
Total Installed Cost (2022$/klm)	$41.42	$40.60	$29.81	$29.06	$28.16	$27.30
Annual Maintenance Cost (2022$/klm)	$1.66	$1.63	$0.77	$0.76	$0.75	$0.74

1. Only a typical dataset is provided because these lamps all have similar efficacies.

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Performance and Cost Characteristics » Commercial LED Low-Bay Luminaire

Final

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	68.1	84.0	40.0	73.0	76.0	61.2	63.7	52.7	54.9	46.3	48.2
System Lumens	4,877	10,000	5,000	10,000	12,000	10,000	12,000	10,000	12,000	10,000	12,000
System Efficacy (lm/W)	71.6	119.0	125.0	137.0	157.9	163.4	188.4	189.7	218.7	216.0	248.9
Ballast Efficiency	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	85	78	84	81	80	81	84	81	84	81	81
Correlated Color Temperature (CCT)	4,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
Average Lifetime (thousand hours)	50	74	75	65	60	65	60	65	60	65	60
Annual Operating Hours (h/y)	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042
Lamp or Luminaire Price (2022$)	$903.82	$281.00	$63.99	$145.46	$285.89	$123.82	$243.37	$111.24	$218.63	$99.09	$194.75
Ballast Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$185.31	$28.10	$12.80	$14.55	$23.82	$12.38	$20.28	$11.12	$18.22	$9.91	$16.23
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Labor Lamp Change (hours)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$865.44	$396.83	$162.99	$244.46	$384.89	$222.82	$342.37	$210.24	$317.63	$198.09	$293.75
Annual Maintenance Cost (2022$)	$69.95	$37.02	$12.23	$24.24	$45.18	$21.55	$39.45	$19.99	$36.12	$18.48	$32.90
Total Installed Cost (2022$/klm)	$177.44	$39.68	$32.60	$24.45	$32.07	$22.28	$28.53	$21.02	$26.47	$19.81	$24.48
Annual Maintenance Cost (2022$/klm)	$14.34	$3.70	$2.45	$2.42	$3.77	$2.16	$3.29	$2.00	$3.01	$1.85	$2.74

1. N/A because the lamp and fixture are both included in the luminaire.

Performance and Cost Characteristics » Commercial High-Bay Lighting Systems

Final

The commercial high-bay lighting characterized in this report is a one-lamp and one-ballast system in a low/high bay fixture that emits greater than 10,000 system lumens. High-bay lighting is defined as "interior lighting where the roof trusses or ceiling height is greater than 25ft. above the floor" (IESNA, 2000). For all lamp technologies, an annual fixture renovation rate of 10% (i.e., 10-year fixture service life) is used to reflect the proportion of equipment that retires each year.

Performance:

- High bay conventional lighting technologies, such as metal halide and sodium vapor lamps, provide higher efficacy ranging from 80 lm/W to 100 lm/W. Older, mercury vapor lamps have much lower efficacy at approximately 40 lm/W.
- CCT and CRI values range broadly based on technology type for high bay products.

Cost:

- The total installed cost is the price of a lamp, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED luminaires, which are sold as one integrated system. Many factors influence the price of LED luminaires including, CRI, lifetime, dimming capabilities, and efficacy. Therefore, typical luminaire prices in 2022 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Annual maintenance costs are the cost of labor for replacing the lamps and the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours for commercial high bay systems (DOE SSL Program, 2012a).
- Commercial lighting disposal costs are estimated to be $0.12 per linear foot of fluorescent lamps, $1.50 per lamp for HID lamps, and $0.50 for CFLs (EPA, 2022).

ENERGY STAR:

- ENERGY STAR does not cover low/high bay luminaires (ENERGY STAR, 2012).

Performance and Cost Characteristics » Commercial High-Bay Lighting Systems

Final

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus would be on improving efficacy, lifetime and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

	Efficacy	Lifetime	Price	Potential for Improvements
Mercury Vapor	0%	0%	-0.5%	Limited because the technology is mature.
Metal Halide	0%	0%	-0.5%	Limited because the technology is mature.
Sodium Vapor	0%	0%	-0.5%	Limited because the technology is mature.

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Performance and Cost Characteristics » Commercial Mercury Vapor High-Bay

Final

DATA[1]	2012	2018	2022	2030[2]	2040[2]	2050[2]
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	400.0	400.0	400.0	N/A	N/A	N/A
Lamp Lumens	15,800	15,800	21,000	N/A	N/A	N/A
Lamp Efficacy (lm/W)	39.5	39.5	52.5	N/A	N/A	N/A
System Wattage	449.4	449.4	449.4	N/A	N/A	N/A
System Lumens	15,800	15,800	21,000	N/A	N/A	N/A
System Efficacy (lm/W)	35.2	35.2	46.7	N/A	N/A	N/A
Ballast Efficiency	89%	89%	89%	N/A	N/A	N/A
CRI	50	50	50	N/A	N/A	N/A
Correlated Color Temperature (CCT)	3,900	3,900	3,900	N/A	N/A	N/A
Average Lamp Life (thousand hours)	24	24	24	N/A	N/A	N/A
Annual Operating Hours (h/y)	3,687	3,687	3,687	N/A	N/A	N/A
Lamp Price (2022$)	$23.81	$23.10	$28.93	N/A	N/A	N/A
Ballast Price (2022$)	$55.39	$53.75	$64.35	N/A	N/A	N/A
Fixture Price (2022$)	$106.65	$103.49	$101.43	N/A	N/A	N/A
Disposal Cost (2022$)	$1.50	$1.50	$1.50	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$1.51	$1.46	$1.38	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$11.76	$11.41	$9.27	N/A	N/A	N/A
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	N/A	N/A	N/A
Labor System Installation (hours)	2.0	2.0	2.0	N/A	N/A	N/A
Labor Lamp Change (hours)	0.5	0.5	0.5	N/A	N/A	N/A
Total Installed Cost (2022$)	$340.29	$334.78	$326.71	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$9.82	$9.71	$9.74	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$21.54	$21.19	$15.56	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$0.62	$0.61	$0.46	N/A	N/A	N/A

1. Only a typical dataset is provided because these lamps all have similar efficacies.

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Performance and Cost Characteristics » Commercial Metal Halide High-Bay

Final

DATA[1]	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	400.0	400.0	400.0	400.0	400.0	400.0
Lamp Lumens	32,000	32,972	42,000	42,000	42,000	42,000
Lamp Efficacy (lm/W)	80.0	82.4	105.0	105.0	105.0	105.0
System Wattage	444.4	444.4	444.4	444.4	444.4	444.4
System Lumens	32,000	32,972	42,000	42,000	42,000	42,000
System Efficacy (lm/W)	72.0	74.2	94.5	94.5	94.5	94.5
Ballast Efficiency	90%	90%	90%	90%	90%	90%
CRI	80	80	80	80	80	80
Correlated Color Temperature (CCT)	4,000	4,000	4,000	4,000	4,000	4,000
Average Lamp Life (thousand hours)	20	20	20	20	20	20
Annual Operating Hours (h/y)	3,760	3,760	3,760	3,760	3,760	3,760
Lamp Price (2022$)	$34.95	$33.91	$42.15	$40.49	$38.51	$36.63
Ballast Price (2022$)	$55.39	$53.75	$64.35	$61.82	$58.80	$55.92
Fixture Price (2022$)	$248.32	$248.32	$248.32	$238.56	$226.90	$215.80
Disposal Cost (2022$)	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50
Lamp Cost (2022$/klm)	$1.09	$1.03	$1.00	$0.96	$0.92	$0.87
System (l/b/f) Cost (2022$/klm)	$10.58	$10.19	$8.45	$8.12	$7.72	$7.34
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	2.0	2.0	2.0	2.0	2.0	2.0
Labor Lamp Change (hours)	0.5	0.5	0.5	0.5	0.5	0.5
Total Installed Cost (2022$)	$493.10	$490.43	$486.82	$472.87	$456.21	$440.36
Annual Maintenance Cost (2022$)	$14.11	$13.91	$14.41	$14.10	$13.72	$13.37
Total Installed Cost (2022$/klm)	$15.41	$14.87	$11.59	$11.26	$10.86	$10.48
Annual Maintenance Cost (2022$/klm)	$0.44	$0.42	$0.34	$0.34	$0.33	$0.32

1. Only a typical dataset is provided because these lamps all have similar efficacies.

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Performance and Cost Characteristics » Commercial Sodium Vapor High-Bay

Final

DATA[1]	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	250.0	250.0	250.0	250.0	250.0	250.0
Lamp Lumens	24,300	24,300	28,500	28,500	28,500	28,500
Lamp Efficacy (lm/W)	97.2	97.2	114.0	114.0	114.0	114.0
System Wattage	297.0	296.6	296.6	296.6	296.6	296.6
System Lumens	24,300	24,300	28,500	28,500	28,500	28,500
System Efficacy (lm/W)	81.8	81.9	96.1	96.1	96.1	96.1
Ballast Efficiency	84%	84%	84%	84%	84%	84%
CRI	22	22	22	22	22	22
Correlated Color Temperature (CCT)	2,100	2,100	2,100	2,100	2,100	2,100
Average Lamp Life (thousand hours)	24	24	24	24	24	24
Annual Operating Hours (h/y)	3,614	3,614	3,614	3,614	3,614	3,614
Lamp Price (2022$)	$53.71	$52.12	$20.37	$19.57	$18.61	$17.70
Ballast Price (2022$)	$90.16	$87.49	$90.09	$86.55	$82.32	$78.29
Fixture Price (2022$)	$280.71	$272.39	$266.98	$256.49	$243.95	$232.02
Disposal Cost (2022$)	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50
Lamp Cost (2022$/klm)	$2.21	$2.14	$0.71	$0.69	$0.65	$0.62
System (l/b/f) Cost (2022$/klm)	$17.47	$16.95	$13.24	$12.72	$12.10	$11.51
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	2.0	2.0	2.0	2.0	2.0	2.0
Labor Lamp Change (hours)	0.5	0.5	0.5	0.5	0.5	0.5
Total Installed Cost (2022$)	$579.02	$566.44	$509.44	$494.61	$476.88	$460.02
Annual Maintenance Cost (2022$)	$14.13	$13.89	$8.26	$8.14	$8.00	$7.86
Total Installed Cost (2022$/klm)	$23.83	$23.31	$17.88	$17.35	$16.73	$16.14
Annual Maintenance Cost (2022$/klm)	$0.58	$0.57	$0.29	$0.29	$0.28	$0.28

1. Only a typical dataset is provided because these lamps all have similar efficacies.

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Performance and Cost Characteristics » Commercial T5 4xF54 HO High-Bay

Final

DATA[1]	2012	2018	2022		2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0
Lamp Lumens	4,850	4,850	4,273	4,750	4,273	4,750	4,273	4,750	4,273	4,750
Lamp Efficacy (lm/W)	89.8	89.8	79.1	88.0	79.1	88.0	79.1	88.0	79.1	88.0
System Wattage	233.8	233.8	233.8	233.8	233.8	233.8	233.8	233.8	233.8	233.8
System Lumens	19,400	19,400	17,092	19,000	17,092	19,000	17,092	19,000	17,092	19,000
System Efficacy (lm/W)	83.0	83.0	73.1	81.3	73.1	81.3	73.1	81.3	73.1	81.3
Ballast Efficiency (BLE)	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%
CRI	86	86	86	86	86	86	86	86	86	86
Correlated Color Temperature (CCT)	4,100	4,100	4,100	4,100	4,100	4,100	4,100	4,100	4,100	4,100
Average Lamp Life (thousand hours)	24	24	25	25	25	25	25	25	25	25
Annual Operating Hours (h/y)	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042
Lamp Price (2022$)	$8.45	$8.20	$4.70	$13.65	$4.51	$13.11	$4.29	$12.47	$4.08	$11.86
Ballast Price (2022$)	$33.43	$32.44	$32.17	$32.17	$30.91	$30.91	$29.39	$29.39	$27.96	$27.96
Fixture Price (2022$)	$129.23	$125.40	$122.91	$122.91	$118.08	$118.08	$112.31	$112.31	$106.82	$106.82
Disposal Cost (2022$)	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48
Lamp Cost (2022$/klm)	$1.74	$1.69	$1.10	$2.87	$1.06	$2.76	$1.00	$2.63	$0.96	$2.50
System (l/b/f) Cost (2022$/klm)	$10.13	$9.83	$10.17	$11.04	$9.77	$10.60	$9.30	$10.08	$8.84	$9.59
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Labor Lamp Change (hours)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total Installed Cost (2022$)	$325.54	$320.47	$291.78	$300.73	$285.50	$294.10	$277.99	$286.17	$270.86	$278.63
Annual Maintenance Cost (2022$)	$12.51	$12.35	$8.68	$14.47	$8.56	$14.12	$8.42	$13.71	$8.29	$13.32
Total Installed Cost (2022$/klm)	$16.78	$16.52	$17.07	$15.83	$16.70	$15.48	$16.26	$15.06	$15.85	$14.66
Annual Maintenance Cost (2022$/klm)	$0.65	$0.64	$0.51	$0.76	$0.50	$0.74	$0.49	$0.72	$0.48	$0.70

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Performance and Cost Characteristics » Commercial LED High-Bay Luminaire

Final

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	212.2	167.0	150.0	137.8	130.0	115.5	109.0	99.4	93.9	87.4	82.5
System Lumens	18,915	18,797	18,500	18,500	18,900	18,500	18,900	18,500	18,900	18,500	18,900
System Efficacy (lm/W)	89.1	112.6	123.3	134.3	145.4	160.2	173.4	186.0	201.4	211.7	229.2
Ballast Efficiency	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	74	78	80	80	80	80	80	80	80	80	80
Correlated Color Temperature (CCT)	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
Average Lifetime (thousand hours)	70	67	100	100	100	100	100	100	100	100	100
Annual Operating Hours (h/y)	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042
Lamp or Luminaire Price (2022$)	$2,842.05	$448.43	$177.54	$195.81	$234.20	$162.12	$193.90	$148.87	$178.06	$136.20	$162.90
Ballast Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$150.25	$23.86	$9.60	$10.58	$12.39	$8.76	$10.26	$8.05	$9.42	$7.36	$8.62
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Labor Lamp Change (hours)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$2,996.49	$602.87	$309.54	$327.81	$366.20	$294.12	$325.90	$280.87	$310.06	$268.20	$294.90
Annual Maintenance Cost (2022$)	$173.01	$36.40	$12.51	$13.25	$14.80	$11.89	$13.17	$11.35	$12.53	$10.84	$11.92
Total Installed Cost (2022$/klm)	$158.42	$32.07	$16.73	$17.72	$19.38	$15.90	$17.24	$15.18	$16.41	$14.50	$15.60
Annual Maintenance Cost (2022$/klm)	$9.15	$1.94	$0.68	$0.72	$0.78	$0.64	$0.70	$0.61	$0.66	$0.59	$0.63

1. N/A because the lamp and fixture are both included in the luminaire.

Refrigeration

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Performance and Cost Characteristics » Commercial Compressor Rack Systems

Final

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Total Capacity (kBtu/h)[1]	1,200	1,200	1,200	1,190	930	N/A	1,190	930	1,190	930	1,190	930
Median Store Size (ft^2)	46,500	31,997	35,197	35,197	35,197	N/A	35,197	35,197	35,197	35,197	35,197	35,197
Power Input (kW)	162	155	162	160	125	N/A	160	125	160	125	160	125
Annual Energy Use (MMWh/y)[2]	1,497	1,497	1,305	1,232	1,160	N/A	1,232	1,160	1,232	1,160	1,232	1,160
Indexed Annual Efficiency[3]	1.00	1.00	1.15	1.21	1.29	N/A	1.21	1.29	1.21	1.29	1.21	1.29
Average Life (years)	15	15	15	15	15	N/A	15	15	15	15	15	15
Total Installed Cost (2022$)	$630,000	$630,000	$488,000	$625,000	$630,000	N/A	$625,000	$630,000	$625,000	$630,000	$625,000	$630,000
Total Installed Cost (2022$/kBtu/h)	$525,000	$525,000	$406,667	$525,210	$677,419	N/A	$525,210	$677,419	$525,210	$677,419	$525,210	$677,419
Annual Maintenance Cost (2022$)[4]	$3,400	$3,400	$3,400	$3,400	$3,400	N/A	$3,400	$3,400	$3,400	$3,400	$3,400	$3,400
Annual Maintenance Cost (2022$/kBtu/h)	$2,833	$2,833	$2,833	$2,857	$3,656	N/A	$2,857	$3,656	$2,857	$3,656	$2,857	$3,656

1. The total capacity represents the nominal compressor capacity required for the entire refrigeration system of a typical supermarket. This refrigeration system usually includes two low temperature racks and two medium temperature racks. For 2018, a 1,200 MBtu/h total cooling capacity is based on a 200-ton estimate for total capacity–80 tons for the medium temperature racks and 20 tons for the low temperature racks.
2. Capacity and annual energy consumption for 2022 and beyond are based on market research and Guidehouse estimates.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Maintenance cost includes oil changes, bearing lubrication, filter replacement, and system functionality checks-approximately half a day per rack of labor for technician is assumed.

- Commercial compressor rack systems that serve commercial supermarket display cases and walk-ins consist of a number of parallel-connected compressors located in a separate machine room. By modulating compressor capacity, these integrated systems provide higher efficiency and mechanical longevity.
- Rack integrators generally supply a packaged compressor rack for which much of the necessary piping, insulation, components, and controls are pre-assembled.
- A typical supermarket will have 10 to 20 compressors mounted in racks in the 3-horsepower (hp) to 15-hp size range. Usually, each rack has three to five compressors serve a series of loads with nearly identical evaporator temperature.
- The duty cycle for compressors is usually in the range of 60% to 70%.
- Energy use and capacity for the Reference Case are projected to remain static over the coming decades because commercial compressor racks systems are a mature technology. The Reference Case assumes low R&D efforts because it is an established technology.

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Performance and Cost Characteristics » Commercial Condensers

Final

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Total Capacity (kBtu/h)[1]	1,680	1,520	1,440	1,440	1,440	N/A	1,440	1,440	1,440	1,440	1,440	1,440
Median Store Size (ft^2)	46,500	31,997	35,197	35,197	35,197	N/A	35,197	35,197	35,197	35,197	35,197	35,197
Power Input (kW)	25	25	18	18	18	N/A	18	18	18	18	18	18
Annual Energy Use (MMWh/y)	120	120	115	106	86	N/A	106	86	106	86	106	86
Indexed Annual Efficiency[2]	1.00	1.00	1.04	1.13	1.40	N/A	1.13	1.40	1.13	1.40	1.13	1.40
Average Life (years)	10	10	10	10	10	N/A	10	10	10	10	10	10
Total Installed Cost (2022$)	$54,000	$60,000	$54,000	$60,000	$80,000	N/A	$60,000	$80,000	$60,000	$80,000	$60,000	$80,000
Total Installed Cost (2022$/kBtu/h)	$32,143	$39,474	$37,500	$41,667	$55,556	N/A	$41,667	$55,556	$41,667	$55,556	$41,667	$55,556
Annual Maintenance Cost (2022$)[3]	$954	$954	$954	$954	$954	N/A	$954	$954	$954	$954	$954	$954
Annual Maintenance Cost (2022$/kBtu/h)	$0.57	$0.63	$0.66	$0.66	$0.66	N/A	$0.66	$0.66	$0.66	$0.66	$0.66	$0.66

1. Total capacity is the total heat rejected (THR) by condensers comprised of two low temperature condensers (THRL = 240 MBtu/h each, suction temperature= -25°F, condensing temperature-110°F) and two medium temperature condensers (THRM = 520 MBtu/h each, suction temperature = 15°F, condensing temperature = 115°F); ambient temperature = 95°F. (NCI, 2009). For 2022 and beyond, capacity was estimated by Guidehouse.
2. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
3. Maintenance cost includes coil cleaning, leak checking, belt replacement as necessary, and system functionality checks.

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Performance and Cost Characteristics » Commercial Condensers

Final

- Condensers are designed with multiple methods of cooling: air-cooled, water-cooled, and evaporative. These units can be single-circuit or a multiple circuit.
- Commercial condensers are remotely located, typically installed on the roof of a supermarket.
- For use with parallel compressors in supermarkets, air-cooled units are the most commonly used condensers. This analysis is based on multiple air-cooled condensers connected to a supermarket refrigeration system comprised of two low temperature condensers and two medium temperature condensers.
- Each compressor rack has a dedicated condenser or a separate circuit of a single common condenser. Condenser temperatures of multiple racks are often different.
- The duty cycle for condensers is usually in the range 50%-70%.
- Energy use is projected to remain static over the coming decades because commercial condensers are a mature technology.

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Performance and Cost Characteristics » Commercial Supermarket Display Cases

Final

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	17,623	11,850	11,850	11,850	11,850	N/A	11,850	11,850	11,850	11,850	11,850	11,850
Median Store Size (ft^2)	46,500	31,997	35,197	35,197	35,197	N/A	35,197	35,197	35,197	35,197	35,197	35,197
Case Length (ft)	12	12	12	12	12	N/A	12	12	12	12	12	12
Annual Energy Use (kWh/y)[1,2]	13,497	10,506	10,506	9,771	9,087	N/A	9,771	9,087	9,771	9,087	9,771	9,087
Annual Energy Use / Case Length (kWh/ft)	1,125	876	876	814	757	N/A	814	757	814	757	814	757
Indexed Annual Efficiency[3]	1.00	1.28	1.28	1.38	1.49	N/A	1.38	1.49	1.38	1.49	1.38	1.49
Average Life (years)	10	10	10	10	10	N/A	10	10	10	10	10	10
Retail Equipment Cost (2022$)	$8,510	$10,650	$7,265	$9,500	$10,680	N/A	$9,500	$10,680	$9,500	$10,680	$9,500	$10,680
Total Installed Cost (2022$)	$10,811	$12,650	$9,265	$11,500	$12,680	N/A	$11,500	$12,680	$11,500	$12,680	$11,500	$12,680
Total Installed Cost (2022$/kBtu/h)	613	1,068	782	970	1,070	N/A	970	1,070	970	1,070	970	1,070
Annual Maintenance Cost (2022$)[4]	$940	$940	$940	$940	$940	N/A	$940	$940	$940	$940	$940	$940
Annual Maintenance Cost (2022$/kBtu/h)	$53.34	$79.32	$79.32	$79.32	$79.32	N/A	$79.32	$79.32	$79.32	$79.32	$79.32	$79.32

1. For 2022 and beyond, energy consumption and cost values were estimated using shipment-weighted averages reported in DOE's 2014 CRE Final Rule Technical Support Document (TSD) for equipment commonly used as display cases. DOE's updated conservation standard went into effect in 2017, so units sold in 2018 are assumed to comply with this standard.
2. For consistency with DOE rulemaking practices, Supermarket Display Case Energy Use reported above includes energy use of the compressor racks and condensers. To avoid double counting, do not add Energy Use from the Compressor Rack or Condenser Systems tabs if calculating total energy consumption.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Maintenance cost includes preventative maintenance costs such as cleaning evaporator coils, drain pans, fans, and intake screens as well as lamp replacements and other lighting maintenance activities. After 2012, these values are based on a reported maintenance and repair cost of $220 per unit for preventative maintenance plus approximately $60 per linear foot for additional repair and maintenance.

Performance and Cost Characteristics » Commercial Supermarket Display Cases

Final

- DOE set federal energy efficiency standards for Commercial Refrigeration Equipment (CRE) in 2009. These standards set maximum daily energy consumption levels, in kilowatt-hours per day, for display cases manufactured sold in the United States on or after January 1, 2012.
- DOE updated its Energy Conservation Standards for Commercial Refrigeration Equipment in 2014 for equipment sold on or after March 27, 2017.
- The table below lists equipment used as supermarket display cases and their corresponding Energy Conservation Standard levels. The maximum allowable daily energy consumption for each equipment class is a linear function of Total Display Area (TDA).

Equipment Description	Standards Equation (2012)	Standards Equation (2017)
Vertical Open Cooler (VOP.RC.M)	0.82xTDA+4.07	0.64xTDA+4.07
Semi-Vertical Open Cooler (SVO.RC.M)	0.83xTDA+3.18	0.66xTDA+3.18
Horizontal Open Cooler (HZO.RC.M)	0.35xTDA+2.88	0.35xTDA+2.88
Transparent-Doored Cooler (VCT.RC.M)	0.22xTDA+1.95	0.15xTDA+1.95
Deli Display Cooler (SOC.RC.M)	0.51xTDA+0.11	0.44xTDA+0.11
Transparent-Doored Freezer (VCT.RC.L)	0.56xTDA+2.61	0.49xTDA+2.61
Horizontal Open Freezer (HZO.RC.L)	0.57xTDA+6.88	0.55xTDA+6.88

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Performance and Cost Characteristics » Commercial Supermarket Display Cases

Final

- According to CBECS 2018 microdata, the average building size for food sale building type is 31,997.
- Unit energy consumption for 2022 and beyond is estimated using a shipment-weighted average by efficiency level and equipment class, using data in DOE's 2014 CRE Final Rule TSD with updated analysis from Guidehouse in 2016. The equipment classes analyzed are listed in the table on the previous slide.
- Supermarket refrigeration systems consist of refrigerated display cases, condensing units, and centralized compressor racks.
- A typical supermarket display case contains lighting, evaporators, evaporator fans, piping, insulation, valves, and controls.
- The efficiency of supermarket display cases can be increased through the use of improved evaporator coils, larger evaporators, higher efficiency evaporator fan blades, high efficiency doors, LED lighting, and improved insulation.
- Energy use is projected to remain static over the coming decades because supermarket display cases are a mature technology.

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Performance and Cost Characteristics » Commercial Reach-In Refrigerators

Final

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[2]	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	2,929	2,400	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349
Size (ft^3)	49	49	46	46	46	47	46	46	46	46	46	46
Annual Energy Use (kWh/y)	2,340	2,222	1,935	1,351	810	810	1,351	810	1,351	810	1,351	810
Annual Energy Use / Volume ($kWh/y/ft^3$)[1]	48	45	42	29	18	17	29	18	29	18	29	18
Indexed Annual Efficiency[3]	1.00	1.05	1.21	1.73	2.89	2.89	1.73	2.89	1.73	2.89	1.73	2.89
Average Life (years)	10	10	10	10	10	10	10	10	10	10	10	10
Retail Equipment Cost (2022$)	$2,624	$2,403	$2,728	$2,780	$3,021	$3,021	$2,780	$3,021	$2,780	$3,021	$2,780	$3,021
Total Installed Cost (2022$)[4]	$3,454	$3,282	$3,591	$3,643	$3,884	$3,884	$3,643	$3,884	$3,643	$3,884	$3,643	$3,884
Total Installed Cost (2022$/kBtu/h)	$1,179	$1,368	$1,529	$1,551	$1,654	$1,654	$1,551	$1,654	$1,551	$1,654	$1,551	$1,654
Annual Maintenance Cost (2022$)[5]	$185	$185	$185	$185	$185	$186	$185	$185	$185	$185	$185	$185
Annual Maintenance Cost (2022$/kBtu/h)	$63	$77	$79	$79	$79	$79	$79	$79	$79	$79	$79	$79

1. EPACT 2005 energy standards went into effect in 2010. 2022 low efficiency cost and energy consumption values are based on minimum compliance with this standard. Unless otherwise noted, all other cases are based on shipment-weighted averages solid- and transparent-doored units reported in the 2014 CRE TSD. DOE's updated Energy Conservation standards went into effect in 2017; therefore, compliance with this standard is assumed for 2022 and beyond.
2. The ENERGY STAR category is based on a shipment weighted average of solid- and transparent-doored units that are minimally compliant with ENERGY STAR v3, effective October 1, 2014. Units compliant with ENERGY STAR are found to be the most efficient reach-in refrigeration equipment on the market in 2022.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Installation cost for 2012 is based on NCI 2009 report that assumes a cost of $863. Installation cost for 2022 and beyond is based DOE's 2014 CRE Final Rule and additional analysis by Guidehouse, which assumes an installation cost of $878 for self-contained equipment.
5. Maintenance costs after 2012 are based on DOE's CRE 2014 Final Rule TSD, which reports $35 annual preventative maintenance, per unit, per year, plus approximately $40 per linear foot, per year of additional repair and maintenance costs for the units characterized.

Performance and Cost Characteristics » Commercial Reach-In Refrigerators

Final

- The Energy Policy Act of 2005 (EPACT 2005) set maximum daily energy consumption levels, in kilowatt-hours per day, for commercial reach-in refrigerators that went into effect on January 1, 2010. The daily energy consumption is based on the volume of the unit (V) in ft^3.
- In 2014, DOE updated its energy conservation standards for reach-in refrigerators, effective March 27, 2017. Both standards are reported in the table below.

Equipment Class	EPCA Standard Level (2010)	DOE Standard Level (2017)
Solid Door (VCS.SC.M)	0.10xV+2.04	0.05xV + 1.36
Glass Door (VCT.SC.M)	0.12xV+3.34	0.1xV+0.86

- In 2013, EPA updated its ENERGY STAR specifications for reach-in refrigerators, effective March 27, 2017. These standards are also based on the refrigerated volume of the unit.

Reach-In Refrigerator Size	0 < V < 15	15 ≤ V < 30	30 ≤ V < 50	50 ≤ V
Solid Door (VCS.SC.M)	0.022xV+0.97	0.066xV+0.31	0.04xV+1.09	0.024xV+1.89
Glass Door (VCT.SC.M)	0.095xV+0.445	0.05xV+1.12	0.076xV+0.034	0.105xV-1.111

- Unit energy consumption for 2012 and beyond was estimated based on shipment-weighted averages by efficiency level and equipment class for 49 ft3 VCS.SC.M and VCT.SC.M units reported in DOE's 2014 CRE Final Rule TSD with updated analysis from Guidehouse in 2016. These units were estimated to comprise approximately 85% and 15% of total reach-in refrigerator shipments, respectively.
- The efficiency of commercial reach-in refrigerators can be increased through the use of efficient compressors, efficient evaporator fans, efficient condenser fans, electric defrost, and more efficient lighting.
- For this referenced scenario, energy use is projected to remain static over the coming decades because reach-in refrigerators are a mature technology.

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Performance and Cost Characteristics » Commercial Reach-In Freezers

Final

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[2]	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	4,341	4,340	4,340	4,340	4,340	4,340	4,340	4,340	4,340	4,340	4,340	4,340
Size (ft^3)	49	49	49	49	49	49	49	49	49	49	49	49
Annual Energy Use (kWh/y)[1]	6,023	5,585	5,585	4,847	4,110	4,110	4,847	4,110	4,847	4,110	4,847	4,110
Annual Energy Use / Volume ($kWh/y/ft^3$)	123	114	114	99	84	84	99	84	99	84	99	84
Indexed Annual Efficiency[3]	1.00	1.08	1.08	1.24	1.47	1.47	1.24	1.47	1.24	1.47	1.24	1.47
Average Life (years)	10	10	10	10	10	10	10	10	10	10	10	10
Retail Equipment Cost (2022$)	$2,886	$2,886	$2,886	$3,175	$3,493	$3,493	$3,175	$3,493	$3,175	$3,493	$3,175	$3,493
Total Installed Cost (2022$)[4]	$3,749	$3,749	$3,749	$4,125	$4,443	$4,443	$4,125	$4,443	$4,125	$4,443	$4,125	$4,443
Total Installed Cost (2022$/kBtu/h)	$864	$864	$864	$950	$1,024	$1,024	$950	$1,024	$950	$1,024	$950	$1,024
Annual Maintenance Cost (2022$)[5]	$181	$181	$181	$181	$181	$181	$181	$181	$181	$181	$181	$181
Annual Maintenance Cost (2022$/kBtu/h)	$41.70	$41.71	$41.71	$41.71	$41.71	$41.71	$41.71	$41.71	$41.71	$41.71	$41.71	$41.71

1. A 49 ft^3 unit was characterized, because it was the representative size selected for DOE's rulemaking analysis.
2. The ENERGY STAR category was based on a solid-doored unit that is minimally compliant with ENERGY STAR v3, effective October 1, 2014.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Installation cost for 2012 and 2018 is based on DOE's on-going CRE rulemaking, which assumes a cost of $863 for self-contained equipment and $950 for 2022 and beyond based on analysis from Guidehouse.
5. Maintenance costs are calculated based on a $35 per unit annual preventative maintenance cost, plus an additional $45 per linear foot repair and maintenance cost estimated based on values reported in the CRE TSD.

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Performance and Cost Characteristics » Commercial Reach-In Freezers

Final

- EPACT 2005 set maximum daily energy consumption levels, in kilowatt-hours per day, for commercial reach-in freezers that went into effect on January 1, 2010. The daily energy consumption is based on the volume of the unit (V) in ft^3.
- In March of 2017, DOE updated its energy conservation standards for commercial refrigeration equipment, including reach-in freezers. Both the EPCA and DOE standards are reported in the table below.

Equipment Class	EPCA (2010)	DOE Standard Level (2017)
Solid Door (VCS.SC.L)	0.4xV+1.38	0.22xV+1.38
Transparent Door (VCT.SC.L)	0.75xV+4.10	0.29xV+2.95

- In 2013, EPA updated its ENERGY STAR specifications for reach-in freezers, effective March 27, 2017. These standards are also based on the refrigerated volume of the unit.

Reach-In Freezer Size	0 < V < 15	15 ≤ V < 30	30 ≤ V < 50	50 ≤ V
Solid Door (VCS.SC.L)	0.21xV+0.9	0.12xV+2.248	0.285xV-2.703	0.142xV+4.445
Glass Door (VCT.SC.L)	0.232xV+2.36	0.232xV+2.36	0.232xV+2.36	0.232xV+2.36

- The commercial reach-in freezer characterized in this report, which is the typical unit according to DOE's 2014 CRE rulemaking, is a 49 cubic ft. solid two-door unit with a nominal compressor size of 4,341 Btu/h.
- The efficiency of commercial reach-in freezers can be increased through the use of efficient compressors, efficient evaporator fans, efficient condenser fans, electric defrost, and more efficient lighting.
- For this referenced scenario, energy use is projected to remain static over the coming decades because reach-in freezers are a mature technology.

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Performance and Cost Characteristics » Commercial Walk-In Refrigerators

Final

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)[1]	37,820	39,422	41,024	41,024	41,024	N/A	41,024	41,024	41,024	41,024	41,024	41,024
Size (ft^2)	305	240	240	240	240	N/A	240	240	240	240	240	240
Annual Energy Use (kWh/y)[2]	30,689	20,040	17,600	16,200	14,800	N/A	16,200	14,800	16,200	14,800	16,200	14,800
Annual Energy Use / Area ($kWh/ft^2/y$)	101	84	73	68	62	N/A	68	62	68	62	68	62
Indexed Annual Efficiency[3]	1.00	1.53	1.74	1.89	2.07	N/A	1.89	2.07	1.89	2.07	1.89	2.07
Insulated Box Average Life (years)	12	12	12	12	12	N/A	12	12	12	12	12	12
Compressor Average Life (years)	10	10	10	10	10	N/A	10	10	10	10	10	10
Retail Equipment Cost (2022$)	$23,598	$19,847	$16,050	$19,847	$23,644	N/A	$16,050	$23,644	$16,050	$23,644	$16,050	$23,644
Total Installed Cost (2022$)[4]	$27,012	$23,897	$20,100	$23,897	$27,694	N/A	$20,100	$27,694	$20,100	$27,694	$20,100	$27,694
Total Installed Cost (2022$/kBtu/h)	$714	$606	$490	$583	$675	N/A	$490	$675	$490	$675	$490	$675
Annual Maintenance Cost (2022$)[5]	$716	$740	$740	$740	$740	N/A	$740	$740	$740	$740	$740	$740
Annual Maintenance Cost (2022$/kBtu/h)	$18.93	$18.77	$18.04	$18.04	$18.04	N/A	$18.04	$18.04	$18.04	$18.04	$18.04	$18.04

1. Assumes medium temperature units are refrigerators.
2. Average unit energy consumption was adapted from the DOE CRE 2016 report by assuming electronically commutated motor (ECM) evaporator fan motors are required for Energy Policy & Conservation Act (EPCA) compliance, as well as ECM condenser fan motors.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Installation cost for 2012 and beyond is based on DOE's Walk-In TSD.
5. Maintenance cost includes checking and maintaining refrigerant charge levels, checking settings, and cleaning heat exchanger coils.

- For 2012 and beyond, the unit characterized was a walk-in storage cooler, based on DOE's WICF TSD.
- A typical walk-in refrigerator includes:
  - insulated floor and wall panels
  - merchandising doors, shelving, and lighting (not included in cost estimate)
  - semi-hermetic reciprocating compressor
  - refrigerant (R404A)
  - condenser
  - evaporator
- Energy consumption is assumed to scale with the AWEF (Annual Walk-in Energy Factor), defined as the ratio of total heat removed from the refrigerated volume per year to the total electrical energy input of refrigeration systems over the same time period.
- The installation cost consists of freight and delivery costs in addition to on-site assembly.

The Energy Independence and Security Act (EISA) of 2007 included prescriptive standards for walk-in refrigerators (coolers) that went into effect in 2009. These prescriptive standards, which are included in the analysis for all units for 2012 and beyond, state that all walk-in refrigerators manufactured after January 1, 2009, must:

- For 2012 and beyond
- have automatic door closers
- have strip doors, spring hinged doors, or other method of minimizing infiltration when doors are open
- contain wall, ceiling, and door insulation of at least R–25, except for glazed portions of doors and structural members
- use electronically commutated motors or three-phase motors (for evaporator fan motors of under 1 horsepower and less than 460 volts)
- use electronically commutated motors, permanent split capacitor-type motors, or three-phase motors (for condenser fan motors of under 1 horsepower)
- use light sources with an efficacy of 40 lumens per watt or more, including ballast losses (if any), except that light sources with an efficacy of 40 lumens per watt or less, including ballast losses (if any), may be used in conjunction with a timer or device that turns off the lights within 15 minutes of when the walk-in refrigerator is not occupied by people.

In 2014, DOE updated its energy conservation standards for walk-in coolers and freezers. Minimum AWEF (Annual Walk-In Energy Factor) was set for refrigeration systems, as well as upper limits on energy consumption attributable to passage, freight, and display doors. DOE elected not to set new standards for the R-value of Walk-In Panels.

ENERGY CONSERVATION STANDARDS FOR WALK-IN COOLERS AND WALK-IN FREEZERS

Class descriptor	Class	Standard level
Refrigeration Systems Minimum AWEF (Btu/W-h)		
Dedicated Condensing, Medium Temperature, Indoor System, <9,000 Btu/h Capacity	DC.M.I, <9,000	5.61
Dedicated Condensing, Medium Temperature, Indoor System, ≥9,000 Btu/h Capacity	DC.M.I, ≥9,000	5.61
Dedicated Condensing, Medium Temperature, Outdoor System, <9,000 Btu/h Capacity	DC.M.O, <9,000	7.60
Dedicated Condensing, Medium Temperature, Outdoor System, ≥9,000 Btu/h Capacity	DC.M.O,≥9,000	7.60
Dedicated Condensing, Low Temperature, Indoor System, <9,000 Btu/h Capacity	DC.L.I, <9,000	$5.93 \cdot 10^{-5} \cdot Q + 2.33$
Dedicated Condensing, Low Temperature, Indoor System, ≥9,000 Btu/h Capacity	DC.L.I, ≥9,000	3.10
Dedicated Condensing, Low Temperature, Outdoor System, <9,000 Btu/h Capacity	DC.L.O, <9,000	$2.30 \cdot 10^{-4} \cdot Q + 2.73$
Dedicated Condensing, Low Temperature, Outdoor System, ≥9,000 Btu/h Capacity	DC.L.O, ≥9,000	4.79
Multiplex Condensing, Medium Temperature	MC.M	10.89
Multiplex Condensing, Low Temperature	MC.L	6.57
Panels Minimum R-value (h-ft2-°F/Btu)		
Structural Panel, Medium Temperature	SP.M	25
Structural Panel, Low Temperature	SP.L	32
Floor Panel, Low Temperature	FP.L	28
Non-Display Doors Maximum energy consumption (kWh/day) **		
Passage Door, Medium Temperature	PD.M	$0.05 \cdot A_{nd} + 1.7$
Passage Door, Low Temperature	PD.L	$0.14 \cdot A_{nd} + 4.8$
Freight Door, Medium Temperature	FD.M	$0.04 \cdot A_{nd} + 1.9$
Freight Door, Low Temperature	FD.L	$0.12 \cdot A_{nd} + 5.6$
Display Doors Maximum Energy Consumption (kWh/day) †		
Display Door, Medium Temperature	DD.M	$0.04 \cdot A_{dd} + 0.41$
Display Door, Low Temperature	DD.L	$0.15 \cdot A_{dd} + 0.29$

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Performance and Cost Characteristics » Commercial Walk-In Freezers

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DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	22,114	23,500	23,500	23,500	23,500	N/A	23,500	23,500	23,500	23,500	23,500	23,500
Size (ft^2) [1]	172	161	161	161	161	N/A	161	161	161	161	161	161
Annual Energy Use (kWh/y)[2]	22,862	22,000	22,000	20,460	19,028	N/A	20,460	19,028	20,460	19,028	20,460	19,028
Annual Energy Use / Area ($kWh/ft^2/y$)	133	124	124	115	107	N/A	115	107	115	107	115	107
Indexed Annual Efficiency[3]	1.00	1.04	1.04	1.12	1.20	N/A	1.12	1.20	1.12	1.20	1.12	1.20
Insulated Box Average Life (years)	12	12	12	12	12	N/A	12	12	12	12	12	12
Compressor Average Life (years)	10	10	10	10	10	N/A	10	10	10	10	10	10
Retail Equipment Cost (2022$)	$22,008	$21,950	$21,950	$22,850	$23,750	N/A	$22,850	$23,750	$22,850	$23,750	$22,850	$23,750
Total Installed Cost (2022$)[4]	$24,058	$23,950	$23,950	$24,850	$25,750	N/A	$24,850	$25,750	$24,850	$25,750	$24,850	$25,750
Total Installed Cost (2022$/kBtu/h)	$1,088	$1,019	$1,019	$1,057	$1,096	N/A	$1,057	$1,096	$1,057	$1,096	$1,057	$1,096
Annual Maintenance Cost (2022$)[5]	$741	$741	$741	$741	$741	N/A	$741	$741	$741	$741	$741	$741
Annual Maintenance Cost (2022$/kBtu/h)	$33.51	$31.53	$31.53	$31.53	$31.53	N/A	$31.53	$31.53	$31.53	$31.53	$31.53	$31.53

1. Based on DOE's 2014 WICF Final Rule TSD and additional analysis by Guidehouse, the average floor area for a walk-in storage freezer as 161 ft^2.
2. EISA 2007 includes prescriptive standards for walk-in freezers that went into effect in 2009. All units for 2012 and beyond include these prescriptive standards. Units for 2022 and beyond are characterized using data from DOE's 2014 WICF rulemaking. All units for 2022 and beyond are assumed to comply with this standard.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Installation cost for 2012 and beyond is based on DOE's WICF TSD and additional analysis by Guidehouse.
5. Maintenance cost includes checking and maintaining refrigerant charge levels, checking settings, and cleaning heat exchanger coils.

- The commercial walk-in freezer characterized in this report is a walk-in storage freezer with an area of 161 ft^2.
- A typical walk-in freezer includes:
  - insulated floor, door, and wall panels
  - semi-hermetic reciprocating compressor
  - refrigerant (R404A)
  - condenser
  - evaporator
- Energy consumption is assumed to scale with the AWEF (Annual Walk-in Energy Factor), defined as the ratio of total heat removed from the refrigerated volume per year to the total electrical energy input of refrigeration systems over the same time period.
- The installation cost consists of freight and delivery costs in addition to on-site assembly.

EISA 2007 included prescriptive standards for walk-in freezers that went into effect in 2009. These prescriptive standards, which are included in all units for 2011 and beyond, state that all walk-in freezers manufactured after January 1, 2009, must:

- have automatic door closers
- have strip doors, spring hinged doors, or other method of minimizing infiltration when doors are open
- contain wall, ceiling, and door insulation of at least R–32, except for glazed portions of doors and structural members
- contain floor insulation of at least R–28
- use electronically commutated motors or three-phase motors (for evaporator fan motors of under 1 horsepower and less than 460 volts)
- use electronically commutated motors, permanent split capacitor-type motors, or three-phase motors (for condenser fan motors of under 1 horsepower)
- use light sources with an efficacy of 40 lumens per watt or more, including ballast losses (if any), except that light sources with an efficacy of 40 lumens per watt or less, including ballast losses (if any), may be used in conjunction with a timer or device that turns off the lights within 15 minutes of when the walk-in freezer is not occupied by people.

In 2014, DOE updated its energy conservation standards for walk-in coolers and freezers. Minimum AWEF (Annual Walk-in Energy Factor) was set for refrigeration systems, as well as upper limits on energy consumption attributable to passage, freight, and display doors. DOE elected not to set new standards for the R-value of Walk-in Panels.

ENERGY CONSERVATION STANDARDS FOR WALK-IN COOLERS AND WALK-IN FREEZERS

Class descriptor	Class	Standard level
Refrigeration Systems Minimum AWEF (Btu/W-h)		
Dedicated Condensing, Medium Temperature, Indoor System, <9,000 Btu/h Capacity	DC.M.I, <9,000	5.61
Dedicated Condensing, Medium Temperature, Indoor System, ≥9,000 Btu/h Capacity	DC.M.I, ≥9,000	5.61
Dedicated Condensing, Medium Temperature, Outdoor System, <9,000 Btu/h Capacity	DC.M.O, <9,000	7.60
Dedicated Condensing, Medium Temperature, Outdoor System, ≥9,000 Btu/h Capacity	DC.M.O,≥9,000	7.60
Dedicated Condensing, Low Temperature, Indoor System, <9,000 Btu/h Capacity	DC.L.I, <9,000	$5.93 \cdot 10^{-5} \cdot Q + 2.33$
Dedicated Condensing, Low Temperature, Indoor System, ≥9,000 Btu/h Capacity	DC.L.I, ≥9,000	3.10
Dedicated Condensing, Low Temperature, Outdoor System, <9,000 Btu/h Capacity	DC.L.O, <9,000	$2.30 \cdot 10^{-4} \cdot Q + 2.73$
Dedicated Condensing, Low Temperature, Outdoor System, ≥9,000 Btu/h Capacity	DC.L.O, ≥9,000	4.79
Multiplex Condensing, Medium Temperature	MC.M	10.89
Multiplex Condensing, Low Temperature	MC.L	6.57
Panels Minimum R-value (h-ft2-°F/Btu)		
Structural Panel, Medium Temperature	SP.M	25
Structural Panel, Low Temperature	SP.L	32
Floor Panel, Low Temperature	FP.L	28
Non-Display Doors Maximum energy consumption (kWh/day) **		
Passage Door, Medium Temperature	PD.M	$0.05 \cdot A_{nd} + 1.7$
Passage Door, Low Temperature	PD.L	$0.14 \cdot A_{nd} + 4.8$
Freight Door, Medium Temperature	FD.M	$0.04 \cdot A_{nd} + 1.9$
Freight Door, Low Temperature	FD.L	$0.12 \cdot A_{nd} + 5.6$
Display Doors Maximum Energy Consumption (kWh/day) †		
Display Door, Medium Temperature	DD.M	$0.04 \cdot A_{dd} + 0.41$
Display Door, Low Temperature	DD.L	$0.15 \cdot A_{dd} + 0.29$

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Performance and Cost Characteristics » Commercial Ice Machines

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DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[6]	Typical	High	Typical	High	Typical	High
Output (pounds [lbs] per day)[1]	300	641	700	700	700	700	700	700	700	700	700	700
Cooling Capacity (Btu/h)[2]	1963	4194	4580	4580	4580	4580	4580	4580	4580	4580	4580	4580
Water Use per Hundred Pounds (gal/hundred lbs)[3]	20	25	25	20	15	15	20	15	20	15	20	15
Energy Use per Hundred Pounds (kWh/hundred lbs)	7.7	7.5	7.1	5.8	4.8	4.8	5.8	4.8	5.8	4.8	5.8	4.8
Annual Energy Use (kWh/y)[4]	3,185	2,502	1,675	1,478	1,190	1,190	1,478	1,190	1,478	1,190	1,478	1,190
Indexed Annual Efficiency[5]	1.00	1.27	1.90	2.15	2.68	2.68	2.15	2.68	2.15	2.68	2.15	2.68
Average Life (years)	8.0	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
Retail Equipment Cost (2022$)	$2,146	$2,616	$2,946	$3,020	$3,368	$3,368	$3,020	$3,368	$3,020	$3,368	$3,020	$3,368
Total Installed Cost (with Bin)	$2,441	$3,626	$3,276	$3,350	$3,737	$3,737	$3,350	$3,737	$3,350	$3,737	$3,350	$3,737
Total Installed Cost (2022$/kBtu/h)	$1,244	$865	$715	$732	$816	$816	$732	$816	$732	$816	$732	$816
Annual Maintenance Cost (2022$)[7]	$826	$826	$800	$800	$800	$800	$800	$800	$800	$800	$800	$800
Annual Maintenance Cost (2022$/kBtu/h)	$421	$197	$175	$175	$175	$175	$175	$175	$175	$175	$175	$175

1. Based on the average output from the Compliance Certification Database and values within 2022 Automatic Commercial Ice Maker (ACIM) TSD.
2. Defined as the average heat load to remove the latent and sensible heat required to freeze the daily output capacity of ice.
3. Water use refers to potable water.
4. EPACT 2005 energy standards went into effect in 2010. The 2015 low values are based on this standard. In 2014, DOE set new standards for commercial ice machines, with compliance required by 2018. The unit characterized for 2012 and beyond uses data from this rulemaking. All units for 2020 and beyond are assumed to comply with the updated standard.
5. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
6. The ENERGY STAR category is based on minimum compliance with the ENERGY STAR v3.0 standard, which went into effect on January 28, 2018. According to this analysis, ENERGY STAR certification is typical for the small air-cooled ice-making head (IMH) unit characterized.
7. Maintenance cost is based on the average cost of equipment within the 700 lb/day output range and includes cleaning and maintaining refrigerant levels, replacing filters, checking water distribution lines for leaks, cleaning, sanitizing, and descaling the bin and water system. Maintenance cost decreases as the size of the ice machine (i.e. output) decreases.

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Performance and Cost Characteristics » Commercial Ice Machines

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- Commercial ice machines are typically integrated with an insulated ice storage bin or mounted on top of a separate storage bin. The retail equipment cost includes the ice making head and the integrated storage bin. Commercial ice machine condensers are either air-cooled or water-cooled. Approximately 90% of all units are the air-cooled type.
- Commercial ice machine maintenance includes periodic cleaning (every 2 to 6 weeks) to remove lime and scale and sanitizing to kill bacteria. Some ice machines are self-cleaning/sanitizing.
- ENERGY STAR® updated its maximum energy consumption levels, in kilowatt-hours per 100 pounds of ice, for air-cooled ice machines that went into effect on January 28, 2018. These efficiency levels are based on the harvest rate, in pounds per 24 hours. (H). Water-cooled ice machines are not eligible for ENERGY STAR certification.

ENERGY STAR Requirements for Air-Cooled Batch-Type Ice Makers			
Equipment Type	Applicable Ice Harvest Rate Range (lbs of ice/24 hrs)	Energy Consumption Rate (kWh/100 lbs ice)	Potable Water Use (gal/hundred lbs ice)
IMH	$200 \le H \le 1600$	$\le 37.72 * H^{-0.298}$	≤ 20.0
RCU	$400 \le H \le 1600$	$\le 22.95 * H^{-0.258} + 1.00$	≤ 20.0
	$1600 \le H \le 4000$	$\le -0.00011 * H + 4.60$	≤ 20.0
SCU	$50 \le H \le 450$	$\le 48.66 * H^{-0.326} + 0.08$	≤ 25.0

ENERGY STAR Requirements for Air-Cooled Continuous-Type Ice Makers		
Equipment Type	Energy Consumption Rate (kWh/hundred lbs ice)	Potable Water Use (gal/hundred lbs ice)
IMH	$\le 9.18 * H^{-0.057}$	≤ 15.0
RCU	$\le 6.00 * H^{-0.162} + 3.50$	≤ 15.0
SCU	$\le 59.45 * H^{-0.349} + 0.08$	≤ 15.0

EPACT 2005 issued standard levels for commercial ice machines with capacities between 50 pounds and 2500 pounds per 24-hour period that are manufactured or sold in the United States on or after January 1, 2010. The energy consumption is based on the harvest rate in pounds per 24 hours (H). In 2015, DOE finalized new standards for ACIMs extending coverage to flake, nugget, and tube-type machines and to capacities up to 4,000 pounds per 24 hours.

Equipment Type	Type of Cooling	Harvest Rate (lbs ice/24 hrs)	Maximum Energy Use (kWh/hundred lbs ice)	Maximum Condenser Water Use (gal/hundred lbs ice)
Ice Making Head	Water	<500	7.80-0.0055 H	200-0.022 H
		≥500 and <1,436	5.58-0.0011 H	200-0.022 H
		≥1,436	4.0	200-0.022 H
	Air	<450	10.26-0.0086 H	Not Applicable
		≥450	6.89-0.0011 H	Not Applicable
Remote Condensing (but not remote compressor)	Air	<1,000	8.85-0.0038 H	Not Applicable
		≥1,000	5.10	Not Applicable
Remote Condensing and Remote Compressor	Air	<934	8.85-0.0038 H	Not Applicable
		≥934	5.3	Not Applicable
Self Contained	Water	<200	11.40-0.019 H	191-0.0315 H
		≥200	7.60	191-0.0315 H
	Air	<175	18.0-0.0469 H	Not Applicable
		≥175	9.80	Not Applicable

Water use is for the condenser only and does not include potable water used to make ice.

2014 DOE Standards

Energy Conservation Standards for Batch-Type Automatic Commercial Ice Makers
Effective January 2018

Equipment Type	Type of Cooling	Harvest Rate lb ice/24 hours	Maximum Energy Use kWh/100 lb ice*	Maximum Condenser Water Use gal/100 lb ice**
Ice-Making Head	Water	<300	6.88 - 0.0055H	200 - 0.022H
		300 and <850	5.80 - 0.00191H	200 - 0.022H
		850 and <1,500	4.42 - 0.00028H	200 - 0.022H
		1500 and <2,500	4.0	200 - 0.022H
		2500 and <4,000	4.0	145
Ice-Making Head	Air	<300	10 - 0.01233H	Not Applicable
		300 and <800	7.05 - 0.0025H	Not Applicable
		800 and <1500	5.55 - 0.00063H	Not Applicable
		1500 and <4,000	4.61	Not Applicable
Remote Condensing (but not remote compressor)	Air	50 and <1,000	7.97 - 0.00342H	Not Applicable
		1,000 and <4,000	4.55	Not Applicable
Remote Condensing and Remote Compressor	Air	<942	7.97 - 0.00342H	Not Applicable
		942 and <4,000	4.75	Not Applicable
Self-Contained	Water	<200	9.5 - 0.019H	191 - 0.0315H
		200 and <2,500	5.7	191 - 0.0315H
		2500 and <4,000	5.7	112
Self-Contained	Air	<110	14.79 - 0.0469H	Not Applicable
		110 and <200	12.42 - 0.02533H	Not Applicable
		200 and <4,000	7.35	Not Applicable

Energy Conservation Standards for Continuous-Type Automatic Commercial Ice Makers
Effective January 2018

Equipment Type	Type of Cooling	Harvest Rate lb ice/24 hours	Maximum Energy Use kWh/100 lb ice*	Maximum Condenser Water Use gal/100 lb ice**
Ice-Making Head	Water	<801	6.48 - 0.00267H	180 - 0.0198H
		801 and <2,500	4.34	180 - 0.0198H
		2,500 and <4,000	4.34	130.5
Ice-Making Head	Air	<310	9.19 - 0.00629H	Not Applicable
		310 and <820	8.23 - 0.0032H	Not Applicable
		820 and <4,000	5.61	Not Applicable
Remote Condensing (but not remote compressor)	Air	<800	9.7 - 0.0058H	Not Applicable
		800 and <4,000	5.06	Not Applicable
Remote Condensing and Remote Compressor	Air	<800	9.9 - 0.0058H	Not Applicable
		800 and <4,000	5.26	Not Applicable
Self-Contained	Water	<900	7.6 - 0.00302H	153 - 0.0252H
		900 and <2,500	4.88	153 - 0.0252H
		2500 and <4,000	4.88	90
Self-Contained	Air	<200	14.22 - 0.03H	Not Applicable
		200 and <700	9.47 - 0.00624H	Not Applicable
		700 and <4,000	5.1	Not Applicable

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Performance and Cost Characteristics » Commercial Beverage Merchandisers

Final

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[2]	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	4,689	4,700	4,700	4,700	4,700	4,700	4,700	4,700	4,700	4,700	4,700	4,700
Size (ft^3)	27	27	27	27	27	27	27	27	27	27	27	27
Annual Energy Use (kWh/y)	1,829	1,635	1,380	1,141	902	902	1,141	902	1,141	902	1,141	902
Annual Energy Use / Volume ($kWh/ft^3/y$)[1]	68	73	55	35	26	26	35	26	35	26	35	26
Indexed Annual Efficiency[3]	1.00	1.12	1.33	1.60	2.03	2.03	1.60	2.03	1.60	2.03	1.60	2.03
Average Life (years)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Retail Equipment Cost (2022$)	$2,382	$2,051	$1,710	$2,762	$3,332	$3,332	$2,762	$3,332	$2,762	$3,332	$2,762	$3,332
Total Installed Cost (2022$)[4]	$2,382	$2,051	$1,710	$2,762	$3,332	$3,332	$2,762	$3,332	$2,762	$3,332	$2,762	$3,332
Total Installed Cost (2022$/kBtu/h)	$508	$436	$364	$588	$709	$709	$588	$709	$588	$709	$588	$709
Annual Maintenance Cost (2022$)	$108	$108	$95	$95	$95	$95	$95	$95	$95	$95	$95	$95
Annual Maintenance Cost (2022$/kBtu/h)	$23.03	$22.98	$20.21	$20.21	$20.11	$20.11	$20.21	$20.11	$20.21	$20.11	$20.21	$20.11

1. EPACT 2005 energy conservation standards went into effect in 2010. In 2015, DOE updated its energy conservation standards for commercial refrigeration equipment, including transparent-doored refrigerators with pull-down capability. Compliance with this standard is required by 2017. Units characterized for 2018 and beyond use data reported in this rulemaking's TSD. Units sold in 2022 and beyond are assumed to comply with this updated standard.
2. The ENERGY STAR category characterizes a unit that is compliant with ENERGY STAR v4, effective March 2017. This standard does not separately define units with pull-down capability.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Beverage merchandisers are shipped ready to be plugged in, so installation costs are assumed to be negligible.

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Performance and Cost Characteristics » Commercial Beverage Merchandisers

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- EPACT 2005 sets maximum daily energy consumption levels, in kilowatt-hours per day, for commercial refrigerators with transparent doors and self-contained condensing unit designed for pull-down temperature applications (i.e., beverage merchandisers) and went into effect on January 1, 2010.
- In 2014, DOE updated its energy consumption standards for commercial refrigeration equipment, including beverage merchandisers, effective March 27, 2015. Both the DOE and EPCA standards are reported below.

Equipment Type	EPCA (2010)	DOE Standards (2017)
Beverage Merchandisers (PD.SC.M)	0.126xV + 3.51	0.11xV+0.81

- In 2013, EPA updated its ENERGY STAR specifications for glass-doored commercial refrigerators, which can be used as beverage merchandisers, effective October 1, 2014. These standards are also based on the volume of the unit (V). Note that ENERGY STAR does not have a separate equipment class for units with pull-down capability.

Beverage Merchandiser Size	0 < V < 15	15 ≤ V < 30	30 ≤ V < 50	50 ≤ V
Glass Door	0.118*V + 1.382	≤ 0.140*V + 1.050	≤ 0.088*V + 2.625	≤ 0.110*V + 1.500

- The beverage merchandiser characterized in this report, which is the typical unit according to DOE's 2014 CRE rulemaking and additional analysis by Guidehouse, is a 27 cubic foot cooler with a single hinged, transparent door, bright lighting, and shelving with a nominal compressor size of 4,700 Btu/h.
- The efficiency of beverage merchandisers can be increased through the use of more efficient compressors, fluorescent lighting with electronic ballasts, LED lighting, and improved insulation.
- For the Reference Case, beverage merchandisers are assumed to be mature technologies with few technology advancements in the coming years that would dramatically improve the efficiency.

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Performance and Cost Characteristics » Commercial Refrigerated Vending Machines

Final

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[2]	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	1,810	1,707	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810
Can Capacity	470	500	500	500	500	500	500	500	500	500	500	500
Size (ft^3)	26	35	35	35	35	35	35	35	35	35	35	35
Annual Energy Use (kWh/y)[1]	1,632	1,550	1,550	1,531	1,443	1,443	1,531	1,443	1,531	1,443	1,531	1,443
Annual Energy Use / Volume ($kWh/ft^3/y$)	63	44	44	44	41	41	44	41	44	41	44	41
Indexed Annual Efficiency[3]	1.00	1.05	1.05	1.07	1.13	1.13	1.07	1.13	1.07	1.13	1.07	1.13
Average Life (years)	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Retail Equipment Cost (2022$)	$3,209	$2,553	$3,059	$3,272	$3,520	$3,520	$3,272	$3,520	$3,272	$3,520	$3,272	$3,520
Total Installed Cost (2022$)	$3,320	$2,705	$3,276	$3,489	$3,737	$3,737	$3,489	$3,737	$3,489	$3,737	$3,489	$3,737
Total Installed Cost (2022$/kBtu/h)	$1,834	$1,585	$1,810	$1,928	$2,065	$2,065	$1,928	$2,065	$1,928	$2,065	$1,928	$2,065
Annual Maintenance Cost (2022$)[4]	$270	$270	$333	$333	$333	$333	$333	$333	$333	$333	$333	$333
Annual Maintenance Cost (2022$/kBtu/h)	$149	$149	$184	$184	$184	$184	$184	$184	$184	$184	$184	$184

1. Energy use for 2018 and beyond is estimated based on DOE's 2020 BVM Final Rule and the 2022 Compliance Certification Database.
2. The ENERGY STAR category assumes units are compliant with the ENERGY STAR v4 standard because combination units are currently not separately defined by ENERGY STAR. This standard went into effect on April 29, 2020. Our analysis finds ENERGY STAR certified equipment to be the most efficient currently available on the market.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Maintenance cost includes preventative maintenance costs such as checking and maintaining refrigerant charge levels, cleaning heat exchanger coils, and an annualized cost for refurbishments/remanufacturing.

Performance and Cost Characteristics » Commercial Refrigerated Vending Machines

Final

- DOE set federal energy efficiency standards for refrigerated vending machines. These standards set maximum daily energy consumption levels, in kilowatt-hours per day, for commercial refrigerated vending machines manufactured or sold in the United States on or after August 31, 2012. The daily energy consumption is based on the volume of the unit (V).
- In December 2015, DOE updated its energy conservation standards for beverage vending machines and defined two new product classes for combination vending machines. The energy conservation standard remains the same in the updated 2022 technical support document for vending machines. Compliance with these standards was required by 2019. For this analysis, compliance with these updated standards is assumed for equipment sold in 2022 and beyond. The updated standards and DOE equipment definitions are listed in the table below.

Equipment Type	Maximum Daily Energy Consumption
Class A (Transparent-Front)	MDEC= 0.052 × V + 2.43
Class B (Solid-Front)	MDEC = 0.052 × V + 2.20
Combination A	MDEC = 0.086 × V + 2.66
Combination B	MDEC = 0.111 × V + 2.04

ENERGY STAR® updated its maximum daily energy consumption efficiency levels, also in kilowatt-hours per day, for refrigerated vending machines that went into effect on April 29, 2020. These efficiency levels are based on refrigerated volume.

Equipment Class	Maximum daily energy consumption (kilowatt-hours per day)
Class A – a refrigerated bottled or canned beverage vending machine that is not a combination vending machine and in which 25% or more of the surface area on the front side of the beverage vending machine is transparent	MDEC = 0.04836 x V + 2.2599
Class B – any refrigerated bottled or canned beverage vending machine that is not considered to be Class A and is not a combination vending machine	MDEC = 0.04576 x V+1.936
Combination A – a combination vending machine where 25% or more of the surface area on the front side of the beverage vending machine is transparent	MDEC = 0.07998 x V + 2.4738
Combination B – a combination vending machine that is not considered to be Combination A	MDEC = 0.09768 x V + 1.7952

Commercial Ventilation

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Performance and Cost Characteristics » Commercial Constant Air Volume

Final

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average[3]	Low[4,5]	Typical[4,6]	High[4,7]	ENERGY STAR	Typical[4,6]	High[4,7]	Typical[4,6]	High[4,7]	Typical[4,6]	High[4,7]
System Airflow (CFM)	15,000	16,300	16,300	16,300	16,300	N/A	16,300	16,300	16,300	16,300	16,300	16,300
System Fan Power (kW)	11.56	11.56	11.56	10.98	10.78	N/A	10.98	10.78	10.98	10.78	10.98	10.78
Specific Fan Power (W/CFM)	0.771	0.709	0.709	0.674	0.661	N/A	0.674	0.661	0.674	0.661	0.674	0.661
Annual Fan Energy Use (kWh/y)[1]	43,924	23,038	23,038	21,886	20,792	N/A	21,886	20,792	21,886	20,792	21,886	20,792
Average Life (years)	35	35	35	35	35	N/A	35	35	35	35	35	35
Total Installed Cost (2022$)[2]	$80,288	$83,083	$83,083	$86,901	$90,651	N/A	$86,901	$90,651	$86,901	$90,651	$86,901	$90,651
Annual Maintenance Cost (2022$)	$1,054	$1,054	$1,054	$1,054	$1,054	N/A	$1,054	$1,054	$1,054	$1,054	$1,054	$1,054
Total Installed Cost (2022$/thousand cubic feet per minute [CFM])	$5,353	$5,097	$5,097	$5,331	$5,561	N/A	$5,331	$5,561	$5,331	$5,561	$5,331	$5,561
Annual Maintenance Cost (2022$/thousand CFM)	$70	$65	$65	$65	$65	N/A	$65	$65	$65	$65	$65	$65

1. Based on 3800 operating hours per year (ADL, 1999) and typical zone air flow requirement profile (ASHRAE S45.11-2012)
2. Total installed cost of 16,300 CFM constant air volume (CAV) air handling unit (AHU) and hypothetical supply ductwork layout
3. Based on ASHRAE 90.1-2016 and 2019 fan power limit (Table 6.5.3.1.1-1) with no pressure drop adjustment. Assumed 80% motor load and 91% motor efficiency
4. ASHRAE 90.1-2016 and 2019 Section 6.5.3.2 require minimum two-speed fan control (no longer always constant volume).
5. Two-speed variable frequency drive (VFD)
6. Modulating VFD
7. Modulating custom engineered VFD

- Constant air volume (CAV) ventilation systems are common, inexpensive, air-side HVAC systems that operate in response to a single control zone. Historically, these systems provide a constant flow rate of air (typically a mix of recirculated and outside air) and adjust the supply temperature of that air in order to maintain the space temperature setpoint. Beginning with ASHRAE 90.1-2013 and continued in ASHRAE 90.1-2019, new CAV ventilation systems were mandated to have at least two fan speed settings with the requirement of a maximum 40% power at 66% flow. Systems with variable speed fans are increasingly popular, making the term "constant air volume" somewhat of a misnomer for this system type. This analysis examines only the fan energy of the CAV system.
- There is movement in the industry and in energy codes to reduce fan power. ASHRAE 90.1 includes fan power limits for CAV systems. Fan power can be minimized through good design practice (efficient duct layout, low pressure drop ductwork, filters, coils), proper fan selection, and high efficiency type fans. ASHRAE 90.1-2019 now requires a minimum fan efficiency grade (FEG, based on AMCA 205-12: Energy Efficiency Classification for Fans) of 67 and a design operating fan efficiency within 15% of the maximum fan total efficiency. There are exceptions to this requirement, including packaged systems such as the CAV system type considered here. Still the fan power limits are expected to become more stringent, and fan efficiency will become more important throughout the industry.
- The unit characterized in this report is a 16,300 CFM CAV system. The average commercial building is approximately 16,300 square feet (CBECS 2018). Assuming 1 CFM is needed per square foot of floor area results in a 16,300 CFM air handling unit.
- A 16,300 CFM CAV packaged indoor air handling unit with cooling and heating coils can be installed for approximately $71,829 (RS Means 2022). Ductwork would cost approximately $9,272 additional ($81,101 total). A two-speed motor (estimated $500 incremental cost) and variable frequency drive (estimated $5,800) add cost. Custom engineered variable frequency drives (estimated $9,550) and premium efficiency motors (estimated additional $1,500) add an additional cost to the system.
- Annual maintenance cost assumes 8 hours worth of labor by a technician to perform the necessary tasks (e.g., filter replacement, draining condenser water, etc.)
- ASHRAE Standard 90.1, which is used as a basis for most state energy codes, limits the fan power (brake HP or nameplate HP) for CAV systems. The 2016 version of Standard 90.1 was used to represent the 2018 minimum efficiency level (state energy codes typically refer to older versions of Standard 90.1 due to code revision cycles).
- Fan energy is affected by several factors, including fan type (e.g., centrifugal, axial), fan blade shape (e.g., forward-curved, backward-curved, backward-inclined, airfoil), drive type (belt or direct), configuration (plenum or housed centrifugal), system effects, duct design, filter and coil pressure drops, motor efficiency, and speed and flow control.

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Performance and Cost Characteristics » Commercial Variable Air Volume

Final

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average[3]	Low[4]	Typical[5]	High[6]	ENERGY STAR	Typical[6]	High[6,7]	Typical[6,7]	High[6,7]	Typical[6,7]	High[6,7]
System Airflow (CFM)	15,000	16,300	16,300	16,300	16,300	N/A	16,300	16,300	16,300	16,300	16,300	16,300
System Fan Power (kW)	15.99	15.99	15.99	15.99	15.99	N/A	15.99	15.19	15.99	15.19	15.99	15.19
Specific Fan Power (W/CFM)	1.066	1.066	0.981	0.981	0.981	N/A	0.981	0.932	0.981	0.932	0.981	0.932
Annual Fan Energy Use (kWh/y)[1]	24,699	24,082	24,082	22,878	21,734	N/A	22,878	21,734	22,878	21,734	22,878	21,734
Average Life (years)	28	28	28	28	28	N/A	28	28	28	28	28	28
Total Installed Cost (2022$)[2]	$103,327	$110,414	$118,814	$124,495	$124,995	N/A	$124,495	$124,995	$124,495	$124,995	$124,495	$124,995
Annual Maintenance Cost (2022$)	$1,054	$1,054	$1,054	$1,054	$1,054	N/A	$1,054	$1,054	$1,054	$1,054	$1,054	$1,054
Total Installed Cost (2022$/thousand CFM)	$6,888	$6,774	$7,289	$7,638	$7,668	N/A	$7,638	$7,668	$7,638	$7,668	$7,638	$7,668
Annual Maintenance Cost (2022$/thousand CFM)	$70	$65	$65	$65	$65	N/A	$65	$65	$65	$65	$65	$65

1. Based on 3800 operating hours per year (ADL, 1999) and typical zone air flow requirement profile (ASHRAES45.11-2012)
2. Total installed cost of 16,300 CFM VAV AHU, VFD, (10) VAV boxes, (10) VAV controllers with associated space temperature sensor, and hypothetical supply ductwork layout
3. Based on ASHRAE 90.1-2016 and 2019 fan power limit (Table 6.5.3.1.1-1) with no pressure drop adjustment. Assumed 80% motor load and 91% motor efficiency
4. ASHRAE 90.1-2016 and 2019 Section 6.5.3.2 minimum power-flow requirement
5. ASHRAE 90.1-2019 fan power limit and typical VAV power-flow relationship for 40%-100% flow
6. ASHRAE 90.1-2019 fan power limit and typical VAV power-flow relationship for 30%-100% flow
7. High aerodynamic efficiency fan

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Performance and Cost Characteristics » Commercial Variable Air Volume

Final

- Variable air volume (VAV) ventilation systems are the most common multi-zone system type specified today for conditioning commercial buildings. These systems provide conditioned air to multiple zone terminal units (VAV boxes) that use dampers to modulate the amount of cool air to each zone. An individual zone thermostat controls the VAV box damper to allow more or less cooling. If a zone requires heating, then the VAV box provides the minimum flow rate and typically includes a reheat coil to meet the space temperature setpoint. As VAV box dampers close in the system, a variable frequency drive reduces fan speed and flow continuously to meet current requirements.
- This analysis examines only the fan energy of the VAV system. VAV systems vary fan speed and flow to meet space conditioning requirements; minimum flow settings apply for DX cooling stages and gas furnace heating stages. Most hours of operation are much lower than full speed, and fan power varies with the cube of fan speed according to fan affinity laws. The 2012 ASHRAE Handbook: HVAC Systems and Equipment (p. 45.11) provided the typical flow profile used for this analysis. The unit characterized in this report is a 16,300 CFM VAV system.
- There is movement in the industry and in energy codes to reduce fan power. ASHRAE 90.1 includes fan power limits for VAV systems. Fan power can be minimized through good design practice (efficient duct layout, low pressure drop ductwork, filters, coils), proper fan selection, and high efficiency type fans. ASHRAE 90.1-2019 now requires a minimum fan efficiency grade (FEG, based on AMCA 205-12: Energy Efficiency Classification for Fans) of 67 and a design operating fan efficiency within 15% of the maximum fan total efficiency. There are exceptions to this requirement, including packaged systems such as the VAV system type considered here. Still the fan power limits are expected to become more stringent, and fan efficiency will become more important throughout the industry.
- A 16,300 CFM VAV packaged indoor air handling unit with cooling and heating coils can be installed for approximately $82,023 (RS Means 2022). Ductwork and (10) VAV boxes with reheat would cost approximately an additional $28,272. (10) VAV controllers and the associated space temperature sensor would cost approximately $8,400 ($118,695 total). A 15 hp variable frequency drive (estimated $5,800) is an additional cost.
- ASHRAE Standard 90.1, which is used as a basis for most state energy codes, limits the fan power for VAV systems (brake HP or nameplate HP). The 2016 version of Standard 90.1 was used to represent the 2018 minimum efficiency level (state energy codes typically refer to older versions of Standard 90.1 due to code revision cycles).
- Annual maintenance cost assumes 8 hours worth of labor by a technician to perform the necessary tasks (e.g., filter replacement, draining condenser water, etc.)
- Fan energy is affected by several factors, including fan type (e.g., centrifugal, axial), fan blade shape (e.g., forward-curved, backward-curved, backward-inclined, airfoil), drive type (belt or direct), configuration (plenum or housed centrifugal), system effects, duct design, filter and coil pressure drops, and motor VFD efficiency.

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Performance and Cost Characteristics » Commercial Fan Coil Units

Final

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average[5]	Low[3]	Typical[5]	High[6]	ENERGY STAR	Typical[4,6]	High[4,7]	Typical[4,7]	High[4,8]	Typical[4,8]	High[4,8,9]
System Airflow (CFM)	800	800	800	800	800	N/A	800	800	800	800	800	800
System Fan Power (kW)	0.241	0.241	0.241	0.148	0.148	N/A	0.141	0.134	0.134	0.136	0.136	0.129
Specific Fan Power (W/CFM)	0.302	0.302	0.301	0.185	0.185	N/A	0.176	0.167	0.167	0.170	0.170	0.162
Annual Fan Energy Use (kWh/y)[1]	543	542	542	333	333	N/A	316	301	301	306	306	291
Average Life (years)	37	37	37	37	37	N/A	37	37	37	37	37	37
Total Installed Cost (2022$)[2]	$2,845	$2,688	$3,038	$3,521	$3,961	N/A	$3,961	$4,161	$3,961	$4,161	$3,961	$4,161
Annual Maintenance Cost (2022$)	$117	$117	$117	$117	$117	N/A	$117	$117	$117	$117	$117	$117
Total Installed Cost (2022$/thousand CFM)	$3,557	$3,360	$3,798	$4,401	$4,951	N/A	$4,951	$5,201	$4,951	$5,201	$4,951	$5,201
Annual Maintenance Cost (2022$/thousand CFM)	$146	$146	$146	$146	$146	N/A	$146	$146	$146	$146	$146	$146

1. Based on 2250 operating hours per year (ADL, 1999) and typical zone air flow requirement profile (ASHRAE S45.11-2012)
2. Total installed cost of 2-ton horizontal two-pipe fan coil unit, housing, and controls
3. Based on ASHRAE 90.1-2016 and 2019 fan power limit (Table 6.5.3.1.1-1) with no pressure drop adjustment. Assumed 80% motor load and 91% motor efficiency
4. Based on ASHRAE 90.1-2016 and 2019 Section 6.5.3.6 requirement of electronically commutated or 70+% efficient fan motor
5. Permanent split capacitor fan motor
6. Electronically commutated fan motor (single speed)
7. Electronically commutated fan motor (two-speed)
8. Electronically commutated fan motor (variable speed)
9. High aerodynamic efficiency fan

Performance and Cost Characteristics » Commercial Fan Coil Units

Final

- Commercial fan coil units (FCUs) are self-contained, mass-produced assemblies that provide cooling, heating, or cooling and heating, but they do not include the source of cooling or heating. The unit characterized in this report is a cooling only (two-pipe), horizontal unit with housing and controls. Fan coil units are typically installed in or adjacent to the space being served and have no (or very limited) ductwork.
- According to manufacturer literature, the cooling capacity for a nominal 800 CFM fan coil unit is about 2 tons. This analysis examines only the fan energy of FCUs.
- Fan coil unit fan motors can be shaded pole, a single-phase AC motor with offset start winding and no capacitor; PSC, a single-phase AC motor with offset start winding with capacitor; or ECM, an AC electronically commutated permanent magnet DC motor. PSC motors are currently the most common motor type in FCUs, but manufacturers also offer single speed, two speed, and ECM motors as an option. ASHRAE 90.1-2019 requires an electronically commutated fan motor (or minimum motor efficiency of 70%) for this system.
- There is movement in the industry and in energy codes to reduce fan power. ASHRAE 90.1 includes fan power limits for FCUs. Fan power can be minimized through good design practice and high efficiency type fans. ASHRAE 90.1-2019 now requires a minimum fan efficiency grade (FEG, based on AMCA 205-12: Energy Efficiency Classification for Fans) of 67 and a design operating fan efficiency within 15% of the maximum fan total efficiency. There are exceptions to this requirement, including small systems such as the FCU considered here. Still the fan power limits are expected to become more stringent, and fan efficiency will become more important throughout the industry.
- Fan coil units have higher maintenance costs than central air systems due to the distributed nature of the system. For each unit, the filters must be changed, and drain systems must be flushed periodically.
- ASHRAE Standard 90.1, which is used as a basis for most state energy codes, limits the fan power (brake HP or nameplate HP). The 2016 version of Standard 90.1 was used to represent the 2018 minimum efficiency level (state energy codes typically refer to older versions of Standard 90.1 due to code revision cycles).
- Fan energy is affected by several factors, including fan type configuration, filter and coil pressure drops, motor efficiency, and fan speed control.

Appendix A
Data Sources

Guidehouse
1200 19th Street, NW, Suite 700
Washington, D.C. 20036

And

SAIC
8301 Greensboro Drive
McLean, VA 22102

Residential Lighting

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Data Sources » Residential General Service Incandescent Lamps (60 watt)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Assume Unchanged	N/A										
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)	DOE, 2008												
Average Lamp Life (thousand hours)	2016 EIA Ref. Case												
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	2016 EIA Ref. Case												
Lamp Cost (2022$/klm)													
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated												
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential General Service Incandescent Lamps (75 watt)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Assume Unchanged	N/A										
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)	DOE, 2008												
Average Lamp Life (thousand hours)	2016 EIA Ref. Case												
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	2016 EIA Ref. Case												
Lamp Cost (2022$/klm)													
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated												
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources» Residential General Service Halogen Lamps (60 watt Incandescent Equivalent)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Assume Unchanged	N/A	Distributor Websites or Product Catalogs	N/A								
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)	DOE, 2008			DOE, 2008									
Average Lamp Life (thousand hours)	2016 EIA Ref. Case	Assume Unchanged		Distributor Websites									
Annual Operating Hours (h/y)	DOE, 2017			DOE, 2017									
Lamp Price (2022$)	2016 EIA Ref. Case	Calculated		Distributor Websites									
Lamp Cost (2022$/klm)	Calculated			Calculated									
Labor Cost (2022$/h)	N/A			N/A									
Labor Installation (hours)													
Total Installed Cost (2022$)	Calculated			Calculated									
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources» Residential General Service Halogen Lamps (75 watt Incandescent Equivalent)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Calculated	N/A	Distributor Websites or Product Catalogs	N/A								
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)	DOE, 2008			DOE, 2008									
Average Lamp Life (thousand hours)	2016 EIA Ref. Case	Distributor Websites or Product Catalogs		Distributor Websites									
Annual Operating Hours (h/y)	DOE, 2017			DOE, 2017									
Lamp Price (2022$)	2016 EIA Ref. Case	Calculated		Distributor Websites									
Lamp Cost (2022$/klm)	Calculated			Calculated									
Labor Cost (2022$/h)	N/A			N/A									
Labor Installation (hours)													
Total Installed Cost (2022$)	Calculated			Calculated									
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Final

Data Sources » Residential General Service Compact Fluorescent Lamps (60 watt Incandescent Equivalent)

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Calculated	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	NCI, 2019					
Lamp Lumens													
Lamp Efficacy (lm/W)			Calculated										
CRI		Assume Unchanged	Distributor Websites or Product Catalogs				N/A						
Correlated Color Temperature (CCT)	Product Catalogs												
Average Lamp Life (thousand hours)	2016 EIA Ref. Case												
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	2016 EIA Ref. Case	Calculated	Distributor Websites or Product Catalogs			N/A	N/A	NCI, 2019					
Lamp Cost (2022$/klm)			Calculated										
Labor Cost (2022$/h)	N/A						N/A						
Labor Installation (hours)													
Total Installed Cost (2022$/klm)	Calculated						N/A	Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential General Service LED Lamps (60 Watt Equivalent)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average		Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)			Calculated					Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
CRI			Distributor Websites or Product Catalogs				N/A	Assume Unchanged					
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)								Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			N/A		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Lamp Cost (2022$/klm)	Calculated												
Labor Cost (2022$/h)	N/A												
Labor Installation (hours)													
Total Installed Cost (2022$/klm)	Calculated						N/A	Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential General Service Filament-LED Lamps (60 Watt Equivalent)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average		Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)			Calculated					Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
CRI			Distributor Websites or Product Catalogs				N/A	Assume Unchanged					
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)								Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			N/A		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Lamp Cost (2022$/klm)	Calculated												
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated						N/A	Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Reflector Lamps (65W BR30 Incandescent)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Assume Unchanged	N/A	Distributor Websites or Product Catalogs	N/A								
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)	DOE, 2012(1)												
Average Lamp Life (thousand hours)	2016 EIA Ref. Case												
Annual Operating Hours (h/y)	DOE, 2017			DOE, 2017									
Lamp Price (2022$)	2016 EIA Ref. Case			Distributor Websites or Product Catalogs									
Lamp Cost (2022$/klm)				Calculated									
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated												
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Reflector Lamps (PAR30 Halogen)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Assume Unchanged	N/A	Distributor Websites or Product Catalogs	N/A								
Lamp Lumens		Calculated											
Lamp Efficacy (lm/W)		Assume Unchanged											
CRI													
Correlated Color Temperature (CCT)	DOE, 2012(1)												
Average Lamp Life (thousand hours)	2016 EIA Ref. Case												
Annual Operating Hours (h/y)	DOE, 2017			DOE, 2017									
Lamp Price (2022$)	2016 EIA Ref. Case	Calculated		Distributor Websites or Product Catalogs									
Lamp Cost (2022$/klm)				Calculated									
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated												
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Reflector Lamps (PAR30 Halogen Infrared Reflector (HIR)

Final

DATA SOURCES	2009	2020	2015				2023	2020		2030		2040	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Calculated	N/A	Distributor Websites or Product Catalogs	N/A								
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI		Assume Unchanged											
Correlated Color Temperature (CCT)	DOE, 2012(1)												
Average Lamp Life (thousand hours)	2016 EIA Ref. Case												
Annual Operating Hours (h/y)	DOE, 2017			DOE, 2017									
Lamp Price (2022$)	2016 EIA Ref. Case	Calculated		Distributor Websites or Product Catalogs									
Lamp Cost (2022$/klm)				Calculated									
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated												
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources» Residential Reflector Lamps (BR30 CFL)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case / Calculated		N/A										
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)	DOE, 2012(1)												
Average Lamp Life (thousand hours)	2016 EIA Ref. Case / Calculated												
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	2016 EIA Ref. Case / Calculated												
Lamp Cost (2022$/klm)													
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated												
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Reflector LED BR30

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)			Calculated					Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
CRI			Distributor Websites or Product Catalogs				N/A	Assume Unchanged					
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)								Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			N/A		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Lamp Cost (2022$/klm)	Calculated												
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated						N/A	Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources» Residential Reflector LED PAR38

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)			Calculated					Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
CRI			Distributor Websites or Product Catalogs				N/A	Assume Unchanged					
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)								Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		Distributor Websites or Product Catalogs			N/A		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Lamp Cost (2022$/klm)	Calculated												
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated						N/A	Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Linear Fluorescent Lamp T12

Final

DATA SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Assume Unchanged	N/A								
Lamp Lumens											
Lamp Efficacy (lm/W)	Calculated										
System Wattage											
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)	2016 EIA Ref. Case	Chapter 5; Table 5.8.16 of GSFL Ballast Final Rule TSD (DOE, 2020)									
CRI	2016 EIA Ref. Case	Assume Unchanged									
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)											
Annual Operating Hours (h/y)	DOE, 2017										
Lamp Price (2022$)	2016 EIA Ref. Case										
Ballast Price (2022$)											
Fixture Price (2022$)											
Lamp Cost (2022$/klm)	Calculated										
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)	2016 EIA Ref. Case										
Labor System Installation (hours)											
Labor Lamp Change (hours)											
Total Installed Cost (2022$)	Calculated										
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Residential Linear Fluorescent Lamp T8

Final

DATA SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	Calculated	Distributor Websites				Calculated					
Lamp Lumens	2016 EIA Ref. Case										
Lamp Efficacy (lm/W)	2015 GSFL TSD, Figure 11.5.4	Calculated									
System Wattage	Calculated										
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)	2016 EIA Ref. Case	Chapter 5; Table 5.8.15 of GSFL Ballast Final Rule TSD (DOE, 2020)									
CRI	2016 EIA Ref. Case	Distributor Websites				Distributor Websites					
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)						Calculated					
Annual Operating Hours (h/y)	DOE, 2017										
Lamp Price (2022$)	2016 EIA Ref. Case	Calculated	Distributor Websites			Calculated					
Ballast Price (2022$)		N/A									
Fixture Price (2022$)		Calculated									
Lamp Cost (2022$/klm)	Calculated										
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)	2016 EIA Ref. Case	Assume unchanged	2022 RS Means Online								
Labor System Installation (hours)											
Labor Lamp Change (hours)			N/A								
Total Installed Cost (2022$)	Calculated										
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources» Residential Linear Fluorescent Lamp T5

Final

DATA SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	Calculated	Distributor Websites				Assume unchanged					
Lamp Lumens	2016 EIA Ref. Case										
Lamp Efficacy (lm/W)	2015 GSFL TSD, Figure 11.5.4	Calculated									
System Wattage	Calculated										
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)	Chapter 5; Table 5.3.32 of GSFL IRL Final Rule TSD (DOE, 2015)	Chapter 5; Table 5.8.6 of GSFL Ballast Final Rule TSD (DOE, 2020)									
CRI	2016 EIA Ref. Case	Distributor Websites									
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)											
Annual Operating Hours (h/y)	DOE, 2017										
Lamp Price (2022$)	2016 EIA Ref. Case	Calculated	Distributor Websites			Calculated					
Ballast Price (2022$)		N/A									
Fixture Price (2022$)		Calculated									
Lamp Cost (2022$/klm)	Calculated										
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)	2016 EIA Ref. Case		2022 RS Means Online								
Labor System Installation (hours)											
Labor Lamp Change (hours)			N/A								
Total Installed Cost (2022$)	Calculated										
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Residential Linear LED Replacement Lamp 2-Lamp System

Final

DATA SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	LED Webscrape Database	DOE Web Scrape Database	Distributor websites			Calculated					
Lamp Lumens						Assume same as 2022 Typical and High					
Lamp Efficacy (lm/W)						Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Wattage	Calculated										
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)	N/A										
CRI	2016 EIA Ref. Case	2016 EIA Ref. Case	Distributor Websites			Distributor Websites					
Correlated Color Temperature (CCT)	2016 EIA Ref. Case	Distributor Websites									
Average Lamp Life (thousand hours)	LED Webscrape Database	DOE Web Scrape Database									
Annual Operating Hours (h/y)	DOE, 2017										
Lamp Price (2022$)	LED Webscrape Database	DOE Web Scrape Database	Distributor Websites			Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)		N/A				N/A					
Fixture Price (2022$)		N/A									
Lamp Cost (2022$/klm)	Calculated										
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)	N/A										
Labor System Installation (hours)											
Labor Lamp Change (hours)											
Total Installed Cost (2022$)	Calculated										
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources» Residential Linear LED Luminaire

Final

DATA SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A										
Lamp Lumens											
Lamp Efficacy (lm/W)											
System Wattage	LED Webscrape Database	DOE Web Scrape Database	Distributor Websites			Calculated					
System Lumens						Assume same as 2022 Typical and High					
System Efficacy (lm/W)						Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Efficiency (BLE)	N/A										
CRI	LED Webscrape Database	DOE Web Scrape Database	Distributor Websites			Distributor Websites					
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)											
Annual Operating Hours (h/y)	DOE, 2017										
Lamp or Luminaire Price (2022$)	LED Webscrape Database	DOE Web Scrape Database	Distributor Websites			Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)	N/A										
Fixture Price (2022$)											
Lamp Cost (2022$/klm)											
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)	2016 EIA Ref. Case		2022 RS Means Online								
Labor System Installation (hours)											
Labor Lamp Change (hours)			N/A								
Total Installed Cost (2022$)	Calculated										
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Residential Outdoor Lamps (Security: BR30 Incandescent)

Final

DATA SOURCES	2009	2020	2015				2023	2020		2030		2040	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Same as indoor Residential Incandescent Reflector												
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)													
Annual Operating Hours (h/y)													
Lamp Price (2022$)													
Lamp Cost (2022$/klm)													
Labor Cost (2022$/h)													
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)													
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Outdoor Lamps (Security: PAR38 Halogen)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Interpolation Based on Commercial PAR38		Same as Commercial PAR38 Halogen										
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)													
Annual Operating Hours (h/y)													
Lamp Price (2022$)													
Lamp Cost (2022$/klm)													
Labor Cost (2022$/h)													
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)													
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Outdoor Lamps (Security: PAR38 HIR)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Interpolated from Commercial PAR38 HIR		Same as Commercial PAR38 HIR										
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)													
Annual Operating Hours (h/y)													
Lamp Price (2022$)													
Lamp Cost (2022$/klm)													
Labor Cost (2022$/h)													
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)													
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Outdoor Lamps (Security: CFL PAR38)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case / Calculated		N/A										
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)	DOE, 2012(1)												
Average Lamp Life (thousand hours)	2016 EIA Ref. Case / Calculated												
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	2016 EIA Ref. Case / Calculated												
Lamp Cost (2022$/klm)													
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated												
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Outdoor Lamps (Security: LED PAR38)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Same as Residential LED PAR38												
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)													
Annual Operating Hours (h/y)													
Lamp Price (2022$)													
Lamp Cost (2022$/klm)													
Labor Cost (2022$/h)													
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)													
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Outdoor Lamps (Porch: A19 Incandescent)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Same as Residential General Service 75W Incandescent												
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)													
Annual Operating Hours (h/y)													
Lamp Price (2022$)													
Lamp Cost (2022$/klm)													
Labor Cost (2022$/h)													
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)													
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Outdoor Lamps (Porch: Halogen A-Type)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Same as Residential General Service 75W Equivalent Halogen												
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)													
Annual Operating Hours (h/y)													
Lamp Price (2022$)													
Lamp Cost (2022$/klm)													
Labor Cost (2022$/h)													
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)													
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Outdoor Lamps (Porch: CFL Bare Spiral)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Calculated	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	NCI, 2019					
Lamp Lumens													
Lamp Efficacy (lm/W)			Calculated										
CRI		Assume Unchanged	Distributor Websites or Product Catalogs				N/A						
Correlated Color Temperature (CCT)	Product Catalogs												
Average Lamp Life (thousand hours)	2016 EIA Ref. Case												
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	2016 EIA Ref. Case	Calculated	Distributor Websites or Product Catalogs			N/A	N/A	NCI, 2019					
Lamp Cost (2022$/klm)			Calculated										
Labor Cost (2022$/h)	N/A						N/A						
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated						N/A	Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Outdoor Lamps (Porch: LED A-Type)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)			Calculated					Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
CRI			Distributor Websites or Product Catalogs				N/A	Assume Unchanged					
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)								Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			N/A		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Lamp Cost (2022$/klm)	Calculated												
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated												
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

Commercial Lighting

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Data Sources » Commercial General Service 100W Incandescent Lamp in Recessed Can Fixture

Final

DATA SOURCES	2012	2018	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Reference Case		N/A										
Lamp Lumens													
Lamp Efficacy (lm/W)													
System Wattage													
System Lumens													
System Efficacy (lm/W)													
Ballast Efficiency (BLE)													
CRI													
Correlated Color Temperature (CCT)	DOE, 2008												
Average Lamp Life (thousand hours)	2016 EIA Reference Case												
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	2016 EIA Reference Case; Calculated												
Ballast Price (2022$)													
Fixture Price (2022$)													
Lamp Cost (2022$/klm)													
System (l/b/f) Cost (2022$/klm)													
Labor Cost (2022$/h)	2016 EIA Reference Case												
Labor System Installation (hours)													
Labor Lamp Change (hours)													
Total Installed Cost (2022$)	Calculated												
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Commercial General Service Halogen Lamp (100W Incandescent Equivalent) in Recessed Can Fixture

Final

DATA SOURCES	2012	2018	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Reference Case	Assume Unchanged	N/A	Product Catalogs	N/A								
Lamp Lumens													
Lamp Efficacy (lm/W)													
System Wattage													
System Lumens													
System Efficacy (lm/W)													
Ballast Efficiency (BLE)													
CRI													
Correlated Color Temperature (CCT)	DOE, 2008												
Average Lamp Life (thousand hours)	2016 EIA Reference Case	Assume Unchanged											
Annual Operating Hours (h/y)	DOE, 2017			DOE, 2017									
Lamp Price (2022$)	2016 EIA Reference Case	DOE, 2019		Distributor Websites									
Ballast Price (2022$)													
Fixture Price (2022$)													
Lamp Cost (2022$/klm)				Calculated									
System (l/b/f) Cost (2022$/klm)													
Labor Cost (2022$/h)	2016 EIA Reference Case			2022 RS Means Online									
Labor System Installation (hours)													
Labor Lamp Change (hours)													
Total Installed Cost (2022$)	Calculated			Calculated									
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Commercial General Service 100W Equivalent CFL Bare Spiral in Recessed Can Fixture

Final

DATA SOURCES	2012	2018	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Reference Case	Calculated / Guidehouse	Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)								NCI, 2019					
System Wattage							Same as lamp wattage						
System Lumens							Calculated						
System Efficacy (lm/W)													
Ballast Efficiency (BLE)													
CRI							N/A	Assume Unchanged					
Correlated Color Temperature (CCT)	2016 EIA Reference Case												
Average Lamp Life (thousand hours)													
Annual Operating Hours (h/y)	DOE, 2017					N/A	DOE, 2017						
Lamp Price (2022$)	2016 EIA Reference Case; Calculated		Distributor Websites				N/A	NCI, 2019					
Ballast Price (2022$)													
Fixture Price (2022$)			NCI, 2019										
Disposal Cost (2022$)	EPA, 2022							EPA, 2022					
Lamp Cost (2022$/klm)	Calculated							NCI, 2019					
System (l/b/f) Cost (2022$/klm)													
Labor Cost (2022$/h)	2016 EIA Reference Case		2022 RS Means Online					2022 RS Means Online					
Labor System Installation (hours)													
Labor Lamp Change (hours)													
Total Installed Cost (2022$)	Calculated							Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Commercial General Service 100W Equivalent LED Replacement Lamp in Recessed Can Fixture

Final

DATA SOURCES	2012	2018	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Reference Case	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)								Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Wattage		Calculated											
System Lumens													
System Efficacy (lm/W)													
Ballast Efficiency (BLE)													
CRI		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	N/A	Assume Unchanged					
Correlated Color Temperature (CCT)						N/A							
Average Lamp Life (thousand hours)						ENERGY STAR, 2020		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)				Assume Unchanged	
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	2016 EIA Reference Case	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	Distributor Websites or Product Catalogs			N/A		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)		N/A						N/A					
Fixture Price (2022$)													
Lamp Cost (2022$/klm)		Calculated						Calculated					
System (l/b/f) Cost (2022$/klm)		N/A						N/A					
Labor Cost (2022$/h)		2016 EIA Reference Case	2022 RS Means Online					2022 RS Means Online					
Labor System Installation (hours)													
Labor Lamp Change (hours)													
Total Installed Cost (2022$)		Calculated						Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Commercial Halogen Reflector Lamp (PAR38) in Recessed Can Fixture

Final

DATA SOURCES	2012	2018	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Reference Case	2016 EIA Reference Case / Calculated, NCI, 2019	N/A	Distributor Websites or Product Catalogs	N/A								
Lamp Lumens													
Lamp Efficacy (lm/W)													
System Wattage													
System Lumens													
System Efficacy (lm/W)													
Ballast Efficiency (BLE)													
CRI													
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)													
Annual Operating Hours (h/y)	DOE, 2017			DOE, 2017									
Lamp Price (2022$)	2016 EIA Reference Case; Calculated			Distributor Websites or Product Catalogs									
Ballast Price (2022$)													
Fixture Price (2022$)													
Lamp Cost (2022$/klm)				Calculated									
System (l/b/f) Cost (2022$/klm)													
Labor Cost (2022$/h)	2016 EIA Reference Case			2022 RS Means Online									
Labor System Installation (hours)													
Labor Lamp Change (hours)													
Total Installed Cost (2022$)	Calculated			Calculated									
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Commercial Halogen Infrared Reflector Lamp (PAR38) in Recessed Can Fixture

Final

DATA SOURCES	2012	2018	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Reference Case		N/A	Distributor Websites or Product Catalogs	N/A								
Lamp Lumens													
Lamp Efficacy (lm/W)													
System Wattage													
System Lumens													
System Efficacy (lm/W)													
Ballast Efficiency (BLE)													
CRI													
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)													
Annual Operating Hours (h/y)	DOE, 2017			DOE, 2017									
Lamp Price (2022$)	2016 EIA Reference Case; Calculated			Distributor Websites or Product Catalogs									
Ballast Price (2022$)													
Fixture Price (2022$)													
Lamp Cost (2022$/klm)				Calculated									
System (l/b/f) Cost (2022$/klm)													
Labor Cost (2022$/h)	2016 EIA Reference Case			2022 RS Means Online									
Labor System Installation (hours)													
Labor Lamp Change (hours)													
Total Installed Cost (2022$)	Calculated			Calculated									
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Commercial LED Reflector Lighting (PAR38)

Final

DATA SOURCES	2012	2018	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Reference Case	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)								Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Wattage		Calculated											
System Lumens													
System Efficacy (lm/W)													
Ballast Efficiency (BLE)													
CRI		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	N/A	Assume Unchanged					
Correlated Color Temperature (CCT)						N/A							
Average Lamp Life (thousand hours)						ENERGY STAR, 2020		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)				Assume Unchanged	
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	2016 EIA Reference Case	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	Distributor Websites or Product Catalogs			N/A		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)		N/A						N/A					
Fixture Price (2022$)		Calculated						Calculated					
Lamp Cost (2022$/klm)		N/A						N/A					
System (l/b/f) Cost (2022$/klm)													
Labor Cost (2022$/h)		2016 EIA Reference Case	2022 RS Means Online					2022 RS Means Online					
Labor System Installation (hours)													
Labor Lamp Change (hours)													
Total Installed Cost (2022$)		Calculated						Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Commercial 4-ft T8 F32 Commodity in 2-Lamp System

Final

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Calculated	Assume same as residential T8								
Lamp Lumens		Assume same as residential T8									
Lamp Efficacy (lm/W)		SSL Forecast for 2018									
System Wattage		Calculated									
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)		Assume unchanged	Chapter 5; Table 5.8.1 of GSFL Ballast Final Rule TSD (DOE, 2020)								
CRI		Assume same as residential T8									
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)											
Annual Operating Hours (h/y)		DOE, 2017									
Lamp Price (2022$)		SSL Forecast for 2018	Assume same as residential T8			Calculated					
Ballast Price (2022$)											
Fixture Price (2022$)											
Disposal Costs (2022$)	EPA, 2022										
Lamp Cost (2022$/klm)	2016 EIA Ref. Case	Calculated									
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)		2016 EIA Ref. Case	2022 RS Means Online								
Labor System Installation (hours)											
Labor Lamp Change (hours)											
Total Installed Cost (2022$)		Calculated									
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources» Commercial 4-ft T8 F28 High-efficiency and High-output in 2-Lamp System

Final

DATA SOURCES	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	2016 EIA Ref. Case	Distributor Websites				
Lamp Lumens						
Lamp Efficacy (lm/W)						
System Wattage	Calculated					
System Lumens						
System Efficacy (lm/W)						
Ballast Efficiency (BLE)	Chapter 5; Table 5.8.1 of GSFL Ballast Final Rule TSD (DOE, 2020)					
CRI	2016 EIA Ref. Case	Distributor Websites				
Correlated Color Temperature (CCT)						
Average Lamp Life (thousand hours)						
Annual Operating Hours (h/y)		DOE, 2017				
Lamp Price (2022$)		Calculated	Distributor Websites	Calculated		
Ballast Price (2022$)						
Fixture Price (2022$)						
Disposal Costs (2022$)	EPA, 2022					
Lamp Cost (2022$/klm)	Calculated					
System (l/b/f) Cost (2022$/klm)						
Labor Cost (2022$/h)	2016 EIA Ref. Case		2022 RS Means Online			
Labor System Installation (hours)						
Labor Lamp Change (hours)						
Total Installed Cost (2022$)	Calculated					
Annual Maintenance Cost (2022$)						
Total Installed Cost (2022$/klm)						
Annual Maintenance Cost (2022$/klm)						

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Data Sources» Commercial 4-ft T5 F28 in 2-Lamp System

Final

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Calculated	Assume same as residential T5								
Lamp Lumens		Assume same as residential T5, 2022									
Lamp Efficacy (lm/W)		SSL Forecast for 2018									
System Wattage	Calculated										
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)	Chapter 5; Table 5.8.6 of GSFL Ballast Final Rule TSD (DOE, 2020)										
CRI	2016 EIA Ref. Case	Assume same as residential T5									
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)											
Annual Operating Hours (h/y)		DOE, 2017									
Lamp Price (2022$)		SSL Forecast for 2018	Assume same as residential T5			Calculated					
Ballast Price (2022$)											
Fixture Price (2022$)											
Disposal Costs (2022$)	EPA, 2022										
Lamp Cost (2022$/klm)	2016 EIA Ref. Case	Calculated									
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)		2016 EIA Ref. Case	2022 RS Means Online								
Labor System Installation (hours)											
Labor Lamp Change (hours)											
Total Installed Cost (2022$)		Calculated									
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial 4-ft Linear LED Replacement Lamp in 2-Lamp System

Final

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	LED Webscrape Database	Distributor websites			Calculated					
Lamp Lumens						Assume same as 2022 Typical and High					
Lamp Efficacy (lm/W)						Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Wattage		Calculated				Calculated					
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)		N/A				N/A					
CRI		Distributor websites									
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)											
Annual Operating Hours (h/y)		DOE, 2017									
Lamp Price (2022$)		LED Webscrape Database	Distributor Websites			Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)		N/A				N/A					
Fixture Price (2022$)											
Lamp Cost (2022$/klm)		Calculated									
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)		Assume unchanged	2022 RS Means Online								
Labor System Installation (hours)											
Labor Lamp Change (hours)											
Total Installed Cost (2022$)		Calculated									
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial 4-ft Linear LED Luminaire to Replace 2-Lamp Systems

Final

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	N/A				N/A					
Lamp Lumens											
Lamp Efficacy (lm/W)											
System Wattage		LED Webscrape Database	Distributor websites			Calculated					
System Lumens						Assume same as 2022 Typical and High					
System Efficacy (lm/W)						Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Efficiency (BLE)		N/A				N/A					
CRI		Distributor websites									
Correlated Color Temperature (CCT)											
Average Lifetime (thousand hours)											
Annual Operating Hours (h/y)		DOE, 2017									
Lamp or Luminaire Price (2022$)		LED Webscrape Database	Distributor Websites			Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)		N/A									
Fixture Price (2022$)											
Lamp Cost (2022$/klm)											
System (l/b/f) Cost (2022$/klm)		Calculated									
Labor Cost (2022$/h)		Assume unchanged	2022 RS Means Online								
Labor System Installation (hours)											
Labor Lamp Change (hours)											
Total Installed Cost (2022$)		Calculated									
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial 4-ft T8 F28 High-efficiency and High-output in 2-Lamp System with Occupancy Sensor

Final

DATA SOURCES	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	2016 EIA Ref. Case	Distributor Websites				
Lamp Lumens						
Lamp Efficacy (lm/W)						
System Wattage		Calculated				
System Lumens						
System Efficacy (lm/W)						
Ballast Efficiency (BLE)		Chapter 5; Table 5.8.1 of GSFL Ballast Final Rule TSD (DOE, 2020)				
CRI		Distributor Websites				
Correlated Color Temperature (CCT)						
Average Lamp Life (thousand hours)						
Annual Operating Hours (h/y)		DOE, 2017				
Lamp Price (2022$)		Calculated	Distributor Websites	Calculated		
Ballast Price (2022$)		N/A				
Fixture Price (2022$)		Calculated	Distributor Websites	Calculated		
Occupancy Sensor Price (2022$)	N/A			Distributor Websites		
Disposal Costs (2022$)	EPA, 2022					
Lamp Cost (2022$/klm)	2016 EIA Ref. Case	Calculated				
System (l/b/f) Cost (2022$/klm)						
Labor Cost (2022$/h)		Assume unchanged	2022 RS Means Online			
Labor System Installation (hours)						
Labor Lamp Change (hours)						
Total Installed Cost (2022$)		Calculated				
Annual Maintenance Cost (2022$)						
Total Installed Cost (2022$/klm)						
Annual Maintenance Cost (2022$/klm)						

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Data Sources » Commercial 4-ft T8 F28 High-efficiency and High-output in 2-Lamp System with Specular Reflector

Final

DATA SOURCES	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	2016 EIA Ref. Case	Distributor Websites				
Lamp Lumens						
Lamp Efficacy (lm/W)						
System Wattage		Calculated				
System Lumens						
System Efficacy (lm/W)						
Ballast Efficiency (BLE)		Chapter 5; Table 5.8.1 of GSFL Ballast Final Rule TSD (DOE, 2020)				
CRI		Distributor Websites				
Correlated Color Temperature (CCT)						
Average Lamp Life (thousand hours)						
Annual Operating Hours (h/y)		DOE, 2017				
Lamp Price (2022$)		Calculated	Distributor Websites	Calculated		
Ballast Price (2022$)		N/A				
Fixture Price (2022$)		Calculated	Distributor Websites	Calculated		
Reflector Price (2022$)	N/A			Distributor Websites		
Disposal Costs (2022$)	EPA, 2022					
Lamp Cost (2022$/klm)	2016 EIA Ref. Case	Calculated				
System (l/b/f) Cost (2022$/klm)						
Labor Cost (2022$/h)		Assume unchanged	2022 RS Means Online			
Labor System Installation (hours)						
Labor Lamp Change (hours)						
Total Installed Cost (2022$)		Calculated				
Annual Maintenance Cost (2022$)						
Total Installed Cost (2022$/klm)						
Annual Maintenance Cost (2022$/klm)						

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Data Sources » Commercial 4-ft T8 F28 High-efficiency and High-output in 2-Lamp System with Occupancy Sensor and Specular Reflector

Final

DATA SOURCES	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	2016 EIA Ref. Case	Calculated	Distributor Websites	Distributor Websites	Distributor Websites	Distributor Websites
Lamp Lumens		Distributor Websites				
Lamp Efficacy (lm/W)						
System Wattage		Calculated				
System Lumens						
System Efficacy (lm/W)						
Ballast Efficiency (BLE)		Chapter 5; Table 5.8.1 of GSFL Ballast Final Rule TSD (DOE, 2020)				
CRI		Distributor Websites				
Correlated Color Temperature (CCT)						
Average Lamp Life (thousand hours)						
Annual Operating Hours (h/y)		DOE, 2017				
Lamp Price (2022$)		Calculated	Distributor Websites	Calculated	Calculated	Calculated
Ballast Price (2022$)						
Fixture Price (2022$)						
Reflector Price (2022$)		N/A		Distributor Websites		
Occupancy Sensor Price (2022$)						
Disposal Costs (2022$)	EPA, 2022					
Lamp Cost (2022$/klm)	2016 EIA Ref. Case	Calculated				
System (l/b/f) Cost (2022$/klm)						
Labor Cost (2022$/h)		Assume unchanged	2022 RS Means Online			
Labor System Installation (hours)						
Labor Lamp Change (hours)						
Total Installed Cost (2022$)		Calculated				
Annual Maintenance Cost (2022$)						
Total Installed Cost (2022$/klm)						
Annual Maintenance Cost (2022$/klm)						

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Data Sources » Commercial 8-ft T8 F59 Typical Efficiency in a 2-Lamp System

Final

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Calculated	Distributor Websites			Assume same as 2022					
Lamp Lumens											
Lamp Efficacy (lm/W)											
System Wattage		Calculated	Calculated			Calculated					
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)		Assume unchanged	Chapter 5; Table 5.8.1 of GSFL Ballast Final Rule TSD (DOE, 2020)								
CRI	2016 EIA Ref. Case	Distributor Websites				Assume same as 2022					
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)											
Annual Operating Hours (h/y)		DOE, 2017									
Lamp Price (2022$)		Calculated	Distributor Websites			Calculated					
Ballast Price (2022$)											
Fixture Price (2022$)											
Disposal Costs (2022$)	EPA, 2022										
Lamp Cost (2022$/klm)	2016 EIA Ref. Case	Calculated									
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)		Assume unchanged	2022 RS Means Online								
Labor System Installation (hours)	Chapter 8; Table 8.2.4 of GSFL IRL Preliminary Analysis TSD (DOE, 2013)										
Labor Lamp Change (hours)	Chapter 8; Table 8.2.4 of GSFL IRL Preliminary Analysis TSD (DOE, 2013)										
Total Installed Cost (2022$)	2016 EIA Ref. Case	Calculated									
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial 8-ft T8 F96 High-Output in a 2-Lamp System

Final

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Assume same as 2022 typical	Distributor Websites			Assume same as 2022					
Lamp Lumens											
Lamp Efficacy (lm/W)											
System Wattage		Calculated									
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)		Chapter 5; Table 5.3.26 GSFL IRL Final Rule TSD (DOE, 2014)									
CRI		Distributor Websites									
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)											
Annual Operating Hours (h/y)		DOE, 2017									
Lamp Price (2022$)		Calculated	Distributor Websites			Calculated					
Ballast Price (2022$)											
Fixture Price (2022$)											
Disposal Costs (2022$)	EPA, 2022										
Lamp Cost (2022$/klm)	2016 EIA Ref. Case	Calculated	Calculated								
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)		2016 EIA Ref. Case	2022 RS Means Online								
Labor System Installation (hours)	Chapter 8; Table 8.2.4 of GSFL IRL Preliminary Analysis TSD (DOE, 2013)										
Labor Lamp Change (hours)	Chapter 8; Table 8.2.4 of GSFL IRL Preliminary Analysis TSD (DOE, 2013)										
Total Installed Cost (2022$)	2016 EIA Ref. Case	Calculated				Calculated					
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial 8-ft Linear LED Replacement Lamp for a 2 Lamp System

Final

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A	2016 EIA Ref. Case, 2015 typical	Distributor Websites			Calculated					
Lamp Lumens						Assume same as 2022 Typical and High					
Lamp Efficacy (lm/W)			Calculated			Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Wattage		Calculated				Calculated					
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)		N/A									
CRI		2016 EIA Ref. Case, 2015 typical	Distributor Websites			Assume same as 2022					
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)											
Annual Operating Hours (h/y)		DOE, 2017									
Lamp Price (2022$)		2016 EIA Ref. Case, 2015 typical	Distributor Websites			Calculated					
Ballast Price (2022$)			N/A								
Fixture Price (2022$)											
Lamp Cost (2022$/klm)			Calculated								
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)		2016 EIA Ref. Case	2022 RS Means Online								
Labor System Installation (hours)		N/A									
Labor Lamp Change (hours)		Chapter 8; Table 8.2.4 of GSFL IRL Preliminary Analysis TSD (DOE, 2013)									
Total Installed Cost (2022$)		Calculated				Calculated					
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial 8-ft Linear LED Luminaire Replacement for a 2-Lamp System

Final

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A	N/A									
Lamp Lumens											
Lamp Efficacy (lm/W)											
System Wattage		2016 EIA Ref. Case, 2015 typical	Distributor Websites			Calculated					
System Lumens						Assume same as 2022 Typical and High					
System Efficacy (lm/W)						Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Efficiency (BLE)		N/A									
CRI		2016 EIA Ref. Case, 2015 typical	Distributor Websites								
Correlated Color Temperature (CCT)											
Average Lifetime (thousand hours)											
Annual Operating Hours (h/y)		DOE, 2017									
Lamp or Luminaire Price (2022$)		2016 EIA Ref. Case, 2015 typical	Distributor Websites								
Ballast Price (2022$)			N/A								
Fixture Price (2022$)											
Lamp Cost (2022$/klm)											
System (l/b/f) Cost (2022$/klm)			Calculated								
Labor Cost (2022$/h)		2016 EIA Ref. Case	2022 RS Means Online								
Labor System Installation (hours)											
Labor Lamp Change (hours)		N/A									
Total Installed Cost (2022$)		2016 EIA Ref. Case	Calculated								
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial Mercury Vapor Low-bay

Final

DATA SOURCES	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	2016 EIA Reference Case	Assume Unchanged	Distributor Websites or Product Catalogs	N/A		
Lamp Lumens						
Lamp Efficacy (lm/W)						
System Wattage						
System Lumens						
System Efficacy (lm/W)						
Ballast Efficiency			Chapter 5; Table 5.7.24 of HID Final Determination TSD (DOE, 2015)			
CRI			Distributor Websites or Product Catalogs			
Correlated Color Temperature (CCT)						
Average Lamp Life (thousand hours)			Chapter 3; Section 3.4.2 of HID Final Determination TSD (DOE, 2015)			
Annual Operating Hours (h/y)	DOE, 2017					
Lamp Price (2022$)	2016 EIA Reference Case; Calculated		Distributor Websites or Product Catalogs			
Ballast Price (2022$)						
Fixture Price (2022$)			Chapter 7 & Appendix 6A; Table 6A.3.4 of HID Final Determination TSD (DOE, 2015), Calculated			
Disposal Cost (2022$)	EPA, 2022					
Lamp Cost (2022$/klm)	Calculated					
System (l/b/f) Cost (2022$/klm)						
Labor Cost (2022$/h)	2016 EIA Reference Case		Chapter 9; Section 9.2.2.1 of HID Final Determination TSD (DOE, 2015)			
Labor System Installation (hours)			2022 RS Means Online			
Labor Lamp Change (hours)						
Total Installed Cost (2022$)	Calculated		Calculated			
Annual Maintenance Cost (2022$)						
Total Installed Cost (2022$/klm)						
Annual Maintenance Cost (2022$/klm)						

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Data Sources » Commercial Metal Halide Low-bay

Final

DATA SOURCES	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	Assume Unchanged		Distributor Websites or Product Catalogs	Calculated		
Lamp Lumens	Distributor Websites or Product Catalogs; Calculated			Assume Unchanged		
Lamp Efficacy (lm/W)				Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		
System Wattage	2016 EIA Reference Case	Assume Unchanged				
System Lumens						
System Efficacy (lm/W)						
Ballast Efficiency			Chapter 5; Table 5.7.24 of HID Final Determination TSD (DOE, 2015)	Assume Unchanged		
CRI						
Correlated Color Temperature (CCT)			Distributor Websites or Product Catalogs			
Average Lamp Life (thousand hours)			Chapter 3; Section 3.4.2 of HID Final Determination TSD (DOE, 2015)	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		
Annual Operating Hours (h/y)	DOE, 2017		DOE, 2017			
Lamp Price (2022$)	Distributor Websites or Product Catalogs ; Calculated		Distributor Websites or Product Catalogs			
Ballast Price (2022$)						
Fixture Price (2022$)	2016 EIA Reference Case; Calculated		Chapter 7 & Appendix 6A; Table 6A.3.4 of HID Final Determination TSD (DOE, 2015), Calculated			
Disposal Cost (2022$)	EPA, 2022					
Lamp Cost (2022$/klm)	2016 EIA Reference Case; Calculated		Calculated			
System (l/b/f) Cost (2022$/klm)						
Labor Cost (2022$/h)	2016 EIA Reference Case		Chapter 9; Section 9.2.2.1 of HID Final Determination TSD (DOE, 2015)			
Labor System Installation (hours)			2022 RS Means Online			
Labor Lamp Change (hours)						
Total Installed Cost (2022$)	Calculated					
Annual Maintenance Cost (2022$)						
Total Installed Cost (2022$/klm)						
Annual Maintenance Cost (2022$/klm)						

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Data Sources » Commercial Sodium Vapor Low-bay

Final

DATA SOURCES	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	2016 EIA Reference Case	Assume Unchanged	Distributor Websites or Product Catalogs	Calculated		
Lamp Lumens				Assume Unchanged		
Lamp Efficacy (lm/W)				Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		
System Wattage						
System Lumens						
System Efficacy (lm/W)						
Ballast Efficiency			Chapter 5; Table 5.7.24 of HID Final Determination TSD (DOE, 2015)	Assume Unchanged		
CRI						
Correlated Color Temperature (CCT)			Distributor Websites or Product Catalogs			
Average Lamp Life (thousand hours)			Chapter 3; Section 3.4.2 of HID Final Determination TSD (DOE, 2015)	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		
Annual Operating Hours (h/y)	DOE, 2017		DOE, 2017			
Lamp Price (2022$)	2016 EIA Reference Case; Calculated		Distributor Websites or Product Catalogs			
Ballast Price (2022$)						
Fixture Price (2022$)			Chapter 7 & Appendix 6A; Table 6A.3.4 of HID Final Determination TSD (DOE, 2015), Calculated			
Disposal Cost (2022$)	EPA, 2022					
Lamp Cost (2022$/klm)	2016 EIA Reference Case; Calculated		Calculated	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		
System (l/b/f) Cost (2022$/klm)						
Labor Cost (2022$/h)	2016 EIA Reference Case		Chapter 9; Section 9.2.2.1 of HID Final Determination TSD (DOE, 2015)			
Labor System Installation (hours)			2022 RS Means Online			
Labor Lamp Change (hours)						
Total Installed Cost (2022$)	Calculated					
Annual Maintenance Cost (2022$)						
Total Installed Cost (2022$/klm)						
Annual Maintenance Cost (2022$/klm)						

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Data Sources » Commercial LED Low-bay Luminaire

Final

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A										
Lamp Lumens											
Lamp Efficacy (lm/W)											
System Wattage	2016 EIA Reference Case	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	N/A	Distributor Websites or Product Catalogs		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency		N/A		N/A		N/A					
CRI		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		Distributor Websites or Product Catalogs		Assume Unchanged					
Correlated Color Temperature (CCT)											
Average Lifetime (thousand hours)						Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)	DOE, 2017			DOE, 2017							
Lamp or Luminaire Price (2022$)	2016 EIA Reference Case	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	N/A	Distributor Websites or Product Catalogs		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)		N/A		N/A							
Fixture Price (2022$)											
Lamp Cost (2022$/klm)											
System (l/b/f) Cost (2022$/klm)		Calculated		Calculated		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Labor Cost (2022$/h)		2016 EIA Reference Case		2022 RS Means Online							
Labor System Installation (hours)											
Labor Lamp Change (hours)											
Total Installed Cost (2022$)	Calculated			Calculated							
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial Mercury Vapor High-Bay

Final

DATA SOURCES	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	2016 EIA Reference Case	Assume Unchanged	Distributor Websites or Product Catalogs	N/A		
Lamp Lumens						
Lamp Efficacy (lm/W)						
System Wattage						
System Lumens						
System Efficacy (lm/W)						
Ballast Efficiency			Chapter 5; Table 5.7.24 of HID Final Determination TSD (DOE, 2015)			
CRI			Distributor Websites or Product Catalogs			
Correlated Color Temperature (CCT)						
Average Lamp Life (thousand hours)			Chapter 3; Section 3.4.2 of HID Final Determination TSD (DOE, 2015)			
Annual Operating Hours (h/y)	DOE, 2017		DOE, 2017			
Lamp Price (2022$)	2016 EIA Reference Case; Calculated		Distributor Websites or Product Catalogs			
Ballast Price (2022$)						
Fixture Price (2022$)			Chapter 7 & Appendix 6A; Table 6A.3.4 of HID Final Determination TSD (DOE, 2015), Calculated			
Disposal Cost (2022$)	EPA, 2022					
Lamp Cost (2022$/klm)	2016 EIA Reference Case; Calculated		Calculated			
System (l/b/f) Cost (2022$/klm)						
Labor Cost (2022$/h)	2016 EIA Reference Case		Chapter 9; Section 9.2.2.1 of HID Final Determination TSD (DOE, 2015)			
Labor System Installation (hours)			2022 RS Means Online			
Labor Lamp Change (hours)						
Total Installed Cost (2022$)	Calculated		Calculated			
Annual Maintenance Cost (2022$)						
Total Installed Cost (2022$/klm)						
Annual Maintenance Cost (2022$/klm)						

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Data Sources » Commercial Metal Halide High-Bay

DATA SOURCES	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	2016 EIA Reference Case	Assume Unchanged	Distributor Websites or Product Catalogs	Calculated		
Lamp Lumens		2016 EIA Reference Case; Calculated		Assume Unchanged		
Lamp Efficacy (lm/W)				Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		
System Wattage		Assume Unchanged				
System Lumens						
System Efficacy (lm/W)						
Ballast Efficiency			Chapter 5; Table 5.7.24 of HID Final Determination TSD (DOE, 2015)	Assume Unchanged		
CRI						
Correlated Color Temperature (CCT)			Distributor Websites or Product Catalogs			
Average Lamp Life (thousand hours)			Chapter 3; Section 3.4.2 of HID Final Determination TSD (DOE, 2015)	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		
Annual Operating Hours (h/y)	DOE, 2017		DOE, 2017			
Lamp Price (2022$)	2016 EIA Reference Case; Calculated		Distributor Websites or Product Catalogs			
Ballast Price (2022$)						
Fixture Price (2022$)			Chapter 7 & Appendix 6A; Table 6A.3.4 of HID Final Determination TSD (DOE, 2015), Calculated			
Disposal Cost (2022$)	EPA, 2022					
Lamp Cost (2022$/klm)	2016 EIA Reference Case; Calculated		Calculated	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		
System (l/b/f) Cost (2022$/klm)						
Labor Cost (2022$/h)	2016 EIA Reference Case		Chapter 9; Section 9.2.2.1 of HID Final Determination TSD (DOE, 2015)			
Labor System Installation (hours)			2022 RS Means Online			
Labor Lamp Change (hours)						
Total Installed Cost (2022$)	Calculated					
Annual Maintenance Cost (2022$)						
Total Installed Cost (2022$/klm)						
Annual Maintenance Cost (2022$/klm)						

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Data Sources » Commercial Sodium Vapor High-Bay

Final

DATA SOURCES	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	2016 EIA Reference Case	Assume Unchanged	Distributor Websites or Product Catalogs	Calculated		
Lamp Lumens				Assume Unchanged		
Lamp Efficacy (lm/W)				Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		
System Wattage						
System Lumens						
System Efficacy (lm/W)						
Ballast Efficiency			Chapter 5; Table 5.7.24 of HID Final Determination TSD (DOE, 2015)	Assume Unchanged		
CRI						
Correlated Color Temperature (CCT)			Distributor Websites or Product Catalogs			
Average Lamp Life (thousand hours)			Chapter 3; Section 3.4.2 of HID Final Determination TSD (DOE, 2015)	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		
Annual Operating Hours (h/y)	DOE, 2017		DOE, 2017			
Lamp Price (2022$)	2016 EIA Reference Case; Calculated		Distributor Websites or Product Catalogs			
Ballast Price (2022$)						
Fixture Price (2022$)			Chapter 7 & Appendix 6A; Table 6A.3.4 of HID Final Determination TSD (DOE, 2015), Calculated			
Disposal Cost (2022$)	EPA, 2022					
Lamp Cost (2022$/klm)	2016 EIA Reference Case; Calculated		Calculated	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		
System (l/b/f) Cost (2022$/klm)						
Labor Cost (2022$/h)	2016 EIA Reference Case		Chapter 9; Section 9.2.2.1 of HID Final Determination TSD (DOE, 2015)			
Labor System Installation (hours)			2022 RS Means Online			
Labor Lamp Change (hours)						
Total Installed Cost (2022$)	Calculated					
Annual Maintenance Cost (2022$)						
Total Installed Cost (2022$/klm)						
Annual Maintenance Cost (2022$/klm)						

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Data Sources » Commercial T5 4xF54 HO High-bay

Final

DATA SOURCES	2012	2018	2022		2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Reference Case	Assume Unchanged	Distributor Websites or Product Catalogs		Calculated					
Lamp Lumens					Assume Unchanged					
Lamp Efficacy (lm/W)					Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Wattage										
System Lumens										
System Efficacy (lm/W)										
Ballast Efficiency (BLE)			GSFL Ballast Final Rule TSD (DOE, 2020)		Assume Unchanged					
CRI			Distributor Websites or Product Catalogs							
Correlated Color Temperature (CCT)										
Average Lamp Life (thousand hours)			Distributor Websites or Product Catalogs		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)	DOE, 2017		DOE, 2017							
Lamp Price (2022$)	2016 EIA Reference Case; Calculated		Distributor Websites or Product Catalogs							
Ballast Price (2022$)										
Fixture Price (2022$)			Chapter 7 & Appendix 6A; Table 6A.3.4 of HID Final Determination TSD (DOE, 2015), Calculated							
Disposal Cost (2022$)	EPA, 2022									
Lamp Cost (2022$/klm)	2016 EIA Reference Case; Calculated		Calculated		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System (l/b/f) Cost (2022$/klm)										
Labor Cost (2022$/h)	2016 EIA Reference Case		2022 RS Means Online							
Labor System Installation (hours)										
Labor Lamp Change (hours)										
Total Installed Cost (2022$)	Calculated									
Annual Maintenance Cost (2022$)										
Total Installed Cost (2022$/klm)										
Annual Maintenance Cost (2022$/klm)										

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Data Sources » Commercial LED High-bay Luminaire

Final

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A										
Lamp Lumens											
Lamp Efficacy (lm/W)											
System Wattage	2016 EIA Reference Case	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	N/A	Distributor Websites or Product Catalogs		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency		N/A		N/A							
CRI		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		Distributor Websites or Product Catalogs		Assume Unchanged					
Correlated Color Temperature (CCT)											
Average Lifetime (thousand hours)						Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)	DOE, 2017			DOE, 2017							
Lamp or Luminaire Price (2022$)	2016 EIA Reference Case	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	N/A	Distributor Websites or Product Catalogs		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)		N/A		N/A							
Fixture Price (2022$)											
Lamp Cost (2022$/klm)											
System (l/b/f) Cost (2022$/klm)		Calculated		Calculated		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Labor Cost (2022$/h)		2016 EIA Reference Case		2022 RS Means Online							
Labor System Installation (hours)											
Labor Lamp Change (hours)											
Total Installed Cost (2022$)	Calculated			Calculated							
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

Refrigeration

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Data Sources » Commercial Compressor Rack Systems

Final

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Total Capacity (kBtu/h)	ADL, 1996	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Median Store Size (ft^2)	Food Marketing Institute (FMI), 2012	CBECS 2018										
Power Input (kW)	Copeland, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Energy Use (MMWh/y)	ADL, 1996 / NCI Analysis, 2015	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Indexed Annual Efficiency	Calculated											
Average Life (years)	Kysor-Warren, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Total Installed Cost (2022$)	NCI, 2009 / NCI Analysis, 2012	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	ADL, 1996 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Condensers

Final

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Total Capacity (kBtu/h)	NCI Analysis, 2008 / Heatcraft, 2008 / ADL, 1996	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Median Store Size (ft^2)	Food Marketing Institute (FMI), 2012	CBECS 2018										
Power Input (kW)	NCI Analysis, 2008 / Heatcraft, 2008 / ADL, 1996	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Energy Use (MMWh/y)	NCI Analysis, 2008 / ADL, 1996	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Indexed Annual Efficiency	Calculated											
Average Life (years)	ADL, 1996 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Total Installed Cost (2022$)	NCI Analysis, 2008 / Heatcraft, 2008 / RS Means, 2007	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Supermarket Display Cases

Final

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	ENERGY STAR	High	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	DOE, 2007 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Median Store Size (ft^2)	Food Marketing Institute (FMI), 2012	CBECS 2018										
Case Length (ft)	DOE, 2016: CRE Report / Guidehouse Analysis 2022											
Annual Energy Use (kWh/y)[1,2]	DOE, 2007 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Energy Use / Case Length (kWh/ft)	Calculated											
Indexed Annual Efficiency[3]	Calculated											
Average Life (years)	DOE, 2007 / NCI Analysis, 2008	DOE, 2016: CRE Report / Guidehouse Analysis 2022										
Retail Equipment Cost (2022$)	DOE, 2007 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022 / The Restaurant Store										
Total Installed Cost (2022$)	DOE, 2007 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)[4]	DOE, 2007 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Reach-In Refrigerators

Final

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	ADL, 1996 / NCI Analysis, 2008	DOE, 2014: CRE Report										
Size (ft^3)	ADL, 1996 / Distributor Web Sites	DOE, 2014: CRE Report										
Annual Energy Use (kWh/y)	ADL, 1996 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022 / ENERGY STAR 2022										
Annual Energy Use / Volume ($kWh/y/ft^3$)	NCI Analysis, 2012	Calculated										
Indexed Annual Efficiency	Calculated											
Average Life (years)	Calculated											
Retail Equipment Cost (2022$)	ACEEE, 2002	DOE, 2014: CRE TSD										
Total Installed Cost (2022$)	ADL, 1996/ Distributor Web Sites / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022 / ENERGY STAR 2022 / The Restaurant Store										
Total Installed Cost (2022$/kBtu/h)	Distributor Web Sites / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$)	Calculated											
Annual Maintenance Cost (2022$/kBtu/h)	NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Reach-In Freezers

Final

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	ADL, 1996 / NCI Analysis, 2008	DOE, 2016: CRE Report										
Size (ft^3)	ADL, 1996 / Distributor Web Sites	DOE, 2016: CRE Report										
Annual Energy Use (kWh/y)	ADL, 1996 / NCI Analysis, 2008	DOE, 2016: CRE Report / Guidehouse Analysis 2022										
Annual Energy Use / Volume ($kWh/y/ft^3$)	NCI Analysis, 2012	Calculated										
Indexed Annual Efficiency	Calculated											
Average Life (years)	ACEEE, 2002	DOE, 2016: CRE Report / Guidehouse Analysis 2022										
Retail Equipment Cost (2022$)	ADL, 1996/ Distributor Web Sites / NCI Analysis, 2008	DOE, 2016: CRE Report / Guidehouse Analysis 2022 / ENERGY STAR 2022 / The Restaurant Store										
Total Installed Cost (2022$)	Distributor Web Sites / NCI Analysis, 2008	DOE, 2016: CRE Report / Guidehouse Analysis 2022										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	NCI Analysis, 2008	DOE, 2016: CRE Report / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Walk-In Refrigerators

Final

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	DOE CRE Report 2016 / CCMS 2022 / Guidehouse Analysis 2022											
Size (ft^2)	DOE 2014 WICF TSD / Guidehouse Analysis 2022											
Annual Energy Use (kWh/y)	ADL, 1996 / PG&E, 2004 / NCI Analysis, 2008	DOE CRE Report 2016 / Guidehouse Analysis 2022										
Annual Energy Use / Area ($kWh/ft^2/y$)	Calculated											
Indexed Annual Efficiency	Calculated											
Insulated Box Average Life (years)	ADL, 1996 / PG&E, 2004	DOE CRE Report 2016 / Guidehouse Analysis 2022										
Compressor Average Life (years)	ADL, 1996 / PG&E, 2004	DOE CRE Report 2016 / Guidehouse Analysis 2022										
Retail Equipment Cost (2022$)	ADL, 1996 / Distributor Web Sites / NCI Analysis, 2008	DOE CRE Report 2016 / Webstaurant 2022 / Guidehouse Analysis 2022										
Total Installed Cost (2022$)	ADL, 1996 / Distributor Web Sites / NCI Analysis, 2008	DOE CRE Report 2016 / Webstaurant 2022 / Guidehouse Analysis 2023										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	ADL, 1996 / FMI, 2005 / NCI Analysis, 2008	DOE CRE Report 2016 / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Walk-In Freezers

Final

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	ADL, 1996 / NCI Analysis, 2008	DOE CRE Report 2016 / CCMS 2022 / Guidehouse Analysis 2022										
Size (ft^2)	ADL, 1996 / NCI Analysis, 2008	Guidehouse Analysis 2022										
Annual Energy Use (kWh/y)	ADL, 1996 / PG&E, 2004 / NCI Analysis, 2008	Guidehouse CRE Report 2016										
Annual Energy Use / Area ($kWh/ft^2/y$)	Calculated											
Indexed Annual Efficiency	Calculated											
Insulated Box Average Life (years)	ADL, 1996 / PG&E, 2004	DOE CRE Report 2016 / Guidehouse Analysis 2022										
Compressor Average Life (years)	ADL, 1996 / PG&E, 2004	DOE CRE Report 2016 / Guidehouse Analysis 2022										
Retail Equipment Cost (2022$)	ADL, 1996 / Distributor Web Sites / NCI Analysis, 2008	DOE CRE Report 2016 / Webstaurant 2022 / Guidehouse Analysis 2022										
Total Installed Cost (2022$)	ADL, 1996 / Distributor Web Sites / NCI Analysis, 2008	DOE CRE Report 2016 / Webstaurant 2022 / Guidehouse Analysis 2023										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	DOE CRE Report 2016 / Guidehouse Analysis 2022											
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Ice Machines

Final

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Output (pounds [lbs] per day)	ADL, 1996 / NCI Analysis, 2008	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022 / CCMS Database 2022										
Water Use per Hundred Pounds (gal/hundred lbs)	ADL, 1996 / Distributor Web Sites	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022 / CCMS Database 2022										
Energy Use per Hundred Pounds (kWh/hundred lbs)	ADL, 1996 / NCI Analysis, 2008	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022										
Annual Energy Use (kWh/y)	ACEEE, 2002 / NCI Analysis, 2012	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022 / ENERGY STAR										
Indexed Annual Efficiency	Calculated											
Average Life (years)	ADL, 1996/ Distributor Web Sites / NCI Analysis, 2008	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022										
Retail Equipment Cost (2022$)	Distributor Web Sites / NCI Analysis, 2008	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022										
Total Installed Cost (with Bin)	NCI Analysis, 2008	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	ADL, 1996 / NCI Analysis, 2008	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Beverage Merchandisers

Final

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	DOE, 2014: CRE Report / Guidehouse Analysis 2022											
Size (ft^3)	ADL, 1996 / Distributor Web Sites	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Energy Use (kWh/y)	ADL, 1996 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022 / ENERGY STAR 2022										
Annual Energy Use / Volume ($kWh/ft^3/y$)	Calculated											
Indexed Annual Efficiency	Calculated											
Average Life (years)	ACEEE, 2002	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Retail Equipment Cost (2022$)	ADL, 1996 / Distributor Web Sites	DOE, 2014: CRE Report / Guidehouse Analysis 2022 / KaTom Restaurant Supply										
Total Installed Cost (2022$)	DOE, 2014: CRE Report / Guidehouse Analysis 2022											
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	DOE, 2014: CRE Report / Guidehouse Analysis 2022											
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Refrigerated Vending Machines

Final

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	DOE, 2015: BVM TSD / Guidehouse Analysis, 2015	DOE, 2022: BVM TSD / Guidehouse Analysis, 2022										
Can Capacity	DOE, 2015: BVM TSD	DOE, 2022: BVM TSD										
Size (ft^3)	DOE, 2022: BVM TSD / Guidehouse Analysis, 2022											
Annual Energy Use (kWh/y)	DOE, 2015: BVM TSD	DOE, 2022: BVM TSD										
Annual Energy Use / Volume ($kWh/ft^3/y$)	Calculated											
Indexed Annual Efficiency	Calculated											
Average Life (years)	DOE, 2015: BVM TSD	DOE, 2022: BVM TSD										
Retail Equipment Cost (2022$)	DOE, 2015: BVM TSD	DOE, 2022: BVM TSD										
Total Installed Cost (2022$)	DOE, 2015: BVM TSD	DOE, 2022: BVM TSD										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	DOE, 2015: BVM TSD / Guidehouse Analysis, 2015	DOE, 2022: BVM TSD / Guidehouse Analysis, 2022										
Annual Maintenance Cost (2022$/kBtu/h)	DOE, 2022: BVM TSD / Guidehouse Analysis, 2022											

Commercial Ventilation

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Data Sources » Commercial Constant Air Volume Ventilation

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DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
System Airflow (CFM)	CBECS 2003 & BED 2007	CBECS 2018										
System Fan Power (kW)	ASHRAE 90.1-2007	ASHRAE 90.1-2016	ASHRAE 90.1-2019	ASHRAE 90.1 2019 / Guidehouse Analysis 2022								
Specific Fan Power (W/CFM)												
Annual Fan Energy Use (kWh/y)												
Average Life (years)	ASHRAE: Service Life Database											
Total Installed Cost (2022$)	2022 RS Means Online											
Annual Maintenance Cost (2022$)	2022 RS Means Online / Guidehouse											
Total Installed Cost (2022$/thousand CFM)	Calculated											
Annual Maintenance Cost (2022$/thousand CFM)	Calculated											

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Data Sources » Commercial Variable Air Volume Ventilation

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DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
System Airflow (CFM)	CBECS 2003 & BED 2007	CBECS 2018										
System Fan Power (kW)	ASHRAE 90.1-2007	ASHRAE 90.1-2016	ASHRAE 90.1-2019	ASHRAE 90.1 2019 / Guidehouse Analysis 2022								
Specific Fan Power (W/CFM)												
Annual Fan Energy Use (kWh/y)												
Average Life (years)	ASHRAE: Service Life Database											
Total Installed Cost (2022$)	2022 RS Means Online											
Annual Maintenance Cost (2022$)	2022 RS Means Online / Guidehouse											
Total Installed Cost (2022$/thousand CFM)	Calculated											
Annual Maintenance Cost (2022$/thousand CFM)	Calculated											

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Data Sources » Commercial Fan Coil Unit

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DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
System Airflow (CFM)	Product Literature											
System Fan Power (kW)	ASHRAE 90.1-2007	ASHRAE 90.1-2016	ASHRAE 90.1-2019	ASHRAE 90.1 2019 / Guidehouse Analysis 2022								
Specific Fan Power (W/CFM)												
Annual Fan Energy Use (kWh/y)												
Average Life (years)	ASHRAE: Service Life Database											
Total Installed Cost (2022$)	2022 RS Means Online											
Annual Maintenance Cost (2022$)	2022 RS Means Online / Guidehouse											
Total Installed Cost (2022$/thousand CFM)	Calculated											
Annual Maintenance Cost (2022$/thousand CFM)	Calculated											

Appendix B
References

Guidehouse
1200 19th Street, NW, Suite 700
Washington, D.C. 20036

And

Leidos
11951 Freedom Drive
Reston, VA 20190

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APPENDIX D

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Presented to:

U.S. Energy Information Administration

Prepared by:

Guidehouse
1200 19th Street, NW, Suite 700
Washington, D.C. 20036

And

Leidos
11951 Freedom Drive
Reston, VA 20190

October 14, 2022

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Objective

The objective of this study is to develop baseline and projected performance and cost characteristics for residential and commercial end-use equipment in an Advanced Case that assumes accelerated adoption of energy-saving technologies due to increased R&D funding and market incentives.

- Examine 2012 and 2018 (commercial) and 2015 and 2020 (residential) baselines, as well as this year's baseline (2022).
  - Review literature, standards, installed base, contractor, and manufacturer information.
  - Provide a relative comparison and characterization of the cost and efficiency of a generic product.
- Forecast technology improvements that are projected to be available through 2050.
  - Review trends in standards, product enhancements, and research and development (R&D).
  - Project impact of product improvements and technology enhancement.

The performance and cost characterization of end-use equipment developed in this study will assist EIA in projecting national primary energy consumption.

Methodology

Input from industry stakeholders, including government, R&D organizations, and manufacturers, was used to project product enhancements concerning equipment performance and cost attributes.

- Technology forecasting involves many uncertainties.
- Technology developments affect performance and cost forecasts.
- Varied sources ensure a balanced view of technology progress and the probable timing of commercial availability.

Definitions

The following tables represent the current and projected efficiencies for residential and commercial building equipment ranging from the installed base in 2012 and 2018 (for commercial products) and 2015 and 2020 (for residential) to the highest efficiency equipment that is expected to be commercially available by 2050, assuming incremental adoption. Below are definitions for the terms used in characterizing the status of each technology.

- **Installed Stock Average**: the installed and *in use* equipment for that year. Represents the installed stock of equipment, but does *not* represent sales.
- **Current Standard**: the minimum efficiency (or maximum energy use) required (allowed) by current U.S. Department of Energy (DOE) standards, when applicable. For lighting, if no product exists at the standard efficiency level, a hypothetical wattage and lumen output is given for the standard's efficiency level.
- **ENERGY STAR®**: the minimum efficiency required (or maximum energy use allowed) to meet the ENERGY STAR® criteria, when applicable. Presented performance data represents certified products just meeting current ENERGY STAR specifications. For lighting, if no products exist at the ENERGY STAR efficiency level, a hypothetical wattage and lumen output is given for the ENERGY STAR efficiency level.
- **Low**: The minimum efficiency product or product mix available on the market. This rating typically reflects minimal compliance with DOE standards.
- **Typical**: the average, or typical, product being sold in the particular timeframe.
- **High**: the product with the highest efficiency available in the particular timeframe.
- **Lumens (lm):** the unit for luminous flux used in the SI unit system. This unit is used to indicate a light source's light output. All reported lumens are initial lumens. 1 kilolumen (klm) = 1,000 lumens.
- **Correlated Color Temperature (CCT)**: a specification of the color appearance of the light emitted by a lamp. Note: CCT is not a performance metric.
- **Color Rendering Index (CRI)**: a scale from 0 to 100 percent indicating how accurate a given light source is at rendering color when compared to a reference light source. The higher the CRI, the better the color rendering ability.
- **British thermal unit (Btu)**: a measure of the heat content of fuels or energy sources. It is the quantity of heat required to raise the temperature of one pound of liquid water by 1°F at the temperature that water has its greatest density (approximately 39 °F). 1 kBtu = 1,000 Btu.
- **Cubic Feet per Minute (CFM)**: a measure of airflow volume equal to the number of cubic feet of air flowing through a two-dimensional plane in one minute.
- **Not Available (N/A)**: data is not available where indicated.

Calculations

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The following metrics are commonly referred to throughout the tables to follow. Below are the calculations for each metric

— **Lighting**

- **System Wattage** = (Lamp Wattage * Ballast Factor) / Ballast Efficiency
- **System Lumens** = Lamp Lumens * Ballast Factor
- **Lamp Efficacy** = Lamp Lumens / Lamp Wattage
- **System Efficacy** = System Lumens / System Wattage
- **Lamp Cost ($/klm)** = Lamp Cost / (Lamp Lumens / 1,000)
- **Total Equipment Cost** = Lamp Cost + Fixture (including ballast) Cost
- **System Cost ($/klm)** = Total Equipment Cost / (System Lumens / 1,000). l/b/f denotes that the cost includes the luminaire, the ballast, and the fixture.
- **Total Installed Cost** = Total Equipment Cost + Labor Installation Cost
- **Ballast Luminous Efficiency (BLE)** = A/(1+B*Avg Total Lamp Arc Power^(-C)) where A, B, and C are pre-defined constants by DOE Energy Conservation Standards for Fluorescent Lamp Ballasts.

— **Commercial Refrigeration**

- **Nominal Capacity over Average Input (Btu in / Btu out)** = (Cooling or Heat Rejection Capacity)*24*365/(Annual Energy Consumption * 3,412)
- **Total Installed Cost** = Retail Equipment Cost + Labor Installation Cost
- **Total Installed Cost ($/kBtu/hour)** = Total Installed Cost*1,000 / (Cooling or Heat Rejection Capacity). h used as an abbreviation for hour throughout
- **Annual Maintenance Cost ($/kBtu/h)** = Annual Maintenance Cost * 1,000 / (Cooling or Heat Rejection Capacity)

— **Ventilation**

- **CFM out / Btu in / h** = System Airflow / (System Fan Power * 3,412)
- **Total Installed Cost ($/1,000 CFM)** = Total Installed Cost * 1,000 / System Airflow
- **Annual Maintenance Cost ($/1,000 CFM)** = Annual Maintenance Cost * 1,000 / System Fan Power

Market Transformation

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The market for the reviewed products has changed since this analysis was performed in 2015. These changes are noted and reflected in the efficiency and cost characteristics.

- DOE issued federal minimum efficiency standards that have gone into effect for General Service Fluorescent Lamps (2012), Incandescent Reflector Lamps (2012), and Fluorescent Lamp Ballasts (2019).

- In April 2022, DOE codified into the Code of Federal Regulations the 45 lumens per watt (lm/W) backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act (10 CFR 430, 87 FR 27439). This action also amended the definition of general service lamps to include previously exempted product classes, such as reflector lamps. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

- DOE published a Final Rule updating energy conservation standards for Refrigerated Beverage Vending Machines at the end of 2015, effective in 2018. DOE also issued federal minimum efficiency standards that have or will soon go into effect for Refrigerated Beverage Vending Machines (2012), Automatic Commercial Ice Makers (2018), Walk-In Coolers and Freezers (2017), and Commercial Refrigeration Equipment (2017).

Residential Lighting

Note: More R&D investment and effort in the lighting industry only changes projections of LED technologies because additional funding and effort will likely not be applied to traditional technologies that have been exceeded in performance by their LED counterparts. Therefore, the inputs for all non-LED technologies remain unchanged from the Reference Case and are not included in this report.

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Performance and Cost Characteristics » Residential General Service Lamps

The residential general service lamps characterized in this report are a 60-watt and a 75-watt medium screw-based (E26) A-type incandescent lamp and their halogen, CFL, and LED equivalents. A standard 60-watt incandescent lamp produces approximately 800 – 850 lumens. A standard 75-watt incandescent lamp produces approximately 1,100 lumens.

Performance:

- A majority of residential lamps have a nominal CCT rating of 2,700K and give off a warm, yellowish white color, but products with CCTs of 3,000K, 3,500K, 4,100K (neutral white), 5,000K (daylight), and 6,500K (blueish white) are also available. Traditional incandescent light bulbs have a nominal CCT of about 2,700K. When replacing a light bulb, it is advised to chose a product with a similar CCT value in order to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100. However, CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination. High CRI products are preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these specific retail and display applications.

Cost:

- Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy. Therefore, typical lamp prices in 2022 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Fixture prices and installation costs are not included for the residential sector. Labor costs are assumed to be negligible because homeowners likely replaces lamps themselves as they burn out. Therefore, total installed cost is the price of a lamp, and annual maintenance costs are the cost of replacing the lamps, which is a function of lamp life, lamp price, and the annual operating hours.
- Disposal costs are not characterized for residential lighting in this analysis. In residential cases, disposal is done by the occupant. Lamp and product burnout are assumed to result in no "added" cost aside from the work performed to install the replacement.

Legislation:

- The Energy Independence and Security Act of 2007 (EISA 2007) established standards for 60-watt general service lamps, effective in 2014, and 75-watt lamps, effective in 2013. These standards cannot be achieved by incandescent bulbs, but can be by halogen, CFL, and LED technologies.
- In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. This action also amended the definition of general service lamps to include previously exempted product classes, such as reflector lamps. These standards can not be achieved by traditional incandescent or halogen technologies currently on the market, and given current and projected trends in industry, they will likely not be met. It is currently assumed that industry will increase its investment in LED technology at the expense of incandescent, halogen, and CFL technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

ENERGY STAR:

- For ENERGY STAR qualification, general service omnidirectional lamps must have a minimum lamp efficacy of 70 lm/W for products with CRI ≥ 90 and 80 lm/W for lamps with CRI < 90. Additionally, the lamps must have a CRI ≥ 80, nominal CCT of 2,700, 3,000, 3,500, 4,000/4,100, 5,000, or 6,000 K, and rated lifetime ≥ 10,000 hours (ENERGY STAR).

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Performance and Cost Characteristics » Residential General Service Lamps

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent, halogen, and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050:

Technology	Efficacy	Lifetime	Price	Potential for Improvements
Incandescent	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
Halogen	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements as of 2022.
CFL	+0.5%	0%	-0.5%	Improvements in efficacy can be made by using more rare-earth phosphors in compact fluorescent lamps.

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Performance and Cost Characteristics » Residential General Service LED Lamps (60 W Incandescent Equivalent)

Higher efficacy compared with Reference Case

DATA	2015	2020	2022				2023[2]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[1]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	8.7	9.2	10.0	8.9	8.0	13.8	17.8	5.7	5.1	4.4	4.0	3.8	3.4
Lamp Lumens	656	803	800	800	800	800	800	800	800	800	800	800	800
Lamp Efficacy (lm/W)	75.5	87.1	80.0	90.0	100.0	80.0	45.0	141.5	157.2	180.2	200.2	209.0	232.1
CRI	81	85	80	81	90	80	N/A	81	90	81	90	81	90
Correlated Color Temperature (CCT)	2,700	2,700	2,700	2,700	2,700	2,700	N/A	2,700	2,700	2,700	2,700	2,700	2,700
Average Lamp Life (thousand hours)	25	21	15	14	18	15	N/A	14	18	14	18	14	18
Annual Operating Hours (h/y)	657	657	657	657	657	657	N/A	657	657	657	657	657	657
Lamp Price (2022$)	$13.53	$4.56	$6.20	$3.92	$5.32	$6.20	N/A	$3.23	$4.39	$2.84	$3.86	$2.46	$3.33
Lamp Cost (2022$/klm)	$20.63	$5.68	$7.75	$4.90	$6.65	$7.75	N/A	$7.02	$7.02	$3.57	$3.57	$2.38	$2.38
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0.0	0.0	0.0	0.0	0.0	0.0	N/A	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$13.53	$4.56	$6.20	$3.92	$5.32	$6.20	N/A	$3.23	$4.39	$2.84	$3.86	$2.46	$3.33
Annual Maintenance Cost (2022$)	$0.35	$0.15	$0.27	$0.18	$0.19	$0.27	N/A	$0.15	$0.16	$0.13	$0.14	$0.11	$0.12
Total Installed Cost (2022$/klm)	$20.63	$5.68	$7.75	$4.90	$6.65	$7.75	N/A	$4.04	$5.49	$3.56	$4.83	$3.07	$4.17
Annual Maintenance Cost (2022$/klm)	$0.54	$0.18	$0.34	$0.22	$0.24	$0.34	N/A	$0.18	$0.20	$0.16	$0.17	$0.14	$0.15

1. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. All LED lighting products exceed the new minimum efficacy standards.

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Performance and Cost Characteristics » Residential General Service Filament- LED Lamps (60 W Incandescent Equivalent)

Higher efficacy compared with Reference Case

DATA	2015	2020	2022				2023[2]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[1]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	9.7	7.1	5.5	6.9	8.0	13.8	17.8	5.4	5.1	4.2	4.0	3.6	3.4
Lamp Lumens	457	650	450	650	800	800	800	800	800	800	800	800	800
Lamp Efficacy (lm/W)	47.1	91.7	81.8	94.8	100.0	80.0	45.0	149.0	157.2	189.8	200.2	220.0	232.1
CRI	82	84	90	84	80	80	N/A	81	90	81	90	81	90
Correlated Color Temperature (CCT)	2,700	2,700	2,700	2,700	2,700	2,700	N/A	2,700	2,700	2,700	2,700	2,700	2,700
Average Lamp Life (thousand hours)	23	21	15	15	15	15	N/A	15	15	15	15	15	15
Annual Operating Hours (h/y)	657	657	657	657	657	N/A	N/A	657	657	657	657	657	657
Lamp Price (2022$)	$15.17	$6.88	$6.25	$5.91	$7.75	N/A	N/A	$4.87	$6.39	$4.29	$5.62	$3.70	$4.86
Lamp Cost (2022$/klm)	$33.20	$10.58	$13.89	$9.09	$9.69	N/A	N/A	$7.02	$7.02	$3.57	$3.57	$2.38	$2.38
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0.0	0.0	0.0	0.0	0.0	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$15.17	$6.88	$6.25	$5.91	$7.75	N/A	N/A	$4.87	$6.39	$4.29	$5.62	$3.70	$4.86
Annual Maintenance Cost (2022$)	$0.43	$0.21	$0.27	$0.26	$0.34	N/A	N/A	$0.21	$0.28	$0.19	$0.25	$0.16	$0.21
Total Installed Cost (2022$/klm)	$33.20	$10.58	$13.89	$9.09	$9.69	N/A	N/A	$6.09	$7.99	$5.36	$7.03	$4.63	$6.07
Annual Maintenance Cost (2022$/klm)	$0.93	$0.33	$0.61	$0.40	$0.42	N/A	N/A	$0.27	$0.35	$0.23	$0.31	$0.20	$0.27

1. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. All LED lighting products exceed the new minimum efficacy standards.

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Performance and Cost Characteristics » Residential Reflector Lamps

The residential reflector lamps characterized in this report are directional lamps that emit approximately 550 – 850 lumens (except for LED PAR38s which have outputs up to 1,700 lumens). Multiple baseline reflector lamps were analyzed, including 65W Incandescent BR30, Halogen PAR30, Halogen Infrared Reflector (HIR) PAR30, CFL BR30, LED BR30, and LED PAR38.

Performance:

- A majority of residential lamps have a nominal CCT rating of 2,700K and give off a warm, yellowish white color, but products with CCTs of 3,000K, 3,500K, 4,100K (neutral white), 5,000K (daylight), and 6,500K (blueish white) are also available. Traditional incandescent light bulbs have a nominal CCT of about 2,700K. When replacing a light bulb, it is advised to chose a product with a similar CCT value in order to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100, but for CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination, with high CRI products being preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these very specific retail and display applications.

Cost:

- Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy.
- Fixture prices and installation costs are not included for the residential sector. Labor costs are assumed to be negligible because homeowners likely replaces lamps themselves as they burn out. Therefore, total installed cost is the price of a lamp, and annual maintenance costs are the cost of replacing the lamps, which is a function of lamp life, lamp price, and the annual operating hours.
- Disposal costs are not characterized for residential lighting in this analysis. In residential cases, disposal is done by the occupant. Lamp and product burnout are assumed to result in no "added" cost aside from the work performed to install the replacement.

Legislation:

- EPAct92 established minimum performance standards for some reflector lamps and provided exemptions for certain specialty applications (e.g., ER/BR, vibration service, more than 5% neodymium oxide, impact resistant, infrared heat, colored). EPAct92 effectively phased-out R-shaped tungsten filament incandescent reflector lamps at certain wattages and bulb diameters, replacing them with more efficient and cost effective tungsten-halogen parabolic aluminized reflector (PAR) lamps. EISA 2007 took away certain exemptions from EPACT 1992, requiring certain previously exempted lamps to meet EPAct92 minimum performance standards by January 1, 2008. The 65W BR30, a large majority of the incandescent reflector lamp market, was still exempted until 2022.
- In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. **This action also amended the definition of general service lamps to include previously exempted product classes, such as reflector lamps.** These standards can not be achieved by traditional incandescent or halogen technologies currently on the market, and given current and projected trends in industry, they will likely not be met. It is currently assumed that industry will increase its investment in LED technology at the expense of incandescent, halogen, and CFL technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

ENERGY STAR:

- For ENERGY STAR qualification, general service, reflector lamps must have a minimum lamp efficacy of 61 lm/W for products with CRI ≥ 90 and 70 lm/W for lamps with CRI < 90, respectively. Additionally, the lamps must have a CRI ≥ 80, nominal CCT of 2,700, 3,000, 3,500, 4,000/4,100, 5,000, or 6,000 K, and rated lifetime ≥ 10,000 hours (ENERGY STAR).

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

Technology	Efficacy	Lifetime	Price	Potential for Improvements
Incandescent	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
Halogen	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements as of 2022.
CFL	+0.5%	0%	-0.5%	In addition to higher efficiency reflector coatings, improvements in efficacy can be made by using more rare-earth phosphors in compact fluorescent lamps. Lifetime improvements can be made by improving the compact fluorescent lamp electrodes.

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Performance and Cost Characteristics » Residential Reflector LED BR30

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Higher efficacy compared with Reference Case

DATA	2015	2020	2022				2023[2]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[1]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	14.2	10.9	11.0	8.8	7.2	10.7	14.4	5.5	4.7	4.8	4.1	4.2	3.7
Lamp Lumens	706	781	800	683	650	650	650	650	650	650	650	650	650
Lamp Efficacy (lm/W)	49.8	71.5	72.7	78.6	90.3	61.0	45.0	119.2	137.0	136.3	156.7	153.4	176.3
CRI	82	85	92	87	90	80	N/A	87	90	87	90	87	90
Correlated Color Temperature (CCT)	2,700	2,700	2,700	2,700	2,700	2,700	N/A	2,700	2,700	2,700	2,700	2,700	2,700
Average Lamp Life (thousand hours)	25	25	25	19	18	15	N/A	19	18	19	18	19	18
Annual Operating Hours (h/y)	730	730	730	730	730	N/A	N/A	730	730	730	730	730	730
Lamp Price (2022$)	$21.40	$15.36	$4.09	$5.01	$5.96	N/A	N/A	$4.11	$4.89	$3.62	$4.31	$3.14	$3.74
Lamp Cost (2022$/klm)	$30.31	$19.66	$5.11	$7.33	$9.17	N/A	N/A	$6.32	$7.53	$5.57	$6.64	$4.83	$5.75
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0.0	0.0	0.0	0.0	0.0	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$21.40	$15.36	$4.09	$5.01	$5.96	N/A	N/A	$4.11	$4.89	$3.62	$4.31	$3.14	$3.74
Annual Maintenance Cost (2022$)	$0.63	$0.45	$0.12	$0.20	$0.24	N/A	N/A	$0.16	$0.19	$0.14	$0.17	$0.12	$0.15
Total Installed Cost (2022$/klm)	$30.31	$19.66	$5.11	$7.33	$9.17	N/A	N/A	$6.32	$7.53	$5.57	$6.64	$4.83	$5.75
Annual Maintenance Cost (2022$/klm)	$0.89	$0.57	$0.15	$0.29	$0.37	N/A	N/A	$0.25	$0.30	$0.22	$0.26	$0.19	$0.23

1. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. All LED lighting products exceed the new minimum efficacy standards.

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Performance and Cost Characteristics » Residential Reflector LED PAR38

Higher efficacy compared with Reference Case

DATA	2015	2020	2022				2023[2]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[1]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	19.2	15.5	17.0	16.4	17.0	10.7	29.9	10.8	11.2	9.4	9.8	8.4	8.7
Lamp Lumens	1,202	1,211	1,200	1,344	1,700	650	1,344	1,344	1,700	1,344	1,700	1,344	1,700
Lamp Efficacy (lm/W)	62.7	77.9	70.6	82.0	100.0	61.0	45.0	124.5	151.7	142.4	173.6	160.2	195.3
CRI	83	86	82	86	82	80	N/A	86	86	86	86	86	86
Correlated Color Temperature (CCT)	3,000	3,000	2,700	3,000	3,000	2,700	N/A	3,000	3,000	3,000	3,000	3,000	3,000
Average Lamp Life (thousand hours)	24	27	25	27	25	15	N/A	27	25	27	25	27	25
Annual Operating Hours (h/y)	730	730	730	730	730	N/A	N/A	730	730	730	730	730	730
Lamp Price (2022$)	$35.23	$22.44	$23.71	$23.09	$15.69	N/A	N/A	$19.40	$13.18	$17.36	$11.79	$15.37	$10.45
Lamp Cost (2022$/klm)	$29.31	$18.54	$19.76	$17.18	$9.23	N/A	N/A	$14.43	$7.75	$12.91	$6.94	$11.44	$6.14
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0.0	0.0	0.0	0.0	0.0	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$35.23	$22.44	$23.71	$23.09	$15.69	N/A	N/A	$19.40	$13.18	$17.36	$11.79	$15.37	$10.45
Annual Maintenance Cost (2022$)	$1.07	$0.60	$0.69	$0.62	$0.46	N/A	N/A	$0.52	$0.38	$0.46	$0.34	$0.41	$0.31
Total Installed Cost (2022$/klm)	$29.31	$18.54	$19.76	$17.18	$9.23	N/A	N/A	$14.43	$7.75	$12.91	$6.94	$11.44	$6.14
Annual Maintenance Cost (2022$/klm)	$0.89	$0.49	$0.58	$0.46	$0.27	N/A	N/A	$0.39	$0.23	$0.35	$0.20	$0.31	$0.18

1. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress presed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023, and for retail and distribution in July 2023. All LED lighting products exceed the new minimum efficacy standards.

Performance and Cost Characteristics » Residential 4-foot Linear 2-Lamp Lighting Systems

This section characterizes commercial linear fixtures that house two 4ft long linear lamps and their integrated luminaire equivalents. The technologies available for this system are linear fluorescent and LED.

- T5 lamps are approximately 40% narrower than T8 lamps and almost 60% narrower than T12 lamps. This narrowness allows T5 lamps to be coated with higher quality, more efficient phosphor blends than larger diameter lamps, resulting in a more efficacious lamp. The compact size of T5 lamps also permits greater flexibility in lighting design and construction.
- LED options for linear fixtures include replacement lamps that can fit directly into an existing fixture and fully integrated luminaires that can be used to replace existing fixtures. LED replacement lamps are also known as TLEDs. Type A TLEDs can be installed with existing ballasts and Type B and C TLEDs require the ballast to be disconnected. Replacement lamps are only sold to go into existing fixtures. If a new fixture is to be installed, a fully integrated LED luminaire is a more cost effective and efficient option. Because LED luminaires are fully integrated, they do not have lamp and fixture efficiency losses associated with ballasts and fixture optics.

Performance:

- Residential linear lamps often have a nominal CCT rating of 3500K, but products with CCTs of 3000K, 4000K, and 4100K (neutral white) are also common. 5000K (daylight) lamps are available as well. When replacing a light bulb, it is important to choose a product with a similar CCT value to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100, but CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination, with high CRI products being preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these very specific retail and display applications.

Cost:

- Many factors influence the price of LED lamps, including CRI, lifetime, dimming capabilities, and efficacy. Therefore, typical lamp prices in 2022 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- The total installed cost is the price of a lamp, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED replacement lamps. which are sold only as a replacement for use in an existing fixture. The LED luminaire is more efficient and cost effective for new installations or fixture retrofits.
- Labor costs for lamp changes are assumed to be negligible because homeowners likely replace lamps themselves as they burn out. Therefore, annual maintenance costs are the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours for residential linear systems.
- Disposal costs are not characterized for residential lighting in this analysis. In residential cases, disposal is done by the occupant. Lamp and product burnout are assumed to result in no "added" cost aside from the work performed to install the replacement.

Legislation:

- Beginning July 14, 2012 (or July 14, 2014, for T8 700-series phosphor lamps), DOE fluorescent lamp standards required a minimum efficacy of 89 lm/W. Although the amended performance-based standards do not explicitly prohibit T12 lamps, no T12 lamps met the standard at the time of its announcement. Since then, however, T12 lamps meeting the standard have entered the market.
- Beginning November 14, 2014, DOE standards required that the characterized residential ballasts have a minimum BLE = 0.993 / (1 + 0.41 * Avg Total Lamp Arc power ^ (- 0.25)). Residential ballasts also must have a minimum power factor of 0.5.
- California's Title 24 mandates the use of electronic ballasts with high efficacy luminaires (including fluorescent) of 13 W or higher (CEC, 2005).

ENERGY STAR:

- ENERGY STAR does not cover linear lamps. (ENERGY STAR, 2020)

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume that manufacturers will focus on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050:

Technology	Efficacy	Lifetime	Price	Potential for Improvements
T12	0%	0%	-0.5%	Limited because the technology is mature.
T8	0%	0%	-0.5%	Limited because the technology is mature.
T5	0%	0%	-0.5%	Limited because the technology is mature.

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Performance and Cost Characteristics » Residential Linear LED Replacement Lamp 2-Lamp System

Final

Higher efficacy compared with Reference Case

DATA	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	18.5	16.3	16.0	13.7	11.0	8.9	7.2	7.7	7.2	7.7	7.2
Lamp Lumens	2,013	2,130	1,800	1,920	1,800	1,920	1,800	1,920	1,800	1,920	1,800
Lamp Efficacy (lm/W)	111.0	130.7	112.5	140.1	163.6	216.1	250.0	250.0	250.0	250.0	250.0
System Wattage	36.9	32.6	32.0	27.4	22.0	17.8	14.4	15.4	14.4	15.4	14.4
System Lumens	3,583	4,004	3,456	3,686	3,456	3,686	3,456	3,686	3,456	3,686	3,456
System Efficacy (lm/W)	97.0	122.8	108.0	134.5	157.1	207.4	240.0	240.0	240.0	240.0	240.0
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	83	81	82	81	80	81	80	81	80	81	80
Correlated Color Temperature (CCT)	4,100	3,500	4,100	4,100	5,000	4,100	5,000	4,100	5,000	4,100	5,000
Average Lamp Life (thousand hours)	55	50	50	54	50	54	50	54	50	54	50
Annual Operating Hours (h/y)	584	584	584	584	584	584	584	584	584	584	584
Lamp Price (2022$)	$27.00	$12.89	$14.63	$11.11	$4.28	$9.97	$3.84	$9.87	$3.80	$9.77	$3.77
Ballast Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$13.41	$6.05	$8.13	$5.79	$2.38	$5.19	$2.13	$5.14	$2.11	$5.09	$2.09
System (l/b/f) Cost (2022$/klm)	$15.07	$6.44	$8.47	$6.03	$2.48	$5.41	$2.22	$5.35	$2.20	$5.30	$2.18
Labor Cost (2022$/h)[2]	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor System Installation (hours)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Change (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$54.00	$25.78	$29.26	$22.22	$8.56	$19.95	$7.68	$19.74	$7.60	$19.55	$7.53
Annual Maintenance Cost (2022$)	$0.57	$0.30	$0.34	$0.24	$0.10	$0.22	$0.09	$0.21	$0.09	$0.21	$0.09
Total Installed Cost (2022$/klm)	$15.07	$6.44	$8.47	$6.03	$2.48	$5.41	$2.22	$5.35	$2.20	$5.30	$2.18
Annual Maintenance Cost (2022$/klm)	$0.16	$0.08	$0.10	$0.07	$0.03	$0.06	$0.03	$0.06	$0.03	$0.06	$0.03

1. N/A because a fixture and an LED replacement lamp would not be purchased separately for a new installation or retrofit when there are integrated LED luminaires that are more efficient and cost effective. These lamps are sold only as replacements to go into existing fixtures.

Assume no labor is associated with lamp replacement in the residential sector because residents likely replace the lamps themselves.

Final

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Performance and Cost Characteristics » Residential Linear LED Luminaire

Higher efficacy compared with Reference Case

DATA	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	50.0	43.1	49.0	44.0	35.0	27.4	21.8	23.0	19.2	21.2	19.2
System Lumens	4,615	4,945	5,024	5,302	4,800	5,302	4,800	5,302	4,800	5,302	4,800
System Efficacy (lm/W)	92.3	114.7	102.5	120.5	137.1	193.4	220.1	230.4	250.0	250.0	250.0
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	83	82	80	79	80	79	80	79	80	79	80
Correlated Color Temperature (CCT)	3,838	3,000	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
Average Lamp Life (thousand hours)	56	58	54	53	50	53	50	53	50	53	50
Annual Operating Hours (h/y)	730	730	730	730	730	730	730	730	730	730	730
Lamp or Luminaire Price (2022$)	$181.60	$158.60	$144.85	$152.54	$207.80	$121.11	$164.98	$105.34	$143.50	$90.11	$122.76
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$78.70	$64.15	$57.66	$57.54	$86.58	$45.68	$68.74	$39.74	$59.79	$33.99	$51.15
Labor Cost (2022$/h)	$80.90	$80.90	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Labor Lamp Change (hours)*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$403.65	$357.65	$322.70	$338.08	$448.60	$275.22	$362.97	$243.68	$320.01	$213.23	$278.52
Annual Maintenance Cost (2022$)	$2.89	$2.49	$2.40	$2.56	$3.52	$2.12	$2.89	$1.91	$2.58	$1.70	$2.27
Total Installed Cost (2022$/klm)	$87.46	$72.33	$64.23	$63.76	$93.46	$51.91	$75.62	$45.96	$66.67	$40.22	$58.03
Annual Maintenance Cost (2022$/klm)	$0.63	$0.50	$0.48	$0.48	$0.73	$0.40	$0.60	$0.36	$0.54	$0.32	$0.47

1. N/A because the lamp and fixture are both included in the luminaire.

Performance and Cost Characteristics » Residential Outdoor Lamps

- The residential outdoor lamps characterized in this report include reflector and general service lamps used for security and/or porch lighting that can be switched on from inside the home (i.e. parking lot/garage and outdoor common area lighting at multifamily buildings are excluded) with lumen outputs of approximately 1,000 – 1,400 lumens. Multiple baseline lamps were analyzed according to estimates of installed base average lumens by lamp type, including:

Security (Reflector Lamps)	Porch (General Service Lamps)
Incandescent BR30	Incandescent A-Type
Halogen PAR38	Halogen A-Type
Halogen Infrared Reflector (HIR) PAR38	CFL Bare Spiral
CFL PAR38	LED A-Type Lamp
LED PAR38	

Performance:

- 65W BR30 is the only viable incandescent reflector lamp due to exemption from EISA 2007. The lumen output of this lamp type is well below other reflector lamp technologies characterized for residential outdoor spaces, thus its use is limited for this application. This product is, as of 2022, expected to be eliminated by DOE's 45 lm/W backstop requirement.
- A majority of residential lamps have a nominal CCT rating of 2,700K and give off a warm, yellowish white color, but products with CCTs of 3,000K, 3,500K, 4,100K (neutral white), 5,000K (daylight), and 6,500K (blueish white) are also available. Traditional incandescent light bulbs have a nominal CCT of about 2,700K. When replacing a light bulb, it is advised to chose a product with a similar CCT value in order to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100. However, CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination. High CRI products are preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these specific retail and display applications.

Cost:

- Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy. Therefore, typical lamp prices in 2015 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Fixture prices and installation costs are not included for the residential sector. Labor costs are assumed to be negligible because homeowners likely replaces lamps themselves as they burn out. Therefore, total installed cost is the price of a lamp, and annual maintenance costs are the cost of replacing the lamps, which is a function of lamp life, lamp price, and the annual operating hours for residential reflector lamps.
- Disposal costs are not characterized for residential lighting in this analysis. In residential cases, disposal is done by the occupant. Lamp and product burnout are assumed to result in no "added" cost aside from the work performed to install the replacement.

Legislation:

- In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. **This action also amended the definition of general service lamps to include previously exempted product classes, such as reflector lamps.** These standards can not be achieved by traditional incandescent or halogen technologies currently on the market, and given current and projected trends in industry, they will likely not be met. It is currently assumed that industry will increase its investment in LED technology at the expense of incandescent, halogen, and CFL technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

ENERGY STAR:

- For ENERGY STAR qualification, general service omnidirectional lamps must have a minimum lamp efficacy of 70 lm/W for products with CRI ≥ 90 and 80 lm/W for lamps with CRI < 90.
- For ENERGY STAR qualification, general service reflector lamps must have a minimum lamp efficacy of 61 lm/W for products with CRI ≥ 90 and 70 lm/W for lamps with CRI < 90.
- Additionally, the lamps must have a CRI ≥ 80, nominal CCT of 2,700, 3,000, 3,500, 4,000/4,100, 5,000, or 6,000 K, and rated lifetime ≥ 10,000 hours (ENERGY STAR).

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

Technology	Efficacy	Lifetime	Price	Potential for Improvements
Incandescent Omnidirectional	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
Incandescent Directional	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
Halogen	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
CFL	+0.5%	0%	-0.5%	In addition to benefiting from higher efficiency reflector coatings, improvements in efficacy can be made by using more rare-earth phosphors in compact fluorescent lamps. Lifetime improvements can be made by improving the compact fluorescent lamp electrodes.

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Performance and Cost Characteristics » Residential Outdoor Lamps (Security: LED Reflector)

Final

Higher efficacy compared with Reference Case

DATA	2015	2020	2022				2023[2]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[1]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	19.2	15.5	17.0	16.4	17.0	10.7	29.9	10.8	11.2	9.4	9.8	8.4	8.7
Lamp Lumens	1,202	1,211	1,200	1,344	1,700	650	1,344	1,344	1,700	1,344	1,700	1,344	1,700
Lamp Efficacy (lm/W)	62.7	77.9	70.6	82.0	100.0	61.0	45.0	124.5	151.7	142.4	173.6	160.2	195.3
CRI	83	86	82	86	82	80	N/A	86	86	86	86	86	86
Correlated Color Temperature (CCT)	3,000	3,000	2,700	3,000	3,000	2,700	N/A	3,000	3,000	3,000	3,000	3,000	3,000
Average Lamp Life (thousand hours)	24	27	25	27	25	15	N/A	27	25	27	25	27	25
Annual Operating Hours (h/y)	730	730	730	730	730	N/A	N/A	730	730	730	730	730	730
Lamp Price (2022$)	$35.23	$22.44	$23.71	$23.09	$15.69	N/A	N/A	$19.40	$13.18	$17.36	$11.79	$15.37	$10.45
Lamp Cost (2022$/klm)	$29.31	$18.54	$19.76	$17.18	$9.23	N/A	N/A	$14.43	$7.75	$12.91	$6.94	$11.44	$6.14
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0.0	0.0	0.0	0.0	0.0	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$35.23	$22.44	$23.71	$23.09	$15.69	N/A	N/A	$19.40	$13.18	$17.36	$11.79	$15.37	$10.45
Annual Maintenance Cost (2022$)	$1.07	$0.60	$0.69	$0.62	$0.46	N/A	N/A	$0.52	$0.38	$0.46	$0.34	$0.41	$0.31
Total Installed Cost (2022$/klm)	$29.31	$18.54	$19.76	$17.18	$9.23	N/A	N/A	$14.43	$7.75	$12.91	$6.94	$11.44	$6.14
Annual Maintenance Cost (2022$/klm)	$0.89	$0.49	$0.58	$0.46	$0.27	N/A	N/A	$0.39	$0.23	$0.35	$0.20	$0.31	$0.18

1. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress presed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. All LED lighting products exceed the new minimum efficacy standards.

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Performance and Cost Characteristics » Residential Outdoor Lamps (Porch: LED A-Type)

Final

Higher efficacy compared with Reference Case

DATA	2015	2020	2022				2023[1]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	12.9	11.8	13.5	11.9	11.0	13.6	24.4	7.6	7.0	6.0	5.5	5.1	4.7
Lamp Lumens	1,073	1,102	1,100	1,089	1,100	1,089	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Lamp Efficacy (lm/W)	83.1	93.5	81.5	92.2	100.0	80	45.0	144.9	157.2	184.6	200.2	214.0	232.1
CRI	81	85	80	86	80	80	N/A	86	80	86	80	86	80
Correlated Color Temperature (CCT)	2,700	2,700	3,000	2,700	2,700	2,700	N/A	2,700	2,700	2,700	2,700	2,700	2,700
Average Lamp Life (thousand hours)	25	21	25	18	25	N/A	N/A	18	25	18	25	18	25
Annual Operating Hours (h/y)	657	657	657	657	657	N/A	N/A	657	657	657	657	657	657
Lamp Price (2022$)	$18.13	$8.48	$4.39	$3.92	$5.29	N/A	N/A	$3.23	$4.36	$2.84	$3.84	$2.46	$3.31
Lamp Cost (2022$/klm)	$16.90	$7.70	$3.99	$3.60	$4.81	N/A	N/A	$7.02	$7.02	$3.57	$3.57	$2.38	$2.38
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0.0	0.0	0.0	0.0	0.0	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$18.13	$8.48	$4.39	$3.92	$5.29	N/A	N/A	$3.23	$4.36	$2.84	$3.84	$2.46	$3.31
Annual Maintenance Cost (2022$)	$0.49	$0.27	$0.12	$0.14	$0.14	N/A	N/A	$0.12	$0.11	$0.10	$0.10	$0.09	$0.09
Total Installed Cost (2022$/klm)	$16.90	$7.70	$3.99	$3.60	$4.81	N/A	N/A	$2.94	$3.97	$2.59	$3.49	$2.23	$3.01
Annual Maintenance Cost (2022$/klm)	$0.45	$0.24	$0.10	$0.13	$0.13	N/A	N/A	$0.11	$0.10	$0.09	$0.09	$0.08	$0.08

1. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress presed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. All LED lighting products exceed the new minimum efficacy standards.

Commercial Lighting

Note: More R&D investment and effort in the lighting industry will only change future projections of LED technologies because additional funding and effort will likely not be applied to traditional technologies that have been exceeded in performance by their LED counterparts. Therefore, the inputs for all non-LED technologies remain unchanged from the Reference Case and are therefore not included in this report.
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Performance and Cost Characteristics » Commercial General Service Lamps in Recessed Can Fixtures

This section characterizes commercial omnidirectional incandescent, halogen, CFL, and LED screw-based general service lamps emitting approximately 1,600 lumens (equivalent to a 100W incandescent lamp) used in recessed can fixtures. A recessed can is a directional fixture set into the ceiling, in which all of the light is directed downwards from the opening. Therefore, an omnidirectional lamp is not well suited for use in such fixtures because light that emits upwards and out of the sides must be reflected downwards and out of the fixture and some light is absorbed in the process. A fixture efficiency of 61% is used to characterize these lumen losses for all omnidirectional lamps. For all lamp technologies, an annual fixture renovation rate of 10% (i.e., 10-year fixture service life) is used to reflect the proportion of equipment that retires each year.

Performance:

- A majority of general service lamps have a nominal CCT rating of 2,700K and give off a warm, yellowish white color, but products with CCTs of 3,000K, 3,500K, 4,100K (neutral white), 5,000K (daylight), and 6,500K (blueish white) are also available. Traditional incandescent light bulbs have a nominal CCT of about 2,700K. When replacing a light bulb, it is advised to chose a product with a similar CCT value in order to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100. However, CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination. High CRI products are preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these specific retail and display applications.

Cost:

- The total installed cost is the price of a lamp, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED replacement lamps which are sold only as a replacement for use in an existing fixture. There are integrated LED luminaires that are more efficient and cost effective for new installations or fixture retrofits. Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy. Therefore typical lamp prices in 2015 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Annual maintenance costs are the cost of labor for replacing the lamps and the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours for commercial general service lamps (DOE SSL Program, 2012a).
- Commercial lighting disposal costs are estimated to be $0.12 per linear foot of fluorescent lamps, $1.50 per lamp for high intensity discharge (HID) lamps, and $0.50 for CFLs (EPA, 2022).

Legislation:

- The Energy Independence and Security Act of 2007 (EISA 2007) established standards for 100W lamps effective in 2012. These standards cannot be achieved by incandescent bulbs, but they can be met by halogen, CFL, and LED technologies from 2012 to 2023.
- In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. This action also amended the definition of general service lamps to include previously exempted product classes, such as reflector lamps. These standards can not be achieved by traditional incandescent or halogen technologies currently on the market, and given current and projected trends in industry, they will likely not be met. It is currently assumed that industry will increase its investment in LED technology at the expense of incandescent, halogen, and CFL technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

ENERGY STAR:

- For ENERGY STAR qualification, general service omnidirectional lamps must have a minimum lamp efficacy of 70 lm/W for products with CRI ≥ 90 and 80 lm/W for lamps with CRI < 90. Additionally, the lamps must have a CRI ≥ 80, nominal CCT of 2,700, 3,000, 3,500, 4,000/4,100, 5,000, or 6,000 K, and rated lifetime ≥ 10,000 hours (ENERGY STAR).

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Performance and Cost Characteristics » Commercial General Service Lamps in Recessed Can Fixtures

Final

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus would be on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

Technology	Efficacy	Lifetime	Price	Potential for Improvements
Incandescent	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
Halogen	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements as of 2022
CFL	+0.5%	0%	-0.5%	Improvements in efficacy can be made by using more rare-earth phosphors in compact fluorescent lamps. Lifetime improvements can be made by improving the compact fluorescent lamp electrodes.

Final

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Performance and Cost Characteristics » Commercial General Service 100W Equivalent LED Replacement Lamp in Recessed Can Fixture

Higher efficacy compared with Reference Case

DATA	2012	2018	2022				2023[2]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[1]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	26.7	14.5	16.0	14.8	13.0	20.0	34.8	9.4	8.3	7.4	6.5	6.4	6.4
Lamp Lumens	1,600	1,528	1,600	1,567	1,600	1,600	1,567	1,567	1,600	1,567	1,600	1,567	1,600
Lamp Efficacy (lm/W)	60.0	105.1	100.0	106.0	123.1	80.0	45.0	166.7	193.5	212.2	246.4	246.1	250.0
System Wattage	26.7	14.5	16.0	14.8	13.0	20.0	34.8	9.4	8.3	7.4	6.5	6.4	6.4
System Lumens[3]	976	932	976	956	976	976	956	956	976	956	976	956	976
System Efficacy (lm/W)	36.6	64.1	61.0	64.7	75.1	48.8	27.5	101.7	118.0	129.5	150.3	150.1	152.5
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	80	80	90	84.8	84	80	N/A	84.8	84.8	84.8	84.8	84.8	84.8
Correlated Color Temperature (CCT)	3,000	3,000	2,700	2,700	5,000	N/A	N/A	2,700	2,700	2,700	2,700	2,700	2,700
Average Lamp Life (thousand hours)	22.0	17.9	25.0	16.9	25.0	15.0	N/A	16.9	25.0	16.9	25.0	16.9	25.0
Annual Operating Hours (h/y)	4,928	4,928	4,928	4,928	4,928	N/A	N/A	4,928	4,928	4,928	4,928	4,928	4,928
Lamp Price (2022$)	$47.45	$11.28	$5.62	$7.04	$3.39	N/A	N/A	$5.81	$2.80	$5.11	$2.46	$4.41	$2.12
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$23.72	$26.38	$22.07	$22.07	$22.07	N/A	N/A	$21.20	$21.20	$20.17	$20.17	$19.18	$19.18
Lamp Cost (2022$/klm)	$25.00	$7.38	$3.51	$4.49	$2.12	N/A	N/A	$3.71	$1.75	$3.26	$1.54	$2.82	$1.33
System (l/b/f) Cost (2022$/klm)	$72.92	$40.40	$28.37	$30.46	$26.09	N/A	N/A	$28.26	$24.59	$26.45	$23.18	$24.68	$21.83
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	N/A	N/A	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	1.0	1.0	1.0	1.0	1.0	N/A	N/A	1.0	1.0	1.0	1.0	1.0	1.0
Labor Lamp Change (hours)	0.05	0.05	0.05	0.05	0.05	N/A	N/A	0.05	0.05	0.05	0.05	0.05	0.05
Total Installed Cost (2022$)	$148.39	$114.88	$93.69	$95.11	$91.46	N/A	N/A	$93.01	$90.00	$91.27	$88.63	$89.59	$87.30
Annual Maintenance Cost (2022$)	$11.49	$4.16	$1.76	$3.02	$1.32	N/A	N/A	$2.66	$1.20	$2.45	$1.14	$2.25	$1.07
Total Installed Cost (2022$/klm)	$152.04	$123.25	$95.99	$99.52	$93.71	N/A	N/A	$97.32	$92.21	$95.51	$90.81	$93.75	$89.45
Annual Maintenance Cost (2022$/klm)	$11.77	$4.46	$1.80	$3.16	$1.35	N/A	N/A	$2.78	$1.23	$2.57	$1.16	$2.35	$1.10

1. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress presed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. All LED lighting products exceed the new minimum efficacy standards.
3. Based on a fixture efficiency of 61% for an omnidirectional lamp installed in a recessed can fixture.

Final

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Performance and Cost Characteristics » Commercial Reflector Lamps in Recessed Can Fixtures

This section characterizes commercial halogen, halogen infrared reflector (HIR), and LED screw-based reflector lamps emitting approximately 1400 lumens used in recessed can fixtures.

- HIR lamps contain a tungsten halogen capsule with a film coating on the inside of the capsule. The coating reflects infrared radiation back into the lamp filament, which forces the filament to burn at a higher temperature. This design increases the efficacy of the lamp, without reducing operating life.
- A recessed can is a directional fixture set into the ceiling, in which all of the light is directed downwards from the opening. Therefore, a reflector lamp, which employs reflective coating to direct light out in only one direction, is well suited for use in such fixtures. However, some light is not able to escape the fixture, and a fixture efficiency of 93% is used to characterize these minimal lumen losses. For all lamp technologies, an annual fixture renovation rate of 10% (i.e., 10-year fixture service life) is used to reflect the proportion of equipment that retires each year.

Performance:

- A majority of reflector lamps have a nominal CCT rating of 2,700K and give off a warm, yellowish white color, but products with CCTs of 3,000K, 3,500K, 4,100K (neutral white), 5,000K (daylight), and 6,500K (blueish white) are also available. Traditional incandescent light bulbs have a nominal CCT of about 2,700K. When replacing a light bulb, it is advised to chose a product with a similar CCT value in order to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100. However, CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination. High CRI products are preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these specific retail and display applications.

Cost:

- The total installed cost is the price of a lamp, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED replacement lamps which are sold only as a replacement for use in an existing fixture. Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy.
- Annual maintenance costs are the cost of labor for replacing the lamps and the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours for commercial reflector lamps (DOE SSL Program, 2012a).
- Commercial lighting disposal costs are estimated to be $0.12 per linear foot of fluorescent lamps, $1.50 per lamp for HID lamps, and $0.50 for CFLs (EPA, 2022).

Legislation:

- EPAct92 established minimum performance standards for some reflector lamps and provided exemptions for certain specialty applications (e.g., ER/BR, vibration service, more than 5% neodymium oxide, impact resistant, infrared heat, colored). EPAct92 effectively phased-out R-shaped tungsten filament incandescent reflector lamps at certain wattages and bulb diameters, replacing them with more efficient and cost effective tungsten-halogen parabolic aluminized reflector (PAR) lamps. EISA2007 took away certain exemptions from EPACT 1992, requiring certain previously exempted lamps to meet EPAct92 minimum performance standards by January 1, 2008. In 2015, DOE issued a final rule that determined that amending the standards for incandescent reflector lamps could not be economically justified.
- In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. **This action also amended the definition of general service lamps to include previously exempted product classes, such as reflector lamps.** These standards can not be achieved by traditional incandescent or halogen technologies currently on the market, and given current and projected trends in industry, they will likely not be met. It is currently assumed that industry will increase its investment in LED technology at the expense of incandescent, halogen, and CFL technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

Performance and Cost Characteristics » Commercial Reflector Lamps in Recessed Can Fixtures

Final

ENERGY STAR:

- For ENERGY STAR qualification, general service reflector lamps must have a minimum lamp efficacy of 61 lm/W for products with CRI ≥ 90 and 70 lm/W for lamps with CRI < 90. Additionally, the lamps must have a CRI ≥ 80, nominal CCT of 2,700, 3,000, 3,500, 4,000/4,100, 5,000, or 6,000 K, and rated lifetime ≥ 10,000 hours (ENERGY STAR).

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus would be on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

Technology	Efficacy	Lifetime	Price	Potential for Improvements
Incandescent	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
Halogen	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements as of 2022
CFL	+0.5%	0%	-0.5%	In addition to higher efficiency reflector coatings, improvements in efficacy can be made by using more rare-earth phosphors in compact fluorescent lamps. Lifetime improvements can be made by improving the compact fluorescent lamp electrodes.

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Performance and Cost Characteristics » Commercial LED Reflector Lighting (PAR38)

Final

Higher efficacy compared with Reference Case

DATA	2012	2018	2022				2023[2]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[3]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	17.2	16.6	17.0	16.4	17.0	22.0	29.9	14.0	11.2	9.4	9.8	8.4	8.7
Lamp Lumens	1,045	1,210	1,200	1,344	1,700	1,344	1,344	1,344	1,700	1,344	1,700	1,344	1,700
Lamp Efficacy (lm/W)	60.9	73.0	70.6	82.0	100.0	61.0	45.0	95.7	151.7	142.4	173.6	160.2	195.3
System Wattage	17.2	16.6	17.0	16.4	17.0	22.0	29.9	14.0	11.2	9.4	9.8	8.4	8.7
System Lumens[1]	972	1,125	1,116	1,250	1,581	1,250	1,250	1,250	1,581	1,250	1,581	1,250	1,581
System Efficacy (lm/W)	56.6	67.9	65.6	76.1	93.0	56.7	41.9	89.0	141.1	132.4	161.4	149.0	181.6
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	83	83	82	86	82	80	N/A	86	82	86	82	86	82
Correlated Color Temperature (CCT)	3,000	3,000	2,700	3,000	3,000	3,000	N/A	3,000	3,000	3,000	3,000	3,000	3,000
Average Lamp Life (thousand hours)	22	15	25	28	25	25	N/A	28	25	28	25	28	25
Annual Operating Hours (h/y)	4,928	4,928	4,928	4,928	4,928	N/A	N/A	4,928	4,928	4,928	4,928	4,928	4,928
Lamp Price (2022$)	$61.98	$28.10	$23.71	$23.09	$15.69	N/A	N/A	$19.40	$13.18	$17.36	$11.79	$15.37	$10.45
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$23.72	$26.38	$22.07	$22.07	$22.07	N/A	N/A	$21.20	$21.20	$20.17	$20.17	$19.18	$19.18
Lamp Cost (2022$/klm)	$59.31	$23.23	$19.76	$17.18	$9.23	N/A	N/A	$14.43	$7.75	$12.91	$6.94	$11.44	$6.14
System (l/b/f) Cost (2022$/klm)	$88.18	$48.42	$41.02	$36.13	$23.88	N/A	N/A	$32.48	$21.75	$30.02	$20.22	$27.64	$18.74
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	N/A	N/A	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	1.0	1.0	1.0	1.0	1.0	N/A	N/A	1.0	1.0	1.0	1.0	1.0	1.0
Labor Lamp Change (hours)	0.05	0.05	0.05	0.05	0.05	N/A	N/A	0.05	0.05	0.05	0.05	0.05	0.05
Total Installed Cost (2022$)	$162.93	$131.71	$111.78	$111.16	$103.76	N/A	N/A	$106.60	$100.38	$103.52	$97.96	$100.55	$95.63
Annual Maintenance Cost (2022$)	$14.75	$10.50	$5.32	$4.64	$3.74	N/A	N/A	$3.99	$3.25	$3.64	$2.98	$3.29	$2.71
Total Installed Cost (2022$/klm)	$167.64	$117.04	$100.16	$88.92	$65.63	N/A	N/A	$85.28	$63.49	$82.81	$61.96	$80.44	$60.48
Annual Maintenance Cost (2022$/klm)	$15.17	$9.33	$4.77	$3.72	$2.37	N/A	N/A	$3.20	$2.05	$2.91	$1.88	$2.63	$1.71

1. Based on a fixture efficiency of 93% for an omnidirectional lamp installed in a recessed can fixture.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress presed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. All LED lighting products exceed the new minimum efficacy standards.
3. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)

Performance and Cost Characteristics » Commercial 4-foot Linear 2-Lamp Lighting Systems

This section characterizes commercial linear fixtures that house two 4ft long linear lamps and their integrated luminaire equivalents. The technologies available for this system are linear fluorescent and LED.

- Linear fluorescent options are T5, T8, and T12 lamps. T5 lamps are approximately 40% narrower than T8 lamps and almost 60% narrower than T12 lamps. This narrowness allows T5 lamps to be coated with higher quality, more efficient phosphor blends than larger diameter lamps, resulting in a more efficacious lamp. The compact size of T5 lamps also permits greater flexibility in lighting design and construction.
- LED options for linear fixtures include replacement lamps that can fit directly into an existing fixture and fully integrated luminaires that can be used to replace existing fixtures. LED replacement lamps are also known as TLEDs. Type A TLEDs can be installed with existing ballasts and Type B and C TLEDs require the ballast to be disconnected. Replacement lamps are only sold to go into existing fixtures. If a new fixture is to be installed, a fully integrated LED luminaire is a more cost effective and efficient option. Because LED luminaires are fully integrated, they do not have lamp and fixture efficiency losses associated with ballasts and fixture optics. For all lamp technologies, an annual fixture renovation rate of 10% (i.e., 10-year fixture service life) is used to reflect the proportion of equipment that retires each year.

Performance:

- Linear lamps often have a nominal CCT rating of 3,500K, but products with CCTs of 3,000K, 4,000K, and 4,100K (neutral white) are also common. 5,000K (daylight) lamps are available as well. When replacing a light bulb, it is important to choose a product with a similar CCT value to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100, but CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination, with high CRI products being preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these very specific retail and display applications.

Cost:

- The total installed cost is the price of two lamps, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED replacement lamp, which are sold only as a replacement for use in an existing fixture. There are integrated LED luminaires that are more efficient and cost effective for new installations or fixture retrofits. Many factors influence the price of LED lamps, including CRI, lifetime, dimming capabilities, and efficacy. Therefore, typical lamp prices in 2022, reflecting a mix of lamp characteristics and features, were used as the basis for projections for both typical and high efficacy products in the future.
- Annual maintenance costs are the cost of labor for replacing the lamps and the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours of 4055 hours per year for commercial 4ft linear systems (DOE SSL Program, 2012a).
- Commercial lighting disposal costs are estimated to be $0.12 per linear foot of fluorescent lamps, $1.50 per lamp for HID lamps, and $0.50 for CFLs (EPA, 2022).

Legislation:

- Beginning July 14, 2012 (or July 14, 2014, for T8 700-series phosphor lamps), DOE fluorescent lamp standards required a minimum efficacy of 89 lm/W. Although the amended performance-based standards do not explicitly prohibit T12 lamps, no T12 lamps met the standard at the time of its announcement. Since then, however, T12 lamps meeting the standard have entered the market.
- California's Title 24 mandates the use of electronic ballasts with high efficacy luminaires (including fluorescent) of 13 W or higher (CEC, 2005).

ENERGY STAR:

- ENERGY STAR does not cover commercial linear luminaires (ENERGY STAR, 2020).

Performance and Cost Characteristics » Commercial 4-foot Linear 2-Lamp Lighting Systems

Final

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume that manufacturers will focus on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

Technology	Efficacy	Lifetime	Price	Potential for Improvements
T8 F32 Commodity	0%	0%	-0.5%	Limited because the technology is mature.
T8 F32 High Efficiency/High Output	0%	0%	-0.5%	Limited because the technology is mature.
T5 F28	0%	0%	-0.5%	Limited because the technology is mature.

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Performance and Cost Characteristics » Commercial 4-ft Linear LED Replacement Lamp in 2-Lamp System

Final

Higher efficacy compared with Reference Case

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	20.8	17.0	16.0	13.7	11.0	8.9	7.2	7.7	7.2	7.7	7.2
Lamp Lumens	2,091	2,003	1,800	1,920	1,800	1,920	1,800	1,920	1,800	1,920	1,800
Lamp Efficacy (lm/W)	100.5	117.8	112.5	140.1	163.6	216.1	250.0	250.0	250.0	250.0	250.0
System Wattage	41.6	34.0	32.0	27.4	22.0	17.8	14.4	15.4	14.4	15.4	14.4
System Lumens	3,555	3,565	3,456	3,686	3,456	3,686	3,456	3,686	3,456	3,686	3,456
System Efficacy (lm/W)	85.4	104.9	108.0	134.5	157.1	207.4	240.0	240.0	240.0	240.0	240.0
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	86	81	82	81	80	81	80	81	80	81	80
Correlated Color Temperature (CCT)	4,100	4,020	4,100	3,500	5,000	3,500	5,000	3,500	5,000	3,500	5,000
Average Lamp Life (thousand hours)	50	54	50	54	50	54	50	54	50	54	50
Annual Operating Hours (h/y)	4,055	3,541	3,541	3,541	3,541	3,541	3,541	3,541	3,541	3,541	3,541
Lamp Price (2022$)	$278.36	$35.06	$14.63	$11.11	$4.28	$9.88	$3.81	$9.66	$3.72	$9.44	$3.64
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$133.10	$17.50	$8.13	$5.79	$2.38	$5.15	$2.11	$5.03	$2.07	$4.92	$2.02
System (l/b/f) Cost (2022$/klm)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Change (hours)	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total Installed Cost (2022$)	$587.35	$70.12	$29.26	$22.22	$8.56	$19.76	$7.61	$19.31	$7.44	$18.89	$7.28
Annual Maintenance Cost (2022$)	$47.63	$6.61	$3.93	$3.17	$2.46	$3.01	$2.39	$2.98	$2.38	$2.95	$2.37
Total Installed Cost (2022$/klm)	$165.20	$19.67	$8.47	$6.03	$2.48	$5.36	$2.20	$5.24	$2.15	$5.12	$2.11
Annual Maintenance Cost (2022$/klm)	$13.40	$1.85	$1.14	$0.86	$0.71	$0.82	$0.69	$0.81	$0.69	$0.80	$0.69

1. N/A because a fixture and an LED replacement lamp would not be purchased separately for a new installation or retrofit when there are integrated LED luminaires that are more efficient and cost effective. These lamps are sold only as replacements to go into existing fixtures.

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Performance and Cost Characteristics » Commercial 4-ft Linear LED Luminaire to Replace 2-Lamp Systems

Final

Higher efficacy compared with Reference Case

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W) [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	51.5	50.0	49.0	44.0	35.0	27.4	21.8	23.0	19.2	21.2	19.2
System Lumens	4,818	4,673	5,024	5,302	4,800	5,302	4,800	5,302	4,800	5,302	4,800
System Efficacy (lm/W)	93.6	93.5	102.5	120.5	137.1	193.4	220.1	230.4	250.0	250.0	250.0
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	84	79	80	79	80	79	80	79	80	79	80
Correlated Color Temperature (CCT)	3,500	3,650	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
Average Lifetime (thousand hours)	67	53	54	53	50	53	50	53	50	53	50
Annual Operating Hours (h/y)	4,055	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431
Lamp or Luminaire Price (2022$)	$723.96	$188.00	$144.85	$152.54	$207.80	$127.58	$173.80	$118.37	$161.25	$109.57	$149.27
Ballast Price (2022$) [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$) [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm) [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$150.25	$40.23	$57.66	$57.54	$86.58	$24.06	$36.21	$22.33	$33.59	$20.67	$31.10
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Labor Lamp Change (hours)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$762.57	$226.61	$322.70	$338.08	$448.60	$160.58	$206.80	$151.37	$194.25	$142.57	$182.27
Annual Maintenance Cost (2022$)	$46.16	$14.67	$11.30	$12.01	$16.52	$10.40	$14.19	$9.80	$13.33	$9.23	$12.51
Total Installed Cost (2022$/klm)	$158.27	$48.49	$64.23	$63.76	$93.46	$30.29	$43.08	$28.55	$40.47	$26.89	$37.97
Annual Maintenance Cost (2022$/klm)	$9.58	$3.14	$2.25	$2.27	$3.44	$1.96	$2.96	$1.85	$2.78	$1.74	$2.61

1. N/A because the lamp and fixture are both included in the luminaire.

Performance and Cost Characteristics » Commercial 8-foot Linear 2-Lamp Lighting Systems

This section characterizes commercial linear fixtures that house two 8ft long linear lamps and their integrated luminaire equivalents. The technologies available for this system are linear fluorescent and LED.

- Linear fluorescent options are T5, T8, and T12 lamps. T5 lamps are approximately 40% narrower than T8 lamps and almost 60% narrower than T12 lamps. This narrowness allows T5 lamps to be coated with higher quality, more efficient phosphor blends than larger diameter lamps, resulting in a more efficacious lamp. The compact size of T5 lamps also permits greater flexibility in lighting design and construction.
- LED options for linear fixtures include replacement lamps that can fit directly into an existing fixture and fully integrated luminaires that can be used to replace existing fixtures. LED replacement lamps are also known as TLEDs. Type A TLEDs can be installed with existing ballasts and Type B and C TLEDs require the ballast to be disconnected. Replacement lamps are only sold to go into existing fixtures. If a new fixture is to be installed, a fully integrated LED luminaire is a more cost effective and efficient option. Because LED luminaires are fully integrated, they do not have lamp and fixture efficiency losses associated with ballasts and fixture optics. For all lamp technologies, an annual fixture renovation rate of 10% (i.e., 10-year fixture service life) is used to reflect the proportion of equipment that retires each year.

Performance:

- Linear lamps often have a nominal CCT rating of 3,500K, but products with CCTs of 3,000K, 4,000K, and 4,100K (neutral white) are also common. 5,000K (daylight) lamps are available as well. When replacing a light bulb, it is important to choose a product with a similar CCT value to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100, but CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination, with high CRI products being preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these very specific retail and display applications.

Cost:

- The total installed cost is the price of two lamps, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED replacement lamps, which are sold only as a replacement for use in an existing fixture. There are integrated LED luminaires that are more efficient and cost effective for new installations or fixture retrofits. Many factors influence the price of LED lamps, including CRI, lifetime, dimming capabilities, and efficacy. Therefore, typical lamp prices in 2022 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Annual maintenance costs are the cost of labor for replacing the lamps and the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours of 4147 hours per year for commercial 8ft linear systems (DOE SSL Program, 2012a).
- Commercial lighting disposal costs are estimated to be $0.12 per linear foot of fluorescent lamps, $1.50 per lamp for HID lamps, and $0.50 for CFLs (EPA, 2022).

Legislation:

- Beginning July 14, 2012 (or July 14, 2014, for T8 700-series phosphor lamps), DOE fluorescent lamp standards required a minimum efficacy of 89 lm/W. Although the amended performance-based standards do not explicitly prohibit T12 lamps, no T12 lamps met the standard at the time of its announcement. Since then, however, T12 lamps meeting the standard have entered the market.
- California's Title 24 mandates the use of electronic ballasts with high efficacy luminaires (including fluorescent) of 13 W or higher (CEC, 2005).

ENERGY STAR:

- ENERGY STAR does not cover commercial linear luminaires (ENERGY STAR, 2020).

Performance and Cost Characteristics » Commercial 8-foot Linear 2-Lamp Lighting Systems

Final

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume that manufacturers will focus on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050:

Technology	Efficacy	Lifetime	Price	Potential for Improvements
T8 F59 Typical Efficiency	0%	0%	-0.5%	Limited because the technology is mature.
T8 F59 High Efficiency	0%	0%	-0.5%	Limited because the technology is mature.
T8 F96 High Output	0%	0%	-0.5%	Limited because the technology is mature.

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Performance and Cost Characteristics » Commercial 8-ft Linear LED Replacement Lamp for a 2-Lamp System

Final

Higher efficacy compared with Reference Case

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A	35.7	34.0	39.0	40.0	25.3	25.9	21.9	22.4	19.8	22.0
Lamp Lumens	N/A	3,975	4,200	4,960	5,500	4,960	5,500	4,960	5,500	4,960	5,500
Lamp Efficacy (lm/W)	N/A	111.2	123.5	127.2	137.5	196.1	212.0	226.7	245.1	250.0	250.0
System Wattage	N/A	71.5	68.0	78.0	80.0	50.6	51.9	43.8	44.9	39.7	44.0
System Lumens	N/A	7,473	8,064	9,523	10,560	9,523	10,560	9,523	10,560	9,523	10,560
System Efficacy (lm/W)	N/A	104.5	118.6	122.1	132.0	188.2	203.5	217.7	235.3	240.0	240.0
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	N/A	80	82	81	82	81	82	81	82	81	82
Correlated Color Temperature (CCT)	N/A	5,000	4,000	4,000	5,000	4,000	5,000	4,000	5,000	4,000	5,000
Average Lamp Life (thousand hours)	N/A	50	50	50	50	50	50	50	50	50	50
Annual Operating Hours (h/y)	N/A	4,147	4,147	4,147	4,147	4,147	4,147	4,147	4,147	4,147	4,147
Lamp Price (2022$)	N/A	$89.59	$33.11	$37.22	$41.44	$32.35	$36.02	$31.71	$35.30	$31.11	$34.64
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	N/A	$19.00	$7.88	$7.50	$7.53	$6.52	$6.55	$6.39	$6.42	$6.27	$6.30
System (l/b/f) Cost (2022$/klm)[1]	N/A	$23.98	$8.21	$7.82	$7.85	$6.79	$6.82	$6.66	$6.69	$6.53	$6.56
Labor Cost (2022$/h)	N/A	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Change (hours)	N/A	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total Installed Cost (2022$)	N/A	$200.80	$84.70	$92.92	$101.36	$83.18	$90.52	$81.90	$89.09	$80.70	$87.76
Annual Maintenance Cost (2022$)	N/A	$16.65	$7.02	$7.71	$8.41	$6.90	$7.51	$6.79	$7.39	$6.69	$7.28
Total Installed Cost (2022$/klm)	N/A	$50.51	$10.50	$9.76	$9.60	$8.73	$8.57	$8.60	$8.44	$8.47	$8.31
Annual Maintenance Cost (2022$/klm)	N/A	$4.19	$0.87	$0.81	$0.80	$0.72	$0.71	$0.71	$0.70	$0.70	$0.69

1. N/A because a fixture and an LED replacement lamp would not be purchased separately for a new installation or retrofit when there are integrated LED luminaires that are more efficient and cost effective. These lamps are sold only as replacements to go into existing fixtures.

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Performance and Cost Characteristics » Commercial 8-ft Linear LED Luminaire Replacement for a 2-Lamp System

Final

Higher efficacy compared with Reference Case

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	N/A	73.0	90.0	78.0	72.0	49.7	45.9	42.4	41.6	37.9	41.6
System Lumens	N/A	8,000	8,200	9,465	10,400	9,465	10,400	9,465	10,400	9,465	10,400
System Efficacy (lm/W)	N/A	109.6	91.1	121.3	144.4	190.4	226.7	223.1	250.0	250.0	250.0
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	N/A	90	80	81	80	81	80	81	80	81	80
Correlated Color Temperature (CCT)	N/A	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000
Average Lifetime (thousand hours)	N/A	75	50	73	100	73	100	73	100	73	100
Annual Operating Hours (h/y)	N/A	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431
Lamp or Luminaire Price (2022$)	N/A	$759.16	$119.99	$142.48	$153.91	$109.90	$118.71	$96.00	$103.70	$82.68	$89.31
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	N/A	$80.00	$14.63	$15.05	$14.80	$11.61	$11.41	$10.14	$9.97	$8.73	$8.59
Labor Cost (2022$/h)	N/A	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	N/A	1.0	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Labor Lamp Change (hours)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	N/A	$708.20	$206.52	$229.01	$240.44	$196.42	$205.24	$182.53	$190.23	$169.20	$175.83
Annual Maintenance Cost (2022$)	N/A	$39.16	$22.40	$17.46	$13.53	$14.40	$11.11	$13.09	$10.08	$11.84	$9.10
Total Installed Cost (2022$/klm)	N/A	$88.53	$25.18	$24.20	$23.12	$20.75	$19.73	$19.28	$18.29	$17.88	$16.91
Annual Maintenance Cost (2022$/klm)	N/A	$4.89	$2.73	$1.84	$1.30	$1.52	$1.07	$1.38	$0.97	$1.25	$0.87

Performance and Cost Characteristics » Commercial Low-Bay Lighting Systems

Final

The commercial low bay lighting characterized in this report is a one-lamp and one-ballast system in a low/high bay fixture that emits between 6,000 and 10,000 system lumens. Low bay lighting is defined as "interior lighting where the roof trusses or ceiling height is less than 25ft. above the floor"(IESNA, 2000). For all lamp technologies, an annual fixture renovation rate of 10% (i.e., 10-year fixture service life) is used to reflect the proportion of equipment that retires each year.

Performance:

- Low bay conventional lighting technologies, such as metal halide and sodium vapor lamps, provide higher efficacy ranging from 80 lm/W to 100 lm/W. Older, mercury vapor lamps have much lower efficacy at approximately 40 lm/W.
- CCT and CRI values range broadly based on technology type for low bay products.

Cost:

- The total installed cost is the price of a lamp, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED luminaires, which are sold as one integrated system. Many factors influence the price of LED luminaires, including CRI, lifetime, dimming capabilities, and efficacy. Therefore, typical luminaire prices in 2022 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Annual maintenance costs are the cost of labor for replacing the lamps and the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours for commercial low-bay systems (DOE SSL Program, 2012a).
- Commercial lighting disposal costs are estimated to be $0.12 per linear foot of fluorescent lamps, $1.50 per lamp for HID lamps, and $0.50 for CFLs (EPA, 2022).

ENERGY STAR:

- ENERGY STAR does not cover low/high bay luminaires (ENERGY STAR, 2012).

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus would be on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

	Efficacy	Lifetime	Price	Potential for Improvements
Mercury Vapor	0%	0%	-0.5%	Limited because the technology is mature.
Metal Halide	0%	0%	-0.5%	Limited because the technology is mature.
Sodium Vapor	0%	0%	-0.5%	Limited because the technology is mature.

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Performance and Cost Characteristics » Commercial LED Low-Bay Luminaire

Final

Higher efficacy compared with Reference Case

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	68.1	84.0	40.0	73.0	76.0	47.1	49.0	40.5	48.0	40.0	48.0
System Lumens	4,877	10,000	5,000	10,000	12,000	10,000	12,000	10,000	12,000	10,000	12,000
System Efficacy (lm/W)	71.6	119.0	125.0	137.0	157.9	212.5	244.9	246.7	250.0	250.0	250.0
Ballast Efficiency	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	85	78	84	81	80	81	84	81	84	81	81
Correlated Color Temperature (CCT)	4,000	4,806	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	4,000
Average Lifetime (thousand hours)	50	74	75	65	60	65	60	65	60	65	60
Annual Operating Hours (h/y)	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042
Lamp or Luminaire Price (2022$)	$903.82	$281.00	$63.99	$145.46	$285.89	$123.82	$243.37	$111.24	$218.63	$99.09	$194.75
Ballast Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$185.31	$28.10	$12.80	$14.55	$23.82	$12.38	$20.28	$11.12	$18.22	$9.91	$16.23
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Labor Lamp Change (hours)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$865.44	$396.83	$162.99	$244.46	$384.89	$222.82	$342.37	$210.24	$317.63	$198.09	$293.75
Annual Maintenance Cost (2022$)	$69.95	$37.02	$12.23	$24.24	$45.18	$21.55	$39.45	$19.99	$36.12	$18.48	$32.90
Total Installed Cost (2022$/klm)	$177.44	$39.68	$32.60	$24.45	$32.07	$22.28	$28.53	$21.02	$26.47	$19.81	$24.48
Annual Maintenance Cost (2022$/klm)	$14.34	$3.70	$2.45	$2.42	$3.77	$2.16	$3.29	$2.00	$3.01	$1.85	$2.74

1. N/A because the lamp and fixture are both included in the luminaire.

Performance and Cost Characteristics » Commercial High-Bay Lighting Systems

The commercial high-bay lighting characterized in this report is a one-lamp and one-ballast system in a low/high bay fixture that emits greater than 10,000 system lumens. High-bay lighting is defined as "interior lighting where the roof trusses or ceiling height is greater than 25ft. above the floor" (IESNA, 2000). For all lamp technologies, an annual fixture renovation rate of 10% (i.e., 10-year fixture service life) is used to reflect the proportion of equipment that retires each year.

Performance:

- High bay conventional lighting technologies, such as metal halide and sodium vapor lamps, provide higher efficacy ranging from 80 lm/W to 100 lm/W. Older, mercury vapor lamps have much lower efficacy at approximately 40 lm/W.
- CCT and CRI values range broadly based on technology type for high bay products.

Cost:

- The total installed cost is the price of a lamp, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED luminaires, which are sold as one integrated system. Many factors influence the price of LED luminaires including, CRI, lifetime, dimming capabilities, and efficacy. Therefore, typical luminaire prices in 2022 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Annual maintenance costs are the cost of labor for replacing the lamps and the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours for commercial high bay systems (DOE SSL Program, 2012a).
- Commercial lighting disposal costs are estimated to be $0.12 per linear foot of fluorescent lamps, $1.50 per lamp for HID lamps, and $0.50 for CFLs (EPA, 2022).

ENERGY STAR:

- ENERGY STAR does not cover low/high bay luminaires (ENERGY STAR, 2012).

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus would be on improving efficacy, lifetime and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

	Efficacy	Lifetime	Price	Potential for Improvements
Mercury Vapor	0%	0%	-0.5%	Limited because the technology is mature.
Metal Halide	0%	0%	-0.5%	Limited because the technology is mature.
Sodium Vapor	0%	0%	-0.5%	Limited because the technology is mature.

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Performance and Cost Characteristics » Commercial LED High-Bay Luminaire

Final

Higher efficacy compared with Reference Case

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	212	167	150	138	130	89	84	76	76	74	76
System Lumens	18,915	18,797	18,500	18,500	18,900	18,500	18,900	18,500	18,900	18,500	18,900
System Efficacy (lm/W)	89	113	123	134	145	208	225	242	250	250	250
Ballast Efficiency	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	74	78	80	80	80	80	80	80	80	80	80
Correlated Color Temperature (CCT)	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
Average Lifetime (thousand hours)	70	67	100	100	100	100	100	100	100	100	100
Annual Operating Hours (h/y)	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042
Lamp or Luminaire Price (2022$)	$2,842.05	$448.43	$177.54	$195.81	$234.20	$162.12	$193.90	$148.87	$178.06	$136.20	$162.90
Ballast Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$150.25	$23.86	$9.60	$10.58	$12.39	$8.76	$10.26	$8.05	$9.42	$7.36	$8.62
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Labor Lamp Change (hours)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$2,957.88	$564.26	$276.54	$294.81	$333.20	$261.12	$292.90	$247.87	$277.06	$235.20	$261.90
Annual Maintenance Cost (2022$)	$170.78	$34.07	$11.18	$11.91	$13.47	$10.55	$11.84	$10.02	$11.20	$9.51	$10.58
Total Installed Cost (2022$/klm)	$156.38	$30.02	$14.95	$15.94	$17.63	$14.11	$15.50	$13.40	$14.66	$12.71	$13.86
Annual Maintenance Cost (2022$/klm)	$9.03	$1.81	$0.60	$0.64	$0.71	$0.57	$0.63	$0.54	$0.59	$0.51	$0.56

1. N/A because the lamp and fixture are both included in the luminaire.

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Final

Refrigeration

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Performance and Cost Characteristics » Commercial Compressor Rack Systems

Final

Lower annual energy use compared with Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Total Capacity (kBtu/h)[1]	1,200	1,200	1,200	1,190	930	N/A	1,190	930	1,190	930	1,190	930
Median Store Size (ft^2)	46,500	31,997	35,197	35,197	35,197	N/A	35,197	35,197	35,197	35,197	35,197	35,197
Power Input (kW)	162	155	162	160	125	N/A	160	125	160	125	160	125
Annual Energy Use (MMWh/y)[2]	1,497	1,497	1,305	1,232	1,160	N/A	1,109	1,044	998	939	898	845
Indexed Annual Efficiency[3]	1.00	1.00	1.15	1.21	1.29	N/A	1.35	1.43	1.50	1.59	1.67	1.77
Average Life (years)	15	15	15	15	15	N/A	15	15	15	15	15	15
Total Installed Cost (2022$)	$630,000	$630,000	$488,000	$625,000	$630,000	N/A	$625,000	$630,000	$625,000	$630,000	$625,000	$630,000
Total Installed Cost (2022$/kBtu/h)	$525,000	$525,000	$406,667	$525,210	$677,419	N/A	$525,210	$677,419	$525,210	$677,419	$525,210	$677,419
Annual Maintenance Cost (2022$)[4]	$3,400	$3,400	$3,400	$3,400	$3,400	N/A	$3,400	$3,400	$3,400	$3,400	$3,400	$3,400
Annual Maintenance Cost (2022$/kBtu/h)	$2,833	$2,833	$2,833	$2,857	$3,656	N/A	$2,857	$3,656	$2,857	$3,656	$2,857	$3,656

1. The total capacity represents the nominal compressor capacity required for the entire refrigeration system of a typical supermarket. This refrigeration system usually includes two low temperature racks and two medium temperature racks. For 2018, a 1,200 MBtu/h total cooling capacity is based on a 200-ton estimate for total capacity–80 tons for the medium temperature racks and 20 tons for the low temperature racks.
2. Capacity and annual energy consumption for 2022 and beyond are based on market research and Guidehouse estimates.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Maintenance cost includes oil changes, bearing lubrication, filter replacement, and system functionality checks-approximately half a day per rack of labor for technician is assumed.

- Commercial compressor rack systems that serve commercial supermarket display cases and walk-ins consist of a number of parallel-connected compressors located in a separate machine room. By modulating compressor capacity, these integrated systems provide higher efficiency and mechanical longevity.
- Rack integrators generally supply a packaged compressor rack for which much of the necessary piping, insulation, components, and controls are pre-assembled.
- A typical supermarket will have 10 to 20 compressors mounted in racks in the 3-horsepower (hp) to 15-hp size range. Usually, each rack has three to five compressors serve a series of loads with nearly identical evaporator temperature.
- The duty cycle for compressors is usually in the range of 60% to 70%.
- Energy use and capacity for the Reference Case are projected to remain static over the coming decades because commercial compressor racks systems are a mature technology. The Reference Case assumes low R&D efforts because it is an established technology.
- **For this Advanced Case, a 10% reduction in energy consumption is assumed to occur over the Reference Case for 2022 and beyond due to vacuum insulated panel (VIP) adoption by display cases and a relaxation in charge size limits for more efficient, low global warming potential (GWP) refrigerants. Also, increased adoption of toxic/flammable refrigerants such as ammonia and propane due to improved safety technology such as leak detection**.

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Performance and Cost Characteristics » Commercial Condensers

Final

Lower annual energy use compared with Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Total Capacity (kBtu/h)[1]	1,680	1,520	1,440	1,440	1,440	N/A	1,440	1,368	1,300	1,300	1,235	1,235
Median Store Size (ft^2)	46,500	31,997	35,197	35,197	35,197	N/A	35,197	35,197	35,197	35,197	35,197	35,197
Power Input (kW)	25	25	18	18	18	N/A	18	18	18	18	18	18
Annual Energy Use (MMWh/y)	120	120	115	106	86	N/A	95	77	86	70	77	63
Indexed Annual Efficiency[2]	1.00	1.00	1.04	1.13	1.40	N/A	1.26	1.55	1.40	1.72	1.55	1.91
Average Life (years)	10	10	10	10	10	N/A	10	10	10	10	10	10
Total Installed Cost (2022$)	$54,000	$60,000	$54,000	$60,000	$80,000	N/A	$60,000	$80,000	$60,000	$80,000	$60,000	$80,000
Total Installed Cost (2022$/kBtu/h)	$32,143	$39,474	$37,500	$41,667	$55,556	N/A	$41,667	$58,480	$46,168	$61,538	$48,598	$64,777
Annual Maintenance Cost (2022$)[3]	$954	$954	$954	$954	$954	N/A	$954	$954	$954	$954	$954	$954
Annual Maintenance Cost (2022$/kBtu/h)	$0.57	$0.63	$0.66	$0.66	$0.66	N/A	$0.66	$0.70	$0.73	$0.73	$0.77	$0.77

1. Total capacity is the total heat rejected (THR) by condensers comprised of two low temperature condensers (THRL = 240 MBtu/h each, suction temperature = -25°F, condensing temperature-110°F) and two medium temperature condensers (THRM = 520 MBtu/h each, suction temperature = 15°F, condensing temperature = 115°F); ambient temperature = 95°F. (NCI, 2009). For 2022 and beyond, capacity was estimated by Guidehouse.
2. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
3. Maintenance cost includes coil cleaning, leak checking, belt replacement as necessary, and system functionality checks.

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Performance and Cost Characteristics » Commercial Condensers

Final

- Condensers are designed with multiple methods of cooling: air-cooled, water-cooled, and evaporative. These units can be single-circuit or a multiple circuit.
- Commercial condensers are remotely located, typically installed on the roof of a supermarket.
- For use with parallel compressors in supermarkets, air-cooled units are the most commonly used condensers. This analysis is based on multiple air-cooled condensers connected to a supermarket refrigeration system comprised of two low temperature condensers and two medium temperature condensers.
- Each compressor rack has a dedicated condenser or a separate circuit of a single common condenser. Condenser temperatures of multiple racks are often different.
- The duty cycle for condensers is usually in the range 50%-70%.
- **For this Advanced Case, a 10% reduction in energy consumption and a 5% reduction in required capacity is assumed to occur over the Reference Case for 2020 and beyond due to VIP adoption by display cases and a relaxation in charge size limits for more efficient, low GWP. Also, increased adoption of toxic/flammable refrigerants such as ammonia and propane due to improved safety technology such as leak detection**.

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Performance and Cost Characteristics » Commercial Supermarket Display Cases

Final

Lower annual energy use, increased installed cost compared with Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	17,623	11,850	11,850	11,850	11,850	N/A	11,850	11,850	11,850	11,850	11,850	11,850
Median Store Size (ft^2)	46,500	31,997	35,197	35,197	35,197	N/A	35,197	35,197	35,197	35,197	35,197	35,197
Case Length (ft)	12	12	12	12	12	N/A	12	12	12	12	12	12
Annual Energy Use (kWh/y)[1,2]	13,497	10,506	10,506	9,771	9,087	N/A	9,282	8,632	8,818	8,201	8,377	7,791
Annual Energy Use / Case Length (kWh/ft)	1,125	876	876	814	757	N/A	774	719	735	683	698	649
Indexed Annual Efficiency[3]	1.00	1.28	1.28	1.38	1.49	N/A	1.45	1.56	1.53	1.65	1.61	1.73
Average Life (years)	10	10	10	10	10	N/A	10	10	10	10	10	10
Retail Equipment Cost (2022$)	$8,510	$10,650	$7,265	$9,500	$10,680	N/A	$9,500	$10,680	$9,500	$10,680	$9,500	$10,680
Total Installed Cost (2022$)	$10,811	$12,650	$9,265	$11,500	$12,680	N/A	$11,500	$12,680	$11,500	$12,680	$11,500	$12,680
Total Installed Cost (2022$/kBtu/h)	613	1,068	782	970	1,070	N/A	970	1,070	970	1,070	970	1,070
Annual Maintenance Cost (2022$)[4]	$940	$940	$940	$940	$940	N/A	$940	$940	$940	$940	$940	$940
Annual Maintenance Cost (2022$/kBtu/h)	$53.34	$79.32	$79.32	$79.32	$79.32	N/A	$79.32	$79.32	$79.32	$79.32	$79.32	$79.32

1. For 2022 and beyond, energy consumption and cost values were estimated using shipment-weighted averages reported in DOE's 2014 CRE Final Rule Technical Support Document (TSD) for equipment commonly used as display cases. DOE's updated conservation standard went into effect in 2017, so units sold in 2018 are assumed to comply with this standard.
2. For consistency with DOE rulemaking practices, Supermarket Display Case Energy Use reported above includes energy use of the compressor racks and condensers. To avoid double counting, do not add Energy Use from the Compressor Rack or Condenser Systems tabs if calculating total energy consumption.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Maintenance cost includes preventative maintenance costs such as cleaning evaporator coils, drain pans, fans, and intake screens as well as lamp replacements and other lighting maintenance activities. After 2012, these values are based on a reported maintenance and repair cost of $220 per unit for preventative maintenance plus approximately $60 per linear foot for additional repair and maintenance.

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Performance and Cost Characteristics » Commercial Supermarket Display Cases

Final

- DOE set federal energy efficiency standards for Commercial Refrigeration Equipment (CRE) in 2009. These standards set maximum daily energy consumption levels, in kilowatt-hours per day, for display cases manufactured sold in the United States on or after January 1, 2012.
- DOE updated its Energy Conservation Standards for Commercial Refrigeration Equipment in 2014 for equipment sold on or after March 27, 2017.
- The table below lists equipment used as supermarket display cases and their corresponding Energy Conservation Standard levels. The maximum allowable daily energy consumption for each equipment class is a linear function of Total Display Area (TDA).

Equipment Description	Standards Equation (2012)	Standards Equation (2017)
Vertical Open Cooler (VOP.RC.M)	0.82xTDA+4.07	0.64xTDA+4.07
Semi-Vertical Open Cooler (SVO.RC.M)	0.83xTDA+3.18	0.66xTDA+3.18
Horizontal Open Cooler (HZO.RC.M)	0.35xTDA+2.88	0.35xTDA+2.88
Transparent-Doored Cooler (VCT.RC.M)	0.22xTDA+1.95	0.15xTDA+1.95
Deli Display Cooler (SOC.RC.M)	0.51xTDA+0.11	0.44xTDA+0.11
Transparent-Doored Freezer (VCT.RC.L)	0.56xTDA+2.61	0.49xTDA+2.61
Horizontal Open Freezer (HZO.RC.L)	0.57xTDA+6.88	0.55xTDA+6.88

Performance and Cost Characteristics » Commercial Supermarket Display Cases

Final

- According to CBECS 2018 microdata, the average building size for food sale building type is 31,997.
- Unit energy consumption for 2022 and beyond is estimated using a shipment-weighted average by efficiency level and equipment class, using data in DOE's 2014 CRE Final Rule TSD with updated analysis from Guidehouse in 2016. The equipment classes analyzed are listed in the table on the previous slide.
- Supermarket refrigeration systems consist of refrigerated display cases, condensing units, and centralized compressor racks.
- A typical supermarket display case contains lighting, evaporators, evaporator fans, piping, insulation, valves, and controls.
- The efficiency of supermarket display cases can be increased through the use of improved evaporator coils, larger evaporators, higher efficiency evaporator fan blades, high efficiency doors, LED lighting, and improved insulation.
- **For 2020 and beyond, accelerated adoption of energy savings technologies is assumed to take place more than in the Reference Case, including accelerated shipments migration to doored over open units, where applicable, as well as vacuum insulated panels.**
- **The incremental cost of VIPs is assumed to decrease from its present value due to increased R&D funding.**
- **Projected installed costs for this Advanced Case are higher than the Reference Case, even assuming increased R&D funding. Advanced energy-saving technologies are assumed to be made financially viable for operators by increased market incentives such as utility efficiency rebate programs and/or carbon pricing.**
- **This Advanced Case assumes a transition from Hydrofluorocarbons (HFC) to more efficient propane and ammonia refrigerants by 2040.**
- **Advanced Case assumes a 5% reduction in energy use per decade based on technology and efficiency improvements.**

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Performance and Cost Characteristics » Commercial Reach-In Refrigerators

Final

Lower annual energy use, increased installed cost compared with Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[2]	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	2,929	2,400	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349
Size (ft^3)	49	49	46	46	46	47	46	46	46	46	46	46
Annual Energy Use (kWh/y)	2,340	2,222	1,935	1,351	810	810	1,283	770	1,283	770	1,283	770
Annual Energy Use / Volume ($kWh/y/ft^3$)[1]	48	45	42	29	18	17	28	17	28	17	28	17
Indexed Annual Efficiency[3]	1.00	1.05	1.21	1.73	2.89	2.89	1.82	3.04	1.82	3.04	1.82	3.04
Average Life (years)	10	10	10	10	10	10	10	10	10	10	10	10
Retail Equipment Cost (2022$)	$2,624	$2,403	$2,728	$2,780	$3,021	$3,021	$3,058	$3,323	$3,323	$3,364	$3,655	$3,655
Total Installed Cost (2022$)[4]	$3,454	$3,282	$3,591	$3,643	$3,884	$3,884	$3,932	$4,197	$4,197	$4,238	$4,529	$4,529
Total Installed Cost (2022$/kBtu/h)	$1,179	$1,368	$1,529	$1,551	$1,654	$1,654	$1,885	$2,568	$1,885	$2,568	$1,885	$2,568
Annual Maintenance Cost (2022$)[5]	$185	$185	$185	$185	$185	$185	$185	$185	$185	$185	$185	$185
Annual Maintenance Cost (2022$/kBtu/h)	$63	$77	$79	$79	$79	$79	$79	$79	$79	$79	$79	$79

1. EPACT 2005 energy standards went into effect in 2010. 2022 low efficiency cost and energy consumption values are based on minimum compliance with this standard. Unless otherwise noted, all other cases are based on shipment-weighted averages solid- and transparent-doored units reported in the 2014 CRE TSD. DOE's updated Energy Conservation standards went into effect in 2017; therefore, compliance with this standard is assumed for 2022 and beyond.
2. The ENERGY STAR category is based on a shipment weighted average of solid- and transparent-doored units that are minimally compliant with ENERGY STAR v3, effective October 1, 2014. Units compliant with ENERGY STAR are found to be the most efficient reach-in refrigeration equipment on the market in 2022.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Installation cost for 2012 is based on NCI 2009 report that assumes a cost of $863. Installation cost for 2022 and beyond is based DOE's 2014 CRE Final Rule and additional analysis by Guidehouse, which assumes an installation cost of $878 for self-contained equipment.
5. Maintenance costs after 2012 are based on DOE's CRE 2014 Final Rule TSD, which reports $35 annual preventative maintenance, per unit, per year, plus approximately $40 per linear foot, per year of additional repair and maintenance costs for the units characterized.

Performance and Cost Characteristics » Commercial Reach-In Refrigerators

Final

- The Energy Policy Act of 2005 (EPACT 2005) set maximum daily energy consumption levels, in kilowatt-hours per day, for commercial reach-in refrigerators that went into effect on January 1, 2010. The daily energy consumption is based on the volume of the unit (V) in ft^3.
- In 2014, DOE updated its energy conservation standards for reach-in refrigerators, effective March 27, 2017. Both standards are reported in the table below.

Equipment Class	EPCA Standard Level (2010)	DOE Standard Level (2017)
Solid Door (VCS.SC.M)	0.10xV+2.04	0.05xV + 1.36
Glass Door (VCT.SC.M)	0.12xV+3.34	0.1xV+0.86

- In 2013, EPA updated its ENERGY STAR specifications for reach-in refrigerators, effective March 27, 2017. These standards are also based on the refrigerated volume of the unit.

Reach-In Refrigerator Size	0 < V < 15	15 ≤ V < 30	30 ≤ V < 50	50 ≤ V
Solid Door (VCS.SC.M)	0.022xV+0.97	0.066xV+0.31	0.04xV+1.09	0.024xV+1.89
Glass Door (VCT.SC.M)	0.095xV+0.445	0.05xV+1.12	0.076xV+0.034	0.105xV-1.111

- Unit energy consumption for 2012 and beyond was estimated based on shipment-weighted averages by efficiency level and equipment class for 49 ft^3 VCS.SC.M and VCT.SC.M units reported in DOE's 2014 CRE Final Rule TSD with updated analysis from Guidehouse in 2016. These units were estimated to comprise approximately 85% and 15% of total reach-in refrigerator shipments, respectively.
- The efficiency of commercial reach-in refrigerators can be increased through the use of efficient compressors, efficient evaporator fans, efficient condenser fans, electric defrost, and more efficient lighting.
- After 2022, the high efficiency cases are based on solid-doored units rather than shipment-weighted averages due to the assumption that stakeholders will increasingly value energy conservation.
- **Unit energy consumption is expected to decrease as a result of DOE's updated energy conservation standards, as well as a transition to more efficient propane refrigerant due to compliance with EPA Significant New Alternatives Policy (SNAP).**
- **For this Advanced Case, the typical unit in 2020 is assumed to comply with DOE's updated energy conservation standards for commercial refrigeration.**
- **A shipments migration from transparent- to solid-doored units is assumed for the Advanced Case.**
- **By 2040, the adoption of vacuum insulated panels is assumed to occur, with the aid of decreased incremental costs due to increased R&D funding.**
- **Projected installed costs for this Advanced Case are higher than the Reference Case, even assuming increased R&D funding. Advanced energy-saving technologies are assumed to be made financially viable for operators by increased market incentives such as utility efficiency rebate programs and/or carbon pricing.**
- **This analysis finds that with increased R&D and market incentives for energy-efficient technologies, a limit of possible efficiency improvements for self-contained, vapor compression refrigeration systems will be reached by 2040.**

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Performance and Cost Characteristics » Commercial Reach-In Freezers

Final

Lower annual energy use, increased installed cost compared with Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[2]	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	4,341	4,340	4,340	4,340	4,340	4,340	4,340	4,340	4,340	4,340	4,340	4,340
Size (ft^3)	49	49	49	49	49	49	49	49	49	49	49	49
Annual Energy Use (kWh/y)[1]	6,023	5,585	5,585	4,847	4,110	4,110	4,362	3,699	3,926	3,329	3,533	2,996
Annual Energy Use / Volume ($kWh/y/ft^3$)	123	114	114	99	84	84	89	75	80	68	72	61
Indexed Annual Efficiency[3]	1.00	1.08	1.08	1.24	1.47	1.47	1.38	1.63	1.53	1.81	1.70	2.01
Average Life (years)	10	10	10	10	10	10	10	10	10	10	10	10
Retail Equipment Cost (2022$)	$2,886	$2,886	$2,886	$3,175	$3,493	$3,493	$3,493	$3,842	$3,842	$4,226	$4,226	$4,649
Total Installed Cost (2022$)[4]	$3,749	$3,749	$3,749	$4,125	$4,443	$4,443	$4,443	$4,792	$4,792	$5,176	$5,176	$5,599
Total Installed Cost (2022$/kBtu/h)	$864	$864	$864	$950	$1,024	$1,024	$1,024	$1,104	$1,104	$1,193	$1,193	$1,290
Annual Maintenance Cost (2022$)[5]	$181	$181	$181	$181	$181	$181	$181	$181	$181	$181	$181	$181
Annual Maintenance Cost (2022$/kBtu/h)	$41.70	$41.71	$41.71	$41.71	$41.71	$41.71	$41.71	$41.71	$41.71	$41.71	$41.71	$41.71

1. A 49 ft^3 unit was characterized, because it was the representative size selected for DOE's rulemaking analysis.
2. The ENERGY STAR category was based on a solid-doored unit that is minimally compliant with ENERGY STAR v3, effective October 1, 2014.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Installation cost for 2012 and 2018 is based on DOE's on-going CRE rulemaking, which assumes a cost of $863 for self-contained equipment and $950 for 2022 and beyond based on analysis from Guidehouse.
5. Maintenance costs are calculated based on a $35 per unit annual preventative maintenance cost, plus an additional $45 per linear foot repair and maintenance cost estimated based on values reported in the CRE TSD.

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Performance and Cost Characteristics » Commercial Reach-In Freezers

Final

- EPACT 2005 set maximum daily energy consumption levels, in kilowatt-hours per day, for commercial reach-in freezers that went into effect on January 1, 2010. The daily energy consumption is based on the volume of the unit (V) in ft^3.
- In March of 2017, DOE updated its energy conservation standards for commercial refrigeration equipment, including reach-in freezers. Both the EPCA and DOE standards are reported in the table below.

Equipment Class	EPCA (2010)	DOE Standard Level (2017)
Solid Door (VCS.SC.L)	0.4xV+1.38	0.22xV+1.38
Transparent Door (VCT.SC.L)	0.75xV+4.10	0.29xV+2.95

- In 2013, EPA updated its ENERGY STAR specifications for reach-in freezers, effective March 27, 2017. These standards are also based on the refrigerated volume of the unit.

Reach-In Freezer Size	0 < V < 15	15 ≤ V < 30	30 ≤ V < 50	50 ≤ V
Solid Door (VCS.SC.L)	0.21xV+0.9	0.12xV+2.248	0.285xV-2.703	0.142xV+4.445
Glass Door (VCT.SC.L)	0.232xV+2.36	0.232xV+2.36	0.232xV+2.36	0.232xV+2.36

Final

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Performance and Cost Characteristics » Commercial Reach-In Freezers

- The commercial reach-in freezer characterized in this report, which is the typical unit according to DOE's 2014 CRE rulemaking, is a 49 cubic ft. solid two-door unit with a nominal compressor size of 4,341 Btu/h.
- The efficiency of commercial reach-in freezers can be increased through the use of efficient compressors, efficient evaporator fans, efficient condenser fans, electric defrost, and more efficient lighting.
- **Unit energy consumption for reach-in freezers is expected to decrease as a result of DOE's updated energy conservation standards, as well as a transition to more efficient propane refrigerant due to EPA SNAP compliance.**
- **The typical unit in 2020 is assumed to comply with DOE's updated energy conservation standards for commercial refrigeration.**
- **By 2040, the adoption of vacuum insulated panels is assumed to occur, with the aid of decreased incremental costs due to increased R&D funding.**
- **Projected installed costs for this Advanced Case are higher than the Reference Case, even assuming increased R&D funding. Advanced energy-saving technologies are assumed to be made financially viable for operators by increased market incentives such as utility efficiency rebate programs.**
- **This analysis finds that with increased R&D and market incentives for energy-efficient technologies, a limit of possible efficiency improvements for self-contained, vapor compression refrigeration systems will be reached by 2040.**

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Performance and Cost Characteristics » Commercial Walk-In Refrigerators

Final

Lower annual energy use compared with Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/hr)[1]	37,820	39,422	41,024	41,024	41,024	N/A	41,024	41,024	41,024	41,024	41,024	41,024
Size (ft^2)	305	240	240	240	240	N/A	240	240	240	240	240	240
Annual Energy Use (kWh/yr)[2]	30,689	20,040	17,600	16,200	14,800	N/A	14,580	13,320	13,122	11,988	11,810	10,789
Annual Energy Use / Area ($kWh/ft^2/yr$)	101	84	73	68	62	N/A	61	56	55	50	49	45
Indexed Annual Efficiency[3]	1.00	1.53	1.74	1.89	2.07	N/A	2.10	2.30	2.34	2.56	2.60	2.84
Insulated Box Average Life (yrs)	12	12	12	12	12	N/A	12	12	12	12	12	12
Compressor Average Life (yrs)	10	10	10	10	10	N/A	10	10	10	10	10	10
Retail Equipment Cost (2022$)	$23,598	$19,847	$16,050	$19,847	$23,644	N/A	$16,050	$23,644	$16,050	$23,644	$16,050	$23,644
Total Installed Cost (2022$)[4]	$27,012	$23,897	$20,100	$23,897	$27,694	N/A	$20,100	$27,694	$20,100	$27,694	$20,100	$27,694
Total Installed Cost (2022$/kBtu/hr)	$714	$606	$490	$583	$675	N/A	$490	$675	$490	$675	$490	$675
Annual Maintenance Cost (2022$)[5]	$716	$740	$740	$740	$740	N/A	$740	$740	$740	$740	$740	$740
Annual Maintenance Cost (2022$/kBtu/hr)	$18.93	$18.77	$18.04	$18.04	$18.04	N/A	$18.04	$18.04	$18.04	$18.04	$18.04	$18.04

1. Assumes medium temperature units are refrigerators.
2. Average unit energy consumption was adapted from the DOE CRE 2016 report by assuming electronically commutated motor (ECM) evaporator fan motors are required for Energy Policy & Conservation Act (EPCA) compliance, as well as ECM condenser fan motors.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Installation cost for 2012 and beyond is based on DOE's Walk-In Technical Support Document (TSD).
5. Maintenance cost includes checking and maintaining refrigerant charge levels, checking settings, and cleaning heat exchanger coils.

Performance and Cost Characteristics » Commercial Walk-In Refrigerators

Final

- For 2012 and beyond, the unit characterized was a walk-in storage cooler, based on DOE's WICF TSD.
- A typical walk-in refrigerator includes:
  - insulated floor and wall panels
  - merchandising doors, shelving, and lighting (not included in cost estimate)
  - semi-hermetic reciprocating compressor
  - refrigerant (R404A)
  - condenser
  - evaporator
- Energy consumption is assumed to scale with the AWEF (Annual Walk-in Energy Factor), defined as the ratio of total heat removed from the refrigerated volume per year to the total electrical energy input of refrigeration systems over the same time period.
- The installation cost consists of freight and delivery costs in addition to on-site assembly.
- **This Advanced Case assumes a projected 10% decrease in energy consumption over the Reference Case due to adoption of more efficient refrigerants.**

The Energy Independence and Security Act (EISA) of 2007 included prescriptive standards for walk-in refrigerators (coolers) that went into effect in 2009. These prescriptive standards, which are included in the analysis for all units for 2012 and beyond, state that all walk-in refrigerators manufactured after January 1, 2009, must:

- For 2012 and beyond
- have automatic door closers
- have strip doors, spring hinged doors, or other method of minimizing infiltration when doors are open
- contain wall, ceiling, and door insulation of at least R–25, except for glazed portions of doors and structural members
- use electronically commutated motors or three-phase motors (for evaporator fan motors of under 1 horsepower and less than 460 volts)
- use electronically commutated motors, permanent split capacitor-type motors, or three-phase motors (for condenser fan motors of under 1 horsepower)
- use light sources with an efficacy of 40 lumens per watt or more, including ballast losses (if any), except that light sources with an efficacy of 40 lumens per watt or less, including ballast losses (if any), may be used in conjunction with a timer or device that turns off the lights within 15 minutes of when the walk-in refrigerator is not occupied by people.

In 2014, DOE updated its energy conservation standards for walk-in coolers and freezers. Minimum AWEF (Annual Walk-In Energy Factor) was set for refrigeration systems, as well as upper limits on energy consumption attributable to passage, freight, and display doors. DOE elected not to set new standards for the R-value of Walk-In Panels.

ENERGY CONSERVATION STANDARDS FOR WALK-IN COOLERS AND WALK-IN FREEZERS

Class descriptor	Class	Standard level
Refrigeration Systems Minimum AWEF (Btu/W-h)		
Dedicated Condensing, Medium Temperature, Indoor System, <9,000 Btu/h Capacity	DC.M.I, <9,000	5.61
Dedicated Condensing, Medium Temperature, Indoor System, ≥9,000 Btu/h Capacity	DC.M.I, ≥9,000	5.61
Dedicated Condensing, Medium Temperature, Outdoor System, <9,000 Btu/h Capacity	DC.M.O, <9,000	7.60
Dedicated Condensing, Medium Temperature, Outdoor System, ≥9,000 Btu/h Capacity	DC.M.O,≥9,000	7.60
Dedicated Condensing, Low Temperature, Indoor System, <9,000 Btu/h Capacity	DC.L.I, <9,000	$5.93 \cdot 10^{-5} \cdot Q + 2.33$
Dedicated Condensing, Low Temperature, Indoor System, ≥9,000 Btu/h Capacity	DC.L.I, ≥9,000	3.10
Dedicated Condensing, Low Temperature, Outdoor System, <9,000 Btu/h Capacity	DC.L.O, <9,000	$2.30 \cdot 10^{-4} \cdot Q + 2.73$
Dedicated Condensing, Low Temperature, Outdoor System, ≥9,000 Btu/h Capacity	DC.L.O, ≥9,000	4.79
Multiplex Condensing, Medium Temperature	MC.M	10.89
Multiplex Condensing, Low Temperature	MC.L	6.57
Panels Minimum R-value (h-ft2-°F/Btu)		
Structural Panel, Medium Temperature	SP.M	25
Structural Panel, Low Temperature	SP.L	32
Floor Panel, Low Temperature	FP.L	28
Non-Display Doors Maximum energy consumption (kWh/day) **		
Passage Door, Medium Temperature	PD.M	$0.05 \cdot A_{nd} + 1.7$
Passage Door, Low Temperature	PD.L	$0.14 \cdot A_{nd} + 4.8$
Freight Door, Medium Temperature	FD.M	$0.04 \cdot A_{nd} + 1.9$
Freight Door, Low Temperature	FD.L	$0.12 \cdot A_{nd} + 5.6$
Display Doors Maximum Energy Consumption (kWh/day) †		
Display Door, Medium Temperature	DD.M	$0.04 \cdot A_{dd} + 0.41$
Display Door, Low Temperature	DD.L	$0.15 \cdot A_{dd} + 0.29$

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Performance and Cost Characteristics » Commercial Walk-In Freezers

Final

Lower annual energy use compared with Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	22,114	23,500	23,500	23,500	23,500	N/A	23,500	23,500	23,500	23,500	23,500	23,500
Size (ft^2) [1]	172	161	161	161	161	N/A	161	161	161	161	161	161
Annual Energy Use (kWh/y)[2]	22,862	17,600	21,400	21,400	21,400	N/A	19,260	19,260	17,334	17,334	15,601	15,601
Annual Energy Use / Area ($kWh/ft^2/y$)	133	109	133	133	133	N/A	120	120	108	108	97	97
Indexed Annual Efficiency[3]	1.00	1.30	1.07	1.07	1.07	N/A	1.19	1.19	1.32	1.32	1.47	1.47
Insulated Box Average Life (years)	12	12	12	12	12	N/A	12	12	12	12	12	12
Compressor Average Life (years)	10	10	10	10	10	N/A	10	10	10	10	10	10
Retail Equipment Cost (2022$)	$22,008	$21,950	$21,950	$22,850	$23,750	N/A	$22,850	$23,750	$22,850	$23,750	$22,850	$23,750
Total Installed Cost (2022$)[4]	$24,058	$23,950	$23,950	$24,850	$25,750	N/A	$24,850	$25,750	$24,850	$25,750	$24,850	$25,750
Total Installed Cost (2022$/kBtu/h)	$1,088	$1,019	$1,019	$1,057	$1,096	N/A	$1,057	$1,096	$1,057	$1,096	$1,057	$1,096
Annual Maintenance Cost (2022$)[5]	$741	$741	$741	$740	$741	N/A	$740	$741	$740	$741	$740	$741
Annual Maintenance Cost (2022$/kBtu/h)	$33.51	$31.53	$31.53	$31.49	$31.53	N/A	$31.49	$31.53	$31.49	$31.53	$31.49	$31.53

1. Based on DOE's 2014 WICF Final Rule TSD and additional analysis by Guidehouse, the average floor area for a walk-in storage freezer as 161 ft^2.
2. EISA 2007 includes prescriptive standards for walk-in freezers that went into effect in 2009. All units for 2012 and beyond include these prescriptive standards. Units for 2022 and beyond are characterized using data from DOE's 2014 WICF rulemaking. All units for 2022 and beyond are assumed to comply with this standard.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Installation cost for 2012 and beyond is based on DOE's WICF TSD and additional analysis by Guidehouse.
5. Maintenance cost includes checking and maintaining refrigerant charge levels, checking settings, and cleaning heat exchanger coils.

- The commercial walk-in freezer characterized in this report is a walk-in storage freezer with an area of 161 ft^2.
- A typical walk-in freezer includes:
  - insulated floor, door, and wall panels
  - semi-hermetic reciprocating compressor
  - refrigerant (R404A)
  - condenser
  - evaporator
- Energy consumption is assumed to scale with the AWEF (Annual Walk-in Energy Factor), defined as the ratio of total heat removed from the refrigerated volume per year to the total electrical energy input of refrigeration systems over the same time period.
- The installation cost consists of freight and delivery costs in addition to on-site assembly.
- **This Advanced Case assumes a projected 10% decrease in energy consumption over the Reference Case due to adoption of more efficient refrigerants.**

EISA 2007 included prescriptive standards for walk-in freezers that went into effect in 2009. These prescriptive standards, which are included in all units for 2011 and beyond, state that all walk-in freezers manufactured after January 1, 2009, must:

- have automatic door closers
- have strip doors, spring hinged doors, or other method of minimizing infiltration when doors are open
- contain wall, ceiling, and door insulation of at least R–32, except for glazed portions of doors and structural members
- contain floor insulation of at least R–28
- use electronically commutated motors or three-phase motors (for evaporator fan motors of under 1 horsepower and less than 460 volts)
- use electronically commutated motors, permanent split capacitor-type motors, or three-phase motors (for condenser fan motors of under 1 horsepower)
- use light sources with an efficacy of 40 lumens per watt or more, including ballast losses (if any), except that light sources with an efficacy of 40 lumens per watt or less, including ballast losses (if any), may be used in conjunction with a timer or device that turns off the lights within 15 minutes of when the walk-in freezer is not occupied by people.

In 2014, DOE updated its energy conservation standards for walk-in coolers and freezers. Minimum AWEF (Annual Walk-in Energy Factor) was set for refrigeration systems, as well as upper limits on energy consumption attributable to passage, freight, and display doors. DOE elected not to set new standards for the R-value of Walk-in Panels.

ENERGY CONSERVATION STANDARDS FOR WALK-IN COOLERS AND WALK-IN FREEZERS

Class descriptor	Class	Standard level
Refrigeration Systems Minimum AWEF (Btu/W-h)		
Dedicated Condensing, Medium Temperature, Indoor System, <9,000 Btu/h Capacity	DC.M.I, <9,000	5.61
Dedicated Condensing, Medium Temperature, Indoor System, ≥9,000 Btu/h Capacity	DC.M.I, ≥9,000	5.61
Dedicated Condensing, Medium Temperature, Outdoor System, <9,000 Btu/h Capacity	DC.M.O, <9,000	7.60
Dedicated Condensing, Medium Temperature, Outdoor System, ≥9,000 Btu/h Capacity	DC.M.O,≥9,000	7.60
Dedicated Condensing, Low Temperature, Indoor System, <9,000 Btu/h Capacity	DC.L.I, <9,000	$5.93 \cdot 10^{-5} \cdot Q + 2.33$
Dedicated Condensing, Low Temperature, Indoor System, ≥9,000 Btu/h Capacity	DC.L.I, ≥9,000	3.10
Dedicated Condensing, Low Temperature, Outdoor System, <9,000 Btu/h Capacity	DC.L.O, <9,000	$2.30 \cdot 10^{-4} \cdot Q + 2.73$
Dedicated Condensing, Low Temperature, Outdoor System, ≥9,000 Btu/h Capacity	DC.L.O, ≥9,000	4.79
Multiplex Condensing, Medium Temperature	MC.M	10.89
Multiplex Condensing, Low Temperature	MC.L	6.57
Panels Minimum R-value (h-ft2-°F/Btu)		
Structural Panel, Medium Temperature	SP.M	25
Structural Panel, Low Temperature	SP.L	32
Floor Panel, Low Temperature	FP.L	28
Non-Display Doors Maximum energy consumption (kWh/day) **		
Passage Door, Medium Temperature	PD.M	$0.05 \cdot A_{nd} + 1.7$
Passage Door, Low Temperature	PD.L	$0.14 \cdot A_{nd} + 4.8$
Freight Door, Medium Temperature	FD.M	$0.04 \cdot A_{nd} + 1.9$
Freight Door, Low Temperature	FD.L	$0.12 \cdot A_{nd} + 5.6$
Display Doors Maximum Energy Consumption (kWh/day) †		
Display Door, Medium Temperature	DD.M	$0.04 \cdot A_{dd} + 0.41$
Display Door, Low Temperature	DD.L	$0.15 \cdot A_{dd} + 0.29$

Performance and Cost Characteristics » Commercial Ice Machines

Final

Lower annual energy use compared with Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[6]	Typical	High	Typical	High	Typical	High
Output (pounds [lbs] per day)[1]	300	641	700	700	700	700	700	700	700	700	700	700
Cooling Capacity (Btu/h)[2]	1963	4194	4580	4580	4580	4580	4580	4580	4580	4580	4580	4580
Water Use per Hundred Pounds (gal/hundred lbs)[3]	20	25	25	20	15	15	20	15	20	15	20	15
Energy Use per Hundred Pounds (kWh/hundred lbs)	7.7	7.5	7.1	5.8	4.8	4.8	5.8	4.8	5.8	4.8	5.8	4.8
Annual Energy Use (kWh/y)[4]	3,185	2,502	1,675	1,478	1,190	1,190	1,330	1,071	1,197	964	1,077	868
Indexed Annual Efficiency[5]	1.00	1.27	1.90	2.15	2.68	2.68	2.39	2.97	2.66	3.30	2.96	3.67
Average Life (years)	8.0	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
Retail Equipment Cost (2022$)	$2,146	$2,616	$2,946	$3,020	$3,368	$3,368	$3,020	$3,368	$3,020	$3,368	$3,020	$3,368
Total Installed Cost (with Bin)	$2,441	$3,626	$3,276	$3,350	$3,737	$3,737	$3,350	$3,737	$3,350	$3,737	$3,350	$3,737
Total Installed Cost (2022$/kBtu/h)	$1,244	$865	$715	$732	$816	$816	$732	$816	$732	$816	$732	$816
Annual Maintenance Cost (2022$)[7]	$826	$826	$800	$800	$800	$800	$800	$800	$800	$800	$800	$800
Annual Maintenance Cost (2022$/kBtu/h)	$421	$197	$175	$175	$175	$175	$175	$175	$175	$175	$175	$175

1. Based on the average output from the Compliance Certification Database and values within 2022 Automatic Commercial Ice Maker (ACIM) TSD.
2. Defined as the average heat load to remove the latent and sensible heat required to freeze the daily output capacity of ice.
3. Water use refers to potable water.
4. EPACT 2005 energy standards went into effect in 2010. The 2015 low values are based on this standard. In 2014, DOE set new standards for commercial ice machines, with compliance required by 2018. The unit characterized for 2012 and beyond uses data from this rulemaking. All units for 2020 and beyond are assumed to comply with the updated standard.
5. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
6. The ENERGY STAR category is based on minimum compliance with the ENERGY STAR v3.0 standard, which went into effect on January 28, 2018. According to this analysis, ENERGY STAR certification is typical for the small air-cooled ice-making head (IMH) unit characterized.
7. Maintenance cost is based on the average cost of equipment within the 700 lb/day output range and includes cleaning and maintaining refrigerant levels, replacing filters, checking water distribution lines for leaks, cleaning, sanitizing, and descaling the bin and water system. Maintenance cost decreases as the size of the ice machine (i.e. output) decreases.

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Performance and Cost Characteristics » Commercial Ice Machines

Final

- Commercial ice machines are typically integrated with an insulated ice storage bin or mounted on top of a separate storage bin. The retail equipment cost includes the ice making head and the integrated storage bin. Commercial ice machine condensers are either air-cooled or water-cooled. Approximately 90% of all units are the air-cooled type.
- Commercial ice machine maintenance includes periodic cleaning (every 2 to 6 weeks) to remove lime and scale and sanitizing to kill bacteria. Some ice machines are self-cleaning/sanitizing.
- ENERGY STAR® updated its maximum energy consumption levels, in kilowatt-hours per 100 pounds of ice, for air-cooled ice machines that went into effect on January 28, 2018. These efficiency levels are based on the harvest rate, in pounds per 24 hours. (H). Water-cooled ice machines are not eligible for ENERGY STAR certification.
- **For this Advanced Case, a 10% reduction in energy consumption is projected over the Reference Case due to the adoption of more efficient refrigerants such as propane, which, while not currently required by EPA SNAP, are a source of possible efficiency improvements.**

ENERGY STAR Requirements for Air-Cooled Batch-Type Ice Makers

Equipment Type	Applicable Ice Harvest Rate Range (lbs of ice/24 hrs)	Energy Consumption Rate (kWh/100 lbs ice)	Potable Water Use (gal/hundred lbs ice)
IMH	$200 \le H \le 1600$	$\le 37.72 * H^{-0.298}$	≤ 20.0
RCU	$400 \le H \le 1600$	$\le 22.95 * H^{-0.258} + 1.00$	≤ 20.0
	$1600 \le H \le 4000$	$\le -0.00011 * H + 4.60$	≤ 20.0
SCU	$50 \le H \le 450$	$\le 48.66 * H^{-0.326} + 0.08$	≤ 25.0

ENERGY STAR Requirements for Air-Cooled Continuous-Type Ice Makers

Equipment Type	Energy Consumption Rate (kWh/hundred lbs ice)	Potable Water Use (gal/hundred lbs ice)
IMH	$\le 9.18 * H^{-0.057}$	≤ 15.0
RCU	$\le 6.00 * H^{-0.162} + 3.50$	≤ 15.0
SCU	$\le 59.45 * H^{-0.349} + 0.08$	≤ 15.0

Performance and Cost Characteristics » Commercial Ice Machines

Final

EPACT 2005 issued standard levels for commercial ice machines with capacities between 50 pounds and 2500 pounds per 24-hour period that are manufactured or sold in the United States on or after January 1, 2010. The energy consumption is based on the harvest rate in pounds per 24 hours (H). In 2015, DOE finalized new standards for ACIMs extending coverage to flake, nugget, and tube-type machines and to capacities up to 4,000 pounds per 24 hours.

Equipment Type	Type of Cooling	Harvest Rate (lbs ice/24 hrs)	Maximum Energy Use (kWh/hundred lbs ice)	Maximum Condenser Water Use (gal/hundred lbs ice)
Ice Making Head	Water	<500	7.80-0.0055 H	200-0.022 H
		≥500 and <1,436	5.58-0.0011 H	200-0.022 H
		≥1,436	4.0	200-0.022 H
	Air	<450	10.26-0.0086 H	Not Applicable
		≥450	6.89-0.0011 H	Not Applicable
Remote Condensing (but not remote compressor)	Air	<1,000	8.85-0.0038 H	Not Applicable
		≥1,000	5.10	Not Applicable
Remote Condensing and Remote Compressor	Air	<934	8.85-0.0038 H	Not Applicable
		≥934	5.3	Not Applicable
Self Contained	Water	<200	11.40-0.019 H	191-0.0315 H
		≥200	7.60	191-0.0315 H
	Air	<175	18.0-0.0469 H	Not Applicable
		≥175	9.80	Not Applicable

Water use is for the condenser only and does not include potable water used to make ice.

2014 DOE Standards

Energy Conservation Standards for Batch-Type Automatic Commercial Ice Makers
Effective January 2018

Equipment Type	Type of Cooling	Harvest Rate lb ice/24 hours	Maximum Energy Use kWh/100 lb ice*	Maximum Condenser Water Use gal/100 lb ice**
Ice-Making Head	Water	<300	6.88 - 0.0055H	200 - 0.022H
		300 and <850	5.80 - 0.00191H	200 - 0.022H
		850 and <1,500	4.42 - 0.00028H	200 - 0.022H
		1500 and <2,500	4.0	200 - 0.022H
		2500 and <4,000	4.0	145
Ice-Making Head	Air	<300	10 - 0.01233H	Not Applicable
		300 and <800	7.05 - 0.0025H	Not Applicable
		800 and <1500	5.55 - 0.00063H	Not Applicable
		1500 and <4,000	4.61	Not Applicable
Remote Condensing (but not remote compressor)	Air	50 and <1,000	7.97 - 0.00342H	Not Applicable
		1,000 and <4,000	4.55	Not Applicable
Remote Condensing and Remote Compressor	Air	<942	7.97 - 0.00342H	Not Applicable
		942 and <4,000	4.75	Not Applicable
Self-Contained	Water	<200	9.5 - 0.019H	191 - 0.0315H
		200 and <2,500	5.7	191 - 0.0315H
		2500 and <4,000	5.7	112
Self-Contained	Air	<110	14.79 - 0.0469H	Not Applicable
		110 and <200	12.42 - 0.02533H	Not Applicable
		200 and <4,000	7.35	Not Applicable

Energy Conservation Standards for Continuous-Type Automatic Commercial Ice Makers
Effective January 2018

Equipment Type	Type of Cooling	Harvest Rate lb ice/24 hours	Maximum Energy Use kWh/100 lb ice*	Maximum Condenser Water Use gal/100 lb ice**
Ice-Making Head	Water	<801	6.48 - 0.00267H	180 - 0.0198H
		801 and <2,500	4.34	180 - 0.0198H
		2,500 and <4,000	4.34	130.5
Ice-Making Head	Air	<310	9.19 - 0.00629H	Not Applicable
		310 and <820	8.23 - 0.0032H	Not Applicable
		820 and <4,000	5.61	Not Applicable
Remote Condensing (but not remote compressor)	Air	<800	9.7 - 0.0058H	Not Applicable
		800 and <4,000	5.06	Not Applicable
Remote Condensing and Remote Compressor	Air	<800	9.9 - 0.0058H	Not Applicable
		800 and <4,000	5.26	Not Applicable
Self-Contained	Water	<900	7.6 - 0.00302H	153 - 0.0252H
		900 and <2,500	4.88	153 - 0.0252H
		2500 and <4,000	4.88	90
Self-Contained	Air	<200	14.22 - 0.03H	Not Applicable
		200 and <700	9.47 - 0.00624H	Not Applicable
		700 and <4,000	5.1	Not Applicable

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Performance and Cost Characteristics » Commercial Beverage Merchandisers

Final

Lower annual energy use compared with Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[2]	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	4,689	4,700	4,700	4,700	4,700	4,700	4,700	4,700	4,700	4,700	4,700	4,700
Size (ft^3)	27	27	27	27	27	27	27	27	27	27	27	27
Annual Energy Use (kWh/y)	1,829	1,635	1,380	1,141	902	902	1,141	902	1,084	857	1,030	814
Annual Energy Use / Volume ($kWh/ft^3/y$)[1]	68	73	55	35	26	26	35	26	35	26	35	26
Indexed Annual Efficiency[3]	1.00	1.12	1.33	1.60	2.03	2.03	1.60	2.03	1.69	2.13	1.78	2.25
Average Life (years)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Retail Equipment Cost (2022$)	$2,382	$2,051	$1,710	$2,762	$3,332	$3,332	$2,762	$3,332	$2,762	$3,332	$2,762	$3,332
Total Installed Cost (2022$)[4]	$2,382	$2,051	$1,710	$2,762	$3,332	$3,332	$2,762	$3,332	$2,762	$3,332	$2,762	$3,332
Total Installed Cost (2022$/kBtu/h)	$508	$436	$364	$588	$709	$709	$588	$709	$588	$709	$588	$709
Annual Maintenance Cost (2022$)	$108	$108	$95	$95	$95	$95	$95	$95	$95	$95	$95	$95
Annual Maintenance Cost (2022$/kBtu/h)	$23.03	$22.98	$20.21	$20.21	$20.11	$20.11	$20.21	$20.11	$20.21	$20.11	$20.21	$20.11

1. EPACT 2005 energy conservation standards went into effect in 2010. In 2015, DOE updated its energy conservation standards for commercial refrigeration equipment, including transparent-doored refrigerators with pull-down capability. Compliance with this standard is required by 2017. Units characterized for 2018 and beyond use data reported in this rulemaking's TSD. Units sold in 2022 and beyond are assumed to comply with this updated standard.
2. The ENERGY STAR category characterizes a unit that is compliant with ENERGY STAR v4, effective March 2017. This standard does not separately define units with pull-down capability.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Beverage merchandisers are shipped ready to be plugged in, so installation costs are assumed to be negligible.

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Performance and Cost Characteristics » Commercial Beverage Merchandisers

Final

- EPACT 2005 sets maximum daily energy consumption levels, in kilowatt-hours per day, for commercial refrigerators with transparent doors and self-contained condensing unit designed for pull-down temperature applications (i.e., beverage merchandisers) and went into effect on January 1, 2010.
- In 2014, DOE updated its energy consumption standards for commercial refrigeration equipment, including beverage merchandisers, effective March 27, 2015. Both the DOE and EPCA standards are reported below.

Equipment Type	EPCA (2010)	DOE Standards (2017)
Beverage Merchandisers (PD.SC.M)	0.126xV + 3.51	0.11xV+0.81

- In 2013, EPA updated its ENERGY STAR specifications for glass-doored commercial refrigerators, which can be used as beverage merchandisers, effective October 1, 2014. These standards are also based on the volume of the unit (V). Note that ENERGY STAR does not have a separate equipment class for units with pull-down capability.

Beverage Merchandiser Size	0 < V < 15	15 ≤ V < 30	30 ≤ V < 50	50 ≤ V
Glass Door	0.118*V + 1.382	≤ 0.140*V + 1.050	≤ 0.088*V + 2.625	≤ 0.110*V + 1.500

Performance and Cost Characteristics » Commercial Beverage Merchandisers

Final

- The beverage merchandiser characterized in this report, which is the typical unit according to DOE's 2014 CRE rulemaking and additional analysis by Guidehouse, is a 27 cubic foot cooler with a single hinged, transparent door, bright lighting, and shelving with a nominal compressor size of 4,700 Btu/h.
- The efficiency of beverage merchandisers can be increased through the use of more efficient compressors, fluorescent lighting with electronic ballasts, LED lighting, and improved insulation.
- For the Reference Case, beverage merchandisers are assumed to be mature technologies with few technology advancements in the coming years that would dramatically improve the efficiency.
- **For this Advanced Case, the typical unit in 2030 is assumed to comply with DOE's updated energy conservation standards for commercial refrigeration**
- **By 2040, the adoption of vacuum insulated panels is assumed to occur, with the aid of decreased incremental costs due to increased R&D funding**
- **Beverage merchandisers may transition from HFC to more efficient propane.**
- **Projected installed costs for this Advanced Case are the same as the Reference Case, assuming increased R&D funding. Advanced energy-saving technologies are assumed to be made financially viable for operators by increased market incentives such as utility efficiency rebate programs and/or carbon pricing.**
- **This analysis finds that with increased R&D and market incentives for energy efficiency technologies, a limit of possible efficiency improvements for self-contained, vapor compression refrigeration systems will be reached by 2040 and a 5% decrease in energy use from 2030 to 2040.**

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Performance and Cost Characteristics » Commercial Refrigerated Vending Machines

Final

Lower annual energy use compared with Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[2]	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	1,810	1,707	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810
Can Capacity	470	500	500	500	500	500	500	500	500	500	500	500
Size (ft^3)	26	35	35	35	35	35	35	35	35	35	35	35
Annual Energy Use (kWh/y)[1]	1,632	1,550	1,550	1,531	1,443	1,443	1,455	1,371	1,382	1,302	1,313	1,237
Annual Energy Use / Volume ($kWh/ft^3/y$)	63	44	44	44	41	41	42	39	39	37	38	35
Indexed Annual Efficiency[3]	1.00	1.05	1.05	1.07	1.13	1.13	1.12	1.19	1.18	1.25	1.24	1.32
Average Life (years)	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Retail Equipment Cost (2022$)	$3,209	$2,553	$3,059	$3,272	$3,520	$3,520	$3,272	$3,520	$3,272	$3,520	$3,272	$3,520
Total Installed Cost (2022$)	$3,320	$2,705	$3,276	$3,489	$3,737	$3,737	$3,489	$3,737	$3,489	$3,737	$3,489	$3,737
Total Installed Cost (2022$/kBtu/h)	$1,834	$1,585	$1,810	$1,928	$2,065	$2,065	$1,928	$2,065	$1,928	$2,065	$1,928	$2,065
Annual Maintenance Cost (2022$)[4]	$270	$270	$333	$333	$333	$333	$333	$333	$333	$333	$333	$333
Annual Maintenance Cost (2022$/kBtu/h)	$149	$149	$184	$184	$184	$184	$184	$184	$184	$184	$184	$184

1. Energy use for 2018 and beyond is estimated based on DOE's 2020 BVM Final Rule and the 2022 Compliance Certification Database.
2. The ENERGY STAR category assumes units are compliant with the ENERGY STAR v4 standard because combination units are currently not separately defined by ENERGY STAR. This standard went into effect on April 29, 2020. Our analysis finds ENERGY STAR certified equipment to be the most efficient currently available on the market.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Maintenance cost includes preventative maintenance costs such as checking and maintaining refrigerant charge levels, cleaning heat exchanger coils, and an annualized cost for refurbishments/remanufacturing.

Performance and Cost Characteristics » Commercial Refrigerated Vending Machines

Final

- DOE set federal energy efficiency standards for refrigerated vending machines. These standards set maximum daily energy consumption levels, in kilowatt-hours per day, for commercial refrigerated vending machines manufactured or sold in the United States on or after August 31, 2012. The daily energy consumption is based on the volume of the unit (V).
- In December 2015, DOE updated its energy conservation standards for beverage vending machines and defined two new product classes for combination vending machines. The energy conservation standard remains the same in the updated 2022 technical support document for vending machines. Compliance with these standards was required by 2019. For this analysis, compliance with these updated standards is assumed for equipment sold in 2022 and beyond. The updated standards and DOE equipment definitions are listed in the table below.

Equipment Type	Maximum Daily Energy Consumption
Class A (Transparent-Front)	MDEC= 0.052 × V + 2.43
Class B (Solid-Front)	MDEC = 0.052 × V + 2.20
Combination A	MDEC = 0.086 × V + 2.66
Combination B	MDEC = 0.111 × V + 2.04

ENERGY STAR® updated its maximum daily energy consumption efficiency levels, also in kilowatt-hours per day, for refrigerated vending machines that went into effect on April 29, 2020. These efficiency levels are based on refrigerated volume.

Equipment Class	Maximum daily energy consumption (kilowatt-hours per day)
Class A – a refrigerated bottled or canned beverage vending machine that is not a combination vending machine and in which 25% or more of the surface area on the front side of the beverage vending machine is transparent	MDEC = 0.04836 x V + 2.2599
Class B – any refrigerated bottled or canned beverage vending machine that is not considered to be Class A and is not a combination vending machine	MDEC = 0.04576 x V+1.936
Combination A – a combination vending machine where 25% or more of the surface area on the front side of the beverage vending machine is transparent	MDEC = 0.07998 x V + 2.4738
Combination B – a combination vending machine that is not considered to be Combination A	MDEC = 0.09768 x V + 1.7952

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Performance and Cost Characteristics » Commercial Refrigerated Vending Machines

Final

- DOE set federal energy efficiency standards for refrigerated vending machines in 2009. These standards set maximum daily energy consumption levels, in kWh/day, for commercial refrigerated vending machines manufactured and/or sold in the United States on or after August 31, 2012. The daily energy consumption is based on the volume of the unit (V).
  - Refrigerated Vending Machines that are fully-cooled (Type A) $\leq 0.055*V + 2.56$
  - Refrigerated Vending Machines that are zone-cooled (Type B) $\leq 0.073*V + 3.16$
- ENERGY STAR® updated its maximum daily energy consumption efficiency levels, also in kWh/day, for refrigerated vending machines, which went into effect on March 1, 2013. These efficiency levels are based on refrigerated volume.

Equipment Type	Maximum Daily Energy Consumption	Low Power Mode Requirement
Class A (Transparent-Front)	MDEC= 0.0523 x V + 2.432	Hard-wired controls and/or software capable of placing the machine into a low power mode during periods of extended inactivity while still connected to its power source
Class B (Solid-Front)	MDEC = 0.0657 x V + 2.844	

- **Currently, stakeholders such as Coca Cola have indicated a preference for CO_2 refrigerant, which is less efficient. However, this Advanced Case scenario assumes a shift to more efficient propane for cost and energy consumption projections due to the superior efficiency of propane refrigerant.**
- **By 2040, the adoption of vacuum insulated panels is assumed to occur, with the aid of decreased incremental costs due to increased R&D funding**
- **Projected installed costs for this Advanced Case are higher than the Reference Case, even assuming increased R&D funding. Advanced energy-saving technologies are assumed to be made financially viable for operators by increased market incentives such as utility efficiency rebate programs and/or carbon pricing.**
- **This analysis finds that with increased R&D and market incentives for energy efficiency technologies, a limit of possible efficiency improvements for self-contained, vapor compression refrigeration systems will be reached by 2040.**

In December 2015, DOE updated its energy conservation standards for beverage vending machines, and defined two new product classes for combination vending machines Compliance with these standards is required by 2019. For this analysis, compliance with these updated standards is assumed for equipment sold in 2020 and beyond. The updated standards and DOE equipment definitions are listed in the table below.

Equipment Class	Maximum daily energy consumption (kilowatt hours per day)
Class A – a refrigerated bottled or canned beverage vending machine that is not a combination vending machine and in which 25 percent or more of the surface area on the front side of the beverage vending machine is transparent	MDEC = 0.052 x V + 2.43
Class B – any refrigerated bottled or canned beverage vending machine that is not considered to be Class A and is not a combination vending machine	MDEC = 0.052 x V + 2.20
Combination A – a combination vending machine where 25 percent or more of the surface area on the front side of the beverage vending machine is transparent	MDEC = 0.086 x V + 2.66
Combination B – a combination vending machine that is not considered to be Combination A	MDEC = 0.111 x V + 2.04

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Final

Commercial Ventilation

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Performance and Cost Characteristics » Commercial Constant Air Volume

Final

Lower annual energy use compared with Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average[3]	Low[4,5]	Typical[4,6]	High[4,7]	ENERGY STAR	Typical[4,6]	High[4,7]	Typical[4,6]	High[4,7]	Typical[4,6]	High[4,7]
System Airflow (CFM)	15,000	16,300	16,300	16,300	16,300	N/A	16,300	16,300	16,300	16,300	16,300	16,300
System Fan Power (kW)	11.56	11.56	11.56	10.98	10.78	N/A	10.98	10.78	10.98	10.78	10.98	10.78
Specific Fan Power (W/CFM)	0.771	0.709	0.709	0.674	0.661	N/A	0.674	0.661	0.674	0.661	0.674	0.661
Annual Fan Energy Use (kWh/y)[1]	43,924	23,038	23,038	21,886	20,792	N/A	20,792	19,752	19,752	18,765	18,765	17,826
Average Life (years)	35	35	35	35	35	N/A	35	35	35	35	35	35
Total Installed Cost (2022$)[2]	$80,288	$83,083	$83,083	$86,901	$90,651	N/A	$86,901	$90,651	$86,901	$90,651	$86,901	$90,651
Annual Maintenance Cost (2022$)	$1,054	$1,054	$1,054	$1,054	$1,054	N/A	$1,054	$1,054	$1,054	$1,054	$1,054	$1,054
Total Installed Cost (2022$/thousand CFM)	$5,353	$5,097	$5,097	$5,331	$5,561	N/A	$5,331	$5,561	$5,331	$5,561	$5,331	$5,561
Annual Maintenance Cost (2022$/thousand CFM)	$70	$65	$65	$65	$65	N/A	$65	$65	$65	$65	$65	$65

1. Based on 3800 operating hours per year (ADL, 1999) and typical zone air flow requirement profile (ASHRAE S45.11-2012)
2. Total installed cost of 16,300 CFM constant air volume (CAV) air handling unit (AHU) and hypothetical supply ductwork layout
3. Based on ASHRAE 90.1-2016 and 2019 fan power limit (Table 6.5.3.1.1-1) with no pressure drop adjustment. Assumed 80% motor load and 91% motor efficiency
4. ASHRAE 90.1-2016 and 2019 Section 6.5.3.2 require minimum two-speed fan control (no longer always constant volume).
5. Two-speed variable frequency drive (VFD)
6. Modulating VFD
7. Modulating custom engineered VFD

- Constant air volume (CAV) ventilation systems are common, inexpensive, air-side HVAC systems that operate in response to a single control zone. Historically, these systems provide a constant flow rate of air (typically a mix of recirculated and outside air) and adjust the supply temperature of that air in order to maintain the space temperature setpoint. Beginning with ASHRAE 90.1-2013 and continued in ASHRAE 90.1-2019, new CAV ventilation systems were mandated to have at least two fan speed settings with the requirement of a maximum 40% power at 66% flow. Systems with variable speed fans are increasingly popular, making the term "constant air volume" somewhat of a misnomer for this system type. This analysis examines only the fan energy of the CAV system.
- There is movement in the industry and in energy codes to reduce fan power. ASHRAE 90.1 includes fan power limits for CAV systems. Fan power can be minimized through good design practice (efficient duct layout, low pressure drop ductwork, filters, coils), proper fan selection, and high efficiency type fans. ASHRAE 90.1-2019 now requires a minimum fan efficiency grade (FEG, based on AMCA 205-12: Energy Efficiency Classification for Fans) of 67 and a design operating fan efficiency within 15% of the maximum fan total efficiency. There are exceptions to this requirement, including packaged systems such as the CAV system type considered here. Still the fan power limits are expected to become more stringent, and fan efficiency will become more important throughout the industry.
- The unit characterized in this report is a 16,300 CFM CAV system. The average commercial building is approximately 16,300 square feet (CBECS 2018). Assuming 1 CFM is needed per square foot of floor area results in a 16,300 CFM air handling unit.
- A 16,300 CFM CAV packaged indoor air handling unit with cooling and heating coils can be installed for approximately $71,829 (RS Means 2022). Ductwork would cost approximately $9,272 additional ($81,101 total). A two-speed motor (estimated $500 incremental cost) and variable frequency drive (estimated $5,800) add cost. Custom engineered variable frequency drives (estimated $9,550) and premium efficiency motors (estimated additional $1,500) add an additional cost to the system.
- Annual maintenance cost assumes 8 hours worth of labor by a technician to perform the necessary tasks (e.g., filter replacement, draining condenser water, etc.)
- ASHRAE Standard 90.1, which is used as a basis for most state energy codes, limits the fan power (brake HP or nameplate HP) for CAV systems. The 2016 version of Standard 90.1 was used to represent the 2018 minimum efficiency level (state energy codes typically refer to older versions of Standard 90.1 due to code revision cycles).
- Fan energy is affected by several factors, including fan type (e.g., centrifugal, axial), fan blade shape (e.g., forward-curved, backward-curved, backward-inclined, airfoil), drive type (belt or direct), configuration (plenum or housed centrifugal), system effects, duct design, filter and coil pressure drops, motor efficiency, and speed and flow control.
- **For this Advanced Case, the projections from 2030 to 2050 for system fan power and annual fan energy use assume a 5% improvement per decade based on the assumption that use of variable frequency drives and incremental improvements in technology will increase.**

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Performance and Cost Characteristics » Commercial Variable Air Volume

Final

Lower annual energy use compared with Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average[3]	Low[4]	Typical[5]	High[6]	ENERGY STAR	Typical[6]	High[6,7]	Typical[6,7]	High[6,7]	Typical[6,7]	High[6,7]
System Airflow (CFM)	15,000	16,300	16,300	16,300	16,300	N/A	16,300	16,300	16,300	16,300	16,300	16,300
System Fan Power (kW)	15.99	15.99	15.99	15.99	15.99	N/A	15.99	15.19	15.99	15.19	15.99	15.19
Specific Fan Power (W/CFM)	1.066	1.066	0.981	0.981	0.981	N/A	0.981	0.932	0.981	0.932	0.981	0.932
Annual Fan Energy Use (kWh/yr)[1]	24,699	24,082	24,082	22,878	21,734	N/A	21,734	20,647	20,647	19,615	19,615	18,634
Average Life (yrs)	28	28	28	28	28	N/A	28	28	28	28	28	28
Total Installed Cost (2022$)[2]	$103,327	$110,414	$118,814	$124,495	$124,995	N/A	$124,495	$124,995	$124,495	$124,995	$124,495	$124,995
Annual Maintenance Cost (2022$)	$1,054	$1,054	$1,054	$1,054	$1,054	N/A	$1,054	$1,054	$1,054	$1,054	$1,054	$1,054
Total Installed Cost (2022$/1000 CFM)	$6,888	$6,774	$7,289	$7,638	$7,668	N/A	$7,638	$7,668	$7,638	$7,668	$7,638	$7,668
Annual Maintenance Cost (2022$/1000 CFM)	$70	$65	$65	$65	$65	N/A	$65	$65	$65	$65	$65	$65

1. Based on 3800 operating hours per year (ADL, 1999) and typical zone air flow requirement profile (ASHRAE S45.11-2012)
2. Total installed cost of 16,300 CFM VAV AHU, VFD, (10) VAV boxes, (10) VAV controllers with associated space temperature sensor, and hypothetical supply ductwork layout
3. Based on ASHRAE 90.1-2016 and 2019 fan power limit (Table 6.5.3.1.1-1) with no pressure drop adjustment. Assumed 80% motor load and 91% motor efficiency
4. ASHRAE 90.1-2016 and 2019 Section 6.5.3.2 minimum power-flow requirement
5. ASHRAE 90.1-2019 fan power limit and typical VAV power-flow relationship for 40%-100% flow
6. ASHRAE 90.1-2019 fan power limit and typical VAV power-flow relationship for 30%-100% flow
7. High aerodynamic efficiency fan

Performance and Cost Characteristics » Commercial Variable Air Volume

Final

- Variable air volume (VAV) ventilation systems are the most common multi-zone system type specified today for conditioning commercial buildings. These systems provide conditioned air to multiple zone terminal units (VAV boxes) that use dampers to modulate the amount of cool air to each zone. An individual zone thermostat controls the VAV box damper to allow more or less cooling. If a zone requires heating, then the VAV box provides the minimum flow rate and typically includes a reheat coil to meet the space temperature setpoint. As VAV box dampers close in the system, a variable frequency drive reduces fan speed and flow continuously to meet current requirements.
- This analysis examines only the fan energy of the VAV system. VAV systems vary fan speed and flow to meet space conditioning requirements; minimum flow settings apply for DX cooling stages and gas furnace heating stages. Most hours of operation are much lower than full speed, and fan power varies with the cube of fan speed according to fan affinity laws. The 2012 ASHRAE Handbook: HVAC Systems and Equipment (p. 45.11) provided the typical flow profile used for this analysis. The unit characterized in this report is a 16,300 CFM VAV system.
- There is movement in the industry and in energy codes to reduce fan power. ASHRAE 90.1 includes fan power limits for VAV systems. Fan power can be minimized through good design practice (efficient duct layout, low pressure drop ductwork, filters, coils), proper fan selection, and high efficiency type fans. ASHRAE 90.1-2019 now requires a minimum fan efficiency grade (FEG, based on AMCA 205-12: Energy Efficiency Classification for Fans) of 67 and a design operating fan efficiency within 15% of the maximum fan total efficiency. There are exceptions to this requirement, including packaged systems such as the VAV system type considered here. Still the fan power limits are expected to become more stringent, and fan efficiency will become more important throughout the industry.
- A 16,300 CFM VAV packaged indoor air handling unit with cooling and heating coils can be installed for approximately $82,023 (RS Means 2022). Ductwork and (10) VAV boxes with reheat would cost approximately an additional $28,272. (10) VAV controllers and the associated space temperature sensor would cost approximately $8,400 ($118,695 total). A 15 hp variable frequency drive (estimated $5,800) is an additional cost.
- ASHRAE Standard 90.1, which is used as a basis for most state energy codes, limits the fan power for VAV systems (brake HP or nameplate HP). The 2016 version of Standard 90.1 was used to represent the 2018 minimum efficiency level (state energy codes typically refer to older versions of Standard 90.1 due to code revision cycles).
- Annual maintenance cost assumes 8 hours worth of labor by a technician to perform the necessary tasks (e.g., filter replacement, draining condenser water, etc.)
- Fan energy is affected by several factors, including fan type (e.g., centrifugal, axial), fan blade shape (e.g., forward-curved, backward-curved, backward-inclined, airfoil), drive type (belt or direct), configuration (plenum or housed centrifugal), system effects, duct design, filter and coil pressure drops, and motor VFD efficiency.
- **For this Advanced Case, the projections from 2030 to 2050 for system fan power and annual fan energy use assume a 5% improvement per decade based on the assumption use of variable frequency drives and incremental improvements in technology will increase.**

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Performance and Cost Characteristics » Commercial Fan Coil Units

Same as Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average[5]	Low[3]	Typical[5]	High[6]	ENERGY STAR	Typical[4,6]	High[4,7]	Typical[4,7]	High[4,8]	Typical[4,8]	High[4,8,9]
System Airflow (CFM)	800	800	800	800	800	N/A	800	800	800	800	800	800
System Fan Power (kW)	0.241	0.241	0.241	0.148	0.148	N/A	0.141	0.134	0.134	0.136	0.136	0.129
Specific Fan Power (W/CFM)	0.302	0.302	0.301	0.185	0.185	N/A	0.176	0.167	0.167	0.170	0.170	0.162
Annual Fan Energy Use (kWh/y)[1]	543	542	542	333	333	N/A	316	301	301	306	306	291
Average Life (years)	37	37	37	37	37	N/A	37	37	37	37	37	37
Total Installed Cost (2022$)[2]	$2,845	$2,688	$3,038	$3,521	$3,961	N/A	$3,961	$4,161	$3,961	$4,161	$3,961	$4,161
Annual Maintenance Cost (2022$)	$117	$117	$117	$117	$117	N/A	$117	$117	$117	$117	$117	$117
Total Installed Cost (2022$/thousand CFM)	$3,557	$3,360	$3,798	$4,401	$4,951	N/A	$4,951	$5,201	$4,951	$5,201	$4,951	$5,201
Annual Maintenance Cost (2022$/thousand CFM)	$146	$146	$146	$146	$146	N/A	$146	$146	$146	$146	$146	$146

1. Based on 2250 operating hours per year (ADL, 1999) and typical zone air flow requirement profile (ASHRAE S45.11-2012)
2. Total installed cost of 2-ton horizontal two-pipe fan coil unit, housing, and controls
3. Based on ASHRAE 90.1-2016 and 2019 fan power limit (Table 6.5.3.1.1-1) with no pressure drop adjustment. Assumed 80% motor load and 91% motor efficiency
4. Based on ASHRAE 90.1-2016 and 2019 Section 6.5.3.6 requirement of electronically commutated or 70+% efficient fan motor
5. Permanent split capacitor fan motor
6. Electronically commutated fan motor (single speed)
7. Electronically commutated fan motor (two-speed)
8. Electronically commutated fan motor (variable speed)
9. High aerodynamic efficiency fan

- Commercial fan coil units (FCUs) are self-contained, mass-produced assemblies that provide cooling, heating, or cooling and heating, but they do not include the source of cooling or heating. The unit characterized in this report is a cooling only (two-pipe), horizontal unit with housing and controls. Fan coil units are typically installed in or adjacent to the space being served and have no (or very limited) ductwork.
- According to manufacturer literature, the cooling capacity for a nominal 800 CFM fan coil unit is about 2 tons. This analysis examines only the fan energy of FCUs.
- Fan coil unit fan motors can be shaded pole, a single-phase AC motor with offset start winding and no capacitor; PSC, a single-phase AC motor with offset start winding with capacitor; or ECM, an AC electronically commutated permanent magnet DC motor. PSC motors are currently the most common motor type in FCUs, but manufacturers also offer single speed, two speed, and ECM motors as an option. ASHRAE 90.1-2019 requires an electronically commutated fan motor (or minimum motor efficiency of 70%) for this system.
- There is movement in the industry and in energy codes to reduce fan power. ASHRAE 90.1 includes fan power limits for FCUs. Fan power can be minimized through good design practice and high efficiency type fans. ASHRAE 90.1-2019 now requires a minimum fan efficiency grade (FEG, based on AMCA 205-12: Energy Efficiency Classification for Fans) of 67 and a design operating fan efficiency within 15% of the maximum fan total efficiency. There are exceptions to this requirement, including small systems such as the FCU considered here. Still the fan power limits are expected to become more stringent, and fan efficiency will become more important throughout the industry.
- Fan coil units have higher maintenance costs than central air systems due to the distributed nature of the system. For each unit, the filters must be changed, and drain systems must be flushed periodically.
- ASHRAE Standard 90.1, which is used as a basis for most state energy codes, limits the fan power (brake HP or nameplate HP). The 2016 version of Standard 90.1 was used to represent the 2018 minimum efficiency level (state energy codes typically refer to older versions of Standard 90.1 due to code revision cycles).
- Fan energy is affected by several factors, including fan type configuration, filter and coil pressure drops, motor efficiency, and fan speed control.

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Appendix A
Data Sources

Guidehouse
1200 19th Street, NW, Suite 700
Washington, D.C. 20036

And

Leidos
8301 Greensboro Drive
McLean, VA 22102

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Residential Lighting

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Data Sources » Residential General Service LED Lamps (60 Watt Equivalent)

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DATA SOURCES	2015	2020	2022				2023**	2030		2040		2050	
	Installed Stock Average		Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)			Calculated					Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
CRI			Distributor Websites or Product Catalogs				N/A	Assume Unchanged					
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)								Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			N/A		Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Lamp Cost (2022$/klm)	Calculated												
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated						N/A	Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential General Service Filament-LED Lamps (60 Watt Equivalent)

DATA SOURCES	2015	2020	2022				2023**	2030		2040		2050	
	Installed Stock Average		Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)			Calculated					Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
CRI			Distributor Websites or Product Catalogs				N/A	Assume Unchanged					
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)								Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			N/A		Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Lamp Cost (2022$/klm)	Calculated												
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated						N/A	Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Reflector LED BR30

DATA SOURCES	2015	2020	2022				2023**	2030		2040		2050	
	Installed Stock Average		Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)			Calculated					Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
CRI			Distributor Websites or Product Catalogs				N/A	Assume Unchanged					
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)								Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)							DOE, 2017						
Lamp Price (2022$)	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			N/A		Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Lamp Cost (2022$/klm)							Calculated						
Labor Cost (2022$/h)							N/A						
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)													
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)			Calculated				N/A	Calculated					
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Reflector LED PAR38

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DATA SOURCES	2015	2020	2022				2023**	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)			Calculated					Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
CRI			Distributor Websites or Product Catalogs				N/A	Assume Unchanged					
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)								Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		Distributor Websites or Product Catalogs			N/A		Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Lamp Cost (2022$/klm)							Calculated						
Labor Cost (2022$/h)							N/A						
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated						N/A	Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Linear LED Replacement Lamp 2-Lamp System

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DATA SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	LED Webscrape Database	DOE Webscrape Database	Distributor Websites			Calculated					
Lamp Lumens						Assume Same as 2022 Typical and High					
Lamp Efficacy (lm/W)						Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Wattage	Calculated										
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)	N/A										
CRI	2016 EIA Ref. Case	Distributor Websites	Distributor Websites								
Correlated Color Temperature (CCT)	2016 EIA Ref. Case										
Average Lamp Life (thousand hours)	LED Webscrape Database	DOE Web Scrape Database									
Annual Operating Hours (h/y)	DOE, 2017										
Lamp Price (2022$)	LED Webscrape Database	DOE Web Scrape Database	Distributor Websites			Calculated					
Ballast Price (2022$)		N/A									
Fixture Price (2022$)											
Lamp Cost (2022$/klm)	Calculated										
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)	N/A										
Labor System Installation (hours)											
Labor Lamp Change (hours)											
Total Installed Cost (2022$)	Calculated										
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Residential Linear LED Luminaire

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DATA SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A										
Lamp Lumens											
Lamp Efficacy (lm/W)											
System Wattage	LED Webscrape Database	DOE Web Scrape Database	Distributor Websites			Calculated					
System Lumens						Assume Same as 2022 Typical and High					
System Efficacy (lm/W)						Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Efficiency (BLE)	N/A										
CRI	LED Webscrape Database	DOE Web Scrape Database	Distributor Websites			Distributor Websites					
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)											
Annual Operating Hours (h/y)	DOE, 2017										
Lamp or Luminaire Price (2022$)	LED Webscrape Database	DOE Web Scrape Database	Distributor Websites			Calculated					
Ballast Price (2022$)	N/A										
Fixture Price (2022$)											
Lamp Cost (2022$/klm)											
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)	2016 EIA Ref. Case		2022 RS Means Online								
Labor System Installation (hours)											
Labor Lamp Change (hours)			N/A								
Total Installed Cost (2022$)	Calculated										
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Residential Outdoor Lamps (Security: LED PAR38)

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DATA SOURCES	2015	2020	2022				2023*	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Same as Residential LED PAR38												
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)													
Average Lamp Life (1000 hrs)													
Annual Operating Hours (hrs/yr)													
Lamp Price (2022$)													
Lamp Cost (2022$/klm)													
Labor Cost (2022$/hr)													
Labor Lamp Installation (hr)													
Total Installed Cost (2022$)													
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Outdoor Lamps (Porch: LED A-Type)

DATA SOURCES	2015	2020	2022				2023*	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR*	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)			Calculated					Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
CRI			Distributor Websites or Product Catalogs				N/A	Assume Unchanged					
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)								Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			N/A		Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Lamp Cost (2022$/klm)	Calculated												
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated												
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Commercial General Service 100W Equivalent LED Replacement Lamp in Recessed Can Fixture

DATA SOURCES	2012	2018	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Reference Case	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)								Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Wattage		Calculated											
System Lumens*													
System Efficacy (lm/W)													
Ballast Efficiency (BLE)													
CRI		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	N/A	Assume Unchanged					
Correlated Color Temperature (CCT)						N/A							
Average Lamp Life (thousand hours)						ENERGY STAR, 2020		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)				Assume Unchanged	
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	2016 EIA Reference Case	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	Distributor Websites or Product Catalogs			N/A	N/A	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)		N/A						N/A					
Fixture Price (2022$)*													
Lamp Cost (2022$/klm)		Calculated						Calculated					
System (l/b/f) Cost (2022$/klm)		N/A						N/A					
Labor Cost (2022$/h)		2016 EIA Reference Case	2022 RS Means Online					2022 RS Means Online					
Labor System Installation (hours)													
Labor Lamp Change (hours)													
Total Installed Cost (2022$)		Calculated						Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Commercial LED Reflector Lighting (PAR38)

DATA SOURCES	2012	2018	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Reference Case	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)								Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Wattage		Calculated											
System Lumens*													
System Efficacy (lm/W)													
Ballast Efficiency (BLE)													
CRI		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	N/A	Assume Unchanged					
Correlated Color Temperature (CCT)						N/A							
Average Lamp Life (thousand hours)						ENERGY STAR, 2020		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)				Assume Unchanged	
Annual Operating Hours (h/y)		DOE, 2017											
Lamp Price (2022$)	2016 EIA Reference Case	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	Distributor Websites or Product Catalogs			N/A		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)		N/A						N/A					
Fixture Price (2022$)		Calculated						Calculated					
Lamp Cost (2022$/klm)		N/A						N/A					
System (l/b/f) Cost (2022$/klm)		2016 EIA Reference Case	2022 RS Means Online					2022 RS Means Online					
Labor Cost (2022$/h)													
Labor System Installation (hours)													
Labor Lamp Change (hours)													
Total Installed Cost (2022$)		Calculated						Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources» Commercial 4-ft Linear LED Replacement Lamp in 2-Lamp System

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	LED Webscrape Database	Distributor Websites			Calculated					
Lamp Lumens						Assume Same as 2022 Typical and High					
Lamp Efficacy (lm/W)						Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Wattage		Calculated									
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)		N/A									
CRI		Distributor Websites									
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)											
Annual Operating Hours (h/y)		DOE, 2017									
Lamp Price (2022$)		LED Webscrape Database	Distributor Websites			Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)		N/A									
Fixture Price (2022$)											
Lamp Cost (2022$/klm)		Calculated									
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)		2016 EIA Ref. Case	2022 RS Means Online								
Labor System Installation (hours)		N/A									
Labor Lamp Change (hours)		Assume unchanged									
Total Installed Cost (2022$)		Calculated									
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial 4-ft Linear LED Luminaire to Replace 2-Lamp Systems

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	N/A									
Lamp Lumens											
Lamp Efficacy (lm/W)											
System Wattage		LED Webscrape Database	Distributor Websites			Calculated					
System Lumens						Assume Same as 2022 Typical and High					
System Efficacy (lm/W)						Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Efficiency (BLE)		N/A				N/A					
CRI		Distributor Websites									
Correlated Color Temperature (CCT)											
Average Lifetime (thousand hours)											
Annual Operating Hours (h/y)		DOE, 2017									
Lamp or Luminaire Price (2022$)		LED Webscrape Database	Distributor Websites			Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)		N/A									
Fixture Price (2022$)											
Lamp Cost (2022$/klm)											
System (l/b/f) Cost (2022$/klm)		Calculated									
Labor Cost (2022$/h)		2016 EIA Ref. Case	2022 RS Means Online								
Labor System Installation (hours)		2022 RS Means Online									
Labor Lamp Change (hours)		N/A									
Total Installed Cost (2022$)		Calculated									
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial 8-ft Linear LED Replacement Lamp for a 2-Lamp System

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A	2016 EIA Ref. Case, 2015 typical	Distributor Websites			Calculated					
Lamp Lumens						Assume Same as 2022 Typical and High					
Lamp Efficacy (lm/W)			Calculated			Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Wattage		Calculated				Calculated					
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)		N/A									
CRI		2016 EIA Ref. Case, 2015 typical	Distributor Websites								
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)											
Annual Operating Hours (h/y)		DOE, 2017									
Lamp Price (2022$)		2016 EIA Ref. Case, 2015 typical	Distributor Websites			Calculated					
Ballast Price (2022$)			N/A								
Fixture Price (2022$)											
Lamp Cost (2022$/klm)			Calculated								
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)			2022 RS Means Online								
Labor System Installation (hours)		N/A									
Labor Lamp Change (hours)		Chapter 8; Table 8.2.4 of GSFL IRL Preliminary Analysis TSD (DOE, 2013)									
Total Installed Cost (2022$)		Calculated									
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial 8-ft Linear LED Luminaire Replacement for a 2-Lamp System

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A	N/A									
Lamp Lumens											
Lamp Efficacy (lm/W)											
System Wattage		2016 EIA Ref. Case, 2015 typical	Distributor Websites			Calculated					
System Lumens						Assume Same as 2022 Typical and High					
System Efficacy (lm/W)						Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Efficiency (BLE)		N/A									
CRI		2016 EIA Ref. Case, 2015 typical	Distributor Websites								
Correlated Color Temperature (CCT)											
Average Lifetime (thousand hours)											
Annual Operating Hours (h/y)		DOE, 2017									
Lamp or Luminaire Price (2022$)		2016 EIA Ref. Case, 2015 typical	Distributor Websites								
Ballast Price (2022$)		N/A									
Fixture Price (2022$)											
Lamp Cost (2022$/klm)											
System (l/b/f) Cost (2022$/klm)		Calculated									
Labor Cost (2022$/h)		2016 EIA Ref. Case, 2015 typical	2022 RS Means Online								
Labor System Installation (hours)											
Labor Lamp Change (hours)		N/A									
Total Installed Cost (2022$)		Calculated									
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial LED Low-Bay Luminaire

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A										
Lamp Lumens											
Lamp Efficacy (lm/W)											
System Wattage	2016 EIA Reference Case	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	N/A	Distributor Websites or Product Catalogs		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency		N/A		N/A		N/A					
CRI		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		Distributor Websites or Product Catalogs		Assume Unchanged					
Correlated Color Temperature (CCT)						Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Average Lifetime (thousand hours)											
Annual Operating Hours (h/y)	DOE, 2017			DOE, 2017							
Lamp or Luminaire Price (2022$)	2016 EIA Reference Case	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		Distributor Websites or Product Catalogs		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)											
Fixture Price (2022$)											
Lamp Cost (2022$/klm)		N/A		N/A		N/A					
System (l/b/f) Cost (2022$/klm)		Calculated		Calculated							
Labor Cost (2022$/h)		2016 EIA Reference Case		2022 RS Means Online		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Labor System Installation (hours)											
Labor Lamp Change (hours)											
Total Installed Cost (2022$)	Calculated			Calculated		Calculated					
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial LED High-Bay Luminaire

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A										
Lamp Lumens											
Lamp Efficacy (lm/W)											
System Wattage	2016 EIA Reference Case	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	N/A	Distributor Websites or Product Catalogs		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)		N/A		N/A		N/A					
CRI		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		Distributor Websites or Product Catalogs		Assume Unchanged					
Correlated Color Temperature (CCT)						Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Average Lifetime (thousand hours)											
Annual Operating Hours (h/y)	DOE, 2017			DOE, 2017		DOE, 2017					
Lamp or Luminaire Price (2022$)	2016 EIA Reference Case	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	N/A	Distributor Websites or Product Catalogs		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)											
Fixture Price (2022$)											
Lamp Cost (2022$/klm)		N/A		N/A		N/A					
System (l/b/f) Cost (2022$/klm)		Calculated		Calculated							
Labor Cost (2022$/h)		2016 EIA Reference Case		2022 RS Means Online		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Labor System Installation (hours)											
Labor Lamp Change (hours)											
Total Installed Cost (2022$)	Calculated			Calculated		Calculated					
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Refrigeration

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Data Sources » Commercial Compressor Rack Systems

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DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Total Capacity (kBtu/h)	ADL, 1996	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Median Store Size (ft^2)	Food Marketing Institute (FMI), 2012	CBECS 2018										
Power Input (kW)	Copeland, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Energy Use (MMWh/y)	ADL, 1996 / NCI Analysis, 2015	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Indexed Annual Efficiency	Calculated											
Average Life (years)	Kysor-Warren, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Total Installed Cost (2022$)	NCI, 2009 / NCI Analysis, 2012	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	ADL, 1996 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Condensers

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DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Total Capacity (kBtu/h)	NCI Analysis, 2008 / Heatcraft, 2008 / ADL, 1996	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Median Store Size (ft^2)	Food Marketing Institute (FMI), 2012	CBECS 2018										
Power Input (kW)	NCI Analysis, 2008 / Heatcraft, 2008 / ADL, 1996	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Energy Use (MMWh/y)	NCI Analysis, 2008 / ADL, 1996	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Indexed Annual Efficiency	Calculated											
Average Life (years)	ADL, 1996 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Total Installed Cost (2022$)	NCI Analysis, 2008 / Heatcraft, 2008 / RS Means, 2007	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Supermarket Display Cases

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DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	ENERGY STAR	High	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	DOE, 2007 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Median Store Size (ft^2)	Food Marketing Institute (FMI), 2012	CBECS 2018										
Case Length (ft)	DOE, 2016: CRE Report / Guidehouse Analysis 2022											
Annual Energy Use (kWh/y)[1,2]	DOE, 2007 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Energy Use / Case Length (kWh/ft)	Calculated											
Indexed Annual Efficiency[3]	Calculated											
Average Life (years)	DOE, 2007 / NCI Analysis, 2008	DOE, 2016: CRE Report / Guidehouse Analysis 2022										
Retail Equipment Cost (2022$)	DOE, 2007 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022 / The Restaurant Store										
Total Installed Cost (2022$)	DOE, 2007 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)[4]	DOE, 2007 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Reach-In Refrigerators

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	ADL, 1996 / NCI Analysis, 2008	DOE, 2014: CRE Report										
Size (ft^3)	ADL, 1996 / Distributor Web Sites	DOE, 2014: CRE Report										
Annual Energy Use (kWh/y)	ADL, 1996 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022 / ENERGY STAR 2022										
Annual Energy Use / Volume ($kWh/y/ft^3$)	NCI Analysis, 2012	Calculated										
Indexed Annual Efficiency	Calculated											
Average Life (years)	Calculated											
Retail Equipment Cost (2022$)	ACEEE, 2002	DOE, 2014: CRE TSD										
Total Installed Cost (2022$)	ADL, 1996/ Distributor Web Sites / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022 / ENERGY STAR 2022 / The Restaurant Store										
Total Installed Cost (2022$/kBtu/h)	Distributor Web Sites / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$)	Calculated											
Annual Maintenance Cost (2022$/kBtu/h)	NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Reach-In Freezers

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	ADL, 1996 / NCI Analysis, 2008	DOE, 2016: CRE Report										
Size (ft^3)	ADL, 1996 / Distributor Web Sites	DOE, 2016: CRE Report										
Annual Energy Use (kWh/y)	ADL, 1996 / NCI Analysis, 2008	DOE, 2016: CRE Report / Guidehouse Analysis 2022										
Annual Energy Use / Volume ($kWh/y/ft^3$)	NCI Analysis, 2012	Calculated										
Indexed Annual Efficiency	Calculated											
Average Life (years)	ACEEE, 2002	DOE, 2016: CRE Report / Guidehouse Analysis 2022										
Retail Equipment Cost (2022$)	ADL, 1996/ Distributor Web Sites / NCI Analysis, 2008	DOE, 2016: CRE Report / Guidehouse Analysis 2022 / ENERGY STAR 2022 / The Restaurant Store										
Total Installed Cost (2022$)	Distributor Web Sites / NCI Analysis, 2008	DOE, 2016: CRE Report / Guidehouse Analysis 2022										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	NCI Analysis, 2008	DOE, 2016: CRE Report / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Walk-In Refrigerators

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	DOE CRE Report 2016 / CCMS 2022 / Guidehouse Analysis 2022											
Size (ft^2)	DOE 2014 WICF TSD / Guidehouse Analysis 2022											
Annual Energy Use (kWh/y)	ADL, 1996 / PG&E, 2004 / NCI Analysis, 2008	DOE CRE Report 2016 / Guidehouse Analysis 2022										
Annual Energy Use / Area ($kWh/ft^2/y$)	Calculated											
Indexed Annual Efficiency	Calculated											
Insulated Box Average Life (years)	ADL, 1996 / PG&E, 2004	DOE CRE Report 2016 / Guidehouse Analysis 2022										
Compressor Average Life (years)	ADL, 1996 / PG&E, 2004	DOE CRE Report 2016 / Guidehouse Analysis 2022										
Retail Equipment Cost (2022$)	ADL, 1996 / Distributor Web Sites / NCI Analysis, 2008	DOE CRE Report 2016 / Webstaurant 2022 / Guidehouse Analysis 2022										
Total Installed Cost (2022$)	ADL, 1996 / Distributor Web Sites / NCI Analysis, 2008	DOE CRE Report 2016 / Webstaurant 2022 / Guidehouse Analysis 2023										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	ADL, 1996 / FMI, 2005 / NCI Analysis, 2008	DOE CRE Report 2016 / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Walk-In Freezers

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	ADL, 1996 / NCI Analysis, 2008	DOE CRE Report 2016 / CCMS 2022 / Guidehouse Analysis 2022										
Size (ft^2)	ADL, 1996 / NCI Analysis, 2008	Guidehouse Analysis 2022										
Annual Energy Use (kWh/y)	ADL, 1996 / PG&E, 2004 / NCI Analysis, 2008	Guidehouse CRE Report 2016										
Annual Energy Use / Area ($kWh/ft^2/y$)	Calculated											
Indexed Annual Efficiency	Calculated											
Insulated Box Average Life (years)	ADL, 1996 / PG&E, 2004	DOE CRE Report 2016 / Guidehouse Analysis 2022										
Compressor Average Life (years)	ADL, 1996 / PG&E, 2004	DOE CRE Report 2016 / Guidehouse Analysis 2022										
Retail Equipment Cost (2022$)	ADL, 1996 / Distributor Web Sites / NCI Analysis, 2008	DOE CRE Report 2016 / Webstaurant 2022 / Guidehouse Analysis 2022										
Total Installed Cost (2022$)	ADL, 1996 / Distributor Web Sites / NCI Analysis, 2008	DOE CRE Report 2016 / Webstaurant 2022 / Guidehouse Analysis 2023										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	DOE CRE Report 2016 / Guidehouse Analysis 2022											
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Ice Machines

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Output (pounds [lbs] per day)	ADL, 1996 / NCI Analysis, 2008	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022 / CCMS Database 2022										
Water Use per Hundred Pounds (gal/hundred lbs)	ADL, 1996 / Distributor Web Sites	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022 / CCMS Database 2022										
Energy Use per Hundred Pounds (kWh/hundred lbs)	ADL, 1996 / NCI Analysis, 2008	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022										
Annual Energy Use (kWh/y)	ACEEE, 2002 / NCI Analysis, 2012	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022 / ENERGY STAR										
Indexed Annual Efficiency	Calculated											
Average Life (years)	ADL, 1996/ Distributor Web Sites / NCI Analysis, 2008	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022										
Retail Equipment Cost (2022$)	Distributor Web Sites / NCI Analysis, 2008	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022										
Total Installed Cost (with Bin)	NCI Analysis, 2008	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	ADL, 1996 / NCI Analysis, 2008	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Beverage Merchandisers

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	DOE, 2014: CRE Report / Guidehouse Analysis 2022											
Size (ft^3)	ADL, 1996 / Distributor Web Sites	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Energy Use (kWh/y)	ADL, 1996 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022 / ENERGY STAR 2022										
Annual Energy Use / Volume ($kWh/ft^3/y$)	Calculated											
Indexed Annual Efficiency	Calculated											
Average Life (years)	ACEEE, 2002	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Retail Equipment Cost (2022$)	ADL, 1996 / Distributor Web Sites	DOE, 2014: CRE Report / Guidehouse Analysis 2022 / KaTom Restaurant Supply										
Total Installed Cost (2022$)	DOE, 2014: CRE Report / Guidehouse Analysis 2022											
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	DOE, 2014: CRE Report / Guidehouse Analysis 2022											
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Refrigerated Vending Machines

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DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	DOE, 2015: BVM TSD / Guidehouse Analysis, 2015	DOE, 2022: BVM TSD / Guidehouse Analysis, 2022										
Can Capacity	DOE, 2015: BVM TSD	DOE, 2022: BVM TSD										
Size (ft^3)	DOE, 2022: BVM TSD / Guidehouse Analysis, 2022											
Annual Energy Use (kWh/y)	DOE, 2015: BVM TSD	DOE, 2022: BVM TSD										
Annual Energy Use / Volume ($kWh/ft^3/y$)	Calculated											
Indexed Annual Efficiency	Calculated											
Average Life (years)	DOE, 2015: BVM TSD	DOE, 2022: BVM TSD										
Retail Equipment Cost (2022$)	DOE, 2015: BVM TSD	DOE, 2022: BVM TSD										
Total Installed Cost (2022$)	DOE, 2015: BVM TSD	DOE, 2022: BVM TSD										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	DOE, 2015: BVM TSD / Guidehouse Analysis, 2015	DOE, 2022: BVM TSD / Guidehouse Analysis, 2022										
Annual Maintenance Cost (2022$/kBtu/h)	DOE, 2022: BVM TSD / Guidehouse Analysis, 2022											

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Commercial Ventilation

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Data Sources » Commercial Constant Air Volume Ventilation

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DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
System Airflow (CFM)	CBECS 2003 & BED 2007	CBECS 2018										
System Fan Power (kW)	ASHRAE 90.1-2007	ASHRAE 90.1-2016	ASHRAE 90.1-2019	ASHRAE 90.1 2019 / Guidehouse Analysis 2022								
Specific Fan Power (W/CFM)												
Annual Fan Energy Use (kWh/y)												
Average Life (years)	ASHRAE: Service Life Database											
Total Installed Cost (2022$)	2022 RS Means Online											
Annual Maintenance Cost (2022$)	2022 RS Means Online / Guidehouse											
Total Installed Cost (2022$/thousand CFM)	Calculated											
Annual Maintenance Cost (2022$/thousand CFM)	Calculated											

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Data Sources » Commercial Variable Air Volume Ventilation

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
System Airflow (CFM)	CBECS 2003 & BED 2007	CBECS 2018										
System Fan Power (kW)	ASHRAE 90.1-2007	ASHRAE 90.1-2016	ASHRAE 90.1-2019	ASHRAE 90.1 2019 / Guidehouse Analysis 2022								
Specific Fan Power (W/CFM)												
Annual Fan Energy Use (kWh/y)												
Average Life (years)	ASHRAE: Service Life Database											
Total Installed Cost (2022$)	2022 RS Means Online											
Annual Maintenance Cost (2022$)	2022 RS Means Online / Guidehouse											
Total Installed Cost (2022$/thousand CFM)	Calculated											
Annual Maintenance Cost (2022$/thousand CFM)	Calculated											

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Data Sources » Commercial Fan Coil Unit

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DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
System Airflow (CFM)	Product Literature											
System Fan Power (kW)	ASHRAE 90.1-2007	ASHRAE 90.1-2016	ASHRAE 90.1-2019	ASHRAE 90.1 2019 / Guidehouse Analysis 2022								
Specific Fan Power (W/CFM)												
Annual Fan Energy Use (kWh/y)												
Average Life (years)	ASHRAE: Service Life Database											
Total Installed Cost (2022$)	2022 RS Means Online											
Annual Maintenance Cost (2022$)	2022 RS Means Online / Guidehouse											
Total Installed Cost (2022$/thousand CFM)	Calculated											
Annual Maintenance Cost (2022$/thousand CFM)	Calculated											

Appendix B
References

Guidehouse
1200 19th Street, NW, Suite 700
Washington, D.C. 20036

And

Leidos
11951 Freedom Drive
Reston, VA 20190

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

REBUTTAL TESTIMONY

OF

MATTHEW J. FOSTER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Q. Please state your name and business address.

A. My name is Matthew J. Foster, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Matthew J. Foster who previously presented direct testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the Attorney General's ("AG") proposed adjustment to Corporate Services operating and maintenance ("O&M") Expense and the Michigan Public Service Commission ("MPSC" or the "Commission") Staff's ("Staff") update to Unamortized Manufactured Gas Plant ("MGP") and MGP Amortization Expense.

Q. Have you prepared any exhibits in conjunction with your rebuttal testimony?

A. Yes, I prepared the following exhibit:

Exhibit A-134 (MJF-13) Gas General Activities Labor Expense.

Q. What adjustments did the AG propose to the Corporate Services Expense?

A. As shown in pages 183 through 184 of his direct testimony, AG witness Sebastian Coppola recommends a reduction of $10,910,000 to the Company's requested Corporate Services O&M projection of $26,874,473. Mr. Coppola calculated the proposed adjustment by using the 2024 General Activities Labor ("General Activities") plus inflation to calculate the forecasted amount for the projected test year.

Q. What is the AG's reasoning for the proposed adjustment to Corporate Services O&M?

A. Starting on line 2, page 183, of Mr. Coppola's testimony, he describes the 2023 General Activities as being "unusual and excessive" as a result of the 2023 expense being larger than recent years.

Q. Does the Company agree with the AG's proposed adjustment to the Corporate Services O&M related to General Activities?

A. No, the Company does not agree with the proposed adjustment. In 2023, General Activities included Voluntary Separation Program ("VSP") expenses of $12.6 million and Employee Incentive Compensation Program ("EICP") expenses of $7.8 million. The Company removed both expenses from the Corporate projected test year O&M as VSP is a non-recurring event and EICP is covered under the direct testimony of Company witness Amy M. Conrad. Per Exhibit A-134 (MJF-13), when excluding these expenses, the adjusted 2023 General Activities is a credit balance of $13.0 million, which is consistent with prior years. Therefore, the projected test year balance of General Activities is in no way "unusual and excessive" as stated by the AG.

Q. Please describe Exhibit A-134 (MJF-13).

A. Exhibit A-134 (MJF-13) reports the expenses included in General Activities. The expense components include Senior Officer Expense, Capitalized Credits, Billing Credits, EICP, VSP, and other miscellaneous expenses.

Q. Please explain why the General Activities has fluctuated in recent years.

A. As shown in Exhibit A-134 (MJF-13), VSP expense included on line 5 and EICP expense included on line 4 are the primary reasons for the fluctuation in General Activities in recent

years. As previously stated, when excluding these expenses, the remaining cost components in General Activities have been reasonably consistent.

Q. Please explain line 8 from Exhibit A-134 (MJF-13).

A. Exhibit A-134 (MJF-13), line 8, calculates Total General Activities less VSP and less EICP expenses. The General Activities calculation, normalizing for VSP and EICP expenses, results in negative expense (credit) of approximately $12 to $13 million in recent years. Line 8 validates that VSP and EICP expense components, which the Company has removed from the projected test year, are driving the General Activities fluctuations noted by the AG as being "unusual."

Q. Does the Company agree with the Staff's adjustments to the Unamortized MGP balance and the test year projection of MGP amortization expense?

A. Yes. The Company agrees with the adjustments proposed by Staff.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

EXHIBIT

OF

MATTHEW J. FOSTER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Gas General Activities Labor Expense

for the Years 2021 - 2024

($000,000)

Case No.: U-21806

Exhibit No.: A-134 (MJF-13)

Page: 1 of 1

Witness: MJFoster

Date: May 2025

Line No.	General Activities Labor Components	2021 Actual	2022 Actual	2023 Actual	2024 Actual
1	Senior Officer Expense	$ 0.7	$ 0.7	$ 0.7	$ 0.7
2	Capitalized Credits	(13.0)	(14.9)	(14.3)	(13.6)
3	Billing Credits	(0.6)	(1.0)	(0.9)	(0.4)
4	EICP included in General Activities Labor	0.2	7.7	7.8	9.1
5	Voluntary Separation Plan expense	-	4.0	12.6	-
6	Miscellaneous Expenses	0.5	1.9	1.5	1.4
7	**Total General Activities Labor Expense**	**$ (12.2)**	**$ (1.6)**	**$ 7.4**	**$ (2.8)**
8	**General Activities Labor Less VSP & EICP Expense; (Line 7 - Line 5 - Line 4)**	**$ (12.4)**	**$ (13.3)**	**$ (13.0)**	**$ (11.9)**

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

REBUTTAL TESTIMONY

OF

SAMUEL M. GELLER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Q. Please state your name and business address.

A. My name is Samuel M. Geller, and my business address is One Energy Plaza, Jackson, Michigan, 49201.

Q. Are you the same Samuel M. Geller who previously presented direct testimony in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to Cost-of-Service Study ("COSS") issues raised in the direct testimonies of Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witnesses Kevin S. Krause and Nicholas M. Revere; Lansing Board of Water and Light and Michigan State University ("LBWL-MSU") witness Timothy S. Lyons, and Citizens Utility Board of Michigan ("CUB") witness Richard J. Bunch.

Q. Have you prepared any exhibits in conjunction with your rebuttal testimony?

A. No.

Q. How is your rebuttal testimony organized?

A. My rebuttal testimony is organized as follows:

I. REBUTTAL OF STAFF WITNESS KRAUSE AND CUB WITNESS BUNCH

II. REBUTTAL OF STAFF WITNESS REVERE

III. REBUTTAL OF LBWL-MSU WITNESS LYONS

I. REBUTTAL OF STAFF WITNESS KRAUSE AND CUB WITNESS BUNCH

Q. Please describe Staff witness Krause's proposed allocator change.

A. Beginning on page 5 of his direct testimony, Staff witness Krause proposes changing the allocator for uncollectible expenses based on revenue. Staff witness Krause reasons that the three-year average of historical write-offs is inappropriate as it does not reflect the reality of the way uncollectible costs are incurred or how they should be borne by the classes. Staff witness Krause argues that uncollectible expenses should be shared by all customers consistent with how their overall costs are recovered by the Company.

Q. Do any other witnesses propose a similar allocator change?

A. Yes. On page 25 of his direct testimony, CUB witness Bunch recommends that the Commission order the Company to allocate uncollectible expenses to each class according to Cost of Service plus Cost of Gas. On page 26 of his direct testimony, Mr. Bunch clarifies that his recommendation is to also allocate uncollectible expenses according to revenue. CUB witness Bunch argues that the current method for allocating uncollectible expenses is inconsistent with past commission orders.

Q. Does the Company agree with Staff witness Krause's proposed allocator change?

A. Yes. The Company will agree to Staff's proposal to use Present Total Revenue (Allocator 111) for uncollectible expenses and discontinue using a three-year average of historical write-offs, as previously approved by the MPSC in its Case No. U-20322 Order. This allocation method follows Staff witness Krause's proposal to allocate uncollectible expenses consistent with the way the Company allocates these expenses in the electric COSS.

Q. Please describe Staff witness Krause's proposal to modify the Company's calculation of customer charges.

A. On page 7 of his direct testimony, Staff witness Krause proposes to calculate customer charges based solely on historical amounts in the instant case. This is a departure from the method approved in the Company's previous gas rate case in which the customer charge was calculated based on a combination of historical and projected expenses. Staff witness Krause argues that utilizing only historical costs ensures that the customer charge calculation will avoid including inappropriate costs in the customer charge.

Q. Does the Company agree with Staff witness Krause's calculation of the customer charge?

A. No. The breakout of test year costs in the COSS based on historic ratios is reasonable and appropriate. Since rates are designed based on a forward-looking test year, customer costs (and the customer charge) should reflect test year costs. Accordingly, the Company applied the same methods and used the same inputs previously approved by the Commission to calculate the customer costs and resulting customer charge in this case.

II. REBUTTAL OF STAFF WITNESS REVERE

Q. Please describe Staff witness Revere's proposed allocator change.

A. On page 7 of his direct testimony, Staff witness Revere proposes allocating FERC account 378 costs based on a composite allocator (shown in Exhibit S-21.0) that seeks to more accurately assigns costs to serve customers based on pressure level. As required in the settlement agreement in Case No. U-21406, the Company submitted a more detailed analysis of the costs in FERC Account 378 in this case which identified the costs associated with measuring and regulating stations serving different pressure levels. The composite

allocator crafted by Staff witness Revere utilizes this information to sort FERC Account 378 costs and assign them based on pressure level.

Q. Does the Company agree with Staff witness Revere's proposed allocator change?

A. Yes. The Company agrees to use Staff witness Revere's composite allocator for FERC account 378 costs. Staff witness Revere's composite allocator better reflects the cost-causative relationship than the Company's current method which allocates costs based on annual and peak usage for all customers at all pressure levels.

III. REBUTTAL OF LBWL-MSU WITNESS LYONS

Q. Please describe LBWL-MSU witness Lyons' proposed allocator change.

A. On pages 12 through 15 of his direct testimony, Mr. Lyons proposes allocating FERC accounts 374, 375, 377, and 378 with Allocator 217 which functionalizes other distribution plant costs into High Pressure ("HP") and non-HP mains before allocating costs to each rate class. LBWL-MSU witness Lyons argues that this approach is widely accepted in the utility industry and ensures that HP customers are not allocated costs for assets that do not serve them.

Q. Does the Company agree with LBWL-MSU witness Lyons' recommendation for FERC account 378?

A. No. As described above, Staff witness Revere's proposal represents a more accurate methodology for allocating other plant distribution expenses. Staff witness Revere's composite allocator uses Company-provided data for FERC account 378 to first evaluate which cost categories should be broken out by pressure class and which should not. As described in Staff witness Revere's testimony on page 7, "Allocator 104 is appropriately applied to the two 'All Other Costs' categories (Huron Compressor Station and

Odorization) which represent approximately 14% of the total, as no evidence has been provided showing those costs are associated with any given pressure level directly." This first step ensures that the over $41 million in these cost categories continue to be allocated to all customer classes based on average and peak use. LBWL-MSU witness Lyons' proposal does not critically examine which cost categories within FERC account 378 serve all pressure classes which allow the XXLT customers to avoid costs that are appropriately allocated to them.

Q. Does the Company agree with LBWL-MSU witness Lyons' recommendation to apply Allocator 217 to the remaining Other - Distribution Plant expenses in FERC accounts 374, 375, and 377?

A. No. The Company also disagrees with LBWL-MSU witness Lyons' approach to functionalizing FERC accounts 374, 375, and 377 based on pressure. Without additional analysis of the composition of the remaining $149 million in Other Distribution Plant, the Company believes it is unreasonable to change the allocation method for FERC accounts 374, 375, and 377 solely based on pressure. As described above, closer study of FERC account 378 revealed that allocating the entirety of Other Distribution Plant expenses based on pressure is inappropriate since it contains costs that are not associated with any particular pressure class. As an example, one of these cost categories cited by Staff witness Revere is the Huron Compressor Station which maintains the pressure and the flow of natural gas to the high-pressure distribution system. All customers, at all pressure levels, are served by high pressure distribution either directly or downstream of the high-pressure system. According to Figure 2 in LBWL-MSU witness Lyons' testimony, FERC account 377 contains $11 million worth of assets serving the very same Huron Compressor station.

If it is not appropriate to allocate Huron Compressor Station Costs within FERC account 378 based solely on pressure, then it stands to reason that allocating an entire account of Huron Compressor Station costs based on pressure is similarly inappropriate.

IV. SUMMARY

Q. Please summarize your response to the direct testimony of Staff, LBWL-MSU, and CUB.

A. 1. The Company agrees with Staff witness Krause's and CUB witness Bunch's proposals to change the allocation of uncollectible expense based on revenue. The Company supports using Present Total Revenue (Allocator 111) for uncollectible expenses in this case. This allocation is consistent with the Company's allocation for uncollectible expenses in the Electric COSS.

2. The Company agrees with Staff witness Revere's proposal to change the allocation of FERC account 378 expenses based on a composite allocator detailed in Exhibit S-21.

3. The Company recommends rejecting LBWL-MSU witness Lyons' proposal to allocate other distribution plant costs in FERC accounts 374, 375, 377, and 378 based on pressure class by using Allocator 217.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

REBUTTAL TESTIMONY

OF

MICHAEL P. GRIFFIN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Q. Please state your name and business address.

A. My name is Michael P. Griffin, and my business address is 4600 Coolidge Highway, Royal Oak, Michigan 48073.

Q. Are you the same Michael P. Griffin that testified previously in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address the proposed reductions to Consumers Energy Company's ("Consumers Energy" or the "Company") projected capital expenditures and Operating and Maintenance ("O&M") expenses and the rejection of an accounting treatment change proposed by Attorney General Dana Nessel ("Attorney General") witness Sebastian Coppola. Next, I will provide rebuttal testimony concerning the proposed increases and reductions to the Company's projected capital expenditures and O&M expenses proposed by Citizens Utility Board ("CUB") witness Ram Veerapaneni. Finally, I will provide rebuttal testimony concerning investment levels in future rate case applications and the suggestion that all utility programs should be assessed for risk reduction and cost effectiveness brought forth by Michigan Environmental Council ("MEC") and Sierra Club ("SC") (collectively, MEC) witness Dr. Sol deLeon.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-12 (MPG-2) Revised	Schedule B-5.5	Projected Capital Expenditures Transmission & Distribution Plant - Summary of Actual & Projected Gas Capital Expenditures;

Exhibit A-61 (MPG-5) Revised	Actual & Projected Gas Transmission and Distribution Capital Expenditures - Capacity/Deliverability Program;
Exhibit A-135 (MPG-8)	Workpapers, WP-MPG-13, WP-MPG-15, WP-MPG-17 and WP-MPG-19;
Exhibit A-136 (MPG-9)	Response to Discovery Request U-21806-CECo-AG_DR2; and
Exhibit A-137 (MPG-10)	Response to Discovery Request U-21806-CUB-CE-0248.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

Q. Please describe Exhibit A-12 (MPG-2), Schedule B-5.5 Revised and Exhibit A-61 (MPG-5) Revised.

A. These exhibits reflect a revision that I am making to my originally filed exhibits and changes I am making to my projections as described in my rebuttal testimony below. Exhibits A-12 (MPG-2), Schedule B-5.5 Revised and A-61 (MPG-5) Revised, reflect adjustments to the Capacity/Deliverability Program and the sub-program Deliverability Base Pipeline. These changes will be further explained in my rebuttal testimony to Attorney General witness Coppola below.

I. ATTORNEY GENERAL WITNESS COPPOLA

Q. On page 60, beginning on line 12, through page 61, line 5, of his direct testimony, Mr. Coppola discusses the Company's Pipeline Integrity Transmission Operated by Distribution ("TOD") capital expenditures. He goes on to state that I provided no other details about activities or work volumes to support the forecasted capital expenditures for the TOD program. Do you agree with this assessment?

A. No, I do not. Included with the Company's initial filing were four workpapers showing Assessment IDs (projects), work dig types, costs, and other information used to develop both the capital and O&M costs for the program for 2023 through 2026. Those workpapers, WP-MPG-13, WP-MPG-15, WP-MPG-17 and WP-MPG-19 are included as Exhibit A-135 (MPG-8).

Q. On page 61, beginning on line 13, through page 62, line 13, of his direct testimony, Mr. Coppola discusses the Company's casing assessment program. As part of his review, he states that casing assessment is a new category of costs and that "the Company stated that is has very limited experience with the cost of inspecting and remediating casings." Do you agree with his statement?

A. No, I do not. This is the third time the Company has assessed the casings on the system since the requirement went into effect in 2004. Additionally, his assertion about the Company stating that it has limited experience is not true and this has been acknowledged by Mr. Coppola. I am including Exhibit A-136 (MPG-9) which is the response to discovery request U-21806-CECo-AG_DR2. In his response, Mr. Coppola acknowledges that the Company did not make the statement that it has very limited experience with the cost of inspecting and remediating casings.

Q. Additionally, as part of his review of the casing assessment program, Mr. Coppola states that the $2.0 million included for assessments in 2025 and 2026 seem to be "ballpark" amounts and that due to the early phase of project development, the test year amount of $2.0 million should be eliminated. Do you agree with this recommendation?

A. No, I do not. The $2.0 million is based on what the Company has historically needed to complete the assessment of casings. The level of planning and cost to accomplish four examinations is complex and expensive. In order to levelize work and cost, the projects are spread across two years. To assess the casings within the system, the Company surveyed and tested them in 2023. The data is then analyzed, and four casings were selected in 2024 for examination in 2025 and 2026. This examination can happen in one of two ways. Utilizing a robotic In-Line Inspection ("ILI") tool or by removing the pipeline from the casing to physically inspect the pipe. If the pipe has to be physically removed from the casing for inspection, new pipe is inserted into the casing to replace the old pipe. The method of examination depends on the configuration of the pipe and possibility of utilizing a robotic ILI tool. As to Mr. Coppola's concern about the phase of these projects, the planning and scheduling phase is a part of the normal cadence required to meet these code requirements. For the casings within our system to be considered assessed, the 2025 and 2026 work must be completed within seven years of the prior assessment. These projects are on track and Mr. Coppola's proposed test year reduction of $2.0 million for casing assessments should be rejected by the Michigan Public Service Commission ("MPSC" or the "Commission").

Q. On page 62, beginning on line 14, through page 63, line 7, of his direct testimony, Mr. Coppola discusses the Company's risk mitigation program cost variability and concludes that the Company's test year projection should be reduced by $2.953 million. Do you agree with his reasoning and assessment of the program?

A. No, I do not. The increase in mileage and cost from 2024 to 2026 is a result of the Company ramping up the program and secure the resources needed to complete more mileage in a single year. In order to align the non-high Consequence area ("HCA") assessments with the HCA assessments, more survey and remediation work would need to be completed than what has been done in prior years. The reason for and importance of this program is shown in Exhibit AG-15 at pages 1 and 2. These assessments will inform the Company of the condition of these pipe segments and improve public safety. A stepped increase in 2024 and 2025 is being used to evaluate and secure the resources necessary for the Company, as well as for the contractors that will be utilized. The increase in 2026 allows the Company to assess all the non-HCA on the pipelines scheduled for assessment that year. In 2024 and 2025, only portions of the non-HCA mileage were assessed for those pipelines. As explained in Exhibit AG-15 (discovery response U21806-AG-CE-0316), performing the non-HCA and HCA assessments together gives the Company a better understanding of cathodic protection of the pipe and allows the Company to address deficiencies in the cathodic protection system more holistically. Risk Mitigation assessments are performed to improve safety of the Company's transmission system by assessing for external corrosion on the pipelines. This will reduce the risk of leaks due to external corrosion and improve the overall safety of the system. For the reasons stated above, Mr. Coppola's

proposed test-year reduction of $2.953 million related to Risk Mitigation assessments should be rejected by the Commission.

Q. On page 64, beginning on line 10 of his direct testimony, Mr. Coppola discusses proposed reduction of $3,491,000 to rate base for the 2023 and 2024 expenditures for project GL-03042 within the Maximum Allowable Operating Pressure ("MAOP") Pipeline capital program for which the Company has stated it no longer intends to complete the project. Do you agree with this recommendation?

A. No, I do not. The Company is willing to remove the dollars from rate base for this project, however, workpaper WP-MPG-2 (Exhibit AG-16) is in whole dollars and not thousands. So the rate base reduction for this project should be $3,491 ($1,692 in 2023 and $1,799 in 2024) and not $3,491,000 as proposed by Mr. Coppola.

Q. On page 63, beginning on line 10 of his direct testimony, Mr. Coppola discusses proposed reductions to the Company's Regulatory Compliance – MAOP Project capital expenditures. In this section, he discusses his assessment of the program and states that the "issues here are the same as in the Distribution MAOP projects." Do you agree with his assessment of the Company's MAOP programs?

A. No, I do not. Please see the rebuttal testimony of Company witness Lincoln D. Warriner which provides rebuttal to the arguments Mr. Coppola makes concerning the MAOP Compliance programs in general.

Q. How did the Company decide the most feasible option for the projects you are sponsoring that require reconfirmation under 49 CFR § 192.624?

A. For the projects requiring reconfirmation, the Company selected an MAOP reconfirmation method that provided benefits beyond compliance for the lack of MAOP Traceable,

Verifiable, and Complete ("TVC") pressure test documentation. For other projects, the Company was able to conduct engineering and construction efficiencies while addressing pressure test documentation issues. Further information about these situations and projects is summarized below. These projects are all shown on Exhibit AG-16.

- For project GL-0341 (STC-LN 1060 Mt. Clemens LR Drain Retirement), the Company selected an MAOP reconfirmation solution that provided benefits beyond compliance for the lack of MAOP TVC pressure test documentation. A part of the gap segment is on a drain line that is not utilized by Company operations employees for liquid removal on the launcher/receiver. The project is opting to retire the drain line instead of re-testing or replacing it and installing a new drain assembly. The remaining portion of the gap along the main line will be re-tested which will be expensed (O&M). The Company evaluated undertaking a pressure reduction on the full gap segment, which was determined to not be feasible due to the negative impacts on gas deliverability to Mt. Clemens city gate. Because of these reasons, it was determined that retirement of the drain line, installation of new drain assembly, and retesting the remaining segment was the best option for safety, delivery, and compliance.

- For project GL-03461 (Line 1900 – Metamora City Gate – Hot Tap Replacement & Mainline Valve Install), the Company selected an MAOP reconfirmation solution that provided benefits beyond compliance for the lack of MAOP TVC pressure test documentation. The project also provides an opportunity to install a new main line valve/dual tap assembly to increase system resiliency during outages and lower the amount of methane released during a partial system outage. Due to the short length of the segment, a pressure test is impractical due to the cost associated with multiple cut-outs and welding required in order to conduct testing. The Company is doing the project in conjunction with other projects on the Line 1900 for efficiency. The Company evaluated undertaking a pressure reduction on this line, but it was determined that this is not feasible due to negative impacts on gas deliverability to/from storage fields and would require additional pressure control devices to be installed. Because of these reasons, it was determined to be in the best interest of safety, deliverability, and compliance for replacement as identified by 49 CFR § 192.624(c)(4).

- For Project GL-03462 (STC-Ln 1060 4" BD Repl), the Company selected an MAOP reconfirmation solution that benefits from construction efficiencies and provides some benefit beyond reconfirmation. Due to the short length of the segment, material verification is impractical as it would require replacement of the whole blowdown ("BD") assembly; it would also require the destruction of the welded end valve in order to obtain a sample. A new flanged end valve will be installed, which will allow for equipment connection during temporary

compression/flaring operations. The new BD assembly will also be designed to meet the current engineering standard. This project will also take place in conjunction with other O&M projects at the site for construction efficiencies (L1060 O&M Pressure test). The Company evaluated undertaking a pressure reduction on the segment, which was determined not to be feasible due to the negative impacts on gas deliverability to the nearby Mt. Clemens city gate, which feeds the distribution system.

- For project B-GL-00289 (2026 project for Capital MAOP Replacement Project), the Company continues to review its records and requires funding to remediate any additional gaps that are discovered in between rate case submittals.

Q. Are there other reasons these projects are being conducted and should be approved by the Commission?

A. Yes, there are. Three of the projects shown on Exhibit AG-16, (GL-03197, GL-03210, and GL-03261) are projects for which the Standardized Engineering Analysis research indicated that segments needed replacement due to a class location change that required remediation regardless of TVC records status per 49 CFR § 192.611. Pressure reduction is not feasible as it would not allow the Company to meet gas deliverability requirements. For the reasons stated above, Mr. Coppola's proposed reduction of $3,902,000 for 2023, $2,153,000 for 2024, $1,205,000 for 10 months ending October 2025, and $2,790,000 for the projected test year should be rejected by the Commission.

Q. On page 65, beginning on line 10, through page 66, line 7, of his direct testimony, Mr. Coppola proposes reductions to several Asset Relocation Transmission Program projects. As part of his analysis, he states that based upon the status of the projects in early March of 2025, the cost level and timing of the capital expenditures is still uncertain and premature to include in rate base. Do you agree with this assessment and reason?

A. No, I do not. Each of these projects are progressing and have undertaken activities commensurate with projects that will be constructed in 2026. Company engineers primarily manage projects being constructed in the current year up until late spring when these projects start to be released for construction. They then begin to work on projects for the next year which would include pre-engineering work such as SAP order creation, design commencement, environmental reviews, and long lead-time material ordering. Then they meet with gas control on when the projects can be done based on all other project work and system demands which determines the final scheduling of construction. Thus, Company engineering sources utilize a prudent cadence prior to construction. Further, the timing of and cost of these projects is shown in Exhibit AG-17 (workpaper WP-MPG-1). The Company continues its normal cadence with these projects which also accounts for overall program risk and which ensures continued safety of the system. Mr. Coppola's recommendation that these projects are too premature to include in rate base and should be rejected by the Commission and the Company's full projection for the Asset Relocation Transmission Program should be approved by the Commission.

Q. On page 67, beginning on line 1, through page 67, line 19, of his direct testimony, Mr. Coppola proposes that the Commission disallow the expenditures for project GM-01047 JXN-Lainsburg Jnc. Meter Installation in the Deliverability Base Field Measurement Program based upon his review. Do you agree with this assessment and reason?

A. No, I do not. This project is at a major interstage where multiple large Company-owned pipelines intersect. Having the available metering data will improve measurement accuracy, and associated reports to identify losses on the system earlier as identified in the benefits that were previously described in discovery response U21806-AG-CE-322-Griffin_ATT_1 (Exhibit AG-18). This investment will allow the Company to continue to conform to the MPSC technical standards described in my direct testimony on page 39, lines 15 through 17. Mr. Coppola's recommendation should be rejected by the Commission and the Company's projection for this project should be approved by the Commission.

Q. On page 68, beginning on line 1, through page 69, line 7, of his direct testimony, Mr. Coppola discusses the Deliverability Base Field Measurement Program. As part of his analysis, on page 68, beginning on line 10, through page 68, line 14, of his direct testimony, Mr. Coppola discusses the $100,000 annual savings the Company would experience with gas analysis buildings that are part of project GM-01089, Williamston Meter Proving Station. Do you agree with his assessment?

A. No, I do not. Mr. Coppola seems to be confusing the Company's physical, permanent building at the site with multiple gas analysis buildings that will be constructed at this site. The $100,000 savings is not from using Company resources to build the Company building

in Williamston Michigan called the Williamston Meter Proving station facility. This is savings from constructing the multiple gas analysis buildings that is described beginning on page 68, line 19 of Mr. Coppola's direct testimony. The savings identified is from utilizing Company internal resources versus relying on third-party resources. Third-party contractors labor rates are significantly higher than the Company, and the third-party contract includes charges for project management, master electrician/journeyman, laborers, and costs for tools and equipment. The Company would only incur costs for labor as the project management and master electrician/journeyman costs would be leveraged by increasing the scope of work of existing licensed and experienced salaried employees.

Q. On page 68, beginning on line 14, through page 68, line 17, of his direct testimony, Mr. Coppola discusses the $50,000 annual efficiency from the Company building a Gas Sampling Site at the Williamston Transmission Meter Proving Station, which would eliminate the need for a vendor's sampling site. He concludes that the analysis is incomplete. Do you agree with this assessment?

A. No, I do not. By utilizing the Williamston Transmission Meter Proving Station Site to construct a Gas Sampling Station, the Company would realize immediate savings in labor resources, travel, and fleet expenses. Currently the Company employs a third-party natural gas analysis lab, located in Traverse City, to perform monthly and annual gas analysis. The Company's Operations employees travel more than 400 miles round-trip, often on a monthly basis. The cost of the gas analysis ranges from $150 to $200, or greater, per sample, depending on the type of analysis required. Gas Samples can range from 10-25 per month. The Company intends to leverage internal salaried employees, skilled and experienced, to perform the gas sample analysis at the Williamston Facility. The costs of

the third party performing the gas analysis would be eliminated as well as the significant costs for travel and fleet expenses. An ancillary value/benefit is the fact that this would reduce the turnaround-time between when a gas sample is taken and analyzed, enhancing gas quality best practices. Currently the Company bundles gas samples to attempt to create efficiencies and reduce travel.

Q. On page 68, beginning on line 18, through page 69, line 1, of his direct testimony, Mr. Coppola discusses the $750,000 annual savings the Company would experience with the Williamston Transmission Meter Proving Station. Do you agree with his assessment?

A. No, I do not. The $750,000 is not for the purchase of tools and equipment. The initial investment in tools and equipment is a one-time cost for the Company. As explained above, the third-party contractor incorporates the recurring costs of tools and equipment on each gas analysis building that they construct. The $750,000 savings would be realized by offsetting the Company's growing costs for constructing the gas analysis buildings out-of-state and leveraging the Williamston Transmission Meter Proving Station as a centralized location, where the Company or a third-party contractor can construct the gas analysis buildings. The current third-party out-of-state facilities are limited in the space they have to construct these gas analysis buildings. The Williamston Facility would have the necessary space, tools, equipment, and resources to realistically double the production output of current gas analysis buildings.

Q. On page 69, beginning on line 1, through page 69, line 4, of his direct testimony, Mr. Coppola discusses the $108,000 annual savings the Company would experience with the Williamston Facility. Do you agree with his assessment?

A. No, I do not. The estimated $108,000 annual savings would be realized by eliminating the Company's out-of-state travel/mileage/hotel expense costs for employees attending Factory Acceptance Testing at the third-party contractor's facility. Currently, the Company requires six representatives to attend the Factory Acceptance Testing to ensure quality control and perform safety, compliance, and functionality testing, for their particular disciplines. Factory Acceptance Testing is required twice, per gas analysis building, onsite at the contractor's facility, for the 50% completion and 100% completion of the gas analysis buildings. In addition to the actual travel/mileage/hotel expenses, there are associated costs during travel for the hourly employees required to attend and perform inspections. The Williamston Facility will be an average of 1.5 hours away from the majority of the Company's employees. This would eliminate most of the travel/hotel expenses and significantly reduce mileage and time charged for travel.

Q. Should the Commission approve the Company's projection for the Williamston Meter Proving Station facility?

A. Yes. This station will allow a testing environment for gas transmission measurement technology to comply with API-1164, which requires any new protocol, application, or software proposed to be added to the Supervisory Control and Data Acquisition ("SCADA") network should be run in a test-bed or development environment to evaluate the potential for impairing the performance of the SCADA system. Not only are the costs of the project reasonable, but I have described above the efficiencies gained with the

project. As shown on Exhibit AG-18, the annual projected efficiency from this project will be over $1,000,000. The Commission should reject Mr. Coppola's proposed reduction.

Q. On page 69, beginning on line 8, through page 69, line 20, of his direct testimony, Mr. Coppola proposes that the Commission disallow the expenditures for project GM-00041 Rose Center Meter Replacement in the Deliverability Base Field Measurement Program based upon his review. Do you agree with this assessment and reason?

A. No, I do not. The reasons for this project include the fact that the asset is at the end of its useful life. The operational deficiencies from the current meter are all described in Exhibit AG-18 (discovery response U21806-AG-CE-322_ATT_1). As seen in Exhibit AG-18, not proactively addressing the age of the measurement asset could impact over/under odorization and inaccuracies in volume measurement (gains or losses in Lost and Unaccounted for calculations for the site) due to inability to change the orifice plate. Mr. Coppola's recommendation should be rejected by the Commission and the Company's projection for this project should be approved by the Commission.

Q. On page 42, beginning on line 5, through page 43, line 2, of his direct testimony, Mr. Coppola proposes reductions to six Deliverability Base Field Measurement Program projects based upon the status of the projects as of early March 2025. Do you agree with this assessment and reason?

A. No, I do not. Each of these projects are progressing and have undertaken activities commensurate with projects that will be constructed in 2026. These are projects that are being actively worked on including site evaluation and other pre-engineering activities. Pre-engineering work would include survey work, SAP order creation, design

commencement, environmental reviews, real estate evaluation, scoping, and long lead-time material ordering. Company engineering sources utilize a prudent cadence prior to construction. The Company continues its normal cadence with these projects. Mr. Coppola's recommendation to remove project costs based upon the status should be rejected by the Commission and the Company's projection for these six projects in the Deliverability Base Field Measurement program should be approved by the Commission.

Q. Beginning on page 70, line 11, through page 70, line 13, of his direct testimony, Mr. Coppola states that the Commission should remove $3,647,000 for the 10 months ending October 2025, and $17,559,000 for the projected test year from the Company's forecasted capital expenditures for the Deliverability Base Field Measurement Program. Do you agree with this recommendation?

A. No, I do not. I have described above the reasons for each of Mr. Coppola's proposed reductions. The Company's full projection for this program should be approved by the Commission.

Q. Beginning on page 70 of his direct testimony, Mr. Coppola discusses his review of the Deliverability Base Pipeline Program. On page 71, lines 5 through 12, he discusses a change to the Company's projects that the Company acknowledged in a discovery response and concludes that there should be a substantial reduction to rate base due to the insufficient information he purports to lack. Do you agree with this assessment?

A. No, I do not. The Company acknowledged in Exhibit AG-19 (discovery response U21806-AG-CE-0333) that the 2025 project, B-GL-00251, had been cancelled and replaced by project GL-03313, a project originally planned for 2026. In that same response, the

Company provided sufficient information pertaining to a project that will be done in place of GL-03313 in 2026. This project, B-GL-00274, is an emergent inoperable valve project that will take place in 2026. The information provided in Exhibit AG-19 included the project phase, reason, and cost. This is the same information that had been provided for all other projects on my original workpaper, WP-MPG-4 (Exhibit AG-19), except for the project location, Ray, Michigan. I have included Exhibit A-12 (MPG-12), Schedule B-5.5 Revised and Exhibit A-61 (MPG-5) Revised to reflect the reductions to rate base for the changes described above.

Q. Beginning on page 71, line 13 of his direct testimony, Mr. Coppola proposes reductions to eleven Deliverability Base Pipeline Program projects based upon the status of the projects as of early March 2025. Do you agree with this assessment and reason?

A. No, I do not. Each of these projects are progressing and have undertaken activities commensurate with projects that will be constructed in 2026. Company engineers primarily manage projects being constructed in the current year up until late spring when these projects start to be released for construction. They then begin to work on projects for the next year which would include pre-engineering work such as SAP order creation, design commencement, environmental reviews, and long lead-time material ordering. Then they meet with gas control on when the projects can be done based on all other project work and system demands which determines the final scheduling of construction. Thus, Company engineering sources utilize a prudent cadence prior to construction. The Company continues its normal cadence with these projects. These projects support maintaining operations in accordance with the Michigan Gas Safety Standards ("MGSS").

Mr. Coppola's recommendation that these projects are too premature to include in rate base should be rejected by the Commission and the Company's projection for the Deliverability Base Pipeline Program shown on Exhibit A-61 (MPG-5) Revised should be approved by the Commission.

Q. On page 72, line 6, through page 74 line 3, of his direct testimony, Mr. Coppola proposes reductions to city gate projects based upon an analysis of the historical average cost of projects in this program. Do you agree with this assessment and reductions?

A. No, I do not. As shown in Mr. Coppola's analysis (Exhibit AG-20, page 6) there is a wide variation in the cost (and scope) of city gate modernization projects. This is because no two city gates are exactly alike, and the work required to modernize a city gate can vary widely. The cost for major rebuild projects during the 2022-2026 time frame range from $3,306,450 for GM-00914 (OVS Dorr CG Rbld) to $13,591,760 for GM-00943 (STC-Orion CG Rbld). It is also worth noting that many of the projects are very small in scope and though they do result in a modernized city gate, these projects do not compare to the size and scope of the majority of the test year projects. For example, project B-GL-00308 only involved installing a remote terminal unit ("RTU") and an emergency shut-down valve ("ESD") and cost $1.3 million and project GM-01078 only involved an ESD and cost $1.2 million. These projects were included in the average project cost calculation conducted by Mr. Coppola which reduces the overall average cost.

Q. What would cause such variability in the cost of these projects?

A. Below are some examples of the differences in scope and by extension cost of various city gate projects:

Small City Gate projects typically involve:

- Partial rebuild – some portion of the site is being rebuilt but not in its entirety;
- Small load – the flow at the city gate results in smaller piping and equipment; and
- Less equipment - may not contain an odorizer or single outlet.

Medium City Gate projects typically involve:

- Partial rebuild – some portion of the site is being rebuilt but not in its entirety;
- Less equipment - may not contain an odorizer or single outlet; and
- Full rebuild of a small to medium load facility.

Large City Gate projects typically involve:

- Full rebuild;
- Facilities that contain odorizers or multiple runs or large equipment;
- Large load – the flow at the city gate results in larger equipment and piping; and
- Includes additional measurement or valving requirements.

Q. Can you provide some examples from Exhibit AG-20, page 6, of projects with varying costs and the equipment installed?

A. Yes, I can. Below are some examples of projects of various sizes and the equipment replaced demonstrating the cost discrepancies in these projects.

Dorr City Gate – Small - $3.3 million:

- Small load with single medium pressure outlet and partial rebuild; and
- Scope included replacement of heater, odorizer, RTU, partial regulation replacement with trip out added and necessary piping; new filter separator. Equipment in the 2" and 4" sizing done for modernization needs. Building was not replaced, minimal site work.

Napoleon-Brooklyn City Gate – Medium –$6.5 million:

- 4" inlet 6" outlet full rebuild, includes medium sized odorizer and equipment; and
- Regulation with ESD, filter separator, heater, odorizer, electrical modernization, building, heater fuel meter, gas chromatograph cabinet, no additional transmission valving needs.

Bancroft City Gate – Large - $11 million:

- Full rebuild 6" inlet and 10" outlet piping; includes odorizer, measurement, and valving; and
- Includes demolition, construction of multiple measurement runs, electrical modernization and yard lighting, heater, odorizer, filter separator, regulation, emergency slam shut devices, meters, Remote Control Valve ("RCV"), check valve installation around tap valves, site work in the form of building, driveway, foundations.

Kalamazoo M Ave City Gate – Large – $13 million:

- Full rebuild with 12" inlet piping, 4 outlets, 2 at 12", 8" and 16"; includes odorization, measurement; and
- Large equipment – heater, filter separator, odorizer, nine regulators, ESD, tie-in valve depth work, new building, driveway, fencing, electrical modernization, ultrasonic meters, hydrocarbon dew point and O2 analyzers, and utilizing a refurbished Gas Chromatograph building.

Q. On page 74, lines 1 through 3, of his direct testimony, Mr. Coppola recommends that the Commission remove $11,074,000 for the 10 months ending October 2025 and $14,408,000 for the projected test year from the city gate program projection. Do you agree with this recommendation?

A. No, I do not. Mr. Coppola's analysis fails to take into account the varying costs of city gate projects. Each project was projected based upon the scope, size, equipment, and other factors described above. The Commission should reject the removal of the dollars proposed by Mr. Coppola for the city gate program.

Q. On page 73, lines 9 through 12, of his direct testimony, Mr. Coppola discusses project status for the 2025 and 2026 projects and says, "it is very likely that the cost for these projects will change and could slip into a future year". Do you agree with this assessment?

A. No, I do not. Mr. Coppola provides no evidence that this could or will likely happen. The status of these projects is in line with the normal cadence for projects in this program. At the time of this discovery response, the 2025 projects were in engineering design as they cannot be constructed until after the heating and storage field injection seasons are completed so that outages can be taken on the pipelines.

Q. Beginning on page 74, line 4, through page 75, line 7, of his direct testimony, Mr. Coppola proposes a reduction to the TED-I Program for seven RCV projects based upon the status of the certain projects as of early March 2025. Do you agree with this assessment and reasoning?

A. No, I do not. The RCV projects Mr. Coppola describes are in the normal phase for RCV projects that will be constructed the following year. The project process for RCVs is the following. The creation of the project scope documents, and potential surveying and material selection typically occur the year prior to construction (in 2025 in this case). The year of construction (2026) includes site survey work not completed in the prior year, the receipt of materials, the engineering and design work, release of design packages, contractor bidding and selection, and finally construction and project closeout. These seven projects are following the normal cadence for RCV projects and are thus not premature to be included in rate base. Mr. Coppola's proposed reduction to the RCV program should be rejected by the Commission.

Q. On page 171, beginning on line 15, through page 172, line 11, of his direct testimony, Mr. Coppola proposes reductions to the Company's MAOP Transmission O&M related to the Standardized Engineering Analysis expenses. Do you agree with this assessment and reasoning?

A. No, I do not. These expenses are a direct result of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 and subsequent 2019 Safety of Gas Transmission Rules issued by the Pipeline and Hazardous Materials Safety Administration ("PHSMA") as described in my direct testimony beginning on page 24, line 21, through page 25, line 22. In MPSC Case No. U-21291, the case cited by Mr. Coppola, the Commission stated, "the 2019 revisions to federal pipeline safety regulations and the 2011 advisory bulletin are not new record keeping requirements and that DTE Gas was previously required by MGSS to perform strength tests, including MAOP tests, and to maintain those records for the life of the pipeline." The Company concurs that the Commission's second statement from this quote is correct; pipeline operators have been required to perform strength tests and keep those records for the life of facility since 1970 when subpart J pressure testing standards were implemented per 49 CFR § 192.517. Regarding the first statement, the Company maintains that the traceable, verifiable, and complete standard that PHMSA implemented in 2019 is an additional threshold beyond the recording requirements described in 49 CFR § 192.517. PHSMA deemed these original standards as not sufficient enough to prevent the recent incidents cited in the regulation; per the 2019 pre-amble, PHMSA states, "the purpose of this final rule is to increase the level of safety associated with the transportation of gas." Per the FAQ-30[1] provided in the Batch 1 FAQs, PHSMA details what it deems as

[1] https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2023-05/Batch-1-FAQs-PHMSA-2019-0225-9-15-20.pdf

a TVC record; there are additional requirements that are not included in 49 CFR § 192.517. As an example of this higher standard, pressure test records are now required to be verifiable, which PHMSA states that they are "confirmed by the purchase order or project specification for the pipeline or the alignment sheet with consistent information." The study is appropriate so the Company can prove that its records now meet the TVC threshold in order to be compliant, which was directed by PHMSA in the 2011 bulletin that states "An operator must diligently search, review and scrutinize documents and records". All of the supporting evidence points to the conclusion that PHMSA intended to increase thresholds for records and require operators to evaluate said records in the name of safety. Therefore, the Company disagrees with Mr. Coppola's proposed 50% reductions.

Q. Is the Company following the guidance from the MPSC Staff in its accounting treatment of these expenses.

A. Yes. This is described in my direct testimony beginning on page 29, line 1, through page 30, line 1.

Q. On page 172, beginning on line 12, through page 173, line 18, of his direct testimony, Mr. Coppola proposes reductions to the Company's Corrosion Control Transmission O&M expenses. In his review, he states that the expense for the test year is not supported by any increased work units or activities. Do you agree with this assessment?

A. No, I do not. The discovery requests Mr. Coppola refers to in his direct testimony and are shown in Exhibit A-59 (MPG-3) were responsive to the information he requested. As shown in the response to discovery request U21806-AG-CE-338, the Attorney General did not ask for work units or activities. Further, in discovery request U21806-AG-CE-760, the

request was to explain what work was being done and not to provide work units or activities.

Q. Were intervenors in this case provided the work units and associated costs in discovery?

A. Yes, they were. Discovery request U21806-CUB-CE-0248, which was sent to all parties to this case provided the number of projects and average cost for each category in this program. Exhibit A-137 (MPG-10) includes the response to discovery request U21806-CUB-CE-0248. The difficulty with projecting work based on units in this program is the variability in the work. Specifically, for atmospheric corrosion projects, a project can be one item at a compressor station, or an entire city gate. The amount of work and resulting cost can be significantly different. Similarly, for recoat projects, the diameter of the pipe as well as length of the project are both variables that are difficult to anticipate and significantly affect the cost. These projected costs will ensure that sufficient funds are available for the Company to complete required work, including those mandated in recent rulemaking, in the required timeframes. Mr. Coppola's reduction to the Company projection in this program should be rejected by the Commission.

Q. On page 195 of his direct testimony, Mr. Coppola states that there is no reason for the Commission to approve the Company's proposal to capitalize hydrotesting of pipelines in certain circumstances. Do you agree with this assessment?

A. No, I do not. The Federal Energy Regulatory Commission has provided accounting guidance and the specific situations where the Company would utilize this accounting treatment is spelled out in Company witness Heather L. Rayl's direct testimony beginning on page 24, lines 1 through 16. In order to be able to capitalize these projects, the Company

needs to get approval from the Commission. Waiting for a project and then seeking approval is not practical. The Commission should reject Mr. Coppola's proposal.

II. CUB WITNESS VEERAPANENI

Q. Beginning on page 9 of his direct testimony, CUB witness Veerapaneni proposes a reduction to the Asset Relocation – Transmission Program expenditures in the test year. Do you agree with his proposal?

A. No, I do not. The Company provided justification for the expenditures in the program through my direct testimony beginning on page 5, line 5, through page 9, line 20. My direct testimony describes the necessity of the expenditures and lists the projects to be conducted. Each project through the test year, the project reason, location, pipe length and approximate construction time frame are further shown in workpaper WP-MPG-1 (Exhibit AG-17). Mr. Veerapaneni simply took the average of the 2023 and 2024 actual expenditures and applied inflation to project a test year amount. The Company's projections are based upon knowledge of specific projects planned for the next several years. Annual projects and program costs vary depending upon customer requests for modifications, regulations, system condition, scope of projects, specific projects, and outage planning. Mr. Veerapaneni did not review the reasonableness of the projects proposed during the test year nor the benefits the projects would provide to customers. This methodology should be rejected by the Commission and the Company's projection should be approved.

Q. Beginning on page 10 of his direct testimony, CUB witness Veerapaneni proposes an increase to the Regulatory Compliance Program expenditures in the test year. Do you agree with his proposal?

A. No, I do not. The Company provided extensive documentation for the expenditures in this program and the sub-programs throughout my direct testimony, beginning on page 10, line 1, through page 30, line 1. These sub-programs are Pipeline Integrity Transmission, Pipeline Integrity TOD, Cathodic Compression, Storage and Pipeline, and MAOP Compliance Pipeline. My direct testimony describes the necessity of the expenditures and the regulations for which these expenditures allow the Company to comply. Mr. Veerapaneni simply took the average of the 2023 and 2024 actual expenditures and applied inflation to project a test year amount. The Company's projections are based upon knowledge of specific projects planned for the next several years. Annual projects and expenditures vary depending upon regulations, system condition, scope of projects, specific projects, and outage planning. Mr. Veerapaneni did not review the reasonableness of the projects proposed during the test year nor the benefits the projects would provide customers. This methodology should be rejected by the Commission and the Company's projection should be approved.

Q. Beginning on page 12 of his direct testimony, CUB witness Veerapaneni proposes an increase to the Capacity/Deliverability Program expenditures in the test year. Do you agree with his proposal?

A. No, I do not. The Company provided extensive documentation for the expenditures in this program and the many sub-programs throughout my direct testimony beginning on page 30, line 8, through page 48, line 20. These programs include TED-I, Deliverability

Base Field Measurement, Deliverability Base Pipeline, Regulator Stations – Distribution, and T&S City Gates. My direct testimony describes the necessity of the expenditures, lists the projects to be conducted and provides the expenditures. These projections are based upon knowledge of specific projects planned for the next several years. Further, capacity requirements can increase due to changes in customer population density in specific locations and also because of changes in system requirements.

Annual projects vary depending upon regulations, system condition, scope of projects, specific projects, and outage planning. The Company believes that the methodology used by CUB is unreasonable. Mr. Veerapaneni did not review the reasonableness of the projects proposed during the test year or the benefits the projects would provide to customers. This methodology should be rejected by the Commission.

Q. On page 17 of his direct testimony, CUB witness Veerapaneni proposes a reduction to the Gas Regulatory Compliance Program O&M expenses in the test year. Do you agree with his proposal?

A. No, I do not. As with the programs mentioned above, I provided a description of the necessity for the expenses in this program in my direct testimony beginning on page 10, line 1, through page 30, line 1. Mr. Veerapaneni simply took the average of the 2023 and 2024 actual amounts and applied inflation to project a test year amount. My direct testimony describes the necessity of the expenses and the regulations for which these expenditures allow the Company to comply. Mr. Veerapaneni did not review the reasonableness of the projects proposed during the test year or the benefits the projects would provide to customers. This methodology should be rejected by the Commission.

III. MEC WITNESS DELEON

Q. On page 30, line 9 of her direct testimony, MEC witness deLeon suggests that all utility programs should be assessed for risk reduction and cost effectiveness. Is it practical for every program to utilize a risk model and cost-effectiveness calculation?

A. No, it is not. For Transmission programs and projects, some projects are customer requested, and a large number are in response to regulatory requirements or to maintain the reliability and resiliency of the Company's system. Thus, not all programs have projects that are as a result of a risk model. Pipeline Integrity and Asset Relocation Transmission programs utilize data from the model to prioritize projects. But a significant portion of the other transmission programs' projects are otherwise indicated. For example, Corrosion Control projects allow the Company to maintain compliance with federal regulations for cathodic protection of facilities. MAOP Compliance Pipeline projects involve MAOP verification and remediation of the Company's transmission pipelines. Most TED-I projects going forward concern the installation of RCVs to improve public safety and minimize gas flows after a failure. The Deliverability Base Field Measurement Program is essential to ensure accurate gas quality and measurement. The Deliverability Base Pipeline Program supports maintaining operations in accordance with the MGSS. City gate investments allow for the rebuilding or other improvements to existing city gate facilities to ensure system reliability and in response to increased customer load demands. Regulator station investments are distribution assets but aimed at maintaining the integrity of 648 regulator station on the Company system.

Q. Beginning on page 41, lines 1 through 5 of her direct testimony, MEC witness deLeon makes recommendations concerning investment levels in future rate case applications. Do you agree with this recommendation?

A. No, I do not. Dr. deLeon seems to be indicating that the Company be frozen at the 2024 level for capital investment amounts regardless of the historical test year or other changes in regulations in future rate case filings. This recommendation is unreasonable. The Company's forward looking rate case filings contain projects and programs supported by expert witness testimony which describe the necessity of the expenditures based upon system conditions, safety improvements and compliance with regulations. This recommendation should be rejected by the Commission.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

EXHIBITS

OF

MICHAEL P. GRIFFIN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Schedule: B-5.5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Capital Expenditures Transmission & Distribution Plant
Summary of Actual & Projected Gas Capital Expenditures
($000)

Case No.: U-21806
Exhibit No.: A-12 (MPG-2) Revised
Schedule: B-5.5
Page: 1 of 1
Witness: MPGriffin
Date: December 2024

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2023	(c) Projected Bridge Period 12 Mos Ending 12/31/2024	(d) Projected Bridge Period 10 Mos Ending 10/31/2025	(e) Projected Bridge Period 22 Mos Ending 10/31/2025	(f) Projected Test Year 12 Mos Ending 10/31/2026
1	Asset Relocation	6,168	17,389	19,138	36,527	24,726
2	Regulatory Compliance	36,139	26,078	24,285	50,362	24,807
3	Capacity/Deliverability	308,275	270,203	133,076	403,278	170,372
4	Total Capital	350,582	313,669	176,499	490,168	219,905

		Projected			
		10 Mos Ending 10/31/2024	12 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	34 Mos Ending 10/31/2026
5	Asset Relocation	15,150	21,377	24,726	61,253
6	Regulatory Compliance	27,176	23,187	24,807	75,170
7	Capacity/Deliverability	245,755	157,965	170,372	574,092
8	Total Capital	288,081	202,529	219,905	710,515

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual & Projected Gas Transmission and Distribution Capital Expenditures
Capacity/Deliverability Program
($000)

Case No.: U-21806
Exhibit No.: A-61 (MPG-5) **Revised**
Page: 1 of 3
Witness: MPGriffin
Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)	
		Historical Year	Projected Bridge Year			Projected Test Year	
Line No	Description	12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	Source
1	**Transmission Enhancements for Deliverability & Integrity ("TED-I")**	**216,361**	**146,790**	**20,192**	**166,982**	**19,145**	Exhibit A-62 (MPG-6)
	Labor	4,591	3,708	995	4,703	1,029	
	Capitalized Engineering/Supv	3,840	209	2,941	3,150	4,135	
	Materials	10,204	3,070	494	3,564	662	
	Contractor	172,830	129,961	13,225	143,186	10,523	
	Non-Labor Overhead	607	430	74	505	26	
	Non-Labor Other	24,289	9,413	2,461	11,874	2,770	
2	**Misc Transmission & Compression**	**257**	**22**	**0**	**22**	**0**	
5%	Labor	7	1	0	1	0	
26%	Capitalized Engineering/Supv	69	6	0	6	0	
-1%	Materials	(4)	(0)	0	(0)	0	
49%	Contractor	131	11	0	11	0	
0%	Non-Labor Overhead	0	0	0	0	0	
20%	Non-Labor Other	55	4	0	4	0	
3	**Deliverability Base Field Measurement**	**5,319**	**6,774**	**10,255**	**17,029**	**19,890**	WP-MPG-3
5%	Labor	266	312	473	785	917	
24%	Capitalized Engineering/Supv	1,339	1,624	2,458	4,082	4,768	
25%	Materials	1,110	1,684	2,549	4,233	4,945	
71%	Contractor	4,161	4,835	7,319	12,154	14,196	
0%	Non-Labor Overhead	26	32	48	79	93	
-25%	Non-Labor Other	(1,585)	(1,713)	(2,593)	(4,306)	(5,029)	
4	**Deliverability Base Pipeline**	**18,757**	**18,014**	**19,120**	**37,134**	**25,073**	WP-MPG-4
8%	Labor	1,560	1,470	1,561	3,031	2,047	
23%	Capitalized Engineering/Supv	4,428	4,216	4,475	8,690	5,868	
13%	Materials	2,152	2,366	2,511	4,878	3,293	
43%	Contractor	8,422	7,836	8,317	16,153	10,906	
1%	Non-Labor Overhead	292	257	272	529	357	
10%	Non-Labor Other	1,902	1,869	1,984	3,853	2,601	
5	**Regulator Stations - Distribution**	**36,262**	**45,690**	**36,039**	**81,729**	**47,274**	WP-MPG-5
10%	Labor	3,565	4,672	3,685	8,356	4,834	
25%	Capitalized Engineering/Supv	9,028	11,221	8,851	20,073	11,610	
11%	Materials	3,270	5,001	3,944	8,945	5,174	
34%	Contractor	13,217	15,691	12,377	28,068	16,235	
1%	Non-Labor Overhead	374	466	367	833	482	
19%	Non-Labor Other	6,808	8,640	6,815	15,454	8,939	
6	**T&S City Gates**	**31,320**	**52,913**	**47,469**	**100,383**	**58,991**	WP-MPG-6
7%	Labor	1,925	3,445	3,091	6,536	3,841	
23%	Capitalized Engineering/Supv	7,333	12,010	10,774	22,784	13,389	
17%	Materials	5,004	9,082	8,147	17,229	10,125	
36%	Contractor	12,499	19,134	17,166	36,300	21,332	
1%	Non-Labor Overhead	417	625	561	1,186	697	
16%	Non-Labor Other	4,142	8,616	7,730	16,346	9,606	
7	**Total Capacity/Deliverability Capital**	**308,275**	**270,203**	**133,076**	**403,278**	**170,372**	
	Labor	11,914	13,608	9,805	23,413	12,667	
	Capitalized Engineering/Supv	26,037	29,286	29,500	58,786	39,771	
	Materials	21,737	21,202	17,647	38,849	24,199	
	Contractor	211,260	177,467	58,404	235,871	73,193	
	Non-Labor Overhead	1,716	1,810	1,323	3,132	1,655	
	Non-Labor Other	35,610	26,829	16,397	43,226	18,887	

Unless noted otherwise, capital "other" costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, and business expenses (e.g., travel, meals, etc.).

This exhibit demonstrates the projected break down for each program into the cost components shown above. The 2023 amounts are the actual amounts. The cost component projections for all programs and projects except for the Mid-Michigan Pipeline MMPL) for 2024 and beyond are based upon the 2023-2024 18 month (Jan 2023 - Jun 2024) average actual percentage of the breakdown of these components in these programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes. Cost confidence levels were not used to develop projected test year costs.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual & Projected Gas Transmission and Distribution Capital Expenditures
Capacity/Deliverability Program

Case No.: U-21806
Exhibit No.: A-61 (MPG-5) **Revised**
Page: 2 of 3
Witness: MPGriffin

($000) Date: December 2024

	(a)	(b)	(c)	(d)	(e)
			Projected		
		10 Mos Ending 10/31/2024	12 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	34 Mos Ending 10/31/2026
8	**Transmission Enhancements for Deliverabil**	**138,586**	**28,397**	**19,145**	**186,127**
	Labor	3,245	1,458	1,029	5,732
	Capitalized Engineering/Supv	67	3,084	4,135	7,285
	Materials	2,626	939	662	4,227
	Contractor	123,056	20,130	10,523	153,709
	Non-Labor Overhead	423	81	26	531
	Non-Labor Other	9,169	2,705	2,770	14,644
9	**Misc Transmission & Compression**	**23**	**(1)**	**0**	**22**
5%	Labor	1	(0)	0	1
26%	Capitalized Engineering/Supv	6	(0)	0	6
-1%	Materials	(0)	0	0	(0)
49%	Contractor	11	(0)	0	11
0%	Non-Labor Overhead	0	0	0	0
20%	Non-Labor Other	5	(0)	0	4
10	**Deliverability Base Field Measurement**	**4,518**	**12,511**	**19,890**	**36,919**
5%	Labor	208	577	917	1,702
24%	Capitalized Engineering/Supv	1,083	2,999	4,768	8,851
25%	Materials	1,123	3,110	4,945	9,178
71%	Contractor	3,225	8,929	14,196	26,351
0%	Non-Labor Overhead	21	58	93	172
-25%	Non-Labor Other	(1,142)	(3,163)	(5,029)	(9,334)
11	**Deliverability Base Pipeline**	**14,136**	**23,440**	**25,073**	**62,648**
8%	Labor	1,154	1,913	2,047	5,114
23%	Capitalized Engineering/Supv	3,308	5,486	5,868	14,662
13%	Materials	1,857	3,079	3,293	8,229
43%	Contractor	6,149	10,196	10,906	27,251
1%	Non-Labor Overhead	201	334	357	892
10%	Non-Labor Other	1,467	2,432	2,601	6,500
12	**Regulator Stations - Distribution**	**42,319**	**39,410**	**47,274**	**129,003**
10%	Labor	4,327	4,029	4,834	13,190
25%	Capitalized Engineering/Supv	10,394	9,679	11,610	31,683
11%	Materials	4,632	4,313	5,174	14,119
34%	Contractor	14,533	13,534	16,235	44,302
1%	Non-Labor Overhead	432	402	482	1,315
19%	Non-Labor Other	8,002	7,452	8,939	24,393
13	**T&S City Gates**	**46,174**	**54,209**	**58,991**	**159,373**
7%	Labor	3,007	3,530	3,841	10,378
23%	Capitalized Engineering/Supv	10,480	12,304	13,389	36,174
17%	Materials	7,925	9,304	10,125	27,354
36%	Contractor	16,697	19,603	21,332	57,632
1%	Non-Labor Overhead	546	640	697	1,883
16%	Non-Labor Other	7,519	8,827	9,606	25,952
13	**Total Capacity/Deliverability Capital**	**245,755**	**157,965**	**170,372**	**574,092**
	Labor	11,942	11,507	12,667	36,116
	Capitalized Engineering/Supv	25,338	33,552	39,771	98,660
	Materials	18,162	20,745	24,199	63,106
	Contractor	163,672	72,392	73,193	309,256
	Non-Labor Overhead	1,623	1,516	1,655	4,794
	Non-Labor Other	25,019	18,253	18,887	62,160

This exhibit demonstrates the projected break down for each program into the cost components shown above. The 2023 amounts are the actual amounts. The cost component projections for all programs and projects except for the Mid-Michigan Pipeline MMPL) for 2024 and beyond are based upon the 2023-2024 18 month (Jan 2023 - Jun 2024) average actual percentage of the breakdown of these components in these programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes. Cost confidence levels were not used to develop projected test year costs.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual & Projected Gas Transmission and Distribution Capital Expenditures
Capacity/Deliverability Program
($000)

Case No.: U-21806
Exhibit No.: A-61 (MPG-5) **Revised**
Page: 3 of 3
Witness: MPGriffin
Date: December 2024

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2023	(c) Projected Bridge Year 12 Mos Ending 12/31/2024	(d) Projected Bridge Year 10 Mos Ending 10/31/2025	(e) Projected Bridge Year 22 Mos Ending 10/31/2025 [Col. (c) + (d)]	(f) Projected Test Year 12 Mos Ending 10/31/2026
	Projects Over $5 Million					
1	**Transmission Enhancements for Deliverability & Integrity ("TED-I")**					
2	TED-I 100A Ovid to Will Pipe Repl	13,864	133,598	6,741	140,339	389
3	STC-Oakland Resilience Interconnect	53	1,161	4,466	5,628	45
4	**Misc Transmission & Compression**					
5	None Identified	-	-	-	-	-
6	**Deliverability Base Field Measurement**					
7	SAG-Grand Blanc Mtr Run Repl	13	1,286	4,320	5,606	524
8	Williamston Transmission Meter Proving Station	-	200	226	426	7,994
9	Northville CS Line 1200 A Meter and Chromatograph Install	-	-	-	-	4,889
10	**Deliverability Base Pipeline**					
11	None identified	-	-	-	-	-
12	**Regulator Stations - Distribution**					
13	MID-63-245 Poseyville Sta Rbld	-	17	4,366	4,383	622
14	**T&S City Gates**					
15	STC-Orion CG Rbld	888	11,942	44	11,986	6
16	JXN-PEPL-Blissfield CG Rbld	1,217	9,479	44	9,523	6
17	FDM-Bancroft CG Rbld	156	1,214	7,472	8,686	1,211
18	JXN-Jxn Hart Rd CG Rbld	-	788	7,436	8,224	1,207
19	FDM-Hanover Horton CG Rbld	-	581	5,926	6,506	1,017
20	SAG-Flint Torrey Rd CG Rebl	-	1,062	6,800	7,862	1,127
21	NVL-Highland CG, Odorizer Rbld	-	880	7,770	8,650	1,249
22	Spring Arbor CG - PEPL & Odorizer	-	-	877	877	7,861
23	Flint CG Irish & Odorizer	-	-	877	877	7,501
24	Climax CG - PEPL	-	-	755	755	8,647
25	South Lyon - Whitmore Lake CG & Odorizer	-	-	472	472	7,912
26	Mendon Leonidas & Odorizer	-	-	472	472	8,611
	Projects Under $5 Million					
27	Transmission Enhancements for Deliverability & Integrity ("TED-I")	202,444	12,031	8,984	21,015	18,711
28	Misc Transmission & Compression	257	22	-	22	-
29	Deliverability Base Field Measurement	5,306	5,288	5,709	10,997	6,484
30	Deliverability Base Pipeline	18,757	18,014	19,120	37,134	25,073
31	Regulator Stations - Distribution	36,262	45,673	31,673	77,346	46,651
32	T&S City Gates	29,059	26,967	8,524	35,491	12,637
33	**Total Capital**	308,275	270,203	133,076	403,278	170,372

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Regulatory Compliance Program
Pipeline Integrity - TOD Capital and O&M Projects - 2023
Pipeline Integrity - Distribution (TOD)- Capital 2023 Costs by Project ID

Case No. U-21806
WP-MPG-13
Page 1 of 2

Portfolio	Assessment ID	Work Type	CAP Expenditure ($)	Internal Approval Y/N
Pipeline Integrity - TOD	Dx1002 - ROY	ECDA	(36,501)	Y
Pipeline Integrity - TOD	Dx1006 - Macomb	ECDA	497,207	Y
Pipeline Integrity - TOD	Dx1026 - Lansing	ECDA	309,601	Y
Pipeline Integrity - TOD	Dx1028 - Greenville	ECDA	380,869	Y
Pipeline Integrity - TOD	Dx1070 - Alma	ECDA	177,938	Y
Pipeline Integrity - TOD	Dx1071 - Alma	ECDA	214,491	Y
Pipeline Integrity - TOD	Dx1089 - Alma	ECDA	243,142	Y
Pipeline Integrity - TOD	Dx1090 - Saginaw	ECDA	207,411	Y
Pipeline Integrity - TOD	Dx1091 - Bad Axe	ECDA	163,603	Y
Pipeline Integrity - TOD	Dx1094 - Saginaw	ECDA	282,904	Y
Pipeline Integrity - TOD	Dx1002 - ROY	ICDA	83,620	Y
Pipeline Integrity - TOD	Dx1010 - Shelby	ICDA	117,599	Y
Pipeline Integrity - TOD	Dx1022 - Grand Ledge	ICDA	97,308	Y
Pipeline Integrity - TOD	Dx1024 - Williamston	ICDA	159,364	Y
Pipeline Integrity - TOD	Dx1027 - Lansing Turner	ICDA	399,119	Y
Pipeline Integrity - TOD	Dx1041 - Flint Lapeer	ICDA	221,017	Y
Pipeline Integrity - TOD	Dx1049 - Flint Torey	ICDA	259,792	Y
Pipeline Integrity - TOD	Dx1064 - Jackson Park	ICDA	(202,369)	Y
Pipeline Integrity - TOD	Dx1065 - Jackson Park	ICDA	253,783	Y
Pipeline Integrity - TOD	Dx1080 - Kalamazoo M Ave	ICDA	479,307	Y
Pipeline Integrity - TOD	Dx1082 - Kalamazoo M Ave	ICDA	716,659	Y
Pipeline Integrity - TOD	Dx1085 - Zilwaukee	ICDA	121,986	Y
Pipeline Integrity - TOD	Dx1087 - Zilwaukee	ICDA	530,377	Y
Pipeline Integrity - TOD	Dx1088 - Zilwaukee	ICDA	321,294	Y
Pipeline Integrity - TOD	Dx1090 - Akron	ICDA	533,705	Y
Pipeline Integrity - TOD	Dx1091 - Bad Axe	ICDA	55,936	Y
Pipeline Integrity - TOD	Dx1092 - Saginaw Dutch	ICDA	244,360	Y
Pipeline Integrity - TOD	Dx1094 - Saginaw Dutch	ICDA	254,548	Y
Pipeline Integrity - TOD	2022 Capital Tools-New Technicians	Project, pipeline repair / replacement	3,544	Y
Pipeline Integrity - TOD	2023 Capital Tools-New Technicians	Project, pipeline repair / replacement	218	Y
Pipeline Integrity - TOD	DAPP 18640 DX1085K 1of6 M13 at CodyEstey	Project, pipeline repair / replacement	1,577,894	Y
Pipeline Integrity - TOD	DAPP 18641 DX1085K CODY ESTEY @ 11 MILE	Project, pipeline repair / replacement	(62,933)	Y
Pipeline Integrity - TOD	DAPP 19038 LINE 1008 SECTION REPLACEMENT	Project, pipeline repair / replacement	342,063	Y
Pipeline Integrity - TOD	DAPP 19698 LINE 1022 CAPITOL AIRPORT	Project, pipeline repair / replacement	5,283	Y
Pipeline Integrity - TOD	DAPP 19963 LINE 1022 WAVERLY	Project, pipeline repair / replacement	(12,246)	Y
Pipeline Integrity - TOD	DAPP 20051 26" MAIN REPLACMENT MUE - Mar	Project, pipeline repair / replacement	140,441	Y
Pipeline Integrity - TOD	DAPP 21114 WAVERLY RD SAGINAW HWY HP	Project, pipeline repair / replacement	2,347,672	Y
Pipeline Integrity - TOD	LAN-DAPP 21114 Waverly Rd Saginaw Hwy	Project, pipeline repair / replacement	(2,204,420)	Y
Pipeline Integrity - TOD	LIV-DAPP11151 Mdlblt, Joy 10" HP Repl	Project, pipeline repair / replacement	48,035	Y
		Total	**9,273,622**	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Regulatory Compliance Program
Pipeline Integrity - TOD Capital and O&M Projects - 2023
Pipeline Integrity - Distribution (TOD) - O&M 2023 Costs by Project ID

Case No. U-21806
WP-MPG-13
Page 2 of 2

Portfolio	Assessment ID	Total O&M Expense ($)	HCA Digs O&M ($)	Non-HCA Digs O&M ($)	Internal Approval Y/N
Pipeline Integrity - TOD	Dx1006	51,036			Y
Pipeline Integrity - TOD	Dx1070, Dx1071, Dx1089 - Alma	3,057			Y
Pipeline Integrity - TOD	Dx1027	43,496	-	66,667	Y
Pipeline Integrity - TOD	Dx1028	111,196	52,196	59,000	Y
Pipeline Integrity - TOD	Dx1070	59,000	-	59,000	Y
Pipeline Integrity - TOD	Dx1071	102,496	-	102,496	Y
Pipeline Integrity - TOD	Dx1089	59,000	-	59,000	Y
Pipeline Integrity - TOD	Dx1090	41,601	26,098	15,504	Y
Pipeline Integrity - TOD	Dx1091	41,601	26,098	15,504	Y
Pipeline Integrity - TOD	Dx1094	102,496	-	102,496	Y
Pipeline Integrity - TOD	Dx1080	26,493			Y
Pipeline Integrity - TOD	gPIMS Annual Reads 2023 (Statewide)	21,688			Y
Pipeline Integrity - TOD	LIV Pipeline Integ IIS, Line 1099	3,980			Y
Pipeline Integrity - TOD	Pipeline Integrity 2022 Lab Cost	12,050			Y
Pipeline Integrity - TOD	Pipeline Integrity 2023 Lab Cost	7,933			Y
Pipeline Integrity - TOD	Pipeline Integrity Middle Material	5,298			Y
Pipeline Integrity - TOD	Dx1027	10,981			Y
Pipeline Integrity - TOD	Dx1028	11,114			Y
Pipeline Integrity - TOD	Dx1041	9,469			Y
Pipeline Integrity - TOD	Dx1080, Dx1082	9,131			Y
Pipeline Integrity - TOD	Dx1087	679			Y
Pipeline Integrity - TOD	Dx1090, Dx1091	7,654			Y
Pipeline Integrity - TOD	Dx1092, Dx1093, Dx1094	7,034			Y
Pipeline Integrity - TOD	Dx1094	829			Y
Pipeline Integrity - TOD	BSI EA 2014-(14, 17, & 18) Retrofit Upgr	23,973			Y
Pipeline Integrity - TOD	BSI EA UT 2020-1871 Repair	1,851			Y
Pipeline Integrity - TOD	DA Dept. TS Repair BSI EA 2390 & 2291	2,727			Y
Pipeline Integrity - TOD	UT Reads - Statewide	33,778			Y
	Total	**811,642**			

Business cases have not been conducted on these projects as the expenditures in the Pipeline Integrity Program represent the necessary inspections and remediation O&M expenses and capital expenditures that allow the Company to remain compliant with regulations mandated by the federal Pipeline & Hazardous Materials Safety Administration (“PHMSA”) and the Commission.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Regulatory Compliance Program
Pipeline Integrity - TOD Capital and O&M Projects - 2024
Pipeline Integrity - Distribution (TOD)- CAP 2024 Costs by Project ID

Portfolio	Assessment ID	Work Type	HCA Assessments ECDA ($)	Non-HCA/MCA Assessments ($)	Casing Assessments ($)	CAP Expenditure ($)	Internal Approval Y/N
Pipeline Integrity - TOD	Dx1015	ECDA Digs	174,653				Y
Pipeline Integrity - TOD	Dx1020	ECDA Digs	174,653				Y
Pipeline Integrity - TOD	Dx1049	ECDA Digs	529,791	387,058			Y
Pipeline Integrity - TOD	Dx1080	ECDA Digs	174,653				Y
Pipeline Integrity - TOD	Dx1080-Class	ECDA Digs	225,387	175,275			Y
Pipeline Integrity - TOD	Dx1099	ECDA Digs	326,855				Y
	ECDA Total		**1,605,992**	**562,333**	**178,444**	**2,346,768**	

			HCA Assessments ICDA ($)	Non-HCA/MCA Assessments ($)			
Pipeline Integrity - TOD	AlmaCG_Dx1070_Downstream of Dx1071	ICDA Digs	160,206				Y
Pipeline Integrity - TOD	AlmaCG_Dx1071_Mainline	ICDA Digs	240,308	523,531			Y
Pipeline Integrity - TOD	AlmaCG_Dx1089_Mainline	ICDA Digs	320,411				Y
Pipeline Integrity - TOD	GreenfieldCG_Dx1020_Mainline	ICDA Digs	213,607	579,609			Y
Pipeline Integrity - TOD	LahserCG_Dx1020_Mainline	ICDA Digs	213,607				Y
Pipeline Integrity - TOD	MtPleasantCG_Dx1070_Mainline	ICDA Digs	213,607				Y
Pipeline Integrity - TOD	NorthLyonCG_Dx1099_Mainline	ICDA Digs	213,607				Y
Pipeline Integrity - TOD	RedRunCG_Dx1002f West_Mainline	ICDA Digs	320,411				Y
Pipeline Integrity - TOD	RedRunCG_Dx1002g_Mainline	ICDA Digs	293,710				Y
Pipeline Integrity - TOD	RedRunCG_Dx1006_Downstream of Dx1002f West	ICDA Digs	160,206				Y
Pipeline Integrity - TOD	RedRunCG_Dx1008_Downstream of 1002f West	ICDA Digs	160,206				Y
Pipeline Integrity - TOD	RedRunCG_Dx1009_Downstream of 1002f West	ICDA Digs	160,206				Y
	ICDA Total		**2,670,092**	**1,103,140**		**3,773,232**	
	Total					**6,120,000**	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Regulatory Compliance Program
Pipeline Integrity - TOD Capital and O&M Projects - 2024
Pipeline Integrity - Distribution (TOD) - O&M 2024 Costs by Project ID

Case No. U-21806
WP-MPG-15
Page 2 of 2

Portfolio	Assessment ID	Work Type	DA Survey O&M ($)	HCA Digs O&M ($)	Non-HCA Digs O&M ($)	Total O&M Expense ($)	Internal Approval Y/N
Pipeline Integrity - TOD	Dx1015	ECDA Digs	35,614	-	70,735		Y
Pipeline Integrity - TOD	Dx1020	ECDA Digs	35,614	70,735	-		Y
Pipeline Integrity - TOD	Dx1049	ECDA Digs	47,598	-	85,387		Y
Pipeline Integrity - TOD	Dx1080	ECDA Digs	59,583	141,469	141,469		Y
Pipeline Integrity - TOD	Dx1080-Class	ECDA Digs	47,598	56,588	141,469		Y
Pipeline Integrity - TOD	Dx1099	ECDA Digs	35,614	70,735	-		Y
	ECDA Total		**261,621**	**339,526**		**601,147**	
Pipeline Integrity - TOD	AlmaCG_Dx1070_Downstream of Dx1071	ICDA Digs	35,611				Y
Pipeline Integrity - TOD	AlmaCG_Dx1071_Mainline	ICDA Digs	20,326				Y
Pipeline Integrity - TOD	AlmaCG_Dx1089_Mainline	ICDA Digs	20,326				Y
Pipeline Integrity - TOD	GreenfieldCG_Dx1020_Mainline	ICDA Digs	20,326				Y
Pipeline Integrity - TOD	LahserCG_Dx1020_Mainline	ICDA Digs	20,326				Y
Pipeline Integrity - TOD	MtPleasantCG_Dx1070_Mainline	ICDA Digs	20,326				Y
Pipeline Integrity - TOD	NorthLyonCG_Dx1099_Mainline	ICDA Digs	35,613				Y
Pipeline Integrity - TOD	RedRunCG_Dx1002f West_Mainline	ICDA Digs	47,598				Y
Pipeline Integrity - TOD	RedRunCG_Dx1002g_Mainline	ICDA Digs	35,614				Y
Pipeline Integrity - TOD	RedRunCG_Dx1006_Downstream of Dx1002f West	ICDA Digs	59,583				Y
Pipeline Integrity - TOD	RedRunCG_Dx1008_Downstream of 1002f West	ICDA Digs	35,614				Y
Pipeline Integrity - TOD	RedRunCG_Dx1009_Downstream of 1002f West	ICDA Digs	35,614				Y
	ICDA Total		**386,876**			**386,876**	
Pipeline Integrity - TOD		UT Sensor Data	**70,735**			**70,735**	Y
		Total				**1,058,758**	

Business cases have not been conducted on these projects as the expenditures in the Pipeline Integrity Program represent the necessary inspections and remediation O&M expenses and capital expenditures that allow the Company to remain compliant with regulations mandated by the federal Pipeline & Hazardous Materials Safety Administration ("PHMSA") and the Commission.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Regulatory Compliance Program
Pipeline Integrity - TOD Capital and O&M Projects - 2025
Pipeline Integrity - Distribution (TOD)- CAP 2025 Costs by Project ID

Case No. U-21806
WP-MPG-17
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Portfolio	Assessment ID	Work Type	CAP Expenditure ($)	Internal Approval Y/N
Pipeline Integrity - TOD	Casings	Casings	2,000,000	Y
Pipeline Integrity - TOD	Risk Mitigation	Risk Mitigation	661,167	Y
Pipeline Integrity - TOD	Dx1002MAC	TOD ECDA	368,000	Y
Pipeline Integrity - TOD	Dx1087	TOD ECDA	184,000	Y
Pipeline Integrity - TOD	Dx1088	TOD ECDA	368,000	Y
Pipeline Integrity - TOD	Dx1088-192710	TOD ECDA	414,000	Y
Pipeline Integrity - TOD	Dx1092	TOD ECDA	138,000	Y
Pipeline Integrity - TOD	Dx1092-192710	TOD ECDA	92,000	Y
Pipeline Integrity - TOD	Dx1093	TOD ECDA	138,000	Y
Pipeline Integrity - TOD	ICDA Digs	TOD ICDA	3,000,000	Y
Pipeline Integrity - TOD	Tool Program	Tool Program	50,000	Y
TOTAL EXPENDITURE			**7,413,167**	

Pipeline Integrity - Distribution (TOD) - O&M 2025 Costs by Project ID

Portfolio	Assessment ID	Work Type	O&M Expense ($)	
Pipeline Integrity - TOD	Dx1008	DA Survey	62,016	Y
Pipeline Integrity - TOD	Dx1014	DA Survey	47,923	Y
Pipeline Integrity - TOD	Dx1022	DA Survey	56,099	Y
Pipeline Integrity - TOD	Dx1022-192710	DA Survey	67,656	Y
Pipeline Integrity - TOD	Dx1085	DA Survey	8,662	Y
Pipeline Integrity - TOD	Dx1008	DA Survey Risk	763	Y
Pipeline Integrity - TOD	Dx1014	DA Survey Risk	5,167	Y
Pipeline Integrity - TOD	Dx1022	DA Survey Risk	99,129	Y
Pipeline Integrity - TOD	Dx1022-192710	DA Survey Risk	40,040	Y
Pipeline Integrity - TOD	Dx1085	DA Survey Risk	120,362	Y
Pipeline Integrity - TOD	Dx1002MAC	TOD ECDA	69,890	Y
Pipeline Integrity - TOD	Dx1087	TOD ECDA	34,945	Y
Pipeline Integrity - TOD	Dx1088	TOD ECDA	69,890	Y
Pipeline Integrity - TOD	Dx1088-192710	TOD ECDA	69,890	Y
Pipeline Integrity - TOD	Dx1092	TOD ECDA	34,945	Y
Pipeline Integrity - TOD	Dx1092-192710	TOD ECDA	34,945	Y
Pipeline Integrity - TOD	Dx1093	TOD ECDA	34,945	Y
Pipeline Integrity - TOD	Tool Program	Tool Program	37,984	Y
Pipeline Integrity - TOD	UT Program	UT Program	189,918	Y
TOTAL EXPENSE			**1,085,169**	

Business cases have not been conducted on these projects as the expenditures in the Pipeline Integrity Program represent the necessary inspections and remediation O&M expenses and capital expenditures that allow the Company to remain compliant with regulations mandated by the federal Pipeline & Hazardous Materials Safety Administration (“PHMSA”) and the Commission.

MICHIGAN PUBLIC SERVICE COMMISSION Case No. U-21806
Consumers Energy Company WP-MPG-19
Regulatory Compliance Program Page 1 of 1
Pipeline Integrity - TOD Capital and O&M Projects - 2026
Pipeline Integrity - Distribution (TOD)- CAP 2026 Costs by Project ID

Portfolio	Assessment ID	Work Type	CAP Expenditure ($)	Internal Approval Y/N
Pipeline Integrity - TOD	Casings	Casings	2,000,000	Y
Pipeline Integrity - TOD	Risk Mitigation	Risk Mitigation	4,865,585	Y
Pipeline Integrity - TOD	Dx1008	TOD ECDA	230,000	Y
Pipeline Integrity - TOD	Dx1014	TOD ECDA	184,000	Y
Pipeline Integrity - TOD	Dx1022	TOD ECDA	184,000	Y
Pipeline Integrity - TOD	Dx1022-192710	TOD ECDA	230,000	Y
Pipeline Integrity - TOD	Dx1085	TOD ECDA	46,000	Y
Pipeline Integrity - TOD	ICDA Digs	TOD ICDA	3,000,000	Y
Pipeline Integrity - TOD	Tool Program	Tool Program	100,000	Y
TOTAL EXPENDITURE			**10,839,585**	

Pipeline Integrity - Distribution (TOD) - O&M 2026 Costs by Project ID

Portfolio	Assessment ID	Work Type	O&M Expense ($)	
Pipeline Integrity - TOD	Dx1009	DA Survey	150,773	Y
Pipeline Integrity - TOD	Dx1019	DA Survey	257,197	Y
Pipeline Integrity - TOD	Dx1019-192710	DA Survey	60,736	Y
Pipeline Integrity - TOD	Dx1024	DA Survey	119,115	Y
Pipeline Integrity - TOD	Dx1041	DA Survey	22,011	Y
Pipeline Integrity - TOD	Dx1062	DA Survey	23,407	Y
Pipeline Integrity - TOD	Dx1064	DA Survey	19,147	Y
Pipeline Integrity - TOD	Dx1065	DA Survey	26,743	Y
Pipeline Integrity - TOD	Dx1082	DA Survey	124,690	Y
Pipeline Integrity - TOD	Dx1019	DA Survey Risk	2,534	Y
Pipeline Integrity - TOD	Dx1019-192710	DA Survey Risk	68,769	Y
Pipeline Integrity - TOD	Dx1024	DA Survey Risk	6,825	Y
Pipeline Integrity - TOD	Dx1041	DA Survey Risk	23,911	Y
Pipeline Integrity - TOD	Dx1064	DA Survey Risk	11,961	Y
Pipeline Integrity - TOD	Dx1065	DA Survey Risk	1,190	Y
Pipeline Integrity - TOD	Dx1082	DA Survey Risk	9,153	Y
Pipeline Integrity - TOD	Dx1082-192710	DA Survey Risk	41,148	Y
Pipeline Integrity - TOD	Dx1008	TOD ECDA	46,772	Y
Pipeline Integrity - TOD	Dx1014	TOD ECDA	46,772	Y
Pipeline Integrity - TOD	Dx1022	TOD ECDA	46,772	Y
Pipeline Integrity - TOD	Dx1022-192710	TOD ECDA	46,772	Y
Pipeline Integrity - TOD	Tool Program	Tool Program	50,839	Y
Pipeline Integrity - TOD	UT Program	UT Program	254,193	Y
TOTAL EXPENSE			**1,461,430**	

Business cases have not been conducted on these projects as the expenditures in the Pipeline Integrity Program represent the necessary inspections and remediation O&M expenses and capital expenditures that allow the Company to remain compliant with regulations mandated by the federal Pipeline & Hazardous Materials Safety Administration (“PHMSA”) and the Commission.

MPSC Case No.	**U-21806**
Responding Party:	Attorney General
Respondent:	Sebastian Coppola
Requestor:	CECo
Question No.:	**2-CE-AG-4**

2-CE-AG-4
The following question pertains to the Company's Pipeline Integrity TOD program, specifically casing assessments. On page 61, beginning on line 6, through page 61, line 8 of his direct testimony, Mr. Coppola states "In response to additional discovery, the Company stated that is has very limited experience with the cost of inspecting and remediating casings." Please provide the specific discovery response and location where the Company made this statement.

Response:

Assuming the reference is to page 62 of Mr. Coppola's direct testimony, that section of the testimony should have been a conclusion reached by Mr. Coppola and not a direct statement attributed to the Company. Mr. Coppola reached his conclusion that the Company had very limited experience with the cost of inspecting and remediating casings based on the following information provided by the Company in response to discovery:

a. AG-CE-0329b: The two casings are scheduled to be inspected using a robotic ILI tool in August of 2025. After the inspection, the condition of the pipe inside the casing will be determined and remediation performed if required.

b. AG-CE-0329e: There weren't any similar casing projects performed in 2022, 2023 or 2024. Casings are assessed every 6 to 7 years.

c. AG-CE-0329f. Currently these casing[s] are in the planning and scheduling phase. The ILI tool vendor is being scheduled along with construction crews to perform excavation and construction.

DR AG-CE-0329 is included in Exhibit AG-15.

Date: 5/2/2025

U21806-CUB-CE-0248
Page **1** of **1**

Question:

30. Refer to Griffin, p. 23, which discusses the Corrosion Control – Transmission O&M Program. Please provide, for 2023-2026, the number of special projects and average cost per project to be completed for each project type listed by Griffin in this category: large atmospheric painting, pipeline recoating, shorted casing remediation, close internal survey.

Response:

The table below shows a breakdown of project types by year for each category.

	2023 Actual			2024 Preliminary Actual			2025 Projection			2026 Projection		
	Units	Avg Cost	Total	Units	Avg Cost	Total	Units	Avg Cost	Total	Units	Avg Cost	Total
Atmospheric Painting (projects)	7	$56,118	$392,825	8	$81,644	$653,155	8	$81,875	$655,000	8	$82,727	$910,000
Pipeline Recoating (feet)	300	$949	$284,634	790	$387	$305,784	2500	$400	$1,000,000	2500	$400	$1,000,000
Shorted casing/Test Stations (projects)	7	$11,704	$81,925	19	$1,702	$32,335	10	$10,000	$100,000	10	$10,000	$100,000
Close Interval survey (miles)	95	$1,975	$187,616	90	$1,972	$177,473	100	$2,000	$200,000	100	$2000	$200,000
Total			$947,000			$1,168,747			$1,955,000			$2,210,000

As stated in my direct testimony, much of the work performed in this program is typically identified in yearly surveys and remediated in a short timeframe.

For atmospheric painting, the annual variations in average cost for projects is due to the nature and size of the projects. This work is typically large painting projects at compressor stations, city gates or valve sites. It may be a portion of the facility (a couple of components of varying size pipe) or the entire facility. The survey for the atmospheric inspection is performed on a 3-year basis. The increase in cost in 2026 is based on doing larger projects since smaller projects were completed in 2023.

Pipeline recoating also has several variables that make establishing a unit cost difficult. The units shown here are in feet, but the pipe diameter plays a significant role as well in determining the final cost. This work consists of excavating the pipe, removing old coating and applying new coating. A large, 26" diameter pipe, will have a larger cost per foot to recoat than a 10" pipe. For the 2024 work, a large project on Line 1200A was identified for recoat and much of the money spent in this category was to recoat this pipeline.

The shorted casings/test station work is a conglomeration of various types of work that include excavating the pipe, inspecting the pipe and installation of test stations to perform future monitoring. Due to the varying nature and complexity of the work, the unit cost can vary as seen between 2023 and 2024. In 2023, more casing investigation work was done, which typically requires deep excavations approximately 10 feet deep. In 2024, more test station work was performed on pipe at more typical/shallower depths.

Witness: MICHAEL P. GRIFFIN
Date: February 26, 2025

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

REBUTTAL TESTIMONY

OF

KENDRA K. GROB

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Q. Please state your name and business address.

A. My name is Kendra K. Grob, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Kendra K. Grob who previously submitted direct testimony in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony will address Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witness Shannon Rueckert's recommended disallowance for Leaving It Better Awards ("LIBA"). My rebuttal testimony will also address Attorney General witness Sebastian Coppola's recommended adjustments for projected active health care, life insurance, and long-term disability ("LTD") expenses.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. No.

LIBA

Q. Staff witness Rueckert's direct testimony, pages 3 to 5, recommends a disallowance of the LIBA program costs. Does Consumers Energy Company ("Consumers Energy" or the "Company") agree with this proposed disallowance?

A. No. The LIBA program rewards employees with highly effective or better performance ratings for exceeding expectations. Recently centralized under the benefits area, LIBA recognizes efforts like taking on extra work for colleagues on extended leave or handling demanding projects. These awards help the Company retain talent, increase morale, enforces behaviors that support company values and improved performance which in turn

benefits customer service. The Commission should approve the O&M and capital costs for continuing LIBA, as it ultimately reduces overall rate costs for customers.

Q. On page 4, lines 7 through 9, of his direct testimony, Mr. Rueckert explained that one reason he recommended the LIBA disallowance was that "[p]romotability and salary increases are already incentives to achieve operational excellence." How do you respond?

A. While merits and annual incentives can promote operational excellence, the LIBA is another tool at the Company's disposal to encourage excellence. It is an instant acknowledgment of exceptional work, reinforcing positive behaviors and motivating employees to maintain high-performance levels. Studies have confirmed that awards differ fundamentally from direct compensation increases, like promotions and merits.[1] And, when designed appropriately, awards can provide further incentive to excel.[2]

Q. On page 4, lines 15–16, of his direct testimony, Mr. Rueckert also noted that the Company's Employee Incentive Compensation Program ("EICP") already provides short-term incentive compensation for operational goals. Does the Company's EICP serve the same function as the LIBA?

A. The Company's EICP differs from LIBA in that the EICP is based on pre-determined performance criteria, whereas the Company has more discretion under LIBA to award employees for outstanding performance after the fact. Both the EICP and LIBA provide value to customers, but in different ways.

[1] Jana Gallus & Bruno S. Frey, *Awards: A strategic management perspective*, 37 STRATEGIC MANAGEMENT JOURNAL 1527 (2016).
[2] Indeed Editorial Team, *Rewards and Incentives in the Workplace (Advantages and Examples)*, at https://www.indeed.com/career-advice/career-development/rewards-incentives (last visited May 12, 2025).

Q. On page 3, lines 19 through 21, of his direct testimony, Mr. Rueckert suggests that LIBA is always awarded in a lump sum of $4,000. Is this always true?

A. No. Awards vary from $250 to $4,000 depending on the nature of the work meriting the award. The Company considers whether a nominee's work benefits the nominee's immediate work area or whether it has a wider department-level or Company-wide impact.

Q. On page 342 of its March 21, 2025 Order in Case No. U-21585, the Commission recognized the potentially valuable benefits that the LIBA program provides. It did not approve recovery of the LIBA expense in that case but did not preclude the possibility it would approve the expense in other cases. It specifically expressed an interest in how the program has been funded in the past and whether the program has previously been included in rates. How has the program been funded in the past and when did this change?

A. The LIBA program was funded as a part of individual department labor costs budgets prior to 2024. In 2024, a formal budget at the corporate level was established to centralize the cost of the program and allow for better visibility into the utilization and benefits.

Q. Staff witness Rueckert's direct testimony, page 5, recommends a disallowance of the LIBA program capital expense of $824,000 for 2024, $702,500 for the 10 months ending October 31, 2025, and $861,000 for the test year ending October 31, 2026. Does the Company agree to the amount of capital listed for those time periods?

A. No. The Company does not agree with Staff's stated costs that 2024 actual capital amount booked was $590,000. The Company does agree that the amounts listed for the 10 months ending October 31, 2025, of $702,500 and $861,000 for the test year ending October 31, 2026, would be the correct capital projections in this gas rate case. However, the

Commission should not disallow any of the projected capital amounts as the cost of the LIBA program should be included in this case as it does benefit the customer overall in reduced labor costs.

Active Health Care, Life Insurance, and LTD Expense

Q. Please summarize Attorney General witness Coppola's proposed adjustment to Active Health Care Expense, Life Insurance, and LTD Expense.

A. On pages 184 and 185 of his direct testimony, Attorney General witness Coppola recommends a $2,754,000 reduction in Active Health Care Expense to reflect his calculated impact of program savings on this expense category.

Q. Do you agree that Active Health Care, Life Insurance, and LTD Expenses should be reduced by $2,754,000 to reflect the program savings reductions?

A. No. First, the amounts listed in discovery request U21806-AG-CE-0686 and Exhibit AG-65 are gross amounts savings for the assumed plan changes for the listed items. So, the amounts are both electric and gas amounts before capitalization. $2,754,000 gross would only be gas operating and maintenance ("O&M") of $483,000. Second, the Attorney General is assuming that these amounts are not included in the projections for this case. This is not true; these savings are included as the Company is still experiencing health care expense increase over the plan changes. Healthcare costs are still trending well above the inflation rates that were used to set the expense in this case. The actual gas O&M portion of the Active Health Care, Life Insurance, and LTD Expense for 2024 was $19.860 million, while the projected expense for 2024 was $18.921 million. The Company's projected Active Health Care Expense remains reasonable. The Commission should not accept the

Attorney General's reduction amount of $2,754,000 for Active Healthcare, Life Insurance, and LTD expenses.

Q. Does this complete your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	))))))	Case No. U-21806

REDACTED

REBUTTAL TESTIMONY

OF

QUENTIN A. GUINN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Q. Please state your name and business address.

A. My name is Quentin A. Guinn, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Quentin A. Guinn who previously filed direct testimony in this proceeding?

A. Yes. I am also adopting the direct testimony and exhibits of Consumers Energy Company ("Consumers Energy" or the "Company") Company witness Corey E. Ballinger.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address Attorney General Dana Nessel ("Attorney General") witness Sebastian Coppola's recommendation that the Michigan Public Service Commission ("MPSC" or the "Commission") remove Fleet Services forecasted capital expenditures of $1,202,000 for the 10 months ending October 2025 and $4,809,000 for the 12 months ending October 2026 for Fleet Vehicle Capital Replacement and Fleet Vehicle Electrification. I will also address Citizens Utility Board of Michigan's ("CUB") witness Joshua W. Denzler's recommendations that: (i) the Commission remove Fleet Services forecasted capital expenditures of $3,390,000 for the 22 months ending October 31, 2025 and $2,580,000 for the 12 months ending October 31, 2026 for Fleet Vehicle Capital Replacement Spend; (ii) the Commission reduce Fleet Services forecasted Operating and Maintenance ("O&M") expenses by [redacted] for the 12 months ending October 31, 2026 for Fleet Responsibility costs; (iii) the Commission order the Company to conduct a more specific study as to the expected savings of electrifying its fleet assets, by asset type (e.g., light duty car, pickup, van, heavy-duty, etc.) and provide the study in its next gas rate case with results incorporated into future requested cost recovery; (iv) the

Commission reduce Fleet Responsibility costs by $15,008,000 in 2025 and $15,008,000 in 2026; (v) the Commission order the Company to provide historical and projected fleet responsibility costs by capital and O&M, with more detailed information on the types of work these dollars support and the value received for these expenditures, by cost category and business unit for future rate cases; (vi) the Commission order the Company to prepare a more detailed analysis of its vehicle idling; (vii) the Commission remove Facility Operations forecasted capital expenditures of $14,937,000 for the 22 months ending October 31, 2025 for the Lansing Service Center Project; (viii) the Commission remove Facility Operations forecasted capital expenditures of $7,199,000 for the 12 months ending October 31, 2026 for the Lansing Service Center Project; (ix) the Commission remove Facility Operations forecasted capital expenditures of $114,000 for the 22 months ending October 31, 2025 for the Hastings Service Center Project; (x) the Commission remove Facility Operations forecasted capital expenditures of $4,380,000 for the 22 months ending October 31, 2025 for the Kalamazoo Service Center Project; and (xi) the Commission remove Facility Operations forecasted capital expenditures of $616,000 for the 12 months ending October 31, 2026 for the Kalamazoo Service Center Project.

Q. Are you sponsoring any exhibits in connection with your rebuttal testimony?

A. No.

Q. Does the Company agree with Attorney General witness Coppola's recommendation on page 99 of his direct testimony that the Commission remove Fleet Services forecasted capital expenditures of $1,202,000 for the 10 months ending October 2025 and $4,809,000 for the 12 months ending October 2026 for Fleet Vehicle Capital Replacement and Fleet Vehicle Electrification?

A. No. Mr. Coppola's proposed reduction is based on an average cost per vehicle in 2024, inflating that cost by inflation factors for 2025 and 2026, and multiplying the resulting average cost by the number of vehicles planned to be purchased in those years. The Company does not purchase the same combination of vehicles each year. Therefore, the average cost per vehicle in the Company's Vehicle Replacement Plan may vary considerably from year to year, and the Company's projected unit costs are based on current manufacturer pricing. The Company's total Fleet Vehicle Capital Replacement Cost is the relevant metric for gauging year-over-year growth in capital spend. For the gas Fleet Vehicle Capital Replacement expenditures, the 2024 projected spend is $9.687 million and the 2025 projected spend is $9.919 million, a 2.4% increase.

Q. Does the Company agree with CUB witness Denzler's recommendation on page 19 of his direct testimony that the Commission remove Fleet Services forecasted capital expenditures of $3,390,000 for the 22 months ending October 31, 2025 and $2,580,000 for the 12 months ending October 31, 2026 for Fleet Vehicle Capital Replacement Spend?

A. No. Mr. Denzler recommended a 20% reduction in these expenditures based on his argument that the Company did not demonstrate the reliability of the Blended Factor model in making vehicle replacement decisions. First, as outlined on pages 8 through 12 of

Company witness Ballinger's direct testimony, the Blended Factor is only one of multiple quantitative and qualitative factors used to make vehicle replacement plan decisions. The efficacy of the Company's replacement plan decision making does not rest solely on the Blended Factor. Second, on page 18 of his direct testimony, Mr. Denzler cites a few instances in which the Company's Blended Factor model failed to accurately predict vehicle failure. As noted on page 12 of Company witness Ballinger's direct testimony, there are over 7,200 units in the Company's vehicle fleet. Therefore, the failure of the Blended Factor to accurately predict a few vehicle failures in this portfolio of over 7,200 assets during the course of several years does not statistically disprove the reliability of the Blended Factor model. Third, Mr. Denzler does not provide any calculation or explanation as to why a 20% disallowance is appropriate for projecting vehicle replacement costs as a result of Mr. Denzler's concerns with the use of the Blended Factor. Finally, the Company has included express reference to the Blended Factor in electric and gas rate case testimony for Fleet Services since the Commission's order issued in Case No. U-20963 in December 2021. During this nearly four-year period, the Commission's orders have not questioned the reliability of the Company's Blended Factor model.

Q. Does the Company agree with CUB witness Denzler's recommendation on page 21 of his direct testimony that the Commission reduce for Fleet Services forecasted O&M expenses of [redacted] for the 12 months ending October 31, 2026 for Fleet Responsibility expense because this total represents estimated fuel and maintenance savings from electric vehicles ("EVs") in the Company's fleet?

A. No. First, Mr. Denzler derived the O&M estimate from an analysis outlined on pages 20 and 21 of his direct testimony. Mr. Denzler's figure, however, is still an estimate based on

estimated savings across the major categories of passenger EVs owned by the Company. In response to discovery request U21806-AG-CE-0229, the Company indicated that it "has not yet incorporated specific fuel, maintenance and other savings assumptions into its budget projections for the replacement of an ICE [internal combustion engine] vehicle with an EV. Deployment of the Test Year units proposed in this case will provide empirical data needed to establish accurate assumptions about fuel, maintenance and other savings to be realized upon replacing ICE vehicles with EVs." Thus, it is premature to include these estimated savings in the projections in this case. Finally, it would be incorrect to assume that these types of savings would be entirely O&M. Fleet Responsibility costs include both an O&M and capital component, estimated in total at approximately 75% capital and 25% O&M based on historical actuals.

Q. How do you respond to CUB witness Denzler's recommendation on page 21 of his direct testimony that the Company conduct a more specific study as to the expected savings of electrifying its fleet assets?

A. The Company agrees to provide more specific information regarding expected savings from electrifying its fleet assets in future cases.

Q. Does the Company agree with CUB witness Denzler's recommendation on page 23 of his direct testimony that the Commission remove forecasted Fleet Responsibility costs of $15,008,000 in 2025 and $15,008,000 in 2026?

A. No. First, as noted on pages 6 and 7 of Company witness Ballinger's direct testimony, Fleet Responsibility costs are incurred to maintain the Company's vehicle fleet. Exhibit A-27 (CEB-2) includes annual historical Fleet Responsibility costs from 2016 through 2023. The amounts in Exhibit A-27 (CEB-2) represent actual Fleet Responsibility costs

and during this eight-year period the Commission never determined that these expenses are not reasonable or prudent. Second, Mr. Denzler notes that the Company is estimating approximately $75 million in Fleet Responsibility costs in 2025 and 2026. Given that actual Fleet Responsibility costs were $86.7 million in 2022 and $80 million in 2023 as shown in Exhibit A-27 (CEB-2), it would not be reasonable to reduce these expected costs by 20% of $75 million in 2025 and 2026. In addition, as discussed above, Fleet Responsibility costs include both an O&M and capital component, estimated in total at approximately 75% capital and 25% O&M. If the Commission adopted a disallowance of Fleet Responsibility costs, which it should not, the disallowance should be 75% capital and 25% O&M.

Q. Does the Company agree with CUB witness Denzler's recommendation on page 23 of his direct testimony that the Company provide historical and projected fleet responsibility costs by capital and O&M, with more detailed information on the types of work these dollars support and the value received for these expenditures, by cost category and business unit in future rate cases?

A. The Company agrees to provide the additional requested detail regarding Fleet Responsibility costs in future cases.

Q. Does the Company agree with CUB witness Denzler's recommendation on pages 26 and 27 of his direct testimony that the Company prepare a more detailed analysis of its vehicle idling?

A. The Company agrees to work on performing such an analysis.

Q. Does the Company agree with CUB witness Denzler's recommendation on pages 29 and 30 of his direct testimony that the Commission remove Facility Operations forecasted capital expenditures of $14,937,000 for the 22 months ending October 31, 2025 for the Lansing Service Center Project?

A. The Company disagrees with a portion of Mr. Denzler's recommendation. As outlined in response to discovery request U21806-AG-CE-0652, the Company's capital expenditures for the Lansing Service Center Project totaled $1,817,000 for the 12 months ended December 31, 2024. The Company's actual capital expenditures totaling $1,817,000 for the Lansing Service Center for the 12 months ended December 31, 2024 should be approved because they have actually been spent on the project. Based on the Commission's determination in Case No. U-21585, the Company will not oppose removal of the remaining forecasted capital expenditures of $13,120,000 ($1,817,000 less than Mr. Denzler's recommended $14,937,000) for the 22 months ending October 31, 2025 for the Lansing Service Center Project. The Company will present post-2024 expenditures for approval in a future rate case.

Q. Does the Company agree with CUB witness Denzler's recommendation on pages 29 and 30 of his direct testimony that the Commission remove Facility Operations forecasted capital expenditures of $7,199,000 for the 12 months ending October 31, 2026 for the Lansing Service Center Project?

A. Based on the Commission's Order in Case No. U-21585, the Company will not oppose this recommendation. The Company will present these expenditures for approval in a future rate case.

Q. Does the Company agree with CUB witness Denzler's recommendation on page 31 of his direct testimony that the Commission remove Facility Operations forecasted capital expenditures of $114,000 for the 22 months ending October 31, 2025 for the Hastings Service Center Project?

A. No. The Company disagrees with a portion of this recommendation. As outlined in my response to discovery request U21806-AG-CE-0652, the Company's capital expenditures for the Hastings Service Center Project totaled $95,000 for the 12 months ended December 31, 2024. The Company's capital expenditures totaling $95,000 for the Hastings Service Center Project for the 12 months ended December 31, 2024 should be approved because they have actually been spent on the project. Based on the Commission's determination in Case No. U-21585, the Company will not oppose removal of the remaining forecasted capital expenditures of $19,000 ($95,000 less than Mr. Denzler's recommended $114,000) for the 22 months ending October 31, 2025 for the Hastings Service Center Project. The Company will present post-2024 expenditures for approval in a future rate case.

Q. Does the Company agree with CUB witness Denzler's recommendation on page 32 of his direct testimony that the Commission remove Facility Operations forecasted capital expenditures of $4,380,000 for the 22 months ending October 31, 2025 and $616,000 in the test year for the Kalamazoo Service Center Project?

A. No. Mr. Denzler's argument that the project is being overbuilt by 40% is incorrect. At page 31 of his direct testimony, Mr. Denzler points to the Company's statement that the renovation will "incorporate and allow for up to 40% future growth opportunities" for his contention that the facility is being overbuilt by 40%. The Company is renovating its

existing Kalamazoo Service Center. As outlined on pages 29 and 30 of my direct testimony in this case, the Company did not construct or add space to the existing facility as part of this renovation. Rather, the footprint of the existing Kalamazoo Service Center is unchanged with renovations being done to the facility as is. While the Company could reduce the size of the facility as part of this renovation by demolishing a portion of the building, demolition of part of the building would add considerably to the cost of this project. It is far more cost effective to simply utilize existing space as is.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

REBUTTAL TESTIMONY

OF

TIMOTHY K. JOYCE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Q. Please state your name and business address.

A. My name is Timothy K. Joyce, and my business address is 17000 Croswell, West Olive, Michigan 49460.

Q. Are you the same Timothy K. Joyce who previously submitted testimony in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut the adjustments to Lost and Unaccounted For ("LAUF") and Consumers Energy Company ("Consumers Energy" or the "Company") Use ("CU") gas, and Compression Operating and Maintenance ("O&M") expenses; and Gas Compression and Storage Capital expenditures and recommendations proposed by Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witnesses Kevin P. Spence, Citizens Utility Board of Michigan ("CUB") witness Ram Veerapaneni and Attorney General Dana Nessel ("AG") witness Sebastian Coppola.

Q. How is the remainder of your rebuttal testimony organized?

A. My rebuttal testimony is organized by topical sections as follows:

I. LAUF and Company Use O&M Expenditure Adjustments

II. Compression O&M Expenditure Adjustment

III. New Well Capital Expenditure Adjustment

IV. Lyon 29/34 (Northville Storage) Dehydration Capital Expenditure Adjustment

V. Storage Capital Expenditure Adjustments

VI. Compression Project Capital Engineering Status Expenditure Adjustment

VII. Compression and Storage Capital Expenditure Adjustments

I. LAUF AND COMPANY USE O&M ADJUSTMENTS

A. O&M Expenditure Summary

Q. Please summarize the adjustments proposed by AG witness Coppola for LAUF and CU O&M expenditures.

A. A comparison of the Company's O&M expenditure projections to those recommended by the AG is provided in the table below:

Description	Company Amount (000)	AG Recommendation (000)	AG Adjustment (000)
LAUF			
12 ME 10/31/26	12,709	7,823	-4,886
CU			
12 ME 10/31/26	5,502	3,702	-1,800
TOTAL	18,211	11,525	-6,686

B. AG Witness Coppola

Q. Please summarize AG witness Coppola's recommendation regarding the amount allocated to LAUF.

A. On pages 178 and 179 of his direct testimony, AG witness Coppola recommends a 221 MMcf reduction in the LAUF volume based on the Company's 2050 net-zero emissions goals, resulting in reduced LAUF expense of $728,000.

Q. Do you agree with this recommendation?

A. No, I do not. There is no mention of the Company's Net Zero goals in the LAUF section of my direct testimony, as suggested by AG witness Coppola, because methane reduction and LAUF are not the same, and should not be treated as synonymous. A reduction in methane emissions does not guarantee a reduction in total LAUF, as LAUF also includes theft, customer billing, metering and storage adjustments, described in my direct testimony on pages 22 through 25. There are methane emissions that are not LAUF, like blowdowns

before construction that are accounted for in project expenses and there are LAUF volumes that are not methane emissions, such as theft and metering inaccuracies. To the extent that there are some methane emissions that are part of LAUF, the use of the five-year average gas loss percentage in the approved LAUF calculation methodology, as shown in Exhibit A-74 (TKJ-3), will account for future methane emission reductions as the Company moves toward its 2050 net-zero goals. Therefore, the Commission should reject Mr. Coppola's position.

Q. On pages 177 and 178 of AG witness Coppola's direct testimony he recommends a reduction of $1.8 million in CU and $4.158 million in LAUF gas due to an error in the calculation WP-TKJ-14 in the Company's original filing, do you agree with the adjustment?

A. No, I do not. After filing the case, an error was identified in WP-TKJ-14, however it did not have an impact on the LAUF and CU calculation. The LAUF and CU calculation uses the forecasted volumes for the projected test year based on a five-year average of Public Act 9 of 1929 ("Act 9") transportation customers only, i.e. a small group of transportation customers who do not take service on a tariff rate, but instead take service pursuant to an Act 9 contract. This information is provided from WP-TKJ-15 as shown on line 20 of Exhibit A-75 (TKJ-4). AG witness Coppola incorrectly concluded that the Gas in Kind ("GIK") volumes from WP-TKJ-14 flow into WP-TKJ-15. See page 177, lines 13-14 of Mr. Coppola's testimony. However, that is not entirely accurate. WP-TKJ-14 includes the GIK volumes of the Company's Act 9 customers plus the GIK volumes of transportation customers who are on a tariff rate; whereas, the volumes shown on WP-TKJ-15 include only Act 9 customers. Nevertheless, Mr. Coppola erroneously replaced the Act 9 value

from WP-TKJ-5 on Exhibit A-75 (TKJ-4) with the five-year historical average he requested of the information included in WP-TKJ-14. Compare Exhibit A-75 (TKJ-4), line 20, column (i) with Exhibit AG-62, line 20, column (i). Contrary to Mr. Coppola's unexplained and unsupported assumption, the error in WP-TKJ-14 did not flow into WP-TKJ-15, so the correction to WP-TKJ-14 had no relationship to the Act 9 GIK value used in Exhibit A-75 (TKJ-4), and Mr. Coppola should not have substituted information from WP-TKJ-14 into that exhibit instead of the correct information from WP-TKJ-15. Due to this incorrect application of the LAUF and CU calculation, the Commission should reject Mr. Coppola's recommended disallowance.

II. COMPRESSION O&M EXPENDITURE ADJUSTMENT

A. O&M Expenditure Recommendation Summary

Q. Please summarize the adjustments proposed for Compression O&M expenditures.

A. A comparison of the Company's O&M expenditure projections to those recommended by CUB is provided in the table below:

Description	Company Amount (000)	CUB Recommendation (000)	CUB Adjustment (000)
2024 Projected	17,030	-	0
2024 Actual	17,142	-	0
12 ME 10/31/26	17,577	18,087	510

B. CUB Witness Veerapaneni

Q. On page 18 of his direct testimony, CUB witness Veerapaneni proposes an adjustment for Compression O&M expenditures. Do you agree with this recommendation?

A. No, I do not. I provided a description of the necessity for the Compression O&M expenditures in my direct testimony beginning on page 7, line 2, through page 10, line 10. Mr. Veerapaneni simply took the average of the 2023 and 2024 actual amounts and applied

inflation to project a test year amount. CUB witness Veerapaneni did not review the reasonableness of the proposed expenditures during the test year or the benefits they would provide to customers. Even though Mr. Veerapaneni's two-year-average methodology results in an increase in O&M expense included in rates in this instance, the Commission should reject his position.

III. NEW WELL CAPITAL EXPENDITURE ADJUSTMENT

A. Capital Expenditure Recommendation Summary

Q. Please summarize the adjustments proposed for New Well capital expenditures.

A. A comparison of the Company's capital expenditure projections to those recommended by the AG is provided in the table below:

Description	Company Amount (000)	AG Recommendation (000)	AG Adjustment (000)
10 ME 10/31/25	28,004	-	-4,647
12 ME 10/31/26	32,296	-	-3,916

B. AG Witness Coppola

Q. On pages 80 through 82 of his direct testimony, AG witness Coppola proposes adjustments to the Company's New Well expenditures. Do you agree with the proposed adjustments?

A. No, I do not. The method that AG witness Coppola uses to determine the proposed adjustments are overly simplistic and do not accurately account for the cost associated with the new well projects. First, Mr. Coppola recommends using a very simple total cost of wells drilled in 2023 and 2024 divided by the number of wells drilled to determine an average cost per new well plus an inflation factor for forecasting the cost of new wells in this case. But that approach assumes that all new wells have a similar geological formation,

drill depths, pipeline lengths, and site preparation. These assumptions are not correct. The Storage Engineering group uses information about the specific attributes of a planned new well to create projected expenses for each of the new well projects. The Company's method is far more accurate for projecting the new well expense than the one proposed by AG witness Coppola. AG witness Coppola's analysis is overly simplistic and does not represent the true new well expense. Therefore, the Commission should reject his position.

IV. LYON 29/34 (NORTHVILLE STORAGE) DEHYDRATION PROJECT CAPITAL EXPENDITURE ADJUSTMENT

A. Capital Expenditure Recommendation Summary

Q. Please summarize the adjustments proposed for Lyon 29/34 (Northville Storage) Dehydration project capital expenditures.

A. A comparison of the Company's capital expenditure projections to those recommended by the AG is provided in the table below:

Description	Company Amount (000)	AG Recommendation (000)	AG Adjustment (000)
2022 Actual	1,149		-1,149
2023 Actual	1,191		-1,191
2024 Actual	6,122		-8,453
10 ME 10/31/25	25,249		-25,351
12 ME 10/31/26	3,649		-4,672

B. AG Witness Coppola

Q. Please summarize AG witness Coppola's recommended capital disallowance regarding the Lyon 29/34 (Northville Storage) Dehydration project.

A. Mr. Coppola raises several concerns with the basis, justification, and business needs that the Company has prudently made concerning the Lyon 29/34 (Northville Storage)

Dehydration project. However, none of Mr. Coppola's concerns are valid. I will address each issue individually below.

Q. On pages 76 and 77 of his direct testimony, Mr. Coppola argues that the total project expense that was included in discovery response U21806-AG-CE-0506 of $37.4 million is different from what was included in the original case filing. Do you agree with his claim about inconsistent project expense estimates?

A. No, I do not. Mr. Coppola claims that WP-TJK-6 shows larger capital expenditures from 2024 to 2026 than what the Company has included in this case, suggesting that the Company itself is confused about its planned investments in the Lyon 29/34 (Northville Storage) Dehydration project. However, WP-TJK-6 includes costs for two other projects at the Northville storage location in addition to the dehydration project. Mr. Coppola has confused and conflated multiple projects. In coming up with his $41 million figure for the Lyon 29/34 (Northville Storage) Dehydration project, Mr. Coppola inflates the total project expense estimates by using the expenses from the two other projects being performed at the Northville storage location that are listed in WP-TKJ-6. Again, the other two projects are independent of the Lyon 29/34 (Northville Storage) Dehydration project and should not be included in its total project expense. The Company has not presented any inconsistent information about the planned spending on the project.

Q. On page 77 of his direct testimony, Mr. Coppola mentions his assessment from previous rate cases that the Company should further evaluate the system for a more cost-effective solution. Do you agree with his assessment?

A. No, I do not. The Company has reviewed technologies and methods to provide the regulatory required 7 lbs/MMcf (max) moisture content as required by Rule 81(4) of the

Commission's Technical Standards for Gas Service (R 460.2381(4)). The project design is reflective of the best evaluated option, providing the ability to operate in a manner that supports the peaking nature of the Northville Lyon 29 and 34 fields, with short cycle "turn on" and "turn off" times, zero emissions, lower O&M costs, and lower installation costs.

Q. On page 78 of his direct testimony, Mr. Coppola states that "[b]eginning in 2021, the Company changed the utilization of the Northville storage fields to be a peaking storage facility to be used only during days in winter when customer gas demand reaches near peak demand." Do you agree with this statement?

A. No, I do not. The Northville Storage fields have always been, and continue to be, operated as peaking fields supporting the gas system during times of peak demand. Peak demand is typically experienced due to seasonal loads and can also be experienced due to additional system constraints such as emergencies that limit the amount of gas delivery to the system. The Ray Fire emergency experienced in January 2019 is one example where peak demand was met with the utilization of the Northville storage fields. In mid-March of 2022, the Northville fields were again dispatched; however, utilization was limited due to high moisture content.

Q. On page 78 of his direct testimony, Mr. Coppola asserts that based on the historical usage of the Northville Storage fields, it is not wise to build a high cost facility that will sit idle and not be utilized other than on rare occasions. Do you agree with his assertion?

A. No, I do not. As seen in Attachments 3 and 4 of discovery response U21806-AG-CE-0506 (attached to Mr. Coppola's testimony as Exhibit AG-22, pages 5 and 6), the field has been limited in use and manually controlled to avoid exceeding the 7 lbs/MMcf moisture

entering the Company's pipeline system to the extent possible. In other words, the dehydration project is needed so that the Company can utilize the Northville Storage fields more reliably without the risk of impacting Company assets and downstream customers. The Northville Storage fields are peaking units and by design are intermittent use associated with peak demand; however, their dispatch to the system is limited based on the moisture testing data over the last five years. The Company has done additional testing and monitoring since recognizing the issue with moisture content exceeding the regulatory limit, to verify performance up to the moisture content threshold of 7 lbs/MMcf, which is the basis for this project. This project is needed to reduce the risk of utilizing these peaking fields to their design capacity during peak demand, ensuring the capability to deliver consistent gas quality performance and improving system resiliency. After completing this project, the fields will no longer have to be a "last on, first off" resource and are more likely to be used each winter.

Q. On pages 78 and 79 of his direct testimony, Mr. Coppola states that gas blending can be an effective strategy for achieving gas quality in limited volumes. Do you agree with his position that gas blending can be utilized?

A. No, I do not. The Company does not consider blending a competent means of ensuring gas quality. Various conditions can affect how and whether gases are mixed in a pipe. Due to the integrated nature of Consumers Energy's gas system, its variable operating conditions, and the fact that the system is not designed to assure mixing of gas from different sources, it would be inaccurate to assume mixing occurs. While Mr. Coppola comments that DTE Gas Company ("DTE") utilizes blending, he provides no specific information regarding

which pipelines or storage fields DTE utilizes blending at nor any analysis concerning the differences between the Company's system and the system operated by DTE.

Q. On pages 79 and 80 of his direct testimony, AG witness Coppola proposes adjustments to the Company's Lyon 29/34 (Northville Storage) Dehydration project expenditures. Do you agree with the proposed adjustments?

A. No, I do not. As I have explained above, the Northville Storage fields are a critical part of the Company's natural gas system providing the ability to meet peak demand. The unique ability and configuration of the Northville Storage fields is such that it requires upgrades to meet the regulatory requirements for gas quality, specifically the threshold for moisture content at 7 lbs/MMcf (max). Utilization of the fields is currently limited due to the moisture content as the fields are shut in when the threshold is met. By installing the dehydration equipment proposed, the Company will have the ability to utilize the field to its peaking capacity, ensure reliable gas measurement, limit corrosive liquid from the pipeline system, provide resiliency to the gas system, and ultimately be able to provide more reliable gas service to its customers. The total removal of the project costs in 2022, 2023, 2024, and the bridge and test year is unwarranted and should be rejected by the Commission.

V. STORAGE CAPITAL EXPENDITURE ADJUSTMENTS

A. Capital Expenditure Summary

Q. Please summarize the adjustments proposed for C-1103, W-1004, W-1005, W-1006 New Well projects, and Hessen Field Pipeline Replacement capital expenditures.

A. A comparison of the Company's capital expenditure projections to those recommended by Staff and the AG is provided in the table below:

Description	Company Amount (000)	Staff Recommendation (000)	Staff Adjustment (000)	AG Recommendation (000)	AG Adjustment (000)
12 ME 12/31/24	3,088	62	-2,946		
10 ME 10/31/25	38,689	0	-38,689		-13,450
12 ME 10/31/26	6,494	0	-6,494		-2,003

B. Staff Witness Spence

Q. On pages 16 through 18 for new wells C-1103, W-1004, W-1005 and W-1006; and pages 19 through 21 for Hessen Storage Pipeline Replacement project, Staff Witness Spence recommends disallowance of the Company's planned capital spending for those projects because the Company does not have approved Act 9 certificates for the projects yet. Do you agree?

A. No. The Act 9 certificate of need process is not a cost approval mechanism. The gas rate case includes a forward-looking projection of expenses that are appropriate for inclusion in rates during the test year. While construction on these projects cannot commence until after Act 9 approval, the Company will incur legitimate expenses for these projects even before construction begins including engineering and procurement activities. All three of these projects are well-positioned to receive a final Act 9 order before the final order in this rate case, and no party has challenged any of the Act 9 applications to date. Furthermore, the Company accounted for the time required to navigate the Act 9 process when planning for the expected start date for construction, so there is no reason to expect misalignment between the start of construction and the rate recovery included in the Company's filing. The Company appreciates Staff witness Spence's acknowledgement on

page 22 of his direct testimony that Staff may withdraw its recommended disallowances if the Act 9 certificates are approved before the final order in this case. Given the circumstances and current status of these Act 9 filings, the Company believes the Commission would be warranted in approving the test year investments for these projects in rate even if the Act 9 certificates have not been finalized when this order is released.

C. AG Witness Coppola

Q. On pages 82 through 83 of his direct testimony, AG witness Coppola proposes that the Commission disallow proposed capital expenditures for the Hessen pipeline replacement because it does not have an approved Act 9 creating uncertainty in the timing of the project expenditures. Do you agree?

A. No. For the reasons discussed above in response to Staff witness Spence, the Commission should reject Mr. Coppola's similar disallowance recommendation.

VI. COMPRESSION CAPITAL EXPENDITURE ADJUSTMENT

A. Capital Expenditure Recommendation Summary

Q. Please summarize the adjustments proposed for Compression capital expenditures.

A. A comparison of the Company's capital expenditure projections to those recommended by the AG is provided in the table below:

Description	Company Amount (000)	AG Recommendation (000)	AG Adjustment (000)
10 ME 10/31/25	786	-	-786
12 ME 10/31/26	29,295	-	-29,295

B. AG Witness Coppola

Q. On pages 83 and 84 of his direct testimony, AG witness Coppola criticizes the length of time that some Company projects remain in engineering design. Is there any merit to this criticism?

A. No. Mr. Coppola's unsupported assumption that the project engineering design durations are "very unusual for the relatively moderate size of the projects being undertaken" is incorrect. The duration of the Company's engineering design phase is appropriate for at least two reasons. First, it reflects and includes an appropriate allotment of time to procure the equipment and materials needed to complete construction of the project. The amount of time needed to procure materials and equipment has increased in recent years, which has extended the engineering design phase for some of the Company's projects. But, that longer duration appropriately reflects the state of the marketplace for procuring those materials and equipment. Second, projects with significant construction durations can have a potential impact on system resilience and reliability and impact the Company's ability to support the gas inventory plans. Therefore, it is not prudent to begin projects with a long construction timeline until the engineering is complete. With the Company's recent focus on optimization of the compression fleet, the Company is focusing on having engineering and procurement activities completed prior to proceeding with construction, which results in longer engineering durations. Again, this is an appropriate practice to minimize potential disruption of the Company's ability to serve its customers. I also disagree with Mr. Coppola's observation that the projects he was referring to are necessarily "moderate" in size. In some instances, the investments reflected in this case include only the early spending for projects that will extend beyond the end of the test year. Contrary to

Mr. Coppola's unwarranted assumption, these are large projects that require a considerable amount of engineering and, therefore, more time to complete the engineering.

Q. Based on his inaccurate claim regarding the "very unusual" duration of engineering design, AG witness Coppola identified thirteen compression projects that will not begin construction until the end of the test year in this case and recommends that the Commission disallow the projects. Do you agree with his recommendation?

A. No. Mr. Coppola correctly notes that thirteen compression projects have construction and completion dates after the test year, but the Company will still incur costs for those projects during the engineering design phase, including costs for material and equipment procurements as discussed abobe. Therefore, Mr. Coppola's recommended disallowances are inappropriate. The correct ratemaking treatment for projects that incur legitimate capital costs during the bridge period and test year but will not be in service before the end of the test year is to apply an AFUDC offset – not to disallow them. Mr. Coppola's argument that these project costs should not be included in rate base should be rejected by the Commission and the Company's full projection for the compression projects should be approved.

VII. COMPRESSION AND STORAGE CAPITAL EXPENDITURE ADJUSTMENTS

A. Capital Expenditure Recommendation Summary

Q. Please summarize the adjustments proposed by AG witness Coppola and CUB witness Veerapaneni for Compression and Storage capital expenditures.

A. A comparison of the Company's capital expenditure projections to those recommended by the AG and CUB are provided in the table below:

Description	Company Amount (000)	AG Recommendation (000)	AG Adjustment (000)	CUB Recommendation (000)	CUB Adjustment (000)
2024 Proj	175,339		0		
2024 Act	165,776		-7,563		
12 ME 10/31/26	162,039			145,031	-17,008

B. AG Witness Coppola

Q. On pages 84 and 85 of his direct testimony, AG witness Coppola proposes adjustments to the Company's 2024 Compression and Storage capital expenditures based on the proposed versus actual spending levels. Do you agree with the proposed adjustments?

A. Yes, the Company accepts the proposed adjustment.

C. CUB Witness Veerapaneni

Q. Beginning on page 14, line 14 of his direct testimony, CUB witness Veerapaneni proposes test year adjustments to the Company's Compression and Storage projects that you are sponsoring. Do you agree with these proposed adjustments?

A. No, I do not. I provided a description of the necessity for the Compression and Storage expenditures in my direct testimony beginning on page 26, line 10, through page 47, line 25. Mr. Veerapaneni simply took the average of the 2023 and 2024 actual amounts and applied inflation to project a test year amount. CUB witness Veerapaneni did not review the reasonableness of the projects proposed during the test year or the benefits the projects would provide to customers. The Company believes that the methodology used by CUB is unreasonable and should be rejected by the Commission.

Q. Does this conclude your rebuttal testimony?

A. Yes.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

REBUTTAL TESTIMONY

OF

ASHLEY E. MESCHKE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Q. Please state your name and business address.

A. My name is Ashley E. Meschke, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Ashley E. Meschke who previously submitted testimony in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut the direct testimony presented by Attorney General witness Sebastian Coppola regarding Consumers Energy Company's ("Consumers Energy" or the "Company") Employee Incentive Compensation Plan ("EICP"). I will specifically respond to Mr. Coppola's comments about the operating performance measures.

Q. Are you sponsoring any exhibits?

A. No.

Q. Please provide an overview of your rebuttal testimony.

A. Mr. Coppola argues that $526,000 of EICP expenses included in the test year should be disallowed. On page 190, lines 8 through 11 of Mr. Coppola's direct testimony, he states that cost savings calculated are inconsistent with recent trends in performance, aspirational, and not based on actual performance. This is incorrect and my rebuttal testimony provides further information to substantiate that customer benefits from the EICP program exceed the cost to customers. Mr. Coppola's recommendation to disallow EICP costs should be rejected.

Q. Are you seeking full recovery of the customer benefits of $3,600,000 as outlined in your direct testimony?

A. No. It is important to clarify that the intent of my testimony is not to recover the full projected cost savings for the test year. Instead, it is intended to provide a reasonable expectation of customer benefits in the test year as the Company achieves operational goals associated with the EICP. My testimony and supplemental exhibits outline $3,600,000 in projected savings – which exceeds the Company's request for recovery of $1,546,000 and is considered reasonable and prudent for the Company's customers.

Q. On page 189, lines 6 through 9, Mr. Coppola indicates that there has been a negative performance trend in safety incidents. Do you agree with his assessment?

A. No. Mr. Coppola's analysis of recordable incidents on a short-term basis to assert a negative trend does not accurately reflect the Company's overall safety performance, as detailed later in my testimony. In 2007 and 2008 the Company incurred 558 and 335 incidents respectively, prompting a transformation in its approach to employee safety and health. Since 2012, recordable incidents have consistently been at or below 150 per year, and the Company has exceeded the average performance of peer utilities nine of the last ten years.

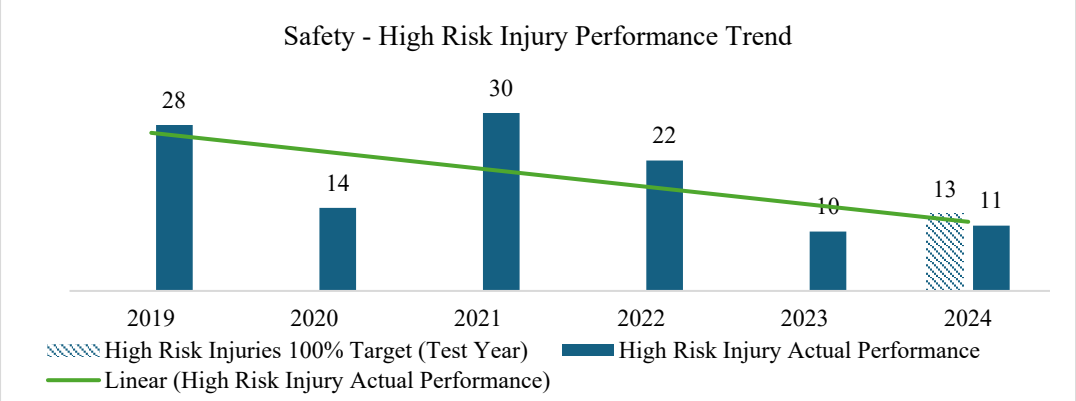
Q. Please explain why only analyzing recordable incidents is not a holistic representation of the Employee Safety EICP operating performance metric.

A. As outlined in Exhibit A-39 (AMC-1), the Employee Safety EICP operating performance measure is composed of three components: (1) Recordable Incident Rate, (2) High Risk Injuries, and (3) Fatalities. The Recordable Incident Rate accounts for 30% of the metric and the total number of recordable incidents is only one variable of the equation outlined in Exhibit A-95 (AEM-1). High-Risk Injuries account for 70% of the metric and include

both OSHA recordable and non-recordable incidents that have the potential to result in a severe injury or fatality. In the event there is a fatality, there is a 0% payout for the Employee Safety operational goal in its entirety. Many peer utilities in the industry are shifting their focus toward high risk and severity-based incidents as opposed to recordables, and the Employee Safety operational measure weighting reflects changes in the industry.

Q. Please explain the trend in High Risk Injuries and fatalities to provide a more holistic representation of the Employee Safety EICP operating performance metric.

A. As previously stated, the Company began tracking High Risk Injuries in 2019, and the historical performance indicates a strong positive performance – with a notable change starting in 2022 which was the first year the metric was included as part of the Employee Safety metric for the EICP.



Additionally, the Company's last employee fatality was in 2018 and this year marks the longest duration in the Company's 139-year history without an employee fatality.

Q. Do you believe the Employee Safety metrics have improved because they have been included in the EICP operating performance measures?

A. Absolutely. As Company witness Amy M. Conrad outlines in her direct testimony on pages 11 through 12, the intent of the EICP operational metrics is to incentivize employees

to participate in increasing productivity and achieving performance metrics that are critical to the Company's utility business and customers. This is one of several examples where including a metric in the Company's EICP has led to positive performance trends. The Employee Safety metric is designed to ensure employee safety and well-being – while preventing productivity losses that can result in delays in completing the work plans that will deliver safe and reliable service to customers and keeping the cost associated with safety incidents low.

Q. On page 189, lines 8 and 9 of Mr. Coppola's direct testimony, there is an indication that achieving 81 recordable incidents is unrealistic. Do you agree?

A. No. This is the target that has been established to drive continuous improvement in the Company's safety performance – while striving to achieve high performance compared to peer utilities in benchmark studies. Although it may be aggressive, it is intended to be challenging, yet achievable to keep employees motivated to achieve the targeted levels of performance. EICP targets are established with the intent of achieving a first quartile performance compared to peer utilities.

Q. On page 189, lines 9 and 10 of Mr. Coppola's direct testimony, Mr. Coppola indicates that the data provided in Exhibit A-96 (AEM-2) does not indicate actual cost savings. Do you agree with his assessment?

A. The Company never stated that the savings shown in my exhibits represent historical costs savings. My exhibits demonstrate the cost savings that the Company would expect to realize and pass on to customers in future if it achieves the operations goals associated with each exhibit. Furthermore, as I discussed earlier in my rebuttal testimony, the Company is not asking the Commission to approve EICP costs equivalent to the expected savings. My

exhibits show that the expected savings are meaningfully higher than the costs to achieve them and justify the modest amount of EICP expense the Company is requesting in this case.

Q. On page 189, lines 11 through 14, Mr. Coppola highlights that the costs associated with safety incidents have increased not decreased and that costs have been erratic between 2020 and 2023. Do you agree with this assessment?

A. No. Mr. Coppola has not provided sufficient analysis to make this claim. The cost outlined in Exhibit A-96 (AEM-2) is broken down by lost time and medical expenses, workers' compensation, and other exposures. To adequately indicate a trend in costs, cost per incident should be analyzed as opposed to total cost. When analyzing these costs between 2020 and 2024, there is a negative trend in costs associated with lost days. In reviewing the cost per incident associated with medical expenses, workers compensation, and other exposures, there has been an increase in actual costs – which is reasonable given national headlines indicating the rise in inflation and healthcare cost since 2020. However, the cost trends are not erratic as Mr. Coppola indicates. These costs are within statistical control limits. Additionally, by including High Risk Injuries into the EICP, the Company is focused on reducing the potential for safety incidents that have the potential to result in a fatality or severe injury – which would more than likely result in higher costs – as opposed to injuries such as insect bites and minor abrasions – which are also included in the cost savings projection.

Q. On page 189, lines 16 through 20, of his direct testimony, Mr. Coppola criticizes the Company's methodology used to calculate customer savings based on projected savings in 2024 versus actual savings for the System Average Interruption Duration Index ("SAIDI") metric. Do you agree with his opinion?

A. No. For the test year, the company leveraged the EICP 100% target for SAIDI of 170 customer minutes to estimate projected cost savings to customers. This is a reasonable approach to indicate the savings customers should expect when the Company achieves targeted levels of SAIDI performance. If the Company leveraged actuals from 2020-2024 and calculated the average impact, the results would have been 155 customer minutes in 2024 – resulting in an eight-minute reduction in customer minutes and customer benefits of $25,115,262 as opposed to the results outlined in Exhibit A-97 (AEM-3). This indicates that the Company's approach to calculate projected savings are conservative and understated by three minutes and $9,687,366.

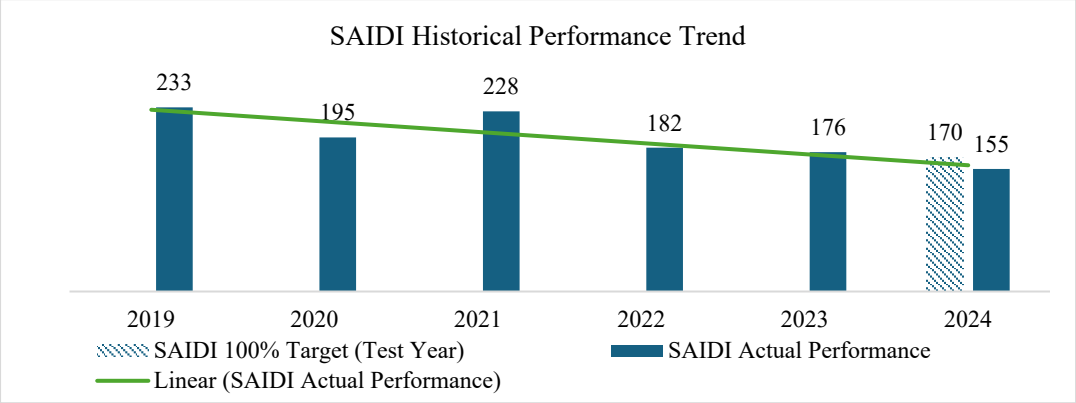
Q. Why does the Company use a four-year historical average to project savings?

A. Leveraging historical averages to set targets and project customer benefits is the best practice in data analytics because it provides a more stable and reliable basis for decision-making. This approach avoids the inconsistencies and anomalies that can arise from year-over-year fluctuations, ensuring that targets are based on consistent long-term trends.

Q. Do you believe the EICP program has positively contributed to SAIDI performance?

A. Yes. This is another example that illustrates a positive performance trend can be observed when a metric is included in the Company's EICP – as outlined earlier in my testimony. If you analyze the longer-term trend in SAIDI performance, you will see a negative trend

over the last several years – demonstrating the Company's commitment to continuous improvement to deliver customer value through EICP operating performance measures.



Q. On page 190, lines 2 through 4, of his direct testimony, Mr. Coppola indicates that there has been a negative performance trend in employee turnover between 2020 and 2023. Do you agree with his statement?

A. No. The 2020 data point selected by Mr. Coppola to indicate a negative trend represents an extreme outlier in the Company's historical performance trend. It should be noted that, in 2020, voluntary turnover during the COVID-19 global pandemic was generally exceptionally low in many industries due to economic uncertainty and unprecedented actions by governments to curtail normal business activity. As referenced in my direct testimony on page 4, lines 11 through 12, the Company's employee turnover rates are significantly lower than the average across peer utilities and indicate a very strong performance. When achieving performance in the top quartiles, it is natural to see some year-over-year variation without significant performance improvement. Instead, the goal is focused on maintaining the Company's strong performance.

Q. On page 190, lines 5 through 7, Mr. Coppola indicates that this is a clear mismatch between employee satisfaction measures and cost savings based on peer company turnover rates. Do you agree with his assessment?

A. No. In Exhibit A-95 (AEM-1), the Company outlines the Culture Index survey questions. The following questions from the survey are leading indicators for employee retention: (1) If I were offered a similar job elsewhere at the same pay, I would stay at the Company; (2) Given your choice, how long would you plan to continue working for the Company?; (3) I would recommend my Company as a good place to work; (4) I feel proud to work for the Company; (5) I feel able to be myself at work; and (6) I feel like I belong at the Company. Consumers Energy's historical trends indicate that there is a strong correlation between its Culture Index and employee turnover. When Culture Index performance is high, the employee turnover is low. Despite fluctuations in year-over-year performance, the Company has consistently exceeded benchmark performance in employee turnover – illustrating that by including the Culture Index in the Company's EICP operational metrics it is achieving a cost savings compared to peer utilities.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief	)))))	Case No. U-21806

REBUTTAL TESTIMONY

OF

HEIDI J. MYERS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Q. Please state your name and business address.

A. My name is Heidi J. Myers, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Heidi J. Myers who previously presented direct testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. I will rebut certain assertions and recommendations of the Association of Businesses Advocating Tariff Equity ("ABATE") witness Jessica A. York and the Citizens Utility Board of Michigan ("CUB") witnesses Ram Veerapaneni and Richard J. Bunch regarding the use of a projected test year and productivity assumptions. I will also address ABATE witness Colin T. Fitzhenry's position taken on inflation. In addition, I will also address Attorney General Dana Nessel ("AG") witness Sebastian Coppola regarding his proposed Operating and Maintenance ("O&M") adjustments related to the Company's Voluntary Separation Program ("VSP"), his proposed adjustments related to the Riverside Storage Field, and his recommendation related to the accounting for the SAP S4/HANA project.

Q. Have you prepared any exhibits in conjunction with your rebuttal testimony?

A. No.

Q. Are there any statements you would like to make regarding your rebuttal testimony?

A. Yes. Any items not specifically addressed in my rebuttal testimony does not indicate my agreement with them.

Test Year

Q. Has the Michigan Public Service Commission ("MPSC" or the "Commission") previously approved Consumers Energy's ability to utilize a Projected Test Year?

A. Yes, the Commission has, for many years, approved the use of projected test years. Most recently in Consumer Energy's electric rate case, Case No. U-21585, the MPSC's March 21, 2025 Order once again approved the use of a projected test year despite being presented with the same arguments from intervening parties that will be addressed in this rebuttal testimony.

Q. What specific guidance did the Commission provide in Case No. U-21585?

A. The Commission "…acknowledges that the use of projected test years by utilities in developing requested rates in rate cases is permissible by statute – subject, however, to the burden that the company prove the accuracy of each and every test year projection." The Commission further opines "… the Commission agrees with the ALJ that "the burden of proof to substantiate projections lies with the utility, and absent sufficient support, historical data may be used to develop the revenue requirement," that "the used and useful standard should be applied on a case-by-case basis," and that "Consumers' projected test year should be adopted in this case, with costs and revenues adjusted based on the preponderance of the evidence." See MPSC Case No. U-21585, March 21, 2025 Order, page 9.

Q. Does ABATE witness York propose to deviate from the Commission's long-standing approval of the use of projected test years?

A. Yes. Starting on page 8 of her direct testimony, Ms. York asserts that all cost projections should be based on historical test year amounts with costs adjusted for known and

measurable changes, but goes on to recommend no rate increase for this case without providing for any known and measurable changes.

Q. What examples does Ms. York provide for known and measurable changes to a historical test year?

A. On pages 8 and 9 of her direct testimony, Ms. York provides four examples of what she considers valid known and measurable changes to a historical test year. They include normalizations to address the effects of volatility, annualization of costs that occur on a periodic basis, but not in every year, annualization of costs that occurred in the later months of the historical year that are expected to continue at that level going forward, and imminent changes in costs that will occur during the period between the end of the historical period and the date new base rates go into effect.

Q. Has Ms. York incorporated her thoughts on valid known and measurable changes in her recommendation to the Commission?

A. She has not. Ms. York did not propose any modifications to the historical test year that she perceives as valid known and measurable adjustments. Her ultimate recommendation to the Commission to have no rate increase based on the results of the historical test year deviates from her own thoughts on the appropriate method to set rates. This alone is reason enough to reject Ms. York's recommendation.

Q. Do you agree with ABATE witness York's rationale for moving away from the long-standing Commission approved use of projected test years?

A. No. The following testimony will individually address each of the points made by Ms. York.

Q. Please comment on Ms. York's assertion on page 6 of her direct testimony that customers experience rate increases sooner using a projected test year than they would under a historical test year.

A. The use of a projected test year provides the calculation of rates necessary during the period for which the rates will be in effect. This is the most accurate way to set rates and, as will be discussed further below, provides intervenors with an opportunity to comment on the Company's plans for spending prior to the dollars actually being spent. Not only does Ms. York's assertion ignore these points, it identifies a fact, that if acted upon by the Commission, would unfairly remove the fundamental ability of the Company to have an opportunity to earn a fair rate of return on its investments and knowingly provide customers rates that are below the cost to serve them.

Q. Do you agree with Ms. York's assertion on page 7 of her direct testimony that a projected test year eliminates cost containment?

A. I do not. The Company has an incentive to hold spending at levels approved in rates and work to spend efficiently. Once rates are established, the Company is left to manage the business within those rates inclusive of risks that are outside the control of the Company such as weather impact on sales. This provides a powerful incentive for cost containment.

Q. Do you agree with Ms. York's assertion on page 7 of her direct testimony that the use of a projected test year handicaps Staff and intervenors in reviewing Consumers Energy's rate filings to ensure the projected capital expenditures and expenses are reasonable because they are not actual capital expenditures?

A. I do not. Providing expected spending for a future test year provides a more transparent rate making process allowing Staff and intervenors an opportunity to understand how dollars

are intended to be spent and opine on the merits of the proposed spending. In comparison, setting rates based on historical spending is inferior as it only allows for review of spending after it has already occurred. This can have unfortunate consequences. If spending is only reviewed after it is spent and only then determined to be an item that should be disallowed from rates, it can lead to write-offs for the Company and an inefficient use of a finite amount of dollars available to invest in the system. This is not good for the Company or customers. Customers are better served by the rate setting process provided by projected test years that allows parties to the rate case proceedings an opportunity to understand and opine on the merits of how dollars will be spent in advance of the spending.

Q. On page 6 of Ms. York's direct testimony, she has included Table JAY-2 titled Historic Test Year and Projected Test Year Rate Sufficiency/(Deficiency). Do you agree with the conclusion that Ms. York reached as a result of the data on this table?

A. I do not. Ms. York's assertion based on the table is that the Company "…would not have been able to seek the large rate increases it has sought in seven out of its eight most recent rate cases, including this proceeding, but for basing the requested rate increases on projected test years." While it may be true that rate requests would be different if the Company were required to rely on a historical test year for rate relief, it would not remove the need for rate relief but would only unfairly delay it. In fact, the very first time rates were established rates on a historical test year it would create a greater deficiency in the next historical year requiring a greater increase in that year. This does not create a regulatory environment conducive to customer interest. ABATE's request to rely on historical test years for setting rates is really an ask to trade an environment where stakeholders and the Commission have an opportunity to weigh in on spending, projects, and programs before they are implemented

for a short-term and inappropriate delay in rate relief. Establishing a built-in regulatory lag as proposed by Ms. York would be detrimental to the Company and its customers, and is inconsistent with the Michigan Law providing for rates to be set using projected test years.

Q. Pages 12 through 13 of Ms. York's direct testimony provides what she labels as her longer-term recommendation to the Commission. How do you respond?

A. In that portion of her direct testimony, Ms. York describes other filings and dockets where ABATE has opined on test years. This portion of her testimony has either already been addressed by the Commission or will be addressed by the Commission in those other dockets.

Q. Have any other witnesses commented on the use of a projected test year?

A. Yes. CUB witness Veerapaneni recommends moving away from a projected test year. He recommends the use of an average of 2023 and 2024 historical data for capital and O&M expense for the case. He indicates that the cycle of annual rate case filings never ends if the MPSC approves even a small portion of the increase and goes on to note that Consumers Energy has the responsibility to provide safe and reliable utility service because Consumers Energy does not have competition to provide gas service. He requests the Commission consider customer's inability to look for other sources of gas and use average historical data for capital and O&M expense.

Q. Please respond.

A. I do not agree with Mr. Veerapaneni's request or reasons for the request. First, Mr. Veerapaneni did not review the Company's capital or O&M expense projects. His testimony described several capital and O&M programs but did not provide any critique of

the proposed spending or rationale as to why the spending was not reasonable or prudent. On one point, I do agree with Mr. Veerapaneni. Consumers Energy is obligated to provide safe and reliable utility service. The testimony of Company witnesses provides support for the needed capital and O&M spending included in the case to do just that. Mr. Veerapaneni does not make any assertions that the Company has not adequately supported the costs included in this case and he does not provide any clear evidence as to why an average of 2023 and 2024 historical spend as the basis for the entirety of capital and O&M expenditures is appropriate. As such, Mr. Veerapaneni's request to base all capital and O&M expense on historical experience is not appropriate and should be rejected by the Commission.

Productivity Factors

Q. Please describe CUB witness Bunch's recommendation related to the use of a productivity factor in this case.

A. On pages 13 through 23 of his direct testimony, CUB witness Bunch supports his recommendation that the Commission apply a productivity adjusted inflation factor to all actual historical O&M and capital project labor costs to determine test-year spending projections. Mr. Bunch also recommends the same treatment for non-labor costs, both O&M and capital. He indicates that the inflation rates supported by the Company should be reduced by a 0.79% productivity factor based on the average annual Michigan labor productivity factor and applied to historical labor costs and he recommends reducing inflation rates by a 0.83% productivity factor based on the non-labor total factor productivity factor to be applied to non-labor O&M and capital. Ultimately, he argues that rates that rise at the rate of inflation are not justified because inflationary pressures on costs should be mitigated by gains in productivity and the Company should be able to fully

recover its costs with rates that rise slower than inflation if it realizes productivity gains. He goes on to argue that utilities do not face competitive pressures to contain costs and a reasonable opportunity to recover their costs should include a reasonable expectation that it demonstrate over time that it is attaining productivity gains comparable to those of companies operating in competitive markets.

Q. Do you agree that projected test year costs should be determined based on historical amounts increased by inflation that has been reduced by a productivity factor?

A. No. The Company strives to continuously improve through its CE Way Operating System that identifies and executes on productivity improvements leveraging new technology and sustainable productivity improvements to help mitigate inflationary pressure and control costs over time. All known cost reductions related to productivity are incorporated in financial exhibits of each witness. Mr. Bunch's recommendation to determine projected test year costs by applying a productivity-adjusted inflation factor to historical actual costs is overly simplistic and does not align with the reality of the costs the Company is experiencing or expects to experience. The standard that must be applied to the projected costs is whether they are reasonable and prudent. Broad productivity adjustments do not meet this standard. If the Commission were to simply apply cost indexes to historical costs, there would be no need for any evidence to be presented in the contested case. Further, Mr. Bunch's recommendation removes the ability for the Company to utilize a projected test year. As noted above, the Commission has indicated numerous times that a projected test year is permissible by statute, and it is the Company's burden to support its rate case projections. The Company witnesses fully support the projected test year costs they sponsor. Any adjustments should be based on the merits of the specific costs in question.

Q. Please respond to Mr. Bunch's conclusion at page 17 of his direct testimony that utilities do not face competitive pressures to contain costs and a reasonable opportunity to recover its costs should include a reasonable expectation that it demonstrate over time that it is attaining productivity gains comparable to those of companies operating in competitive markets.

A. As noted above, I do not consider this an appropriate consideration in determining proper rates. However, even it were, the Company has in fact demonstrated over time that its rates have remained lower than inflation. Company witness Neal P. Dreisig provides testimony that over the past 10 years customer bill increases are well below inflation.

Q. Mr. Bunch also indicates that the Company's costs must be increasing at rates higher than inflation because the proposed rate increase is higher than inflation. Please respond.

A. Mr. Bunch has not considered all necessary facts to make this assertion. He went on to discuss only the changes in O&M expense when trying to connect cost increases to the proposed rate increase. However, changes in O&M expense only explains 17% of the proposed increase or a 1.8% increase which is lower than inflation. The largest driver of the proposed increase is the needed investments in the system which represents additions of capital assets and are not necessarily indicative of a rise in costs. They represent additions of assets that serve customers and are supported in great detail by other Company witnesses.

Q. Has Mr. Bunch provided evidence that the productivity factors are appropriately applied to costs incurred by the Company?

A. No. Mr. Bunch provided no explanation of how his suggested productivity factors are calculated or used in practice, nor did he provide compelling evidence that they would be

appropriately used to set utility rates. The U.S. Bureau of Labor Statistics ("BLS") indicates that labor productivity is equal to output divided by hours worked and the total factor productivity is equal to output divided by combined inputs.[1] Mr. Bunch's broadbrush proposal to apply productivity factors to all capital and O&M costs ignores the fact that the Company does not have control over all costs and may have less control over the inputs used to calculate the productivity factors than other companies. Any recommended adjustments to projected costs should be based on the merits of those specific costs.

Q. CUB witness Bunch also recommends that the Commission replicate the order it issued in Consumers Energy's electric rate case, Case No. U-21585, namely that it should direct Consumers Energy to present more detailed evidence to demonstrate that it is in fact offsetting inflation by productivity in the Company's next gas rate case. Do you agree with this recommendation?

A. No. In each rate case the Company must demonstrate that its costs are reasonable and prudent. The Company strives to continuously improve its efficiency through the CE Way Operating System and incorporates known savings in its financial exhibits. However, accurately measuring productivity gains that accumulate over time and pointing to a specific spending line item in the case that is impacted can be complex. Productivity as defined by the BLS, is outputs divided by inputs. Trying to identify each and every change in either outputs or inputs in the context of productivity as part of a regulatory filing would be overly burdensome. The Company understands its obligation to provide clear cost projections along with support for the reasonableness of its projections and responds to feedback received in Commission orders. Requesting more information on specific cost items, if

[1] https://www.bls.gov/productivity/educational-material/labor-productivity-total-factor-productivity-comparison.htm

needed, is a more constructive request than requesting an overly complex isolation of all productivity included in the case.

Q. Does Consumers Energy agree that the Company must support all costs included in its rate cases?

A. Yes. It is on this basis that I again respectfully requesting the Commission reject the recommendations of ABATE witness York and CUB witnesses Bunch and Veerapaneni to leverage either a productivity factor, historical based capital and O&M costs, or outright rejection of using a projected test year as a means to disallow projects without deeper consideration. Disallowances for all projects and programs in this manner would disregard the evidence provided by the Company witnesses in support of the reasonableness and prudence of investments. The Company requests the Commission continue to evaluate each proposed project on its individual merits in the instant case to determine its reasonableness and prudency.

Inflation

Q. Describe ABATE witness Fitzhenry's proposal related to inflation.

A. At pages 18 and 19 of his direct testimony, Mr. Fitzhenry proposes to use the Blue Chip GDP Chained Price Index ("Chained Price Index") as a replacement for the Consumers Price Index ("CPI") that the Company used in the case. Mr. Fitzhenry argues that the basket of goods in the Chained Price Index is updated each year to reflect what people are actually buying. He goes on to say that this is unlike the CPI, which uses a fixed basket for a set period. He also provides an analysis showing that there is a higher correlation to the actual cost of gas meters for the Chained Price Index than the CPI. Ultimately, he recommends the Commission replace the CPI with the Chained Price Index indicating that the CPI

non-labor inflation rate is well above the consensus industry experts' opinion of the Chained Price Index.

Q. Please respond.

A. As will be illustrated, there are numerous issues with the conclusions drawn by Mr. Fitzhenry. The Commission should maintain its long-standing practice of approving the use of CPI in rate cases.

Q. Do you agree with Mr. Fitzhenry's assessment at page 18 of his direct testimony that the CPI is inferior to the Chained Price Index because the Chained Price Index is updated annually?

A. I do not. The CPI is updated periodically. The BLS indicates that these updates are made to "reflect more recent consumer spending patterns; this provides a logical opportunity to rework the item classification scheme so that it will recognize the emergence of new items, the changes to existing items and their relative importance, and the ways that people view consumer goods and services."[2] As such, the CPI should not be viewed as inferior to the Chained Price Index because the Chained Price Index is updated annually.

Q. Should Mr. Fitzhenry's correlation analysis be considered in deciding the appropriate inflation index for this case?

A. No. Starting on page 19 of his direct testimony, Mr. Fitzhenry did an analysis to find the correlation for one expense item, gas meters, to the CPI and the Chained Price Index finding that there was a higher correlation to the Chained Price Index. However, the nature of both of the indexes is to provide inflation rates for a basket of goods, not just one item. It is not

[2] https://www.bls.gov/cpi/additional-resources/revision-1998-item-structure.htm

appropriate to draw the conclusion that the Chained Price Index is more appropriate than the CPI based on a correlation review of one expense item.

Q. Mr. Fitzhenry ultimately concludes that the Commission should adopt the Chained Price Index for inflation in this case also indicating that its use is a consensus industry opinion. Does he explain what a consensus industry opinion represents?

A. No. Mr. Fitzhenry does not explain what a consensus industry opinion represents and provides no proof or support that this is true. This unsupported assertion should be disregarded.

Q. Is there a long standing practice for Commission approval of the CPI for use in rate cases?

A. Yes. The Commission has consistently approved the use of CPI. The Commission most recently approved the use of CPI in DTE Electric Company's rate case, Case No. U-21534. At page 76 of the January 23, 2025 Order the Commission stated:

> The Commission also rejects the proposal to switch to use of the Real GDP Chained Price Index. As the company points out, the CPI is the most widely used measure of inflation, and the Commission finds ABATE failed to show how the Real GDP Chained Price Index is superior to the CPI-Urban for either labor or non-labor costs or why the Real GDP Chained Price Index's customer substitution treatment is superior to the periodic updates made in the CPI's basket of goods.

The facts in this case are similar and Mr. Fitzhenry has not provided adequate support to move to the Chained Price Index. The Commission should approve the continued use of the CPI for inflation.

Voluntary Separation Program

Q. Can you summarize the testimony and recommendations of AG witness Coppola regarding the Company's 2023 VSP?

A. AG witness Coppola proposed adjustments in the amount of $7,989,000 related to the Company's 2023 VSP. On pages 181 and 182 of his direct testimony, he indicates that the Company did not provide any underlying calculations showing how the cost savings were calculated or any supporting schedules that would show the cost savings were actually included in the projected test year in each exhibit for the affected departments. His ultimate recommendation is for the Commission to remove the entire $7,989,000 of VSP savings from the Company's forecasted O&M expense for the projected test year.

Q. Please respond.

A. The Company did not provide a calculation of the savings because the savings provided are actual amounts. Through discovery, the Company disclosed the number of employees by area and the dollar value of the savings associated with these employees leaving the Company. The Company was also not able to provide specific workpapers that identify these VSP savings in each witness exhibit. However, this is for good reason. With the exception of Company witness Matthew J. Foster who sponsors corporate O&M expense, O&M witnesses include total projected O&M expense based on the forecasted needs in their business area. When considering those needs for the projected period of this case, each witness had knowledge and used the knowledge of the VSP savings when developing their O&M expense for the case. Company witness Foster does forecast corporate O&M by inflating historical O&M expense. However, he also removed VSP savings from the historical year prior to inflating the historical O&M expense. All of the VSP savings were

considered in the development of this case and have been properly incorporated. It is not appropriate to remove the VSP savings as recommended by Mr. Coppola.

Accounting For SAP S4/HANA

Q. Please describe AG witness Coppola's recommendations regarding the SAP S4/HANA project.

A. At page 91 of his testimony Mr. Coppola indicates that the project is too premature to include any capital expenditures in this rate case and to defer large forecasted O&M costs in a regulatory asset without firm plans for project execution. Again on page 180 of his direct testimony, he recommends the denial of the proposed regulatory asset accounts related to the SAP S4/HANA project relying on his assertions that the project is premature and inadequately justified and all requested approvals related to the project should be denied.

Q. Does the Company agree that SAP S4/HANA costs should not be included in this case?

A. No. Company witness Stacy H. Baker provides continued support for the inclusion of the SAP S4/HANA project in her rebuttal testimony.

Q. Do you agree with Mr. Coppola that the accounting requests related to the SAP S4/HANA project should be denied?

A. No. As explained in my direct testimony, approval of the deferral of the O&M expense associated with the project will allow the Company to spread the O&M costs of the project over the life of the assets resulting from this project tying the recovery of the expense to the time period over which the spending will be providing benefits. This is also true for the request to extend the amortization period over which the cloud implementation costs for the SaaS solutions to 15 years. These requests reduce the burden to customers, avoid spikes in

IT O&M expense and the need for customers to experience those spikes in rates. Mr. Coppola does not provide any critique of these accounting requests other than his assertion that the project is too preliminary for it to be included in this case. Company witness Baker has proven this to be incorrect. As such, the Commission should approve the inclusion of the SAP S4/HANA project and the associated accounting requests.

Riverside Storage Field

Q. Please describe AG witness Coppola's adjustments related to the Riverside Storage Field.

A. At pages 108 and 174 of his direct testimony Mr. Coppola has recommended removing the regulatory asset in working capital and amortization associated with the sale of the Riverside Storage Field indicating that the expected sale was terminated by the buyer.

Q. Does the Company agree with these adjustments proposed by Mr. Coppola?

A. Yes. However, if the amounts associated with the sale are removed from the case based on the assumption that there will not be a sale of the Riverside Storage Field, the plant assets should be added back into the case.

Q. Please explain further.

A. Consistent with Staff witness Robert F. Nichols' recommendation beginning at page 5 of his direct testimony, if the effects of the Riverside Storage Field sale are removed from the case the plant in service, depreciation reserve, depreciation expense, and property tax should be added back in. If the Riverside Storage Field assets are not sold, the cost associated with the assets should be included in rates. Mr. Nichols went on to support a recommendation provided by the Company in response to an audit question. This recommendation is to use any amount collected in rates related to the Riverside Storage Field assets as a reduction to

the established regulatory asset related to the sale, in the event that the Riverside Storage Field is sold. The Company agrees with Staff's position in the case related the Riverside Storage Field.

Q. How should the Commission treat Mr. Coppola's proposed adjustments?

A. The Commission should only adopt Mr. Coppola's proposed adjustments to working capital and amortization expense related to the Riverside Storage Field if there are also adjustments made to plant in service, depreciation reserve, depreciation expense, and property tax to add the Riverside Storage Field back into the case consistent with Staff's adjustments in the case.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

REBUTTAL TESTIMONY

OF

KRISTINE A. PASCARELLO

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Q. Please state your name and business address.

A. My name is Kristine A. Pascarello, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. Are you the same Kristine A. Pascarello that testified previously in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address the capital reductions proposed by Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witness Cynthia L. Creisher and the requested regulatory deferral mechanism for the Leak Detection and Repair program proposed by Staff witness Jacob G. Martus. Additionally, I will address the capital expenditure reductions for the Material Condition and Gas Operations Other programs proposed by Attorney General witness Sebastian Coppola, Association of Businesses Advocating Tariff Equity ("ABATE") witness Colin T. Fitzhenry, Citizens Utility Board of Michigan ("CUB") witness Ram Veerapaneni, Michigan Environmental Council ("MEC") and Sierra Club ("SC") (collectively, "MEC") witness Dr. Sol deLeon. I will also provide rebuttal testimony concerning proposed reductions to Consumers Energy Company's ("Consumers Energy" or the "Company") projected Gas Engineering and Supply Operating and Maintenance ("O&M") expenses recommended by Attorney General witness Coppola and CUB witness Veerapaneni.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-138 (KAP-8)	Discovery Response U21806-AG-CE-0431, Attachment 1;
Exhibit A-139 (KAP-9)	Discovery Response U21806-AG-CE-0426;

Exhibit A-140 (KAP-10) Audit Response U21806-SA-CE-0388;

Exhibit A-141 (KAP-11) Discovery Response U21806-MNSC-CE-0075, Attachment 2; and

Exhibit A-142 (KAP-12) EIRP Project List Detail.

I. STAFF WITNESS CREISHER

1. Material Condition – EIRP

Q. Please summarize Staff witness Creisher's recommendation regarding the Enhanced Infrastructure Replacement Program ("EIRP").

A. On page 8 of her direct testimony, Staff witness Creisher states that Staff generally supports the Company's proposed capital expenditures for the EIRP and the plan to reduce approximately 5% of vintage main per year, targeting program completion by 2035. Ms. Creisher also describes the Company's progress since Case No. U-21490, in reducing the cost per mile for plastic main pipe installation and encourages the Company to continue implementing measures to manage costs.

Q. While Staff is generally supportive of the Company's projected capital expenditures for EIRP, are you recommending any adjustments to the Company's filed projections?

A. Yes, I am. The Company discovered an error in the forecasted miles for the Northeast region caused by a feet to miles conversion error in the 2025 program year. This correction was included as an attachment to discovery response U21806-AG-CE-0431 and is provided as Exhibit A-138 (KAP-8). The corrected capital expenditures are $247,018,590 in the 2025 program year, with $204,611,703 in the 10 months ending October 31, 2025, and $250,809,975 in the test year ending October 31, 2026. This results in reductions of

$3,272,223 for the 2025 program year, which are made up of $2,710,465 for the 10 months ending October 31, 2025, and $561,759 for the test year ending October 31, 2026.

2. Material Condition - Non-Modeled

Q. Please summarize Staff witness Creisher's recommendation regarding the Material Condition Non Modeled ("MCNM") program.

A. Beginning on page 8 of her direct testimony, Ms. Creisher summarizes the Company's proposed capital expenditures for the MCNM program, which includes replacement projects to address emergent issues. She states that Staff does not support the proposed level of capital expenditure, based on preliminary actual costs for the Line 1010 project that the Company provided, which is included as Staff Exhibit S-22.1 and Exhibit S-22.2.

Q. In Exhibit S-22.0, Ms. Creisher shows a recommended reduction in the Company's proposed MCNM expenditures of $4,054,000 for the 10 months ending October 31, 2025, and $3,500,000 for the test year 12 months ending October 31, 2026. Do you agree with the recommendation?

A. Yes, I do. The reduction is based on Company provided adjustments to the Line 1010 project based on updated project estimates.

3. Compliance and Controls

Q. Please summarize Staff witness Creisher's recommendation regarding the Compliance and Controls – Advanced Methane Detection ("AMD") project.

A. Beginning on page 10 of her direct testimony, Ms. Creisher summarizes the various projects which are included in the Compliance and Controls program and projected expenditures referencing Table 10 on page 73 of my direct testimony. She continues that Staff does not support the proposed level of capital expenditures, noting that the Company

no longer projects to spend $265,000 on the AMD project in 2025 as provided in the Company's response to Attorney General's Discovery Request U21806-AG-CE-0422, which is included as Staff Exhibit S-22.3. On page 11 of her direct testimony, Ms. Creisher recommends capital expenditures in Compliance and Controls be reduced to $182,000 for the 10 months ending October 31, 2025. Additionally, Ms. Creisher provides information that an incorrect capital expenditure reduction of $295,000 was provided for Staff's revenue deficiency calculation. The impacts of this adjustment are not fully reflected in the testimony and exhibits of other Staff witnesses or in the Staff's revenue deficiency supported by Staff witness Robert F. Nichols II and will be adjusted in Staff's brief.

Q. In Exhibit S-22.0, Ms. Creisher shows Staff recommended reduction in the Company's proposed Compliance and Controls expenditures of $265,000 for the 10 months ending October 31, 2025. Do you agree with the recommendation?

A. Yes, I do. The reduction is based on the Company provided adjustments to the AMD project expenditures.

Q. Are there any other adjustments that should be made to the Compliance and Controls projects shown in Table 10 on page 73 of your direct testimony?

A. Yes, there is an adjustment required for the Damage Prevention and Miss Dig capital expenditure. As described on page 82 of my direct testimony, at the time of filing this case, the Company projected $954,000 for the Irth Solutions software used for damage prevention and 811 ticket management. As provided in discovery response U21806-AG-CE-0426, included as Exhibit A-139 (KAP-9), the Company has determined that only a portion of the software cost will be capitalized. The gas portion of the software cost has been reduced to $829,082, with $195,000 as capital and $634,082 as O&M. This change

will reduce the capital test year amount shown in Exhibit A-83 (KAP-5), line 4, from $4,168,000 to $3,409,000 and increase the O&M test year amount shown in Exhibit A-81 (KAP-2), line 12, from $1,231,000 to $1,865,082.

II. STAFF WITNESS MARTUS

Q. Please summarize Staff witness Martus' recommendation regarding the Leak Detection and Repair ("LDAR").

A. Beginning on page 4, Staff witness Martus' direct testimony discusses the Company's requested regulatory deferral mechanism for the LDAR rule and its intention to comply once published. He acknowledges the Company's plan to repair all known grade 2 and grade 3 leaks (Leak Backlog) regardless of the rules publication and the proposed $1,510,000 in capital expenditure detailed in Exhibit S-17.2. On page 5, Mr. Martus states that Staff supports repairs for safety and finds the cost reasonable, regardless of the LDAR rule publication. On page 6, he includes that Staff does not support the regulatory deferral mechanism for LDAR due to an executive order issued in January 2025, making the rule's publication unlikely during the requested deferral period.

Q. Do you agree with Staff witness Martus' recommendation?

A. Yes, I do.

III. ATTORNEY GENERAL WITNESS COPPOLA

1. Material Condition EIRP

Q. Please summarize Attorney General witness Coppola's recommendation regarding the EIRP.

A. Beginning on page 38 of his direct testimony, Attorney General witness Coppola discusses the history and changes in the EIRP. Beginning on page 39, line 16, Mr. Coppola

summarizes the 13 years of the EIRP historical installation and expenditures. On page 40, he provides additional information regarding the Transmission Operated by Distribution ("TOD") pipe installation. Mr. Coppola incorrectly calculates on line 11 that the Company has replaced 33.4 miles of TOD pipe with 58.3 miles of new main. The 58.3 miles of new steel main installed includes both TOD and high pressure ("HP") steel projects, which are also included in the totals and cost per mile calculations on page 39 of his direct testimony. After expressing his concerns regarding the growth of the EIRP and the project expenditure, beginning on page 40 of his direct testimony, Mr. Coppola describes two concerns regarding the capital spending plans for 2025 and 2026.

1. Uncertainty about seven EIRP projects scheduled for 2026 being completed in the test year based on the status of engineering design; and

2. Projected expenditures for 2025 and 2026 reaching a new peak level representing a 38% increase in less than three years. Mr. Coppola states on page 42 of his direct testimony that the Company is not meeting its commitment to refrain from spending, citing the settlement agreement in Case No. U-21490.

On page 43 of his direct testimony, Mr. Coppola recommends a maximum spending cap of $197 million for the 12 months ending October 2026, with future spending levels adjusted for the Consumer Price Index ("CPI") rate of inflation. He acknowledges that the proposed spending cap will reduce the number of miles the Company plans to retire and install. However, he argues that the spending cap would incentivize the Company to reduce the cost per mile and reduce competition for limited resources. He suggests a three-to-five-year extension of the program as a reasonable trade-off to balance against customer affordability concerns.

Q. How do you respond to Mr. Coppola's characterization of the "increasing spending trend" in EIRP?

A. The capital expenditures I am sponsoring are important to replace aged at-risk pipe intended to improve safety and reliability. The Company continues to look for additional cost reduction opportunities such as those described in my direct testimony on page 46. As shown in Exhibit A-138 (KAP-8) on lines 41 and 51, these opportunities resulted in the 2024 actual cost per mile to be $216,500 less than the 2023 actual cost per mile. Also, as stated in my direct testimony and shown in Exhibit A-138 (KAP-8), the Company is not projecting the regional cost per mile of plastic pipe for 2025 or 2026 above 2023 levels. The Company has made progress toward reducing the cost per mile for plastic main installation in the the EIRP. Reducing vintage main by 5% per year is a prudent and reasonable approach to enhancing safety and reliability. This strategy mitigates risks associated with aging infrastructure and ensures compliance with modern safety standards. It also improves the overall reliability of the gas distribution system and reduces maintenance costs. Systematically replacing older pipelines can prevent hazardous incidents, ensure a stable gas supply, and achieve long-term benefits.

Q. On page 45 of his direct testimony, Attorney General witness Coppola states that the Company has not provided evidence that the planned increase in spending is tied to any increase in safety risks. How do you respond?

A. While Attorney General witness Coppola asserts that most high-risk mains and services should have been replaced through the Company's risk-based approach over the past 12 years, it is crucial to recognize that the Company still has over 1,400 miles of vintage mains that have continued to age during this period. Despite the downward trend in gas

leak data, the presence of these aging pipelines poses ongoing risks to safety and reliability. As shown in Figure 20 of the Company's Natural Gas Delivery Plan ("NGDP"), Exhibit A-42 (NPD-1), many of these pipelines were installed in the 1950s or earlier. The Company provided several examples in discovery, included in Exhibit AG-9, of recent system incidents that have occurred. Vintage mains, particularly those installed before modern construction standards, are more susceptible to leaks, breaks, and other failures due to material degradation and outdated manufacturing practices. The continued aging of these pipelines necessitates a proactive replacement strategy to mitigate potential hazards and ensure the long-term integrity of the gas distribution system. Therefore, the assertion that most high-risk mains have been replaced does not account for the substantial volume of remaining vintage mains that still require attention to maintain safety and reliability.

Q. On page 45 of his direct testimony, Mr. Coppola recommends the disallowance of $84,889,000 from the Company's forecasted capital expenditures for the projected test year and recommends establishing a spending budget for the EIRP of $197 million to be adjusted for the CPI rate of inflation in future years. Do you agree with the recommendation?

A. No, I do not. First, I will address the seven projects which Mr. Coppola expresses uncertainty about being ready for construction in the test year, recommending a disallowance of $84,889,000. These projects are progressing through the design process during 2025 and have activities aligned with projects scheduled for construction in 2026. There is no reason to believe that these projects will not be constructed as planned, at the projected expenditures, in the test year. Company engineers manage projects for the upcoming year, which include pre-engineering tasks such as order creation, design

commencement, environmental reviews, and ordering long lead-time materials. Following this, they coordinate with gas control to determine the optimal timing for project execution based on other ongoing projects and system demands, finalizing the construction schedule. Company engineering follows a prudent and standard cadence prior to construction. All seven of the identified projects are on track for construction in the test year as planned. The seven projects are identified in a table on page 41 of Mr. Coppola's testimony and are included below.

Line # Page 3 Exh. A-82	EIRP Project Description	Projected Test Year Capex
17	SAG4 - Ph 1,2,3	17,749
18	BCY2 - Ph 2	7,344
19	ALM2 - Ph 1,7,8	9,303
20	ALM5 - Ph 2 Line 1070g	4,713
23	ROK10 - Ph 1,2,3,4,5,6	15,423
24	ROK7 - Ph 4,5,6,7,8	23,625
25	KAL3 - Ph 8,9,10	6,732
	Total	$ 84,889

As seen in the project descriptions, the proposed projects are individual phases of larger EIRP projects. If these phases are not constructed as planned, it could be detrimental to the cohesion of the larger project, including impacts on construction sequencing due to each phase typically designed to build upon the previous one, and wasted resources in permitting, planning, and initiating each phase. If essential phases are skipped, it can introduce new risks or exacerbate existing ones within the remaining vintage pipe and can result in delays in project deliverables such as tie-ins and service replacements. Therefore, Mr. Coppola's recommendation that these projects are too premature to include in the rate base should be rejected by the Commission, and the Company's projection for these

projects should be approved. The Commission should approve the funding for these projects to allow the Company to move forward with the projects and their associated benefits.

Q. How do you respond to Mr. Coppola's recommendation regarding implementation of spending caps on the EIRP?

A. Spending caps would likely lead to programmatic cuts and hinder the Company's ability to manage projects effectively, including maintaining the appropriate level of resources. Creating a spending cap would result in cuts to both the program and the workforce. Spending caps fail to address the evolving needs of the program, the economy, and other circumstances that may arise, requiring the Company to respond flexibly. Additionally, spending caps can have unintended consequences, such as disincentivizing process improvements. If a cap is reached before the end of the year, it could lead to layoffs or reduced production levels as projects may allocate funds to cover the entire year rather than optimizing efficiency. This scenario shifts the focus from improving processes and productivity to merely staying within budget constraints. The Company has reduced unit costs and the additional spending being requested is due to increased miles planned because of productivity improvements, not higher unit costs. The $215.3 million for the 12 months ending September 2025 from Case No. U-21490 was based on 113.1 miles, whereas the Company is now projecting that it will complete 138 miles in the Case No. U-21490 test year. And while Mr. Coppola notes that the projected test year spending level is 38% higher than 2023 levels, it is important to note that there is also a 37% increase in the number of projected miles from 108.9 in 2023 to 149 miles in the test year as shown in Table 7 on page 49 of my direct testimony. The Company's plan to retire 5% of vintage

mains each year is essential to mitigate the risks associated with aging pipelines. Therefore, the Commission should reject Mr. Coppola's recommended disallowances for the seven 2026 EIRP projects and the EIRP spending cap of $197 million.

2. Material Condition Non-Modeled Program

Q. Please summarize Attorney General witness Coppola's recommendation regarding the MCNM Program.

A. Beginning on page 45 of his direct testimony, Mr. Coppola summarizes the forecasted capital expenditures for the MCNM program and how this program differs from the EIRP. He also states that the Company is expanding the program to undertake four projects, the wrought iron main replacement, the high-pressure waterway crossings, leak mitigation, and replacing obsolete meters and included the projected expenditures for each program. On pages 46 through 48 of his direct testimony, Mr. Coppola provides an assessment of these four projects and the Line 1010 project. Based on his assessment of the five projects, Mr. Coppola is proposing a reduction of $8,121,000 for 2024, $7,108,000 for the 10 months ending October 31, 2025, and $20,525,000 in the test year for the MCNM program.

Q. What is your response to Mr. Coppola's proposed reduction to remove $1,250,000 for the 10 months ending October 2025 and $4,417,000 for the projected test year for the Wrought Iron Mains project?

A. I disagree with the proposed reduction. On page 45 of his direct testimony, Mr. Coppola states that the Company has expanded the MCNM program to supplement the EIRP and that this vintage material work should be done in the EIRP. His assertion is incorrect. The MCNM program, as described in my direct testimony on page 51, line 10, includes projects

based on operational improvements that may not be represented effectively in risk model results. Additionally, as described in my direct testimony on page 52, standard pressure projects primarily made up of cast iron have been completed within the MCNM program. Cast Iron is also a vintage material type included in the EIRP. According to the Company's discovery response on page 2 of Exhibit AG-10, the remaining 12 miles of wrought iron main is planned to be split between EIRP and MCNM. On page 54 of my direct testimony, I explain that due to the lower quality materials used to manufacture wrought iron pipelines, it is not possible to choose a welding procedure that ensures the quality of the finished weld is adequate for use on the gas system. Page 5 of Exhibit AG-10 further explains that the risk model used to select EIRP projects does not account for whether the main is weldable. Audit Response U21308-SA-CE-0388, included as Exhibit A-140 (KAP-10), details that the wrought iron main replacements planned to be completed in MCNM are small segments of pipe. These smaller segments may not be prioritized in the EIRP risk modeling and could result in a leak requiring an emergent project, similar to the example provided on page 5 of Exhibit AG-10. Since the wrought iron mains are part of the Company's medium pressure system, replacing the remaining miles of wrought iron pipe is prudent for reliability and safety and the Commission should reject Mr. Coppola's recommendation.

Q. What is your response to Mr. Coppola's proposed reduction to remove $500,000 for the 10 months ending October 2025 and $5,000,000 for the projected test year for the HP Waterway Crossings project?

A. I disagree with the proposed reduction. On page 47 of his direct testimony, Mr. Coppola argues that the projects planned for the test year are early in development and premature to be included in rate base for this case. However, like the EIRP projects described earlier in

this testimony, these projects are progressing through the design process during 2025 and have activities aligned with projects scheduled for construction in 2026, following the Company's engineering standard cadence prior to construction. The Company fully intends to complete the projects as presented in this case, and there is no reason to believe that these projects cannot be completed as planned. Therefore, Mr. Coppola's recommendation that these projects are too premature to include in rate base should be rejected by the Commission, and the Company's projection for these projects should be approved so that the Company can move forward with these important projects.

Q. What is your response to Mr. Coppola's proposed reduction to remove $2,970,000 for 2024, $208,000 for the 10 months ending October 2025, and $3,375,000 for the projected test year for the Leak Mitigation project?

A. I disagree with the proposed reduction. On page 47 of his direct testimony, Mr. Coppola states that my direct testimony is devoid of any explanation or supporting evidence to justify this spending. However, on page 51, line 23 of my direct testimony, I state that additional details on leaks and obsolete meters are included in the Material Conditions Renewals program. As noted on page 59, line 8 of my direct testimony and on page 4 in Exhibit AG-10, the Company confirmed that the key difference between the MCNM program and the Material Condition Renewals program is planned replacements are in MCNM and emergent field-initiated projects are included in the Material Condition Renewals program. The leak details included in the Material Condition Renewals program apply to this program as well. The leak mitigation included in the MCNM program is planned leak replacements, which have been completed within this program in the past. The increase in planned leaks, detailed on page 4 of Exhibit AG-10, highlights the higher

volume and costs compared to previous years. Consequently, the Company identified the leak mitigation work within the MCNM program as one of the drivers for increased expenditures in the program. The Company's projection for these projects should be approved to allow the Company the funding needed to address leaks in the MCNM program.

Q. What is your response to Mr. Coppola's proposed reduction to remove $3,083,000 for the projected test year for the Obsolete Meters project?

A. I disagree with the proposed reduction. On page 48 of his direct testimony, Mr. Coppola states there is no testimony supporting the forecasted capital spending in 2026. However, on page 51, lines 20 through 23 of my direct testimony, I state that the Company is planning to complete 5,500 obsolete meter replacements and that additional details on obsolete meters is included in the Material Conditions Renewals program. As noted on page 59, line 8 of my direct testimony and on page 4 in Exhibit AG-10, the Company confirmed that the key difference between the MCNM program and the Material Condition Renewals program is that planned replacements are in MCNM and emergent field-initiated projects are included in the Material Condition Renewals program. The obsolete meter replacement details included in my direct testimony on page 63, line 1 though page 64 line 8, which also references the Customer Metering section of the Company's NGDP, Exhibit A-42 (NPD-1), apply to the MCNM program as well. The obsolete meter replacements included in the MCNM program are planned meter replacements, which are intended to meet meter exchange requirements and minimize risks of extended customer outages during emergent meter exchanges while the Company evaluates meter technologies for future use. The increase in planned meter replacements, detailed on page 4 of Exhibit AG-10, also provides

details on volume and cost. Consequently, the Company identified the obsolete meter replacement work within the MCNM program as one of the drivers for increased expenditures in the program. Therefore, the Company's projection for these projects should be approved to allow the Company to meet meter exchange requirements and ensure all customers have the necessary meters.

Q. What is your response to Mr. Coppola's proposed reduction for the Line 1010 project of $5,150,000 for 2024, $5,150,000 for the 10 months ending 2025, and $4,650,000 for the projected test year?

A. I disagree with the proposed reduction. On page 48 of his direct testimony, Mr. Coppola states that although this line was purchased from another utility, proper pressure test documentation is the Company's responsibility, and the customers should not have to pay the full cost to replace the line as a result of incomplete pressure test documentation and lack of other traceable, verifiable, and complete ("TVC") records from the original installation of the pipeline and recommends a disallowance of 50% of the cost to replace this pipeline. The Pipeline and Hazardous Materials Safety Administration ("PHMSA") TVC standard is a requirement that did not exist prior to the 2020 rule amendment. Pipeline segments installed prior to test record requirements implemented in 1970 were previously "grandfathered," or exempt, from original construction pressure test documentation requirements and allowed to operate at the highest actual operating pressure observed between 1965 and 1970. The updated 2020 rules limited this exemption to pipelines operating below 30% of the specified minimum yield strength ("SMYS"). As a result, the Company must reconfirm the maximum allowable operating pressure ("MAOP") for all pre-1970 pipelines operating above 30% SMYS. Additional details on the PHMSA TVC

compliance standards are included in the MAOP projects section of Company witness Lincoln D. Warriner's rebuttal testimony. The Company evaluated multiple scenarios including repressure testing the entire Line 1010. Unlike the lines on the Company's gas transmission system, which are designed to allow for isolation, Line 1010 is part of the distribution system, directly responsible for feeding customers. This limits the Company's ability to remove that line from service for pressure testing, and therefore, the retest option was determined to not be feasible for Line 1010. Replacing Line 1010 was the best evaluated alternative and allows the Company to include improvements that serve customers such as replacing an 8" steel high pressure section with a 12" steel high pressure pipe to meet customer demand. Knowing that retesting Line 1010 is infeasible while maintaining service to customers, and with the 2020 rule changes for TVC records, and considering the additional capital improvements included in the Line 1010 replacement project, excluding 50% of the projected expenditures is not reasonable and the Commission should reject this recommendation.

3. Material Condition Renewals

Q. Please summarize Attorney General witness Coppola's recommendation regarding the Material Condition Renewals Program.

A. Beginning on page 49 of his direct testimony, Mr. Coppola stated that he found the proposed expenditures to be reasonable. However, Mr. Coppola noted that the Company anticipated a new PHMSA LDAR rule in early 2025, potentially increasing leak repairs, and forecasted an additional $1.5 million for the test year. Since the rule is currently on hold due to a Presidential Executive Order, Mr. Coppola recommends that the Commission remove the $1.5 million from the forecasted capital expenditures for the projected test year.

Q. What is your response to Mr. Coppola's proposed reduction?

A. I disagree with the proposed reduction. As stated on page 65, lines 16 through 21 of my direct testimony, the Company is seeking this funding to address the known leak elimination requirements of the rule and plans to eliminate the backlog of known leaks regardless of when the LDAR rule is published. The elimination of the leak backlog is prudent to significantly reduce system risks and ensure public safety. By proactively addressing these issues, the Company can prevent potential hazards, protect communities, and enhance the overall reliability and efficiency of the distribution system. Therefore, Mr. Coppola's recommendation to reduce $1.5 million from the forecasted capital expenditures for the projected test year should be rejected by the Commission.

4. <u>Material Condition Vintage Service Replacement</u>

Q. Please summarize Attorney General witness Coppola's recommendation regarding the Material Condition Vintage Service Replacement ("VSR") Program.

A. Beginning on page 51 of his direct testimony, Mr. Coppola argues that the Company's forecasted increases of 64% for 2025 and 131% for 2026 compared to 2024 levels appear excessive and unsupported by recent trends. Mr. Coppola recommends a forecast of 2,564 replacements, which is the actual number of replacements in 2024. Therefore, he recommends that the Commission remove capital expenditures of $11,631,000 for the 10 months ending October 2025 and $23,875,000 for the 12 months ending October 2026.

Q. What is your response to Mr. Coppola's proposed reduction?

A. I disagree with the proposed reduction. As described in my direct testimony on page 69, vintage services are identified in the three categories: In-Grid, Proactive In-Grid, and Proactive Out-of-Grid. The In-Grid vintage services are replaced as part of EIRP project

work. The increase in the number of vintage services replaced in the VSR program is related to the reduction in vintage services replaced within the EIRP due to the decrease in large grid projects and the increase in smaller segment projects. The decrease in large EIRP grid projects means that more vintage services are classified as Proactive Out-of-Grid and are not designed and constructed with EIRP projects. On page 51 of his direct testimony, Mr. Coppola compares the number of VSR replacements to those completed in 2022-2024. A more appropriate comparison would be to use the replacement rates in years prior to 2022, during which time the EIRP was only completing smaller segment projects. As shown on Exhibit AG-11, page 2, prior to 2022, VSR program units range from 5,056 in 2021 to 9,381 in 2018. The decrease in vintage services in EIRP/Other Programs is also shown in the table included on page 2 of Exhibit AG-11. Therefore, the proposed reduction to 2,564 service replacements in the VSR program would result in an overall reduction in the number of replacements in 2025 and 2026, to 5,736 and 5,186 respectively, as the number of services completed by EIRP/Other Programs is lower in 2025 and 2026. This would reduce the total number of replacements to lower than 2024 actuals. Replacing the remaining vintage services is prudent for reliability and safety and the Commission should reject Mr. Coppola's recommendation.

5. <u>Gas Operations – Other - AMD</u>

Q. Please describe the proposed reduction for AMD capital expenditures within the Compliance and Controls program recommended by Attorney General witness Coppola.

A. Beginning at page 53 of his direct testimony, Mr. Coppola provides his assessment of the AMD project and argues that it produces only marginal benefits at best. He recommends

that the Commission reject the Company's proposed capital expenditures for the AMD system of $4,650,000 for 2024, $221,000 for the 10 months ending October 2025, and $3,181,000 for the 12 months ending October 2026. Additionally, on page 165 of his direct testimony, Mr. Coppola recommends that the Commission remove all related AMD O&M expense from 2021 through 2026 of $1,969,000, which includes $572,508 for the 12 months ending October 2026, from this rate case as well.

Q. What is your response to Mr. Coppola's proposed reductions for AMD?

A. I recommend that the Commission reject both the capital and O&M adjustments proposed by Attorney General witness Coppola. As described in my direct testimony beginning on page 73, AMD technology is designed to identify methane leaks with exceptional precision, detecting methane in parts per billion ("ppb") compared to traditional equipment that measures in parts per million ("ppm"). This heightened sensitivity allows for the identification of even the smallest leaks. While Mr. Coppola only focused on leak detection in his direct testimony, other key features of AMD include measuring emission rates, tracking the path of methane emissions (breadcrumbing), providing precise geospatial data, and time-stamped datalogging. These capabilities make AMD a powerful tool for monitoring and managing methane emissions more effectively. The technology enables the Company to prioritize high-risk leaks, improving public safety through the Super Emitter Program, which identifies and escalates remediation of the largest methane-emitting leaks. AMD is more effective at locating below-ground leaks, enhancing safety. Benefits to customers include enhanced safety, risk-based prioritization, increased detection sensitivity, and support for environmental goals, aiding the Company in achieving net zero methane emissions. Overall, AMD enhances the Company's ability to

manage methane emissions, contributing to improved public safety and environmental sustainability.

6. Gas Operations – Other - ECAP

Q. Please describe the proposed reduction for Enterprise Corrective Action Program ("ECAP") capital expenses recommended by Attorney General witness Coppola.

A. Beginning on page 56 of his direct testimony, Mr. Coppola argues that the program and proposed expenditures lack clarity on the specific benefits and achievements. Mr. Coppola recommends that the Commission remove all capital expenditures for ECAP from 2023 through the projected test year. He is proposing a reduction of the capital expenditures of $49,000 for 2023, $204,000 for 2024, $167,000 for the 10 months ending October 2025, and $33,000 for the projected test year based on his argument that the Company has not shown the value of the capital spending.

Q. What is your response to the proposed reduction for ECAP?

A. I disagree with the proposed reduction. As described in my direct testimony beginning on page 80, ECAP was initiated at Consumers Energy in 2020 to support safe and excellent operations through a structured platform for issue management and compliance. ECAP enhances transparency in reporting issues, identifying trends, and closing compliance and safety gaps with corrective actions based on risk thresholds. It aids in managing processes, analyzing data, and informing operational decisions to maintain the integrity of the energy infrastructure. Since 2022, ECAP has supported adherence to Gas Safety Management System ("GSMS") standards in Gas Operations, Engineering, and Regulatory. Resolving non-conforming conditions, reducing customer concerns, promoting continuous improvement, and standardizing problem-solving methods are all customer benefits. In

2025, Phase 4 expands the ECAP program to Corporate Safety & Health and Environmental, and improved performance here will directly contribute to cost savings for the customers through a reduction in lost time and expense. I recommend that the Commission reject the adjustment proposed by Attorney General witness Coppola.

7. Geospatial Inventory and Modeling Program

Q. Please describe the proposed reduction for the Geospatial Inventory and Modeling Program capital and O&M expenses recommended by Attorney General witness Coppola.

A. Beginning at page 58 of his direct testimony, Mr. Coppola argues that the Utility Network project involves only a marginal improvement in functionality and does not have a cost/benefit analysis, and recommends that the Commission remove $2,888,000 for 2024, $10,255,000 for the 10 months ending October 2025, and $7,513,000 for the projected test year from the Company's forecasted capital expenditures. Additionally, on page 181 of Mr. Coppola's direct testimony, he recommends disallowance of $517,000 in O&M expenses for the projected test year for the Utility Network project.

Q. What is your response to the proposed reduction for the Geospatial Inventory and Modeling Program?

A. I disagree with the proposed reduction. The Utility Network project is essential for transforming the Company's current GIS platform to the Esri Utility Network Model, establishing a unified data model for gas transmission, distribution, and stations. This transformation is crucial due to the growing business requirements for advanced analytics and regulatory mandates that necessitate granular geospatial insights. The current GIS platform will soon become unsupported as Esri shifts its product development focus to the

ArcGIS Utility Network Management extension, ArcGIS Enterprise, and ArcGIS Pro. The existing core technology of ArcMap and the geometric network has reached its capability limits, and Esri will no longer build additional functionality for these systems. Additionally, Esri utility solution partners are moving their product lines to support only the Utility Network. The Utility Network project mitigates risks associated with the end of product support, enables detailed asset management and location-based analytics, and provides real-time GIS capabilities. It increases productivity through shortcuts, templates, and streamlined workflows, offers extensive tracing tools, 3D visualization functionality, and robust editing tools that enforce data integrity. The project also supports long transactions, allowing future network model changes, and provides up-to-date network views and historical snapshots. These capabilities will result in greater insight, efficiency, and improved safety and delivery to customers in Michigan. The current geospatial platform supports a large variety of critical processes. At present, GIS is required, and in many cases foundational to the core regulatory required process including but not limited to:

- Annual DOT & National Pipeline Mapping System Reporting
- Material Verification & MAOP Analysis
- Leak, Corrosion & Regulation Inspections
- Inline Inspection/Direct Assessment
- Transmission, Distribution and Storage Risk Modeling
- System load analysis and emergency response
- Facility locating, damage prevention risk analysis
- Construction & Emergent location and system configuration awareness

- New customer and system improvement design
- Advanced methane detection

Allowing the platform to become technically obsolete and unsupported would put all these processes at significant risk of either hindering or completely halting the Company's ability to maintain safe operations. Additionally, the longer the Company goes unsupported, the more likely and impactful those issues become. The Company has already started to experience the impacts of having unsupported GIS systems with their Gas Transmission GIS and had to remediate incompatibilities with no vendor support options. Managing a major platform in this status is unsustainable. Therefore, the Utility Network project is a necessary investment to address technology obsolescence and ensure continued operational excellence. The Commission should reject the adjustment proposed by Attorney General witness Coppola.

8. <u>Gas Engineering and Supply O&M Expense</u>

Q. Please describe the proposed reduction for Gas Engineering and Supply ("GE&S") O&M expenses recommended by Attorney General witness Coppola.

A. Beginning on page 162 of his direct testimony, Mr. Coppola proposes reductions totaling $5,258,000 in projected GE&S O&M expenses included in this rate case. His proposed reductions include $1,513,000 in the System Integrity department, $1,259,000 in the Quality Lean department, $1,969,000 in the Regulatory and Compliance department for AMD O&M expenses, and $517,000 in the Geospatial Inventory and Modeling Program for Utility Network O&M expenses. The proposed reductions for AMD and Utility

Network are discussed earlier in this testimony with the proposed reductions in capital expenditures for these programs.

9. System Integrity O&M Expense

Q. Please describe the proposed reduction for System Integrity O&M expenses recommended by Attorney General witness Coppola.

A. Beginning on page 162 of his direct testimony, Mr. Coppola is proposing a reduction of $1,513,000 of projected O&M expenses in the test year for the System Integrity department based on the argument that the Company did not provide sufficient information showing cost changes resulting from departmental reorganizations and where costs were offset in other functions or areas.

Q. What is your response to the proposed reduction for System Integrity?

A. I disagree with the proposed reduction. The shift in O&M expenses is unrelated to any departmental reorganization or additional job duties. As detailed in my response to discovery request U21806-AG-CE-0381, included in Exhibit AG-57, page 4, this change involves reclassifying existing salaries and expenses as O&M costs due to inspection and remediation work, which includes capital replacements or O&M repairs. This reclassification does not result in an offset or removal of O&M costs in other areas, contrary to Mr. Coppola's suggestion. Instead, it represents a shift from capital to O&M. The removal of $1,513,000 in this salary and expense program is not prudent and would result in a reduction of necessary workforce to complete the federally and state-regulated integrity management work. I recommend that the Commission reject the adjustment proposed by Attorney General witness Coppola.

10. Project Management and Quality Lean O&M Expense

Q. Please describe the proposed reduction for Project Management and Quality Lean O&M expenses recommended by Attorney General witness Coppola.

A. Beginning on page 164 of his direct testimony, Mr. Coppola summarizes the expenses and responsibilities provided by the Company of the Quality Lean department and is proposing a reduction of $1,259,000 of projected O&M expenses in the test year for the Project Management and Quality Lean department based on his argument that the Company has not provided evidence showing significant benefits or cost reductions to justify the value of the department.

Q. What is your response to the proposed reduction for Project Management and Quality Lean?

A. I disagree with the proposed reduction. The purpose of the Lean Office is to accelerate value delivery by building lean capabilities in the organization – specifically leveraging the CE Way lean operating system to effectively manage and improve performance. The Lean Office mobilizes resources to support organizations in the application of lean tools (e.g., value stream mapping, data analysis, waste elimination, problem solving, standardized work development, etc.) to support performance improvement. Specific examples outlined in Case No. U-21806 of where the CE Way has been leveraged to achieve performance results include (1) Employee Incentive Compensation Plan operational performance measures – where $3,600,000 in benefits have been identified by Company witness Ashley E. Meschke in her direct testimony on page 11, lines 8 through 13, and (2) the EIRP plastic pipeline cost per mile reductions – where a $216,500 reduction per mile compared to the 2023 actual cost per mile as described earlier in this testimony.

The Quality Lean department supports quality implementation in planning and execution of work throughout the Company, and the Commission should approve the projected funding in order to continue to support overall business efficiency and continuous performance improvement.

IV. ABATE WITNESS FITZHENRY

1. Material Condition - EIRP

Q. Please summarize ABATE witness Fitzhenry's recommendation regarding the EIRP.

A. As summarized on page 10 of his direct testimony, Mr. Fitzhenry argues that there is no need to accelerate investment in EIRP and that the Company has historically completed less work than originally forecasted. He recommends reducing capital expenditures by $79.4 million in 2025 and $92.1 million in 2026.

Q. On page 9 of his direct testimony, ABATE witness Fitzhenry states that the Company has not demonstrated that there are excessive safety risks with the proposed main replacement projects. Do you agree with this observation?

A. No, I do not. On page 9 of his direct testimony, Mr. Fitzhenry states that the projects included in Table CTF-4 were risk ranked according to probabilistic risk modeling. The Company currently uses a relative risk model called the Distribution Risk Analysis Model ("DRAM") for ranking projects. Additionally, discovery request U-21806-AB-CE-0467 only requested information on the top 25 highest risk distribution main segments in the risk model, included as page 5 to Exhibit AB-5. Thus, Mr. Fitzhenry's argument is based on an analysis of only 25 out of 544,000 segments. This represents a mere 0.0046% of the total segments, which is not a statistically significant sample size to draw his conclusions about the overall safety risks of the proposed main replacement projects. His direct testimony

states that only 8 out of the top 25 segments have a risk score greater than the group average of 7.7. However, this fails to consider the broader context. Among the top 1,000 segments, the average risk score is 0.48, indicating that the top 25 segments are significantly higher risk compared to the majority of segments. The total risk score for all segments is 1,077, and, as shown in Exhibit AB-5, page 5, the 25 projects in question contribute a combined risk score of 192. This means these 25 segments account for roughly 18% of the total risk on the system. Addressing these high-risk segments is crucial for improving overall safety and reliability. Mr. Fitzhenry's direct testimony suggests that the Company can selectively replace only the highest risk distribution mains. However, this approach may overlook the cumulative risk posed by segments with lower individual scores but significant collective risk. A comprehensive replacement strategy is necessary to ensure long-term safety and reliability.

Q. How do you respond to Mr. Fitzhenry's recommended reduction in EIRP capital expenditures?

A. The Commission should reject the recommendation. First, the financial data used, as shown in Exhibit AB-5 on page 1, does not represent the entire annual EIRP capital expenditures. As included in the Notes section on the exhibit, the dollar amounts included only represent specific order types. A detailed summary of actual and projected capital EIRP expenses was provided in this case as Exhibit A-84 (KAP-6), and updated during discovery, included as Exhibit A-138 (KAP-8). Using the correct data, the five-year average is $171.5 million, not the $143 million included in Mr. Fitzhenry's direct testimony. And since 2021, the Company began completing larger projects using the grid approach, which plans for and constructs large scale EIRP projects. Using the three-year

average, the average capital expenditures increase to $220.3 million. Second, Mr. Fitzhenry uses the data provided on page 7 of Exhibit AB-5 to calculate that the Company planned 128 miles and $250 million for 2023. This was the EIRP plan as filed in the Company's 2023 EIRP Planning Report in Case No. U-21148. This amount was also included in my direct testimony in Case No. U-21308. While the settlement agreement reached in Case No. U-21148 states that the EIRP will continue with increased spending of $250 million for the 12 months ending September 30, 2023, it also states that Consumers Energy will review and address the length of the EIRP in the next NGDP, considering a program completion date beyond 2030. The reduction in the 2023 plan from $250 million and 128 miles to $182 million and 109 miles was related to the Company's decision to extend the program to 2035 after conducting the review agreed to in the U-21148 settlement. The Company divided the larger projects into phases to be completed across multiple years. These changes can be seen by comparing the 2023 EIRP Planning Report, filed in December 2022, to the 2023 Performance Report, filed in April 2024.

2023 Planning Report (U-21148)

Project Name	Total Est Cost	Total Installed (Feet)
KAL1	$13,671,221	43,787
MAC3	$35,138,479	75,886
MAC4	$25,342,863	80,604
FLT1	$12,058,882	34,268
FLT3	$24,514,185	84,646
BCY1	$42,643,780	115,316
LAN5	$40,550,692	133,068
ROK4	$21,478,123	63,585
ROK5	$3,407,328	8,976
EIRP Grid Projects Subtotal	**$218,805,554**	**640,136**
1070H (TOD)	$25,931,991	35,640
EIRP TOD Projects Subtotal	**$25,931,991**	**35,640**
		(miles)
EIRP Program Projects Total	**$244,737,544**	**675,776**	**128**
2022 Project Carryover Cost	**$5,262,456**	
Estimated EIRP Distribution Total	**$250,000,000**	

2023 Performance Report (U-21308)

Project Name	Total Est Cost	Total Installed (Feet)
KAL1 (phase 3)	$7,199,255	21,525
MAC3 (phase 2,3)	$13,496,841	42,700
MAC4 (phase 2,4-10)	$20,284,581	80,378
FLT1 (phase 2-5,6)	$14,555,890	35,459
FLT3 (phase 1-4)	$12,309,929	77,539
BCY1 (phase 3-7,9,10)	$35,089,086	110,711
LAN5 (phase 2-7,10)	$32,726,206	70,076
ROK4 (phase 4,7,9,10)	$9,897,937	38,675
ROK5 (phase 1-3)	$7,510,376	24,192
FLT4 (phase 1)	$880,801	11,055
MDL1 (phase 2)	$5,670,136	18,461
SAG3 (phase 1,5)	$1,072,240	2,836
LIV3 (phase 6)	$63,934	6,640
EIRP Grid Projects Subtotal	**$160,757,211**	**540,247**
1070H (TOD)	$10,230,205	34,948
EIRP TOD Projects Subtotal	**$10,230,205**	**34,948**
Retirements from Prior Years Install	**$5,565,075**	**0**
		(miles)
EIRP Program Projects Total	**$176,552,491**	**575,195**	**109**
2022 Project Carryover Cost	**$5,262,549**	
Future Year Project Costs	**$111,592**	
Estimated EIRP Distribution Total	**$181,926,631**	

In addition, as shown in my direct testimony, on page 50, the Company exceeded the installed miles requirement from the settlement agreement in Case No. U-21308, completing 126.1 miles compared to 110.8 miles for less than $214 million. Lastly, as discussed in my direct testimony and earlier in this rebuttal testimony, the replacement of vintage mains is prudent for reliability and safety and the Commission should reject Mr. Fitzhenry's recommendation to reduce these expenditures and slow the pace of replacements.

V. CUB WITNESS VEERAPANENI

Q. Please summarize the methodology used by Mr. Veerapaneni to calculate proposed reductions to the Company's projected capital expenditures and O&M expenses.

A. On page 8 of CUB witness Veerapaneni's direct testimony, he states that using 2023 and 2024 historical data is appropriate to project test year expenditures and that he used the two-year historical average for calculating the capital expenditures and O&M expenses for the test year.

Q. How does the test year capital expenditure amount proposed by Mr. Veerapaneni for the Gas Distribution – Material Condition program compare to the test year capital expenditure supported by your testimony and exhibits in this proceeding?

A. As stated on pages 12 and 13 of his direct testimony and shown in Exhibit CUB-10, Mr. Veerapaneni projected $287,898,000 compared to the Company's projection of $385,665,000 for the 12 months ending October 31, 2026, resulting in a $97,767,000 reduction.

Q. How does the test year capital expenditure amount proposed by Mr. Veerapaneni for the Gas Operations Other program compare to the test year capital expenditure supported by your testimony and exhibits in this proceeding?

A. As stated on page 13 of his direct testimony and shown in Exhibit CUB-10, Mr. Veerapaneni projected $10,555,000 compared to the Company's projection of $17,090,000 for the 12 months ending October 31, 2026, resulting in a $6,535,000 reduction.

Q. How does the test year O&M expense amount proposed by Mr. Veerapaneni for the Gas Engineering and Supply O&M expenses compare to the test year O&M expenses supported by your testimony and exhibits in this proceeding?

A. As stated on page 17 of his direct testimony and shown in Exhibit CUB-11, Mr. Veerapaneni projected $18,200,000 compared to the Company's projection of $22,195,000 for the 12 months ending October 31, 2026, resulting in a $3,995,000 reduction.

Q. What is your response to Mr. Veerapaneni's proposed reductions?

A. CUB's proposed methodology of projecting capital test year expenditures and O&M expenses using two years of historical actual data is unreasonable. For the Gas Distribution capital projects, Mr. Veerapaneni did not discuss the reasonableness of the projects proposed during the test year or the benefits the projects would provide to customers. For the Gas Engineering and Supply O&M test year expenses, Mr. Veerapaneni did not discuss the reasonableness of the department expenses and did not account for the Company changes described on page 7 of my direct testimony. The proposed reductions fail to account for the significant support I provided throughout my direct testimony for the benefits that are expected because of the planned spending and the reasonableness of the projected spending amounts. Therefore, the Commission should reject Mr. Veerapaneni's recommendations.

VI. MEC WITNESS DELEON

1. Material Condition EIRP

Q. Please summarize MEC witness deLeon's EIRP recommendation.

A. On page 40 of her direct testimony, Dr. deLeon recommends that EIRP reporting include risk-ranking information and narrative descriptions regarding the use of risk-ranking driving for remediation projects. Dr. deLeon recommends using probabilistic risk models and cost-effectiveness calculations when selecting EIRP projects and proposes changes to the EIRP reports to include summarizing examined remediations, their cost-effectiveness relative to alternatives, and reasons for selecting specific remediations. For future rate cases, Dr. deLeon recommends the Company significantly increase the use of probabilistic risk modeling and cost-effectiveness calculations for all asset classes, that these models should be accessible to stakeholders and the Commission, and that the Company should develop these models for the next rate case. On page 42 of her direct testimony, Dr. deLeon recommends the Commission should require the Company to implement probabilistic risk models for EIRP before increasing EIRP spending levels above the 2024 investment level of $195,587,000.

Q. What is your response to the proposed reduction for EIRP expenditures?

A. I disagree with the proposed reduction. First, although the Company did not include a risk rank narrative in the initial filing of this case, the risk ranking for each EIRP project was included in WP-KAP-3, and is provided as Exhibit A-142 (KAP-12). Additionally, in the Settlement Agreement of Case No. U-17643, an additional requirement to include risk rankings for all projects in a separate column was added to the Company's EIRP Performance Report, with which the Company has complied. The risk ranks for EIRP

projects are included in two separate MPSC reports that the Company files annually: the EIRP Planning Report and the EIRP Performance Report. As described on page 36 of my direct testimony, EIRP projects are selected by the gas engineering teams using a risk model that assesses the risks and threats of each pipe segment, according to the Company's Distribution Integrity Management Program ("DIMP"). The Company uses this risk-based approach, combined with subject matter expert input, to select EIRP replacement projects. The Company did provide the narrative for 2025 projects in discovery response U21806-MNSC-CE-0075_Pascarello_Attachment_2, included as Exhibit A-141 (KAP-11). The stated reason for selection of EIRP projects provided in Table 7, on page 36, of Dr. deLeon's testimony incorrectly identifies Transmission projects as EIRP projects.

Q. Should the Commission require the Company to perform the additional EIRP reporting discussed on page 40 of Dr. deLeon's direct testimony?

A. No. The Company already provides risk ranking information in both the EIRP Planning Report and the EIRP Performance Report by project.

Q. Should the Company be required to perform the probabilistic risk modeling and cost effectiveness analysis for EIRP prior to expenditures increasing above 2024 levels?

A. No. While probabilistic risk models offer an assessment of potential hazards, their implementation can be complex and time-consuming. The complexity of accurately modeling costs and benefits, especially in dynamic and uncertain environments, such as continued use of pipes made from vintage materials, can lead to oversimplified or flawed analyses. This is shown in Figure 5 on page 37 of Dr. deLeon's direct testimony. In this cost effectiveness example, the analysis only focused on the number of leaks remediated by the EIRP in the report year and did not address the footnote in the report stating that this

count is based on scheduled leaks that were remediated with the project as opposed to making a repair and the count does not include historical, permanently repaired leaks. Reported annual leak remediations falls short as a measure of cost effectiveness for vintage material pipes due to historical repairs, safety concerns, and reliability issues. Also, the purpose of the EIRP is not leak remediation; it is vintage material replacement to enhance safety and improve reliability. Leak remediation is a benefit of replacing vintage pipe but is not a good measure of cost effectiveness of the EIRP. Additionally, Dr. deLeon states on page 22 of her direct testimony that the proposed test year expenditures show nearly a 30% increase from 2024 expenditures levels but fails to discuss that there is a 71% increase in planned steel pipe replacement using the miles shown in Table 6 on page 45 of my direct testimony. Described on page 47 of my direct testimony, the 2026 cost for steel projects is $3.91 million per mile compared to $1.4 million per mile for plastic pipe installation. As described on page 37 of my direct testimony, EIRP projects have a defined scope focused on replacement of vintage material pipe and elimination of the standard pressure system. The current risk assessment methods used by the Company prioritize high-risk segments based on several factors including pipe material type, age, soil conditions, and leak history. While the Company is currently planning to begin implementing probabilistic risk modeling for distribution assets in 2027 to identify projects for 2030, the Commission should not cap EIRP spending at 2024 levels prior to this implementation. The EIRP projects enhance system safety, improve reliability, and reduce emissions by replacing vintage leak prone pipe. The Company's proposed increase in spending is essential to support the annual installed mileage required for timely program completion. Reducing the budget to the 2024 investment level of $195,587,000 could hinder progress and extend

the timeline, potentially leaving outdated and leak-prone pipes in service longer than necessary. The capital expenditures I am sponsoring are important to replace aged at-risk pipe intended to improve safety and reliability. Therefore, the Commission should reject Dr. deLeon's recommendations, and the focus should remain on the Company's plan of reducing vintage main miles by approximately 5% per year to meet the 2035 completion goal.

2. Material Condition VSR

Q. Please summarize MEC witness deLeon's VSR recommendations.

A. Dr. deLeon recommends that the VSR program should incorporate probabilistic risk models for distribution assets and that the Commission require the Company to implement these models before increasing VSR spending levels. Additionally, Dr. deLeon recommends capping the program at the 2024 investment level of $18,666,000.

Q. What is your response to the proposed reduction for the VSR program?

A. I disagree with the proposed reduction. First, as discussed above, while probabilistic risk models offer an assessment of potential hazards, their implementation can be complex and time-consuming. The VSR program began using the Company's DRAM in 2025. The current risk assessment methods have proven effective in prioritizing high-risk areas in other programs such as the EIRP. As discussed in the response to Attorney General Coppola earlier in this testimony, the proposed increase in the number of vintage services replaced in the VSR program is related to the reduction in vintage services replaced within the EIRP due to the decrease in large grid projects and the increase in smaller segment projects. The decrease in large EIRP grid projects means that more vintage services are classified as Proactive Out-of-Grid and are not designed and constructed with EIRP

projects. Capping the VSR program spending at the 2024 investment level of $18,666,000 is not advisable. The proposed increase in spending is essential to support the annual number of services required for timely program completion. Reducing the budget could hinder progress and extend the timeline, potentially leaving outdated and leak-prone services in use longer than necessary. The capital expenditures I am sponsoring are important to replace aged at-risk services intended to improve safety and reliability. Therefore, the Commission should reject Dr. deLeon's recommendations.

3. Material Condition Non-Modeled

Q. Please summarize MEC witness deLeon's MCNM recommendation.

A. Dr. deLeon recommends that the Company incorporate probabilistic risk models for distribution assets and that the Commission require the Company to implement these models. Additionally, Dr. deLeon recommends capping the MCNM program at the 2024 investment level of $38,256,000.

Q. What is your response to the proposed reduction for the MCNM program?

A. I disagree with the proposed reduction. The additional $18 million projected in the MCNM project is related to the four Company initiated projects described in my direct testimony beginning on page 54. The wrought iron main replacement at $5 million, the high-pressure waterway crossings at $5 million, leak mitigation at $4 million, and replacing obsolete meters at $3.7 million. The Commission should reject Dr. deLeon's recommendations to allow the Company to complete these important projects for the benefit of customers.

4. Alternatives to Pipe Replacements

Q. What is your response to MEC witness deLeon's testimony on alternatives to pipe replacements as they relate to the EIRP and MCNM programs?

A. Dr. deLeon's direct testimony, page 40, recommends that when probabilistic risk models are available for distribution assets, the Company should summarize in its EIRP reports remediations examined, cost effectiveness of projects relative to alternatives, and explanations of why the Company's remediation was selected. Additionally, Dr. deLeon's direct testimony, page 42, states that the Company does not consider pipe repair or non-pipe alternatives ("NPA") for the EIRP or the MCNM program, based on discovery responses indicating that repairs are not completed in either program. The EIRP and MCNM programs are focused on replacing infrastructure. Leak repairs, on the other hand, are managed through other dedicated programs. Replacing pipes made of vintage materials or due to emergent system issues is crucial due to inherent safety and reliability issues, such as corrosion, leaks, and breaks, which pose risks to public safety and service continuity. While NPAs like electrification and energy efficiency measures can reduce demand for natural gas, they would not address immediate and critical infrastructure problems. Modern pipes also reduce methane emissions, contributing to environmental sustainability, whereas NPAs might not fully mitigate emissions from existing leaks. Investing in pipe replacement ensures a reliable gas supply, and enhances public safety, making a comprehensive and effective solution.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

EXHIBITS

OF

KRISTINE A. PASCARELLO

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Detailed Summary of Actual & Projected Capital Expenses
Enhanced Infrastructure Replacement Program
($000)

Case No.: U-21806
Exhibit No.: A-138 (KAP-8)
Page: 1 of 3
Witness: KAPascarello
Date: May 2025

U21806-AG-CE-0431_Pascarello_Attachment_1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Detailed Summary of Actual & Projected Capital Expenses
Enhanced Infrastructure Replacement Program
($000)

Case No.: U-21806
Exhibit No.: A-84 (KAP-6)
Page: 1 of 3
Witness: KAPascarello
Date: December 2024

Line #		Company Regions			
		Southwest (SW)	Northeast (NE)	Southeast (SE)	Total
	Company Costs:				
1	**2023 Actual Total [(1)]**				
2	Total Services Renewal, Retired Tie-overs	1,358	3,322	3,969	8,649
3	**Miles Main Installed**	**17.35**	**55.12**	**36.47**	**108.9**
4	Total Service/Miles	78	60	109	79
5	Project Cost ($M)	$40.7	$79.8	$56.1	$176.6
6	Carry-Over & Future Year ($M)	$1.0	$2.4	$1.9	$5.4
7	**Total Cost ($(Million)**	**$41.7**	**$82.2**	**$58.0**	**$181.9**
8	**Cost per Mile**	**$ 2,402,397**	**$ 1,492,154**	**$ 1,590,322**	**$ 1,669,978**
9	EIRP Facilities (expenditures shown in Facilities **Exhibit A-70 (QAG-3)**				$ 3,550,319
10	**2023 Total EIRP Program and Facilities capital expenditures**				**$ 181,930,182**
11					
12	**2024 Projected Total**				
13	Total Services Renewal, Retired Tie-overs	2,150	4,426	5,538	12,114
14	**Miles Main Installed**	**43.64**	**42.44**	**48.56**	**134.6**
15	Total Service/Miles	49	104	114	90
16	Project Cost ($M)	$61.8	$58.7	$70.1	$190.6
17	Carry-Over & Future Year ($M)	$1.1	$2.3	$1.7	$5.0
18	**Total Cost ($(Million)**	**$62.8**	**$60.9**	**$71.8**	**$195.6**
19	**Cost per Mile**	**$ 1,440,092**	**$ 1,435,338**	**$ 1,479,113**	**$ 1,452,667**
20	**EIRP Facilities (expenditures shown in Facilities Exhibit A-70 (QAG-3)**				**$ 6,088,574**
21	**2023 Total EIRP Program and Facilities capital expenditures**				**$ 201,675,656**
11					
12	**2024 Preliminary Actual**				
13	Total Services Renewal, Retired Tie-overs	2,079	4,094	4,772	10,945
14	**Miles Main Installed**	**41.82**	**41.36**	**44.25**	**127.4**
15	Total Service/Miles	50	99	108	86
16	Project Cost ($M)	$62.5	$57.4	$67.9	$187.8
17	Carry-Over & Future Year ($M)	$1.1	$2.3	$1.7	$5.1
18	**Total Cost ($(Million)**	**$63.6**	**$59.7**	**$69.6**	**$193.0**
19	**Cost per Mile**	**$ 1,521,528**	**$ 1,443,915**	**$ 1,573,229**	**$ 1,514,287**
20	**EIRP Facilities (expenditures shown in Facilities Exhibit A-70 (QAG-3)**				**$ 5,844,204**
21	**2023 Total EIRP Program and Facilities capital expenditures**				**$ 198,817,961**
22					
23	**2025 Projected Total**				
24	Total Services Renewal, Retired Tie-overs	2,588	2,689	7,251	12,528
25	**Miles Main Installed**	**30.32**	**52.19**	**59.47**	**142.0**
26	Total Service/Miles	85	52	122	88
27	Project Cost ($M)	$50.8	$110.8	$83.6	$245.3
28	Carry-Over & Future Year ($M)	$1.0	$2.1	$1.9	$5.0
29	**Total Cost ($(Million)**	**$51.8**	**$112.9**	**$85.5**	**$250.3**
30	**Cost per Mile**	**$ 1,709,238**	**$ 2,163,624**	**$ 1,438,423**	**$ 1,762,831**
31					
32	**2026 Projected Total**				
33	Total Services Renewal, Retired Tie-overs	1,320	4,126	6,457	11,903
34	**Miles Main Installed**	**30.89**	**57.47**	**61.96**	**150.3**
35	Total Service/Miles	43	72	104	79
36	Project Cost ($M)	$68.5	$88.0	$90.1	$246.6
37	Carry-Over & Future Year ($M)	$1.0	$2.1	$1.9	$5.0
38	**Total Cost ($(Million)**	**$69.5**	**$90.1**	**$92.0**	**$251.6**
39	**Cost per Mile**	**$ 2,249,156**	**$ 1,568,140**	**$ 1,484,958**	**$ 1,673,806**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Detailed Summary of Actual & Projected Capital Expenses
Enhanced Infrastructure Replacement Program
($000)

Case No.: U-21806
Exhibit No.: A-138 (KAP-8)
Page: 2 of 3
Witness: KAPascarello
Date: May 2025

U21806-AG-CE-0431_Pascarello_Attachment_1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Detailed Summary of Actual & Projected Capital Expenses
Enhanced Infrastructure Replacement Program
($000)

Case No.: U-21806
Exhibit No.: A-84 (KAP-6)
Page: 2 of 3
Witness: KAPascarello
Date: December 2024

		Company Regions			
		Southwest (SW)	Northeast (NE)	Southeast (SE)	
40	**2023 actual capital expeditures [1]:**				
41	2023 Actual Cost Per Mile - Plastic	$ 2,343,464	$ 1,434,706	$ 1,537,740	**$ 1,625,519**
42	Number of Miles of Main - Plastic	17.3	48.5	36.5	102.3
43	2023 Preliminary Actual EIRP Costs - Plastic	$40,655,999	$69,578,082	$56,088,205	$166,322,286
44	TOD Project (ALM3) (6.62miles)		$10,230,205		$10,230,205
45	Carry-Over & Future Year ($M)				$5,374,140
46	2023 Preliminary Actual EIRP Capital Expenditures				**$181,926,631**
47	EIRP Facilities (expenditures shown in Facilities **Exhibit A-70 (QAG-3)**)				$ 3,550,319
48	**2023 actual total EIRP Program and Facilities capital expenditures**				**$ 185,476,950**
49					
50	**2024 projected capital expeditures:**				
51	2024 Forecasted Cost Per Mile - Plastic	$ 1,306,077	$ 1,382,187	$ 1,365,542	**$ 1,353,912**
52	Number of Miles of Main - Plastic	36.6	42.4	47.4	126.4
53	2024 Forecasted EIRP Costs - Plastic	$47,802,418	$58,660,016	$64,672,069	$171,134,504
54	TOD/HP Steel Projects - 8.24 miles	$13,965,551	$0	$5,473,207	$19,438,758
55	Carry-Over & Future Year ($M)	$1,077,625	$2,255,727	$1,680,468	$5,013,820
56	2024 Projected EIRP Capital Expenditures				**$195,587,082**
57	**Projected 10 month ending October 31, 2024**				**$ 172,399,356**
58	EIRP Facilities (expenditures shown in Facilities **Exhibit A-70 (QAG-3)**)				$ 6,088,574
59	**2024 forecasted total EIRP Program and Facilities capital expenditures**				**$ 201,675,656**
49					
50	**2024 preliminary actual capital expeditures:**				
51	2024 Forecasted Cost Per Mile - Plastic	$ 1,388,892	$ 1,387,892	$ 1,445,297	**$ 1,408,956**
52	Number of Miles of Main - Plastic	34.5	41.4	43.0	119.0
53	2024 Forecasted EIRP Costs - Plastic	$47,980,701	$57,409,031	$62,218,122	$167,607,855
54	TOD/HP Steel Projects - 8.48 miles	$14,558,357	$0	$5,681,335	$20,239,692
55	Carry-Over & Future Year ($M)	$1,096,828	$2,317,346	$1,712,035	$5,126,210
56	2024 Projected EIRP Capital Expenditures				**$192,973,757**
57	**Preliminary Actual 10 month ending October 31, 2024**				**$ 173,397,304**
58	EIRP Facilities (expenditures shown in Facilities **Exhibit A-70 (QAG-3)**)				$ 5,844,204
59	**2024 Preliminary Actual total EIRP Program and Facilities capital expenditures**				**$ 198,817,961**
60					
61	**2025 projected capital expeditures (Corrected) [2]:**				
62	2025 Forecasted Cost Per Mile - Plastic	$ 1,306,077	$ 1,382,187	$ 1,365,542	**$ 1,357,311**
63	Number of Miles of Main - Plastic	25.8	33.8	58.5	118.1
64	2025 Forecasted EIRP Costs - Plastic	$33,719,049	$46,752,317	$79,847,224	$160,318,590
65	TOD/HP Steel Projects - 21.5 miles	$17,100,000	$60,800,000	$3,800,000	$81,700,000
66	Carry-Over & Future Year ($M)	$1,000,000	$2,100,000	$1,900,000	$5,000,000
67	2025 Projected EIRP Capital Expenditures				**$247,018,590**
68	**Projected 10 month ending October 31, 2025**				**$ 204,611,703**
69	EIRP Facilities (expenditures shown in Facilities **Exhibit A-70 (QAG-3)**				$ -
70	**2025 forecasted total EIRP Program and Facilities capital expenditures**				**$ 247,018,590**
71					
72	**2026 projected capital expeditures:**				
73	2026 Forecasted Cost Per Mile - Plastic	$ 1,345,259	$ 1,423,653	$ 1,406,508	**$ 1,404,251**
74	Number of Miles of Main - Plastic	20.4	55.0	60.9	136.2
75	2026 Forecasted EIRP Costs - Plastic	$27,457,048	$78,265,841	$85,597,258	$191,320,148
76	TOD/HP Steel Projects - 14.1 miles	$41,019,906	$9,747,936	$4,507,772	$55,275,613
77	Carry-Over & Future Year ($M)	$1,000,000	$2,100,000	$1,900,000	$5,000,000
78	2026 Projected EIRP Capital Expenditures				**$ 251,595,761**
79	**Projected 12 month ending October 31, 2026**				**$ 250,809,975**
80	EIRP Facilities (expenditures shown in Facilities **Exhibit A-70 (QAG-3)**				$ -
81	**2026 forecasted total EIRP Program and Facilities capital expenditures**				**$ 251,595,761**

[1] Reference: 2023 EIRP Annual Performance Report filing U-21308

[2] Highlighted sections are corrected miles and projected expenditures due to a feet to miles conversion error for the BCY2 project

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Detailed Summary of Actual & Projected Capital Expenses
Enhanced Infrastructure Replacement Program
($000)

Case No.: U-21806
Exhibit No.: A-138 (KAP-8)
Page: 3 of 3
Witness: KAPascarello
Date: May 2025

U21806-AG-CE-0431_Pascarello_Attachment_1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Detailed Summary of Actual & Projected Capital Expenses
Enhanced Infrastructure Replacement Program
($000)

Case No.: U-21806
Exhibit No.: A-84 (KAP-6)
Page: 3 of 3
Witness: KAPascarello
Date: December 2024

		Company Regions			
Line #		Southwest (SW)	Northeast (NE)	Southeast (SE)	Total
	Company Costs:				
1	**2018 Actual Total**				
2	Total Services Renewal, Retired Tie-overs	649	1,411	2,563	4,623
3	**Miles Main Installed**	**13.26**	**15.20**	**24.37**	**52.8**
4	Total Service/Miles	49	93	105	88
5	Project Cost ($M)	$34.7	$12.7	$37.3	$84.6
6	Carry-Over & Future Year ($M)	$.9	$.3	$1.0	$2.2
7	**Total Cost ($(Million)**	**$35.6**	**$13.0**	**$38.2**	**$86.8**
8	**Cost per Mile**	**$ 2,684,825**	**$ 853,844**	**$ 1,567,901**	**$ 1,642,797**
9					
10	**2019 Actual Total**				
11	Total Services Renewal, Retired Tie-overs	643	1,087	3,192	4,922
12	**Miles Main Installed**	**8.86**	**11.30**	**30.57**	**50.7**
13	Total Service/Miles	73	96	104	97
14	Project Cost ($M)	$12.7	$12.6	$48.2	$73.5
15	Carry-Over & Future Year ($M)	$.9	$.8	$3.2	$4.9
16	**Total Cost ($(Million)**	**$13.5**	**$13.4**	**$51.5**	**$78.4**
17	**Cost per Mile**	**$ 1,527,539**	**$ 1,185,190**	**$ 1,683,162**	**$ 1,545,060**
18					
19	**2020 Actual Total**				
20	Total Services Renewal, Retired Tie-overs	641	1,500	6,373	8,514
21	**Miles Main Installed**	**10.22**	**15.50**	**45.55**	**71.3**
22	Total Service/Miles	63	97	140	119
23	Project Cost ($M)	$15.2	$21.9	$76.9	$114.0
24	Carry-Over & Future Year ($M)	$.6	$.9	$3.0	$4.5
25	**Total Cost ($(Million)**	**$15.8**	**$22.8**	**$80.0**	**$118.5**
26	**Cost per Mile**	**$ 1,544,687**	**$ 1,470,051**	**$ 1,755,749**	**$ 1,663,349**
27					
28	**2021 Actual Total**				
29	Total Services Renewal, Retired Tie-overs	5,000	3,794	5,014	13,808
30	**Miles Main Installed**	**68.94**	**45.53**	**42.70**	**157.2**
31	Total Service/Miles	73	83	117	88
32	Project Cost ($M)	$72.0	$86.2	$67.9	$226.1
33	Carry-Over & Future Year ($M)	$.3	$1.9	$2.5	$4.7
34	**Total Cost ($(Million)**	**$72.3**	**$88.1**	**$70.4**	**$230.8**
35	**Cost per Mile**	**$ 1,048,660**	**$ 1,934,649**	**$ 1,648,117**	**$ 1,468,180**
36					
37	**2022 Actual Total**				
38	Total Services Renewal, Retired Tie-overs	3,622	4,327	6,125	14,074
39	**Miles Main Installed**	**51.40**	**66.10**	**44.60**	**162.1**
40	Total Service/Miles	70	65	137	87
41	Project Cost ($M)	$58.9	$92.9	$76.5	$228.4
42	Carry-Over & Future Year ($M)	$6.3	$5.7	$7.7	$19.8
43	**Total Cost ($(Million)**	**$65.3**	**$98.6**	**$84.3**	**$248.1**
44	**Cost per Mile**	**$ 1,269,571**	**$ 1,491,824**	**$ 1,889,774**	**$ 1,530,842**

(1) Reference: EIRP Annual Performance Report filing for each year

U21806-AG-CE-0426
Page **1** of **2**

Question:

139. Refer to page 82 of Ms. Pascarello's direct testimony on the Damage Prevention and MISS DIG software purchase. Please:
a. Explain how the new software will prevent damage to gas facilities.
b. Explain how the additional features, such as photo AI and augmented reality, work and how they will ensure safety.
c. If the $1.6 million is for a five-year subscription, is the Company capitalizing the $954,000 for the gas business or establishing a deferred debit and amortizing 1/5th to O&M expense each year? Explain why.

Response:

a. This software assists in preventing damages and reduce public safety risk through the following:

- Utilized as a ticket management solution which enables visibility into contractor and internal staking and locating performance data and as a backup work management solution if supplemental support is needed. The solution provides ticket execution performance analytics and reporting to ensure compliance with PA 174. This enables PA 174 required positive response to MISS DIG ticket requests.
- Provides analytics, reporting, and risk scoring to enable efficient and effective proactive field interventions supporting coaching and training of 3rd party excavators and associated performance and workload management capabilities. Solution enables automated workflows integrated with Damage Prevention programs and public awareness communications.

b. Additional capabilities supporting reducing damages and public safety risk include:

- AI – determines likelihood and impact of any incident that may occur to Company facilities through utilization of photo AI quality assurance audit processes to identify staking and locating anomalies that enables more rapid risk mitigation while utilizing machine learning for continuous improvement.
- Augmented reality will enable users to view underground assets onsite with support of site walks and quality assurance audit use cases.

c. At the time of filing this case, the Company projected $954,000 in capital expenditures for this software purchase based on the new functionality offered. The Company has now determined that only a portion of the software cost will be capitalized. The gas portion of the software cost has been reduced to a total of $829,082, with $195,000 as capital and $634,082 as O&M. This change will reduce the capital test year amount shown in Exhibit A-83 (KAP-5), line 4, from $4,168,000 to $3,409,000 and increase the O&M test year amount shown in Exhibit A-81 (KAP-2), line 12, from

$1,231,000 to $1,865,082. The entire subscription cost will occur in the test year of this case. The Company is not establishing a deferred debit or amortizing 1/5 to O&M.

Witness: Kristine A. Pascarello
Date: March 12, 2025

U21806-SA-CE-388
Requested By: Cindy L. Creisher (CLC-10)
Respondent: Kristine A. Pascarello
Date of Response: 3/18/2025
Page **1** of **1**

Question:

With reference to the direct testimony of Witness Kristine Pascarello on page 55, lines 1-7, provide a list of segments of wrought iron pipe that includes the length, location, and projected cost of replacement by year for the replacement work that is planned to be completed in 2025 and 2026. The projected replacement costs should include detail of capital expenditures that are projected to fall within the 12 months ending October 31, 2026.

Response:

The Material Condition Non-Modeled program plans to replace 7.64 miles of the remaining 12 miles of wrought iron. The remainder of the 12 miles are included in the 2026 EIRP KAL11 Bangor project. The replacement plan by year with related miles and capital expenditures planned in Material Condition Non-Modeled is:

Year	Miles Replaced	Location/Approx. Length	$
2025	1.3	Lawton: 4,499 ft Hartford: 1,905 ft	$1,500,000.00
2026	4.5	Several small pipe segments of various footage in Comstock, Schoolcraft, Vicksburg, Parchment, Paw Paw, and Galesburg totaling 4.5 miles	$5,000,000.00

To avoid construction during the heating season, projects are planned to for April through October, so the entire 2026 projection of $5 million will fall within the 12 months ending October 31, 2026.

U21806-MNSC-CE-0075_Pascarello_Attachment_2

Parent Project Number (PPN)	DAPP #	Pipe Pressure	Headquarters	Project Location	Project Name	Total Vintage Retired	Cast Iron	Coated & Wrapped (C&W)	Bare Steel (BS)	Threaded & Coupled (T&C)	Wrought Iron	Plastic	Code 3 (Ft)	Install Plastic	Install Steel	Construct	Risk Rank	Selection Reason
PPN4104SWJAC	21975	MP - Plastic	SW - Lansing/ Jackson	Tecumseh	JAC1 (Tecumseh)	2,491	-	94	2,453	38	-	74	-	2,375	-	CE	#5 SP/MP Segments	1950 Bare Steel, T&C MP Pipe that was risk ranked #5 for SP/MP Segments. This pipe was within SP/MP Grid #55
PPN4108NESAG	30153	HP - Steel	NE - Saginaw	Saginaw	SAG9 MP (Ph. 2)		-	-	2,474	-	-	-	-	1,800	-	CE	*added to Phase 1 of SAG9*	Two large county drains in the area of the HP work in Phase 1, so we decided to add this MP work to avoid HP services crossing these drains and add MP pipe and services.
PPN4122NESAG	20193	HP - Steel	NE - Saginaw	Saginaw	SAG6 TOD Line 1087G (TOD)	24,799	-	647	24,799	-	-	-	250	-	35,000	Contractor	TOD	1933 Bare steel 10" HP Pipe operating at >20% SMYS. Originally planned for 2024 but was rolled into plan for 2025. This is the #4 risk ranked TOD pipe segment. Moving this pipe from the RR ROW was an additional benefit into the road ROW.
PPN4109NESAG	21770	HP - Steel	NE - Saginaw	Saginaw	SAG8 (Junction Rd HP)	22,113	-	360	22,113	-	-	6	-	-	13,700	CE	#2 HP	1950 Bare Steel 6" HP Pipe that was risk ranked #2 for HP Segments
PPN4108NESAG	21771	HP - Steel	NE - Saginaw	Saginaw	SAG9 Ph 1 (Shields HP)	2,474	-	-	2,474	-	-	-	-	-	2,410	CE	#3 HP	1933 Bare Steel 10" HP Pipe that was risk ranked #3 for HP Segments. Additionally we added some MP pipe to remove some customer HP Stands.
PPN4094NESAG	21768,9	SP - Plastic	NE - Saginaw	Saginaw	SAG11 (Ph. 1,2)	8,337	3,758	2,489	2,090	-	-	-	-	11,372	-	CE	#3 SP/MP Segments	1960 Bare Steel 12" SP Pipe and 1940 Cast Iron 2", 4", 6" SP Pipe that was risk ranked #3 for MP Segments. Additionally we will be converting ~ 8,000' of SP plastic pipe to MP plastic pipe. This pipe is within SP/MP Grids #4, #127, #309
PPN4127NESAG	22650,1	SP - Plastic	NE - Saginaw	Saginaw	SAG12 (Ph. 1)	19,978	#####	1,629	-	-	-	135	-	5,280	-	CE	SP/MP Grids #220, #326	1920, 1930, 1940, 1950 Cast Iron 4", 6", and 8" SP Pipe. SAG12 Phases 1 and 2 were added to the 2025 plan to help reduce the amount of SP pipe on the system. They were not chosen as part of the risk ranking. We ended up pulling some of this work into 2024 and pushing some into 2026 to balance crew availability. The SP system in this area has had over +1,000 maintenance calls on this system in the previous two years before project selected. Also to the west of this project MDOT has work coming east in the upcoming years so we are replacing pipe ahead of their work.
PPN4032SEROK	19946,7,9,50	MP - Plastic	SE - Royal Oak	Royal Oak	ROK4 (2,3,5,6)	13,099	-	26,989	7,735	5,364	-	443	-	28,581	-	CE	SP/MP Grids #43, #408, #468	1920, 1930, 1940, 1950 Bare Steel and Threaded & Coupled 2" and 6" MP Pipe. ROK4 Project was started in 2023. Phases 4, 5 and 6 are carrying over from 2024 and Phase 3 was added to complete the work efficiently in one area.
PPN4036SEROK	19482	MP - Plastic	SE - Royal Oak	Royal Oak	ROK6 (Ph. 5)	160	-	17,595	-	160	-	85	-	17,763	-	CE	SP/MP Grids #141	1940, 1950 Bare Steel and Threaded & Coupled 2", 4" MP Pipe. This project was added to the 2025 plan as we had additional capacity for work and this phases had been scoped and planned early as a potential contingency project. This phase is part of a larger grid project started in 2024 but will be fully constructed in 2025, so it isn't listed as carryover. The risk rank in this report applies only to this phase, not the higher-risk phase the overall grid project was built around.
PPN4071SEROK	20561	SP - Plastic	SE - Royal Oak	Royal Oak	ROK13 (Ph. 1)	24,770	#####	1,305	3,631	-	-	3,179	-	21,729	-	CE	SP/MP Grids #13	1920, 1930, 1940 Cast Iron and Bare Steel 6", 8", 10", 12" SP Pipe. This project was added due to risk rank SP/MP Grid #13 and the companies goal to have all SP pipe retired by 2030.
PPN4058SEROK	20409	SP - Plastic	SE - Royal Oak	Royal Oak	ROK14	10,088	9,266	854	-	-	-	356	-	8,793	-	CE	SP/MP Grids #13	1900, 1910, 1920, 1930, 1940 Cast Iron 6", 8", 10", 16" SP Pipe. This project was added due to risk rank SP/MP Grid #13 and the companies goal to have all SP pipe retired by 2030.
PPN4097SEROK	21949,52,3,4	MP - Plastic	SE - Royal Oak	Royal Oak	ROK15 (Ph. 1-4)	3,913	-	3,158	3,535	378	-	39	3,735	6,618	-	CE	#4 SP/MP Segments	1920, 1950 Bare Steel and Threaded & Coupled 2" MP Pipe risk ranked #4 for SP/MP Pipe Segments. This pipe is within SP/MP Grids #20, #78.
PPN4098SEROK	21957	MP - Plastic	SE - Royal Oak	Royal Oak	ROK16 (Ph. 1)	1,108	-	318	1,108	-	-	61	-	1,130	-	CE	#1 SP/MP Segments	1940, 1950 Bare Steel 4" MP Pipe that was risk ranked #1 for SP/MP Pipe Segments. This pipe falls within SP/MP Grid #44.
PPN4099SEROK	21958	MP - Plastic	SE - Royal Oak	Royal Oak	ROK17 (Ph. 1)	441	-	-	441	-	-	82	-	500	-	CE	#10 SP/MP Segments	1950 Bare Steel 2" MP Pipe that was risk ranked #10 for SP/MP Pipe Segments. This pipe falls within SP/MP Grid #50.
PPN4117SWOWS	21989	HP - Steel	NE - Flint	Owosso	OWS1	7,700	-	280	7,700	-	-	-	-	-	8,050	CE	#12 HP	1933 Bare Steel 6" HP Pipe that was risk ranked #12 for HP segments.
PPN4125SWOWS	22607,8	MP - Plastic	NE - Flint	Owosso	OWS2 (Ph. 1,2)	13,224	-	7,382	1,239	11,985	-	1,287	11,841	23,300	-	CE	SP/MP Grid #55	1925 Bare Steel, T&C 6" MP Pipe that was selected as a SME Project to address 3 - 5 lb. MP system in Corunna
PPN4077NEMDL	20620	MP - Plastic	NE - Midland	Midland	MDL2 (Ph. 1)	12,680	-	13,180	-	-	-	-	6,225	13,190	-	CE	#5 SP/MP Segments	1920 Bare Steel 6" MP Pipe that was risk ranked #5 for MP Segments. We added additional footage to avoid tying into 1928 bare steel pipe. This project expands across SP/MP Grids #5, #235, #430. This work helps to retire pipe ahead of planned multi=phase civic work with Road Commission.
PPN4063SEMAC	20624,5,6,7,8 ,9,30,31	MP Plastic	SE - Macomb	Macomb	MAC12 (Ph. 1-8)	81,432	-	37,228	16,426	65,006	-	2,308	10,376	111,406	-	CE	SP/MP Grid #1	1900, 1920, 1930, 1940, 1950 Bare Steel and Threaded & Coupled 2", 4", and 6" MP Pipe. This pipe was the #1 Risk Ranked SP/MP Grid. Additionally over 2 miles of pipe not cathodically protected.
PPN4095SEMAC	21922	MP - Plastic	SE - Macomb	Macomb	MAC14 (Ph. 2)	14,837	-	2,096	-	14,837	-	320	4,730	19,860	-	CE	#6 SP/MP Segments	1920 through 1940 Threaded & Coupled 2", 4" MP Pipe that was risk ranked #6 for MP Segments. MAC14 is a larger Grid project to be completed in future years. The pipe is within the SP/MP Grid #117
PPN4106SELIV	22036	HP - Steel	SE - Livonia	Livonia	LIV6 (Ph. 1) Line 1019W (TOD)	-	-	5,050	-	-	-	-	-	2,778	5,050	Contractor	TOD	1960 C&W 10" HP Pipe operating at >20% SMYS. This is the 1st of three phases addressing pipe along Middlebelt Road. This is a SME Project for TOD addressing external corrosion concerns.
PPN4012SELIV	19186	MP - Plastic	SE - Livonia	Livonia	LIV3 (Ph. 5)	14,569	-	3,054	-	14,569	-	-	-	17,623	-	CE	SP/MP Grids #972	1940 Bare Steel 4" MP Pipe and 1950 Threaded & Coupled 2" MP Pipe. LIV3 Grid was started in 2024. To keep crews on the project make economical sense versus having them move to alternate projects. This phase is part of a larger grid project started in 2024 but will be fully constructed in 2025, so it isn't listed as carryover. The risk rank in this report applies only to this phase, not the higher-risk phase the overall grid project was built around.
PPN4050SELIV	20325,6,7,8,9 ,31	MP - Plastic	SE - Livonia	Livonia	LIV4 (Ph.1-5,7)	70,901	-	739	4,701	66,200	-	1,209	4,054	71,956	-	CE	SP/MP Grids #7	1950 Threaded & Coupled 2', 4", 6" MP Pipe. Phases 3,4,5 are in the 7th risk ranked grid for SP/MP Pipe. We decided to complete all of the phases for this LIV4 project in order to take advantage of crew efficiency working in one area.
PPN4114SWLAN	21985	HP - Steel	SW - Lansing/ Jackson	Lansing	LAN8 (Lk. Lansing/Larch)	4,736	-	1,227	4,736	-	-	-	-	-	5,840	Contractor	#8 HP	1940 Bare Steel 6" HP Pipe that was risk ranked #8 for HP Segments. The city has a Combined Sewer Overflow (CSO) Project and we have worked with them to coordinate this work.
PPN4113SWLAN	21986	HP - Steel	SW - Lansing/ Jackson	Lansing	LAN9 (Lk, Lansing Rd)	5,725	-	164	5,725	-	-	-	-	-	5,800	Contractor	#4 HP	1940 Bare Steel 6" HP Pipe that was risk ranked #4 for HP Segments. Additionally we added MP pipe to be installed to eliminate long sided HP services.
PPN4009SWLAN	19205,6,7,8,9	MP - Plastic	SW - Lansing/ Jackson	Lansing	LAN4 (Ph. 4-8)	33,735	-	34,002	10,319	23,416	-	1,586	7,863	83,105	-	CE	SP/MP Grids #33, #116, #135, #175, #200, #211, #423, #1538	1900, 1920, 1930, 1940, and 1950 Bare Steel and Threaded & Coupled 2" MP Pipe. LAN4 Project was started in 2024. Phases 4,5, are currently under construction and retirement will roll into 2025. Phases 6,7,8 were rolled into 2025 to keep crews working efficiently on this project.
PPN4017SWLAN	22576	MP - Steel	SW - Lansing/ Jackson	Lansing	LAN5 (Ph. 11)	155	-	412	-	-	-	-	155	1,270	-	Contractor	SP/MP Grids #22	1910 Bare Steel 6" MP Pipe. LAN5 Phase 9 which is under construction in 2024 had to have a portion of pipe split off and made into this Phase 11. This phase is handling the steel pipe in the Red Cedar River Crossing. Close work with the municipality on bridge work.

U21806-MNSC-CE-0075_Pascarello_Attachment_2

Parent Project Number (PPN)	DAPP #	Pipe Pressure	Headquarters	Project Location	Project Name	Total Vintage Retired	Cast Iron	Coated & Wrapped (C&W)	Bare Steel (BS)	Threaded & Coupled (T&C)	Wrought Iron	Plastic	Code 3 (Ft)	Install Plastic	Install Steel	Construct	Risk Rank	Selection Reason
PPN4102SWLAN	21973,4	MP - Plastic	SW - Lansing/ Jackson	Lansing	LAN7 (Eaton & Mason)	270	-	1,655	270	-	-	166	1,294	1,634	-	CE	#7 and #9 SP/MP Segments	1940 Bare Steel 2" MP Pipe and 1950 Coated & Wrapped Pipe that were risk ranked #7 and #9 for MP segments. These pipe segments are part of the SP/MP Grids #35 and #40.
PPN4042SWKAL	19657,8,60, 61,21010	SP - Plastic, HP - Steel	SW - Lansing/ Jackson	Kalamazoo	KAL2 (Ph. 1,2,4,5,10)	46,294	#####	4,385	2,485	-	114	2,167	-	47,930	2,345	CE	SP/MP Grid #138	1900, 1910, 1920, 1930, 1940, 1950 Cast Iron, Wrought Iron and Bare Steel 2", 4", 6", 8", and 10" SP Pipe. This grid was originally planned in 2024 but was removed for resource availability reasons. Plan to construct 1/2 of this grid in 2025 and replace a small segment of Vintage HP pipe. Additionally, due to Kalamazoo's permit restrictions which prohibit construction activities during winter months, it is important that we prioritize and complete this project within the limited construction window available. This ensures that we can effectively utilize the permissible construction period and avoid delays that could arise from seasonal restrictions.
PPN4100SWKAL	21969, 30156	HP - Steel	SW - Lansing/ Jackson	Kalamazoo	KAL6 (W. Main & W. Michigan)	6,569	-	362	6,569	-	-	-	-	-	9,994	Contractor	#9 HP	1950 Bare Steel 6" HP Pipe that was risk ranked #9 for HP Segments. Existing line has casing at Amtrak RR crossing, which is cathodically shorted and also punctured so additional piping was added. Compliance issue with this casing and this project will resolve.
PPN4090SEHWL	21618,21,22	HP - Steel	NE - Flint	Howell	HWL2 (Ph. 1,4,5)	5,755	-	1,766	5,755	-	-	10	-	-	6,595	CE	#7 HP	1928 Bare Steel 6" HP Pipe that was risked ranked #7 for HP segments. Adjacent to a CE Initiated Project to replace additional bare steel HP Pipe.
PPN4105NEFLT	22021	MP Plastic	NE - Flint	Flint	FLT6 (Ph. 2)	2,139	-	144	178	1,961	-	21	-	3,271	-	CE	SP/MP Grid #581	1940, 1950 Bare Steel and Threaded & Coupled 2" MP Pipe. This work was added to the FLT6 Phase 1 project to take advantage of crew availability and close proximity to FLT6 Phase 1. We would be causing a risk if we replaced the HP on PH1 and not replace this vintage pipe on PH2.
PPN4067NEFLT	20657,8,9	MP - Plastic, HP - Steel	NE - Flint	Flint	FLT5 (Ph. 1-3)	22,283	-	23,020	18,225	4,058	-	1,098	-	44,086	-	CE	#1 HP	1928 Bare Steel 6" HP Pipe that was risked ranked #1 for HP segments. Able to retire some HP-Steel and replace with MP-Plastic. The MP pipe expands across SP/MP Grids #90, #94, #103, #226, #299. By combining this work in one year less disruption to the municipality. By retiring this vintage pipe, we hope to help the city relive some traffic routing conditions with their future MDOT work.
PPN4105NEFLT	21855	HP - Steel	NE - Flint	Flint	FLT6 (Ph. 1) Line 1045	5,984	-	-	5,984	-	-	-	-	-	4,729	Contractor	#10 HP	1940 Bare Steel 12" HP Pipe that was risk ranked #10 for HP segments and was part of a request for SME replacement. Multiple couplings on this line.
PPN4107NEBCY	21807	MP - Plastic	NE - Midland	Bay City	BCY3 (Ph. 1)	3,333	-	56	3,333	-	-	2	-	1,000	-	CE	#2 SP/MP Segments	1946 Bare Steel 2" MP Pipe that was risk ranked #2 for MP Segments. This pipe expands across SP/MP Grids #34 and #46
PPN4044NEBCY	19914, 30349,50	SP - Plastic	NE - Saginaw	Bay City	BCY2 (Ph. 3,7,8)	31,179	#####	9,054	805	1,088	-	2,815	-	30,990	-	CE	SP/MP Grids #83, 119, 137,310, 316	1940 and 1950 SP Cast Pipe that has been coordinated with city work on multiple streets within the Bay City Area. By removing our vintage main ahead of city work we can avoid future disruption to completed road work. Phase 3 moves some pipe that the city is addressing a "sinking" road issue they are trying to address. This BCY2 project has been broken up into multiple phases to work around civic work, MDOT Bridge work, and traffic routing.
PPN4075NEALM	20617, 30218,9	MP Plastic	NE - Midland	Alma	ALM2 (4,6,7)	31,355	-	-	5,212	27,428	2,856	-	500	38,700	-	CE	SP/MP Grids #194, #300	1900, 1940, 1950 Wrought Iron, Bare Steel, and Threaded & Coupled 2" and 4" MP Pipe. This project was added to the plan as the city (St. Louis) had planned civic work and we took advantage of removing the vintage pipe ahead of their work so that we would not need to come back and tear up newly paved roads.
PPN4111NEALM	21667	HP - Steel	NE - Midland	Alma	ALM5 (Ph. 1) Line 1070G	14,681	-	-	14,681	-	-	-	-	125	14,000	CE	TOD	1945 Bare Steel 6" HP Pipe that was selected as a SME Project due to multiple incidents of line being struck by outside parties. (Shallow pipe within a farm field)
PPN4110NEALM	21767	MP - Plastic	NE - Midland	Alma	ALM4 (Ph. 1)	3,909	-	2,085	3,909	-	-	346	-	4,900	-	CE	#8 SP/MP Segments	Pre 1930 Bare Steel 2" MP Pipe that was risk ranked #8 for MP Segments. This pipe is located within the SP/MP Grid #76. Completing this work will help with future civic work in the city (Ithaca).

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
EIRP Project List Detail

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Date: May 2025

Case No. U-21806
WP-KAP-3

2025 Projects List by Region

	Zone/Region	S=Segment G=Grid HP=High Pressure (Steel)	DRAM Risk Rank SP/MP/HP	MP/SP Vint Main (miles)	HP Vint Main (miles)	Installed MP Plastic	Installed HP Steel	HP SIZE
Northeast Zone				**24.2**	**12.9**	**36.2**	**9.4**	
	HWL2 (Ph 1,4,5) (Fowlerville)	HP	7		1.0		1.2	8" S-HP
	OWS2 Corruna (Ph 1,2)	S	55	2.5		4.4		
	FLT6 (Ph 1,2) Line 1045	HP	10	0.5	1.1	0.6	0.9	
	FLT5 (Ph 1,2,3) *includes FLT8 & FLT9*	MP/HP	2, 10	3.8	2.7	8.3		retire
	OWS1 - Durand from SW Area	HP	12		1.5		1.5	4", 6" S-HP
	BCY3 (Ph 1) Section 135509	S	2	0.0		0.2		
	ALM2 (Ph 4, 7 and 6) St. Louis	MP	194, 300	6.7		7.3		
	ALM4_1 Section 110336 Ithaca	S	8	0.7		0.9		
	MDL2 (Ph 1)	S	5	2.4		2.5		
	ALM5 PH1 Line 1070g	HP	TIMP Model		2.0	0.02	2.7	8" S-HP
	SAG11 (Ph 1,2) Section 125424	S	3	1.6		2.2		
	SAG12 (Ph 1)	S	39	0.0		1.0		
	BCY2 (Ph 3,7,8)	S	42	5.9		8.4		
	SAG8 Frankenmuth(Junction Rd)	HP	2		4.2		2.6	6" S-HP
	SAG9 Shields (Center Rd S of M46) & Ph2	HP	3		0.5	0.3	0.5	12" S-HP
Southeast Zone				**55.7**	**0.0**	**57.9**	**0.0**	
	MAC14 (Ph 2)	S	6	3.8		3.8		
	MAC12 (Ph 1,2,3,4,5,6,7,8)	G	1	17.8		21.1		
	LIV3 Phase 5	S	972	3.3		3.3		
	LIV4 (Ph 1,2,3,4,5,7)	S	7	13.5		13.6		
	ROK4 (Ph 2,3,5,6)	S	43	7.1		5.4		
	ROK16 Section 026016 Bloomfield Hills	S	1	0.2		0.2		
	ROK17 Section 026131 Birmingham	S	10	0.1		0.1		
	ROK15 (Ph 1,2,3,4) Section 016105	S	4	1.3		1.3		
	ROK13 (Ph 1)	S	13	3.8		4.1		
	ROK6 Phase 5	S	156	3.0		3.4		
	ROK14	S	13	2.1		1.7		
Southwest Zone				**18.1**	**3.6**	**25.8**	**4.5**	
	LAN7 Section 020105 Mason	S	**7**	0.2		0.3		
	LAN4 (Ph 4,5,6,7,8)	S	116	7.8		**15.7**		
	LAN5 Phase 11	S	**36**	0.0		0.2		
	LAN7 Section 020334 Eaton	S	**9**	0.04		0.04		
	KAL2 (Ph 1,2,4,5,10 HP)	G	138	9.6	0.5	9.1	0.4	8" S-HP
	LAN9 - Lake Lansing Rd	HP	4		1.0		1.1	12" S-HP
	LAN8 - Lansing (north of svc center)	HP	8		0.9		1.1	12" S-HP
	KAL6 (W. Michigan Ave & W. Main)	HP	9		**1.2**		**1.9**	8" S-HP
	JAC1 Section 555427 Tecumseh	S	**5**	0.4		0.4		
			Totals	**98.1**	**16.5**	**120.0**	**13.9**	
TOD Projects								
	SAG6 TOD Line 1087g	HP	TOD	0.0	*4.8*		6.6	12" S-HP
	LIV6 Ph1 Line 1019W	HP	TOD	0.0	0.0	0.5	1.0	**12" S-HP**
			Grand Total	**98.1**	**21.3**	**120.5**	**21.5**	

The 2025 EIRP projects listed in this workpaper were internally approved on August 6, 2024. EIRP projects do not have completed business cases since the projects are selected using the Company's Distribution Risk Analysis Model ("DRAM") to target highest ranked risk pipe segments and include other factors such as project size, location, system characteristics, and municipality planned projects, such as road reconstruction, sanitary or water main projects, or other local, state, and federally funded projects.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
EIRP Project List Detail

Case No.: U-21806
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Date: May 2025

Case No. U-21806
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2026 Projects List by Region

	Zone/Region	S=Segment G=Grid HP=High Pressure (Steel)	DRAM Risk Rank SP/MP/HP	MP/SP Vint Main (miles)	HP Vint Main (miles)	Installed MP Plastic	Installed HP Steel	HP SIZE
Northeast Zone				**50.0**	**2.6**	**55.0**	**2.5**	
	FLT11 (Ph 1,2,3,4,5,6)	G	75	13.1		14.5		
	OWS3 (Ph 1,2)	S	54	4.5		5.4		
	FLT5 Phase 5 *includes FLT10*	S	9 and 23	2.0		2.2		
	GRV2 Imlay City (E Capac Rd) Line 1041	HP	14		0.6	0.1	0.4	4" S-HP
	SAG12 (Ph 1)	S	17	4.1		3.0		
	SAG7 (Ph 1)	S	6	1.5		1.7		
	SAG4 (Ph 1,2,3)	SP	21, 41, 76	12.1		14.5		
	BCY2 (Ph 2) carryover from 2025	G	1	6.1		6.0	0.0	
	ALM2 (Ph 1,7,8) carryover from 2025	S	3	6.6		7.6		
	ALM5 (Ph 2) Line 1070g	HP	TIMP Model		2.0		2.1	8" S-HP
Southeast Zone				**53.3**	**0.2**	**60.9**	**0.2**	
	MAC13 (Ph 5,6,7) Gloede Segment	S	4	2.4		3.2		
	MAC11 (Ph 2,3,5,6,7,11)	S/HP	1, 4	11.1	0.2	12.0	0.2	6" S-HP
	MAC12 (Ph 9) carryover from 2025	G		2.0		2.1		
	ROK12 (Ph 1,2)	S	2, 7	3.9		3.9		
	ROK8 (Ph 4)	S	7	0.8		0.9		
	ROK10 (Ph 1,2,4)	S	62	5.0		5.0		
	ROK21	S	60	2.9		*3.1*		
	ROK26	S	48	2.7		*3.4*		
	ROK10 (Ph 3,5,6)	S	62	5.9		*7.6*		
	ROK7 (Ph 4,5,6,7,8)	G	35	16.1		*19.3*		
	LIV4 (Ph 6) carryover from 2025	S	471	0.5		0.5		
Southwest Zone				**17.1**	**8.2**	**20.0**	**8.3**	
	KAL3 (Ph 8,9,10)	G	3	5.0		5.5		
	LAN4 Ph8 carryover from 2025	S	116	1.7		2.3		
	LAN12 (040121 Okemos)	S	5	0.2		0.2		
	KAL7 (Michigan Ave Galesburg)	HP	1		3.0		3.0	6" S-HP
	KAL8 (VW Ave east of Schoolcraft)	HP	5		2.8		2.8	6" S-HP
	LAN13 Thornapple Lake Rd at M66	HP	6		2.4		2.4	6" S-HP
	KAL11 (Ph 1,2,3) - Bangor	S	83	7.1		7.6		
	LAN14 Mt Hope and Chippewa (Meridian Twp)	S	16	3.1		4.4		
			Totals	**120.4**	**11.0**	**135.8**	**11.0**	
TOD Projects								
	LIV6 Ph2 Line 1019W	HP	Livonia		0.0	0.4	0.9	12" S-HP
	LAN10 Ph1 & Ph2 Line 1022	HP	Lansing		0.0		2.2	12" S-HP
			Grand Total	**120.4**	**11.0**	**136.2**	**14.1**	

The 2026 EIRP projects listed in this workpaper were internally approved on August 20, 2024. EIRP projects do not have completed business cases since the projects are selected using the Company's Distribution Risk Analysis Model ("DRAM") to target highest ranked risk pipe segments and include other factors such as project size, location, system characteristics, and municipality planned projects, such as road reconstruction, sanitary or water main projects, or other local, state, and federally funded projects.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

REDACTED

REBUTTAL TESTIMONY

OF

JAMES P. PNACEK, JR

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Q. Please state your name and business address.

A. My name is James P. Pnacek, Jr., and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. Are you the same James P. Pnacek, Jr. who previously filed direct testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. I will discuss the withdrawal of the Company's request for Leak Detection and Repair ("LDAR") deferred expense considerations from my direct testimony. I will address recommendations made by Attorney General witness Sebastian Coppola involving operating and maintenance ("O&M") expenses, specifically related to Gas Line Staking and Locating, Leak Survey and Repair, and Enhanced Infrastructure Replacement Program ("EIRP") Training. I will also address recommendations made by Citizens Utility Board ("CUB") witness Ram Veerapaneni involving adjustments to various Gas Operations O&M expenses including Leak Survey and Repair. I will also address recommendations made by Association of Businesses Advocating Tariff Equity ("ABATE") witness Colin T. Fitzhenry involving Leak Repair and Survey O&M expenses.

Q. What exhibit are you sponsoring in connection with your rebuttal testimony?

A. I am sponsoring the following exhibits:

Exhibit A-143 (JPP-5) CONF	Staking Bid Analysis;
Exhibit A-144 (JPP-6) CONF	Staking Bidder List and Summary; and
Exhibit A-145 (JPP-7)	EIRP OM&C Headcount Analysis.

Leak Repair and Survey

Q. In your direct testimony, you indicated that the Company expected final LDAR rules to be published in January 2025 and to go into effect six months later. Has there been any new development related to the LDAR rules since you filed your direct testimony?

A. Yes. The Pipeline and Hazardous Materials Safety Administration ("PHMSA") sent the Final Rule for LDAR to the Federal Register in mid-January. However, the Federal Register was unable to formally publish the rule prior to the change in Presidential administrations and the issuance of President Trump's Executive Order: Regulatory Freeze Pending Review. Based on the submitted final rule, which has not yet been published, the general compliance date for O&M activities that require capital and O&M funding is January 1, 2028.

Q. How has this development impacted the Company's requested relief in this case?

A. With this new compliance date, the Company will no longer be requesting the Michigan Public Service Commission ("MPSC" or the "Commission") to approve the Company's proposal to defer any test year O&M expense that occurs as a result of the requirements of the final rule that are above the requested funding in this case, as previously requested on page 10, lines 9 through 16, of my direct testimony. The Company agrees with the recommendation of MPSC Staff ("Staff") witness Jacob G. Martus that the LDAR deferral mechanism should not be approved in this current rate case.

Q. Several parties' witnesses (Attorney General witness Coppola, ABATE witness Fitzhenry, and CUB witness Veerapaneni) recommended that the Commission disallow the $1.3 million of O&M included in your direct testimony for Leak Repair and Survey due to the delay in publishing final LDAR rules. Do you agree with those recommendations?

A. No. As I state in my direct testimony, the Company plans to eliminate the backlog of known leaks on the system at an accelerated rate as part of its work plan, regardless of the timing of the LDAR rule publication. The Company plans to spend $1,300,000 to address the anticipated leak backlog on the system for the test year in the Leak Survey and Repair program section of my testimony. (See my direct testimony, starting at page 39, line 6, through page 40, line 2.) The Company's decision to reduce the leak backlog was independent of the publication of the LDAR rule. The delay in the LDAR rule publication is not a basis for not including the $1,300,000 for the leak backlog. The Company is accelerating the reduction of leaks on the leak backlog for customer safety, risk reduction, and emissions reduction to serve all of the Company's customers and increase public trust. Staff witness Martus took the correct approach in his testimony when he proposed that the Commission should not approve any deferral for LDAR work beyond the $1.3 million to address the backlog but did not propose any reduction of the money needed to address the backlog. The Commission should reject the recommended reductions proposed by Attorney General witness Coppola, ABATE witness Fitzhenry, and CUB witness Veerapaneni.

Q. On page 17, lines 3 through 11, of his direct testimony, ABATE witness Fitzhenry presents Table CTF-7 and claims that this data supports his conclusion that the Company does not have a leak backlog. Do you agree with this claim?

A. No. Mr. Fitzhenry incorrectly concludes that there is no backlog based on his observation that the number of known leaks repaired in 2023 was 27% below the average number of leaks repaired over the last five years. However, the data presented in Table CTF-7 is not useful for determining whether a leak backlog exists. It only shows and can only represent the number of leaks eliminated according to the data in the Company's Department of Transportation ("DOT") report annual filings. The data from Table CTF-7 does not show how many identified leaks were in the backlog before the Company made those repairs. It also does not show the number of new leaks found in each of those years. For example, if more leaks are found in a year than are repaired, then it results in a leak backlog addition. The Company's leak backlog represents any open leak that is currently on the system and has not yet been repaired. It is illogical and incorrect to conclude that a leak backlog does not exist based solely on data showing a decline in the leaks being repaired in Table CTF-7. Contrary to Mr. Fitzhenry's claim, the Company does have a leak backlog, and the Commission should disregard ABATE witness Fitzhenry's incorrect claim to the contrary.

Q. What is the Company's recent leak backlog?

A. The Company ended 2023 with a leak backlog of 5,618 leaks and ended 2024 with a leak backlog of 5,480 leaks.

Q. On page 16, lines 13 through 21, of his direct testimony, CUB witness Veerapaneni recommends that the Commission should base the spending level for Leak Repair and Survey on his 2023 and 2024 average O&M approach. Do you agree with this recommendation?

A. No. The Company believes that the methodology used by CUB is unreasonable. CUB witness Veerapaneni did not review the reasonableness of the proposed work being undertaken during the test year or the benefits that would be provided to customers.

As I state in my direct testimony starting at page 10, line 5 to line 14, the Company plans to eliminate the backlog of known leaks on the system at an accelerated rate as part of its work plan, regardless of the timing of the LDAR rule publication. The Company plans to spend $1,300,000 to address the anticipated leak backlog on the system for the test year in the Leak Survey and Repair program section of my testimony. The Company is accelerating the reduction of leaks on the leak backlog for customer safety, risk reduction, and emissions reduction to serve all of the Company's customers and increase public trust. The Commission should reject Mr. Veerapaneni's alternative methodology for calculating Leak Repair and Survey expense, which is not based on the Company's actual plans.

Attorney General Witness Coppola - Gas Staking and Locating O&M Expenses

Q. With regard to Staking and Locating expenses, on page 167, lines 14 through 18, of his direct testimony, Attorney General witness Coppola states that typically gas utilities share the cost of locating underground facilities when MISS DIG is requested to locate underground facilities by customers, contractors, and other parties. Do you agree with this statement?

A. No. The word "typically" implies the Shared Resource Model for the State of Michigan is the standard for gas utilities. This is not an accurate statement. In fact, Consumers Energy has been an outlier among Michigan utilities in recent years for using a Shared Services Model of staking. The Commission has been aware of that for at least three years. In Case No. U-21148, Consumers Energy's 2022 gas rate case, Staff witness David Chislea (Director of the Commission's Gas Safety and Operations Division) testified: "Consumers Energy is the only gas utility in Michigan that attempts to use contractors for initially marking of gas distribution facilities. DTE Gas Company employs locating technicians in its operations group and supplements that team with contractors in the large metropolitan areas during times of peak ticket volumes. To Staff's knowledge, all other gas distribution utilities are utilizing Company technicians for marking facilities." See Mr. Chislea's Direct Testimony in Case No. U-21148, page 17, line 19, through page 18, line 2 (filed April 8, 2022). The Company's transition from the Shared Resource Model to the Dedicated Resource Model moves Consumers Energy in line with other Michigan gas utilities. Mr. Coppola's statement is not accurate, since Consumers Energy, DTE Gas, SEMCO, and MGU all use a dedicated asset-staking model. The Commission should disregard Mr. Coppola's inaccurate claim.

Q. On page 168, lines 1 through 6, of his direct testimony, Attorney General witness Coppola characterizes the Company-only dedicated staking and locating program in Oakland and Kent Counties as an experimental program to establish whether the incremental benefits justified the incremental cost of a dedicated program. Do you agree with this characterization?

A. No. The Company never characterized its dedicated staking approach in Oakland and Kent Counties as "experimental" in its testimony in Case Nos. U-21308, U-21490, or the current case. The Company does not view this as an "experimental" program nor did the Company intend to only evaluate the incremental benefits against incremental cost to decide whether it should potentially return to the Shared Resource Model. Mr. Coppola's statement implies that the Company has put a financial value on public safety. That is not accurate. The Company has not put a financial value on public safety. The use of dedicated staking contractors in Oakland and Kent Counties was not a test-case for justifying the Dedicated Staking Model in other parts of the Company's service territory.

Q. Why did the Company consider transitioning its entire service territory to a Dedicated Staking Model?

A. I discuss some of the key reasons for moving to a Dedicated Staking Model approach on pages 48 and 49 of my direct testimony. Given the lower level of performance that the Company observed as the result of its prior use of the Shared Resource Model, the Company views the changes to the staking and locating program, originating in Oakland County Gas-Only program, as an initiative to improve public safety by meeting timeliness obligations within Public Act 174 of 2013, improve staking accuracy, and improve excavator communication while pursuing the lowest cost approach that yields the intended

benefits of the staking and locating program. Furthermore, as discussed in my direct testimony and later in my rebuttal testimony, the Dedicated Resource Model is the lowest average unit cost staking option. There is no incremental cost associated with the Dedicated Resource Model when compared to the Shared Resource Model. Continuing with the Shared Resource Model, and not transitioning to the Dedicated Resource Model, would increase the program cost by $3,667,000 for the Company's remaining gas service territory in the test year.

Q. On page 168, line 7 through line 14, of his direct testimony, Attorney General witness Coppola states that the Company didn't attempt to work with the Shared Resource Model staking and locating contractors to "resolve whatever problems with performance existed and in turn minimize the cost of staking and location." Do you agree with this statement?

A. No. First, it is incorrect to claim that Consumers Energy did not work with its Shared Resource Model Contractor to resolve problems that arose during the course of its service. The Company conducted quarterly performance reviews with the Shared Resource Model Contractor to review ongoing performance and continuous improvement. These reviews were executed throughout the three-year agreement ending March 2025 with performance issues being identified and communicated to the Shared Resource Model Contractor. Despite these reviews, the Shared Resource Model Contractor did not resolve all of the performance issues identified by the Company during the contract life cycle. Second, it is incorrect to imply that the Company transitioned to a Dedicated Resource Model solely because of unresolved performance issues with its previous Shared Resource Model

Contractor. I have already discussed the variety of valid reasons why the Company transitioned to a Dedicated Resource Model for its staking work.

Q. On page 168, lines 15 through 19, of his direct testimony, Attorney General witness Coppola states that the Company did not provide any evidence that there was a "serious problem with staking and locating . . . that cannot be resolved in other ways." Do you agree with this statement?

A. No. Again, Attorney General witness Coppola ignores the numerous other reasons the Company transitioned to a Dedicated Resource Model and continues to falsely claim that the Company's sole reason for making the change was to address "serious problems" with its Shared Resource Model Contractor. As stated on page 50, lines 6 through 9, of my direct testimony, the Company plans to expand the program to "continue to improve public safety, reduce damages, mitigate communication risks with excavators, improve quality, and comply with timeliness requirement within Public Act 174." Additionally, the staking contract with the contractor that the Company uses for its Shared Resource Model expired in the first quarter of 2025. See page 50 of my direct testimony. In anticipation, the Company sent out a request for proposal ("RFP") in the third quarter of 2024 for staking services for the Company's remaining gas service territory that at the time was under the Shared Contractor resource model. The request included options for both shared and dedicated services. The Company only received one bid from a contractor willing to provide services under a Shared Resource Model, but several willing to provide services under a Dedicated Resource Model. The bids yielded an average unit cost for the Dedicated Resource Model that was below the average unit cost of the sole Shared Resource Model Contractor staking model bid. To clarify, the Shared Resource Model Contractor's bid

came in at a significantly higher rate than the previous contracted rate it had with the Company. In other words, the results from the RFP showed that the Company no longer had an option to simply continue its prior Shared Resource Model contract on the same terms or at the same price. The bid from the Shared Resource Model Contractor also came in higher than the bid from the lowest Dedicated Resource Model Contractor. Thus, the statement in my direct testimony remains accurate: the bids yielded an average unit cost for the Dedicated Resource Model Contractor that was below the average unit cost of the Shared Resource Model Contractor was relative to the new higher bid received from the Shared Resource Model Contractor. In short, of the available options after the previous Share Resource Model contract ended, the least expensive option available to the Company was a Dedicated Resource Model contract. As stated in my direct testimony, the analysis shows the Dedicated Contractor model is on average $10.90 less on a per-unit basis when compared to the Shared Contractor model. Continuing with the Shared Contractor model, and not transitioning to the Dedicated Contractor resource model, would increase the program cost by $3,667,000 for the Company's remaining gas service territory in the test year. The decision to expand the use of the Dedicated Resource Model to the remainder of the Company's service territory was based on the improved performance and lower unit cost of the Dedicated Resource Model compared to the Shared Resource Model. In summary, the Dedicated Resource Model aligns the Company to the approach of other gas utilities in the state, improves staking performance, increases public safety, while using the lowest cost option. Continuing with a Shared Resource Model would have meant using a less effective, higher cost option. That is clearly not reasonable. The Commission should disregard the arguments made by Attorney General witness Coppola.

Q. On page 168, line 20, through page 169, line 4, of his direct testimony, Attorney General witness Coppola argues that the Company's claim that the Dedicated Resource Model is lower cost than the Shared Resource Model is "counter to the historical evidence presented by the Company." Do you agree with this statement?

A. No. The "historical evidence" that Mr. Coppola is referring to is the contract price under the Company's expired contract for shared-resource staking. That price is no longer available. This project was competitively bid, and the Company has been transparent providing the bid analysis, the actual bids received, and the staking contracts to the Attorney General during discovery. Exhibit A-143 (JPP-5) CONF shows the bid analysis and Exhibit A-144 (JPP-6) CONF shows the contractors requested to bid and those who responded. While previously the Shared Resource Model Contractor unit cost was below the Dedicated Resource Model unit cost, historical pricing is not a guarantee of future pricing. As shown in Exhibit A-143 (JPP-5) CONF, the Shared Resource Model Contractor unit cost is higher than the Dedicated Resource Model Contractor's bid. Although the Company provided the information in Exhibits A-143 (JPP-5) CONF and A-144 (JPP-6) CONF to the Attorney General in discovery, Mr. Coppola ignores this information in his testimony. The Commission should disregard Attorney General witness Coppola's incorrect statements.

Q. On page 169, line 4 through line 9, of his direct testimony, Attorney General witness Coppola claims that the Company's bidding process cannot be relied upon because the Company has publicly expressed its preference in at least the last two rate cases to move to a Dedicated Resource Model and that contractors have limited their bids based on that preference. Do you agree with this claim?

A. No. The transition to the Dedicated Resource Model supports public safety and customer value. It was necessary for the Company to disclose its staking and locating approach in the rate case process and all bidding contractors would have access to the same information provided in the cases. This project was competitively bid, and the Company has been transparent providing the bid analysis, the bids received, and the staking contracts to the Attorney General's witness during discovery. The Company indicated in the RFP that it would likely move to the Dedicated Resource Model in 2025 at least for Kalamazoo and Ingham Counties. The Company indicated that the final determination about which counties would transition to a Dedicated Resource Model in this contract would be made after the bid review. At the time of the RFP, the Company was not planning to transition all the counties in its service territory from the Shared Resource Model to the Dedicated Resource Model. As shown on Exhibit A-144 (JPP-6) CONF, 22 suppliers were invited to submit proposals. All bidders were given the opportunity to submit a proposal for: (i) only the Dedicated Resource Model, (ii) only the Shared Resource Model, and/or (iii) both models for all territories excluding Oakland and Kent counties. The Company received five bids. Four of those bids were to supply service for the Dedicated Resource Model only and one bid was to supply service for the Shared Resource Model only. No contractor bid on both approaches. [**BEGIN CONF**] [redacted]

[redacted] [**END CONF**]. The winning staking contractor was determined based on a transparent, competitive bidding process resulting in the selection of the contractor with the lowest overall average unit cost and best value being selected to perform the staking activities to ensure public safety. The Commission should disregard Attorney General witness Coppola's claims to the contrary.

Q. On page 169, line 12, through page 170, line 2, of his direct testimony, Attorney General witness Coppola recommends that the Commission remove the incremental O&M expense of $11,184,000 included by the Company in the projected test year. Do you agree with this disallowance?

A. No. For the reasons discussed above, there is no valid reason to reduce the Company's forecasted staking and locating expenses for the test year, which are based on the Company's new contract for staking services. The Company competitively bid the staking activities, performed a bid analysis to evaluate the bids, and selected the lowest overall average unit cost contractor with the best value to perform the staking activities and ensure public safety. Adopting Mr. Coppola's proposal would significantly understate the Company's expected costs for its staking and locating work during the test year. The Commission should reject Mr. Coppola's recommendation to disallow the Staking and Locating incremental O&M.

Attorney General Witness Coppola – Staking and Locating Deferred Accounting

Q. With regard to Staking and Locating Deferred Accounting, on page 194, line 15, through page 195, line 4, of his direct testimony, Attorney General witness Coppola recommends that the Commission reject the staking deferral request the Company proposed in the test year. Do you agree with this recommendation?

A. No. As I discussed in my direct testimony, there are valid reasons to anticipate more volatility in the number of staking requests during the test year than in prior years, meaning there is greater uncertainty about the accuracy of staking forecasts. With staking requests increasing due to fiber optic and other infrastructure work, the actual staking demand the Company experiences in 2026 could be above the Company's historical staking volume

forecast. The Company has requested the deferral mechanism to cover O&M expenditures associated with expected fluctuations in the volume of staking tickets. The Company based its deferral request mainly on two high-speed internet infrastructure grant programs administered by the Michigan High-Speed Internet Office. The first program is Realizing Opportunities with Broadband Infrastructure Networks ("ROBIN"). According to the State of Michigan's Labor and Economic Opportunities website, the ROBIN program includes $250.6 million to expand high-speed internet service to unserved locations in the state. All program funds must be expended by the end of the 2026 calendar year. The second program is the Broadband Equity, Access, and Deployment Program ("BEAD"). According to the State of Michigan's Labor and Economic Opportunities website, as of 2023, close to 500,000 households are unserved or underserved by high-speed internet infrastructure. BEAD is designed to ensure that every one of Michigan's unserved and underserved homes and businesses can get connected to reliable high-speed internet infrastructure. Approval of Michigan's final list of subgrantees and the locations to be served is anticipated to occur in mid-2025. After final approval, subgrantees will have four years to complete their infrastructure projects and begin delivering service. These two infrastructure projects have the potential to significantly increase staking volumes above forecasted levels. The deferral mechanism benefits both the Company and customers as it allows for refund and recovery without building the unknown cost into rates. Attorney General witness Coppola's recommendation should be rejected by the Commission and the Commission should approve the recommendation made by Staff witness Martus related to the staking and locating deferral.

Attorney General Witness Coppola - EIRP Training Expenses

Q. On page 170, lines 7 through 17, of his direct testimony, Attorney General witness Coppola claims that the Company did not explain the increase in its EIRP training expense. Do you agree with his statements?

A. No. The reason for the increased training expense is explained on pages 86 and 87 of my direct testimony. The Attorney General simply ignores the testimony, which explains that the EIRP workforce continues to experience employees transferring to other operating departments within the Company and that this movement results in the need for hiring and training to allow for appropriate staffing as the Company implements the Natural Gas Deliver Plan. Mr. Coppola's claim that EIRP is a "mature program" is irrelevant to the issue because, no matter how mature a program is, when employees leave the program for other opportunities within the Company, their replacements will still need to be trained.

Q. On page 170, lines 15 through 17, of his direct testimony, Attorney General witness Coppola claims that the Company stated in discovery that the increased EIRP expense was needed because "the EIRP workforce continues to grow." Is that an accurate reflection of the Company's discovery response to the Attorney General?

A. No. Exhibit AG-58, which shows the Company's response to discovery request U21806-AG-CE-0561-Revised, repeats my direct testimony. The response does not state that the EIRP workforce continues to grow, in fact the EIRP workforce has been declining as shown in Exhibit A-145 (JPP-7). The additional training expenses are for new hire and step promotion training caused by movement in the existing workforce. Attorney General witness Coppola's mischaracterization of my testimony and discovery response presents a fallacious strawman argument.

Q. What is the Company's historical experience related to employee turnover in EIRP?

A. As shown in Exhibit A-145 (JPP-7), the Gas Construction EIRP Program had a headcount of 495 Operating, Maintenance, and Construction ("OM&C") employees at the end of 2020. From the end of 2020 to the end of 2024, the program lost 116 employees due to headcount reductions but also needed to hire 216 new OM&C employees to replace some of the 379 OM&C employees that remained after the headcount reductions. This means a total of 332 employees left Gas Construction during this time period. As Exhibit A-145 (JPP-7) shows, this is a turnover rate of 76%.

Q. Given the turnover history and the Company's future plans for EIRP, what additional hiring does the Company plan to do to maintain the appropriate staffing for the program?

A. As shown on Exhibit A-145 (JPP-7), the Company plans to hire a total of 145 OM&C employees for 2025 and 2026. The hiring is necessary to support the increase in the EIRP work plan miles from 118.1 miles of plastic in 2025 to 136.2 miles of plastic in 2026 as shown in the Exhibit A-138 (KAP-8). As previously stated, the Company needs to expend an incremental $1,656,000 for new-hire and step-promotion training, which is necessary to support the forecasted increase in the EIRP Capital work plan. Attorney General witness Coppola's recommendation to disallow the EIRP Training O&M should be rejected by the Commission. Attorney General witness Coppola has also recommended scaling back the EIRP capital program. The Commission should reject that proposal also. Company witness Pascarello discusses the reasons for rejecting that proposal in her rebuttal testimony.

CUB Witness Veerapaneni - Test Year Calculation

Q. With regard to Gas Operations expenses, on page 16, lines 2 through 10 of his direct testimony, CUB witness Veerapaneni proposes a decrease to the Company's O&M expenses for the Gas Operations Division based on the concept of using a two-year historical average. Do you agree with this approach?

A. No. The Company believes that the methodology used by CUB is unreasonable. CUB witness Veerapaneni did not review the reasonableness of the proposed work being undertaken during the test year or the benefits that would be provided to customers. The Commission should reject this recommendation.

Q. With regard to Gas Operations – Other expenses, on page 17, lines 10 through 15, of his direct testimony, CUB witness Veerapaneni proposes an increase to the Company's O&M expense for the Gas Operations-Other Programs based on the concept of using a two-year historical average. Do you agree with this approach?

A. No. The Company believes that the methodology used by CUB is unreasonable. CUB witness Veerapaneni did not review the reasonableness of the proposed work being undertaken during the test year or the benefits that would be provided to customers. The Commission should reject this recommendation.

Q. With regard to Gas Storage expenses, on page 18, lines 10 through 19, of his direct testimony, CUB witness Veerapaneni proposes an increase to the Company's O&M expense for Gas Operations - Storage based on the concept of using a two-year historical average. Do you agree with this approach?

A. No. The Company believes that the methodology used by CUB is unreasonable. CUB witness Veerapaneni did not review the reasonableness of the proposed work being

undertaken during the test year or the benefits that would be provided to customers. The Commission should reject this recommendation.

Q. On Exhibits CUB-9, line 3, and CUB-11, line 3, CUB witness Veerapaneni proposes a decrease to the Company's O&M expense for the Gas Operations – Field Ops Services program based on the concept of using a two-year historical average. Do you agree with this approach?

A. No. The Company did not find any discussion on this proposed decrease in CUB witness Veerapaneni's testimony. Reference for the decrease was found only in Exhibits CUB-9 and CUB-11. The Company believes that the methodology used by CUB is unreasonable. CUB witness Veerapaneni did not review the reasonableness of the proposed work during the test year in the O&M Programs or the benefits the O&M Programs would provide to customers. The Commission should reject this recommendation.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

REDACTED

EXHIBITS

OF

JAMES P. PNACEK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

A-143 (JPP-5) Confidential
Being Filed Under Seal with the MPSC

A-144 (JPP-6) Confidential
Being Filed Under Seal with the MPSC

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
EIRP OM&C Headcount Analysis

Case No.: U-21806
Exhibit No.: A-145 (JPP-7)
Page: 1 of 1
Witness: JPPnacek
Date: May 2025

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Year	**Headcount (year ending) [1]**	**Headcount change from previous year**	**Cumulative Headcount loss since 2020**	**# of Employee Hired**	**Cumulative Employee's hired since 2020**	**Number of Employee lost from previous year**	**Cumulative Employee loss since 2020**
2020	**495**						
2021	486	9	9	128	128	137	137
2022	423	63	72	27	155	90	227
2023	414	9	81	23	178	32	259
2024	379	35	**116**	38	**216**	73	**332**
2025 Projected				45	45		
2026 Projected				100	**145**		

Average Number Employees since 2020	439
Employee Turnover Rate	76%

[1] Data for 2020-2024 EIRP Performance reports Attachment 5
Note: Headcount is OM&C only

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

REBUTTAL TESTIMONY

OF

HEATHER L. RAYL

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Q. Please state your name and business address.

A. My name is Heather L. Rayl, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Heather L. Rayl who previously presented direct testimony in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to: (i) present an adjusted revenue deficiency reflecting the rebuttal positions of Consumers Energy Company's ("Consumers Energy" or the "Company") witnesses; and (ii) address certain arguments and recommendations related to the revenue requirement made by Sebastian Coppola on behalf of Attorney General Dana Nessel ("Attorney General"), and the Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witnesses Justin J. Hecht, Robert F. Nichols, Charles E. Putnam, and Timothy G. Witt.

Q. Have you prepared any exhibits in conjunction with your rebuttal testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-146 (HLR-52)	Adjusted Revenue Deficiency for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-147 (HLR-53)	Adjusted Rate Base for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-148 (HLR-54)	Adjusted Utility Plant for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-149 (HLR-55)	Capital Spending Reconciliation for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-150 (HLR-56)	Adjusted Working Capital for the Projected 12-Month Period Ending October 31, 2026;

Exhibit A-151 (HLR-57)	Adjusted Net Operating Income for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-152 (HLR-58)	Reconciliation of Adjusted Net Operating Income for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-153 (HLR-59)	Adjusted Operations & Maintenance Expenses for the Projected 12-Month Period Ending October 31, 2026;
Exhibit A-154 (HLR-60)	Income Tax Effect of Interest for the Projected 12-Month Period Ending October 31, 2026; and
Exhibit A-155 (HLR-61)	Interest Synchronization Adjustment for the Projected 12-Month Period Ending October 31, 2026.

ADJUSTED REVENUE DEFICIENCY

Q. Please describe Exhibits A-146 (HLR-52) through A-155 (HLR-61).

A. Exhibits A-146 (HLR-52) through A-155 (HLR-61) present the calculation of the Company's adjusted revenue deficiency for the projected 12-month period ending October 31, 2026. As shown on line 8, column (e), of Exhibit A-146 (HLR-52), the Company has recalculated a test year revenue deficiency of $217.7 million, a reduction of $30.3 million from the Company's original filing in this case.

Q. Why is the Company proposing an adjusted test year revenue deficiency?

A. Based on certain facts and circumstances revealed subsequent to filing the case, the Company believes it is appropriate and necessary to make the adjustments.

Q. Please summarize the proposed adjustments to the revenue deficiency.

A. The Company has made the following adjustments to its originally filed revenue deficiency:

1. Decrease to net utility plant of $40.3 million, depreciation expense of $11.3 million, and property tax expense of $0.9 million. A list of the individual

adjustments, with descriptions and sources, is provided on Exhibit A-148 (HLR-54) and Exhibit A-149 (HLR-55);

2. Increase to unamortized manufactured gas plant of $0.5 million and associated amortization expense of $0.1 million as discussed by Company witness Matthew J. Foster;

3. Decrease to working capital of $143.5 million. A list of the individual adjustments, with descriptions and sources, is provided on Exhibit A-150 (HLR-56); and

4. Increases to gross margin of $1.1 million and operating and maintenance ("O&M") expenses of $0.5 million and a decrease to amortization expense of $3.0 million and general tax expense of $0.5 million. A list of the individual adjustments, with descriptions and sources, is provided on Exhibit A-152 (HLR-58).

WORKING CAPITAL

Q. Attorney General witness Coppola proposed adjustments to reduce the Company's working capital deferred debits balance to: (1) correct for an error made in the calculation of the S4/HANA cloud implementation adjustment (direct testimony page 106, line 5 through page 107, line 4) and (2) correct for an error in the calculation of the prepaid cloud computing adjustment (direct testimony page 107, line 5 through page 108, line 5). Do you agree with these adjustments?

A. Yes. Based on the rebuttal testimony of Company witness Stacy H. Baker, the Company agrees with the Attorney General's reduction of the Company's working capital deferred debits balance for the correction of the S4/HANA cloud implementation and the prepaid cloud computing adjustments of $1.7 million and $1.0 million, respectively.

Q. Attorney General witness Coppola (direct testimony page 108, line 6 through line 16) and Staff witness Nichols (direct testimony page 5, line 21 through page 6, line 14) proposed an adjustment to reduce working capital and associated amortization expense as the sale of the Riverside Storage Field was not completed as originally anticipated. Do you agree with this adjustment?

A. Yes. Based on the rebuttal testimony of Company witness Heidi J. Myers, the Company agrees with the Attorney General witness Coppola's and Staff witness Nichols' $7.4 million reduction of the Company's working capital deferred debits balance and a $3.0 million reduction of amortization expense. As supported by Company witness Myers and Staff witness Nichols, the effects of the Riverside Storage Field sale have been removed from the revenue deficiency calculation and the plant-in-service, depreciation reserve, depreciation expense, and property tax balances related to the Riverside Storage Field have been added back to the case.

Q. Attorney General witness Coppola (direct testimony page 108, line 17 through page 109, line 11) and Staff witness Hecht (direct testimony page 6, lines 7 through line 14) proposed an adjustment to increase accrued taxes. Do you agree with this adjustment?

A. Yes. The Company inadvertently made an error in its calculation of accrued taxes and agrees with the Attorney General witness Coppola's and Staff witness Hecht's $127.8 million decrease in working capital.

Q. Staff witness Hecht (direct testimony page 5, line 14 through line 21) proposed an adjustment to reduce the Company's working capital deferred debits balance to remove a non-utility account. Do you agree with this adjustment?

A. Yes. The Company agrees with Staff witness Hecht's $0.2 million reduction of the Company's working capital deferred debits balance and the removal of the non-utility account from working capital.

GENERAL TAX EXPENSE

Q. Staff witness Putnam proposed an adjustment to reduce the Company's general tax expense balance (direct testimony page 7, line 18 through page 9, line 2). Do you agree with this adjustment?

A. Yes. The Company based its projected payroll tax expense on its historical 2023 expenses, adjusted for inflation through December 31, 2026, which is incorrect. The inflation adjustment should have ended at the October 31, 2026 test year date. In addition, the Company used its 2023 historical sales and use tax expenses as the basis for projecting sales and use taxes for the test year. Historical sales and use tax expense included an audit settlement related to activity predating 2023. Although paid in 2023, the audit settlement activity should have been excluded from the calculation of projected sales and use tax. Therefore, the Company agrees with Staff witness Putnam's $0.5 million reduction of general tax expense.

DEPRECIATION RESERVE AND DEPRECIATION EXPENSE

Q. Staff witness Witt proposed an adjustment to reduce the Company's depreciation reserve (direct testimony page 6, line 2 through line 19) and depreciation expense balances (direct testimony page 7, line 17 through page 8, line 9). Do you agree with these adjustments?

A. Yes. The Company inadvertently used the incorrect depreciation rates in the calculation of depreciation reserve and depreciation expense and agrees with Staff witness Witt's $20.4 million reduction of the depreciation reserve balance and $8.9 million reduction of depreciation expense.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

EXHIBITS

OF

HEATHER L. RAYL

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Revenue Deficiency
For the Projected 12-Month Period Ending October 31, 2026
$(000)

Case No.: U-21806
Exhibit No.: A-146 (HLR-52)
Page: 1 of 1
Witness: Heather L. Rayl
Date: May 2025

Line No.	(a) Description	(b) Source - Adjustments	(c) Initial Filing {1}	(d) Adjustments	(e) Rebuttal Position
1	Rate Base	Exhibit No.: A-147 (HLR-53)	11,750,740	(183,308)	11,567,432
2	Adjusted Net Operating Income	Exhibit No.: A-151 (HLR-57)	545,492	11,272	556,763
3	Overall Rate of Return	Line 2 / line 1	4.64%	0.17%	4.81%
4	Required Rate of Return	Exhibit No.: A-14 (MRB-1)	6.22%	0.00%	6.22%
5	Income Required	Line 1 * line 4	730,838	(11,401)	719,437
6	Income Deficiency (Sufficiency)	Line 5 - line 2	185,346	(22,672)	162,674
7	Revenue Conversion Factor		1.3381	1.3381	1.3381
8	Revenue Deficiency (Sufficiency)	Line 6 * line 7	248,008	(30,338)	217,670

Notes

{1} Source: Exhibit No.: A-12 (HLR-28)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Rate Base
For the Projected 12-Month Period Ending October 31, 2026
$(000)

Case No.: U-21806
Exhibit No.: A-147 (HLR-53)
Page: 1 of 1
Witness: Heather L. Rayl
Date: May 2025

Line No.	(a) Description	(b) Source - Adjustments	(c) Initial Filing {1}	(d) Adjustments	(e) Rebuttal Position
1	Total Utility Plant	Exhibit No.: A-149 (HLR-55)	14,907,264	(62,095)	14,845,170
2	Depreciation Reserve	Exhibit No.: A-149 (HLR-55)	(4,665,713)	21,795	(4,643,918)
3	Customer Advances for Construction	---	(19,159)	-	(19,159)
4	Net Unamortized MGP	Company witness Rayl	19,967	471	20,438
5	Net Utility Plant	Sum of lines 1 through 4	10,242,359	(39,829)	10,202,530
6	Working Capital	Exhibit No.: A-150 (HLR-56)	1,508,381	(143,479)	1,364,902
7	Total Rate Base	Line 5 + line 6	11,750,740	(183,308)	11,567,432

Notes

{1} Source: Exhibit No.: A-12 (HLR-31)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Utility Plant
For the Projected 12-Month Period Ending October 31, 2026
$(000)

Case No.: U-21806
Exhibit No.: A-148 (HLR-54)
Page: 1 of 1
Witness: Heather L. Rayl
Date: May 2025

Line No.	(a) Description	(b) Source	(c) Utility Plant	(d) Depreciation Reserve	(e) Net Utility Plant
1	Utility Plant - Initial Filing	Exhibit No.: A-12 (HLR-31)	14,907,264	(4,665,713)	10,241,552
	Adjustments				
2	Correction of Depreciation Rates	Exhibit No.: A-149 (HLR-55), line 1	-	20,447	20,447
3	2024 IT capital expenditures	Exhibit No.: A-149 (HLR-55), line 2	(5,668)	2,078	(3,590)
4	IT Application Currency Corporate Capital Project	Exhibit No.: A-149 (HLR-55), line 3	(24)	4	(20)
5	Application Currency Project - Electric & Gas Shared	Exhibit No.: A-149 (HLR-55), line 4	(31)	5	(26)
6	ARP-Collaboration	Exhibit No.: A-149 (HLR-55), line 5	(10)	1	(8)
7	ARP-Physical Security	Exhibit No.: A-149 (HLR-55), line 6	(127)	19	(108)
8	Next Generation eSOMS	Exhibit No.: A-149 (HLR-55), line 7	(63)	6	(57)
9	Project B-GL-00251	Exhibit No.: A-149 (HLR-55), line 8	(417)	12	(405)
10	Project B-GL-03042	Exhibit No.: A-149 (HLR-55), line 9	(3)	0	(3)
11	Compression & Storage 2024 Underspend	Exhibit No.: A-149 (HLR-55), line 10	(7,563)	344	(7,219)
12	Lansing Service Center	Exhibit No.: A-149 (HLR-55), line 11	(16,720)	216	(16,504)
13	Hastings Service Center	Exhibit No.: A-149 (HLR-55), line 12	(19)	0	(19)
14	Riverside Storage Facility Utility Plant	Exhibit No.: A-149 (HLR-55), line 13	11,349	(2,293)	9,056
15	Distribution Gas Ops - Comp & Controls	Exhibit No.: A-149 (HLR-55), line 14	(380)	5	(375)
16	MCNM - reduced estimate for Line 1010 project	Exhibit No.: A-149 (HLR-55), line 15	(5,804)	116	(5,688)
17	Compliance and Control Projects	Exhibit No.: A-149 (HLR-55), line 16	(265)	6	(259)
18	Material Condition - ERIP	Exhibit No.: A-149 (HLR-55), line 17	(2,991)	67	(2,925)
19	New Business - Mains, Services, and Meter Stands	Exhibit No.: A-149 (HLR-55), line 18	(12,790)	326	(12,464)
20	New Business - Large New Business Projects	Exhibit No.: A-149 (HLR-55), line 19	(5,043)	137	(4,905)
21	Asset Relocation - Civic Improvement Projects	Exhibit No.: A-149 (HLR-55), line 20	(14,365)	282	(14,083)
22	Asset Relocation - Reimbursable Projects	Exhibit No.: A-149 (HLR-55), line 21	(1,163)	17	(1,146)
23	Total Adjustments	Sum of lines 2 through 14	(62,095)	21,795	(40,300)
24	Utility Plant - Rebuttal Position	Line 1 + line 23	14,845,170	(4,643,918)	10,201,252

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capital Spending Reconciliation
For the Projected 12-Month Period Ending October 31, 2026
$(000)

Case No.: U-21806
Exhibit No.: A-149 (HLR-55)
Page: 1 of 1
Witness: Heather L. Rayl
Date: May 2025

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
			Cap Ex Adj. Increase / (Decrease)						Projected Test Year Impacts					
Line No.	Description	Plant Model Category	Source	12-Mo Ended 12/31/23 Increase / (Decrease)	12-Mo Ended 12/31/24 Increase / (Decrease)	10-Mo Ended 10/31/25 Increase / (Decrease)	12-Mo Ended 10/31/26 Increase / (Decrease)	Composite Deprec. Rate	Property Tax Rate	Total CapEx Adjustment Increase / (Decrease)	Avg. Plant Adjustment Increase / (Decrease)	Avg. Accum. Deprec. Increase / (Decrease)	Avg. Net RB Increase / (Decrease)	Deprec. Increase / (Decrease)	Prop. Tax Increase / (Decrease)
1	Correction of Depreciation Rates	Various	Company witness Rayl	-	-	-	-	0.00%	1.40%	-	-	(20,447)	20,447	(8,856)	-
2	2024 IT capital expenditures	Information Technology	Company witness Baker	-	(5,668)	-	-	20.00%	1.40%	(5,668)	(5,668)	(2,078)	(3,590)	(1,134)	(79)
3	IT Application Currency Corporate Capital Project	Information Technology	Company witness Baker	-	-	(15)	(18)	20.00%	1.40%	(33)	(24)	(4)	(20)	(5)	(0)
4	Application Currency Project - Electric & Gas Shared	Information Technology	Company witness Baker	-	-	(19)	(23)	20.00%	1.40%	(42)	(31)	(5)	(26)	(6)	(0)
5	ARP-Collaboration	Information Technology	Company witness Baker	-	-	(6)	(7)	20.00%	1.40%	(13)	(10)	(1)	(8)	(2)	(0)
6	ARP-Physical Security	Information Technology	Company witness Baker	-	-	(73)	(109)	20.00%	1.40%	(182)	(127)	(19)	(108)	(25)	(2)
7	Next Generation eSOMS	Information Technology	Company witness Baker	-	-	-	(126)	20.00%	1.40%	(126)	(63)	(6)	(57)	(13)	(1)
8	Project B-GL-00251	Transmission	Company witness Griffin	-	(159)	(283)	50	2.29%	1.40%	(392)	(417)	(12)	(405)	(10)	(6)
9	Project B-GL-03042	Transmission	Company witness Griffin	(2)	(2)	-	-	2.29%	1.40%	(3)	(3)	(0)	(3)	(0)	(0)
10	Compression & Storage 2024 Underspend	Compression/Storage	Company witness Joyce	-	(7,563)	-	-	2.48%	1.40%	(7,563)	(7,563)	(344)	(7,219)	(188)	(106)
11	Lansing Service Center	Facilities	Company witness Guinn	-	-	(13,120)	(7,199)	1.56%	1.40%	(20,319)	(16,720)	(216)	(16,504)	(261)	(234)
12	Hastings Service Center	Facilities	Company witness Guinn	-	-	(19)	-	1.56%	1.40%	(19)	(19)	(0)	(19)	(0)	(0)
13	Riverside Storage Facility Utility Plant	Compression/Storage	Company witness Myers	-	-	-	-	2.09%	1.40%	-	11,349	2,293	9,056	237	159
14	Distribution Gas Ops - Comp & Controls	Distribution	Company witness Pascarello	-	-	-	(759)	2.54%	1.40%	(759)	(380)	(5)	(375)	(10)	(5)
15	MCNM - reduced estimate for Line 1010 project	Distribution	Company witness Pascarello	-	-	(4,054)	(3,500)	2.54%	1.40%	(7,554)	(5,804)	(116)	(5,688)	(147)	(81)
16	Compliance and Control Projects	Distribution	Company witness Pascarello	-	-	(265)	-	2.54%	1.40%	(265)	(265)	(6)	(259)	(7)	(4)
17	Material Condition - ERIP	Distribution	Company witness Pascarello	-	-	(2,710)	(562)	2.54%	1.40%	(3,272)	(2,991)	(67)	(2,925)	(76)	(42)
18	New Business - Mains, Services, and Meter Stands	Distribution	Company witness Warriner	-	(3,067)	(5,714)	(8,018)	2.54%	1.40%	(16,799)	(12,790)	(326)	(12,464)	(324)	(179)
19	New Business - Large New Business Projects	Distribution	Company witness Warriner	-	(1,948)	(685)	(4,819)	2.54%	1.40%	(7,452)	(5,043)	(137)	(4,905)	(128)	(71)
20	Asset Relocation - Civic Improvement Projects	Distribution	Company witness Warriner	-	-	(9,408)	(9,913)	2.54%	1.40%	(19,321)	(14,365)	(282)	(14,083)	(364)	(201)
21	Asset Relocation - Reimbursable Projects	Distribution	Company witness Warriner	-	-	(203)	(1,919)	2.54%	1.40%	(2,122)	(1,163)	(17)	(1,146)	(29)	(16)
22	Total		Sum of lines 1 through 21	(2)	(18,407)	(36,574)	(36,922)			(91,904)	(62,095)	(21,795)	(40,300)	(11,347)	(869)

Notes

Source: Col. (h): WP-HLR-20
Source: Col. (i): Exhibit No.: A-99 (BJV-1)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Working Capital
For the Projected 12-Month Period Ending October 31, 2026
$(000)

Case No.: U-21806
Exhibit No.: A-150 (HLR-56)
Page: 1 of 1
Witness: Heather L. Rayl
Date: May 2025

Line No.	(a) Description	(b) Initial Filing {1}	(c) Adjustments		(d) Rebuttal Position
1	Cash, cash equivalents, and restricted cash	$ 28,393	$ (5,263)	{2}	$ 23,130
2	Accounts and notes receivable	109,689	-		109,689
3	Materials and supplies	55,983	-		55,983
4	Gas stored underground	382,036	-		382,036
5	Prepayments	543,707	-		543,707
6	Accrued revenue	123,914	-		123,914
7	Deferred taxes	176,164	-		176,164
8	Deferred debits	466,865	(10,411)	{3}	456,454
9	Total assets	1,886,750	(15,674)		1,871,076
10	Accounts payable	234,904	-		234,904
11	Customer deposits	11,793	-		11,793
12	Accrued interest	42,561	-		42,561
13	Dividends payable	14,780	-		14,780
14	Accrued taxes	12,399	127,805	{4}	140,204
15	Other liabilities	30,215	-		30,215
16	Deferred credits	31,718	-		31,718
17	Total liabilities	378,369	127,805		506,174
18	Working capital	$ 1,508,381	$ (143,479)		$ 1,364,902

Notes

{1} Source: Exhibit No.: A-12 (HLR-34)

{2} Source: Company witness Bleckman

{3}

Removal of Riverside Storage regulatory asset	Source: Company witness Myers	(7,398)
Correction of projected working capital S4/HANA cloud implementation adjustment	Source: Company witness Rayl	(1,746)
Correction of projected working capital prepaid cloud implementation adjustment	Source: Company witness Rayl	(1,034)
Removal of non-utility account from working capital	Source: Company witness Rayl	(233)
Total deferred debits adjustment		(10,411)

{4} Source: Company witness Rayl

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Net Operating Income
For the Projected 12-Month Period Ending October 31, 2026
$(000)

Case No.: U-21806
Exhibit No.: A-151 (HLR-57)
Page: 1 of 1
Witness: Heather L. Rayl
Date: May 2025

Line No.	(a) Description	(b) Initial Filing {1}	(c) Adjustments {2}	(d) Rebuttal Position
1	Sales Revenues	2,182,075	1,119	2,183,193.80
2	Transportation Revenues	102,396	-	102,396.36
3	Other Revenues	28,666	-	28,666.46
4	Total Operating Revenue	2,313,137	1,119	2,314,256.61
5	Cost of Gas Sold	737,588	-	737,588
6	LAUF	12,709	-	12,709
7	Company Use Gas	5,502	-	5,502
8	Other O&M Expense	297,904	485	298,389
9	Depreciation	374,164	(11,347)	362,817
10	Amortization	10,239	(2,905)	7,334
11	Property Taxes	201,200	(869)	200,331
12	General Taxes	19,785	(461)	19,325
13	Other (Local) Taxes	838	31	869
14	State Income Tax	25,256	1,026	26,281
15	Federal Income Tax	83,757	3,888	87,646
16	Total Operating Expenses	1,768,943	(10,152)	1,758,791
17	Net Operating Income	544,194	11,272	555,466
18	AFUDC	1,298	-	1,298
19	Net Operating Income, Including AFUDC	545,492	11,272	556,763
	Net Operating Income Adjustments			
20	Income Tax Effect of Interest {3}	---- Included in Lines 12, 13, and 14 ----		
21	Interest Synchronization Adjustment {3}	---- Included in Lines 12, 13, and 14 ----		
22	Total Adjusted Net Operating Income	545,492	11,272	556,763

Notes

{1} Source: Col.(b): Exhibit No.: A-12 (HLR-36)
{2} Source: Col.(c): Exhibit No.: A-152 (HLR-58)
{3} Income tax effects of interest and interest synchronization adjustments are included in the calculation of local, state, and federal income tax. The separate calculations can be found on Exhibit No.: A-154 (HLR-60) Exhibit No.: A-155 (HLR-61)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Reconciliation of Adjusted Net Operating Income
For the Projected 12-Month Period Ending October 31, 2026
$(000)

Case No.: U-21806
Exhibit No.: A-152 (HLR-58)
Page: 1 of 1
Witness: Heather L. Rayl
Date: May 2025

Line No.	(a) Description	(b) Source	(c) Sales Revenues	(d) Transportation Revenues	(e) Other Revenues	(f) COGS	(g) LAUF	(h) Co. Use	(i) Other O&M	(j) Deprec.	(k) Amort.	(l) Property Taxes	(m) General Taxes	(n) CIT	(o) SIT	(p) FIT	(q) NOI	(r) AFUDC	(s) Adjusted NOI
1	Adjusted Net Operating Income - Initial Filing	Exhibit No.: A-12 (HLR-36)	2,182,075	102,396	28,666	737,588	12,709	5,502	297,904	374,164	10,239	201,200	19,785	838	25,256	83,757	544,194	1,298	545,492
	Adjustments																		
2	RIA credit projections	Company witness Sherwani	1,119	-	-	-	-	-	-	-	-	-	-	2	59	222	836	-	836
3	2024 IT Capital Expenditures Underspend	Company witness Baker	-	-	-	-	-	-	(2)	-	-	-	-	0	0	0	1	-	1
4	HR Support Pack & Business Software Upgrade 202	Company witness Baker	-	-	-	-	-	-	(20)	-	-	-	-	0	1	4	15	-	15
5	HR Support Pack & Business Software Upgrade 202	Company witness Baker	-	-	-	-	-	-	(40)	-	-	-	-	0	2	8	30	-	30
6	Application Currency Project - Electric & Gas Shared	Company witness Baker	-	-	-	-	-	-	(8)	-	-	-	-	0	0	2	6	-	6
7	Standard Work Plan Program	Company witness Baker	-	-	-	-	-	-	(71)	-	-	-	-	0	4	14	53	-	53
8	Next Generation eSOMS	Company witness Baker	-	-	-	-	-	-	(8)	-	-	-	-	0	0	2	6	-	6
9	Distribution Gas Ops - Comp & Controls	Company witness Pascarello	-	-	-	-	-	-	634	-	-	-	-	(1)	(33)	(126)	(474)	-	(474)
10	Depreciation	Exhibit No.: A-149 (HLR-55) col.(n)	-	-	-	-	-	-	-	(11,347)	-	-	-	18	595	2,254	8,480	-	8,480
11	MPG Amortization	Company witness Foster	-	-	-	-	-	-	-	-	54	-	-	(0)	(3)	(11)	(40)	-	(40)
12	Riverside Storage Field Amortization	Company witness Myers									(2,959)			5	155	588	2,211	-	2,211
13	General Taxes	Company witness Rayl	-	-	-	-	-	-	-	-	-	-	(461)	1	24	92	344	-	344
14	Property Tax Expense	Exhibit No.: A-149 (HLR-55) col.(o)	-	-	-	-	-	-	-	-	-	(869)	-	1	46	173	650	-	650
15	Income Tax Effect of Interest	Exhibit No.: A-154 (HLR-60)	-	-	-	-	-	-	-	-	-	-	-	5	175	664	(844)	-	(844)
16	Interest Synchronization Adjustment	Exhibit No.: A-155 (HLR-61)	-	-	-	-	-	-	-	-	-	-	-	0	1	3	(4)	-	(4)
17	Total Adjustments	Sum of lines 2 through 16	1,119	-	-	-	-	-	485	(11,347)	(2,905)	(869)	(461)	31	1,026	3,888	11,272	-	11,272
18	Adjusted Net Operating Income - Rebuttal Position	Line 1 + line 17	2,183,194	102,396	28,666	737,588	12,709	5,502	298,389	362,817	7,334	200,331	19,325	869	26,281	87,646	555,466	1,298	556,763

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Operations & Maintenance Expenses
For the Projected 12-Month Period Ending October 31, 2026
$(000)

Case No.: U-21806
Exhibit No.: A-153 (HLR-59)
Page: 1 of 1
Witness: Heather L. Rayl
Date: May 2025

Line No.	Description	(a) Initial Filing {1}	(b) Adjustments {2}	(c) Rebuttal Position
1	LAUF	$ 12,709	$ -	$ 12,709
2	Company Use Gas	5,502	-	5,502
3	Gas Compression Storage	17,577	-	17,577
4	Gas Operations	133,635	-	133,635
5	Pipeline Integrity	18,549	-	18,549
6	Transmission	4,580	-	4,580
7	Gas Engineering & Supply	22,195	634	22,829
8	Customer Experience & Operations	31,846	-	31,846
9	Operations Support	9,525	-	9,525
10	IT & Security - Operations	36,758	-	36,758
11	IT & Security - Investments	17,948	(149)	17,798
12	Pension Plans A/B	(34,801)	-	(34,801)
13	Defined Company Contribution Plan	8,155	-	8,155
14	401(k) Employees' Savings Plan	6,615	-	6,615
15	Active Health Care/ Insurance/ LTD	19,765	-	19,765
16	Retiree Health Care and Life Insurance	(42,702)	-	(42,702)
17	Other Benefits	3,218	-	3,218
18	Pension volatility mechanism amortization	(791)	-	(791)
19	OPEB volatility mechanism amortization	(1,423)	-	(1,423)
20	Incentive Compensation	1,546	-	1,546
21	Uncollectible Expense	15,327	-	15,327
22	Injuries & Damages	2,279	-	2,279
23	MGP Direct Projected Management Costs	930	-	930
24	Corporate Services	26,874	-	26,874
25	Jobwork expenses	61	-	61
26	Interest expense on security deposits	237	-	237
27	OPEN	-	-	-
28	Total Other O&M Expense	316,115	485	316,600
29	Less: LAUF	12,709	-	12,709
30	Less: Company Use Gas	5,502	-	5,502
31	Total Other O&M Expense	$ 297,904	$ 485	$ 298,389

Notes

{1} Source: Col. (e), Exhibit No.: A-12 (HLR-41)
{2} Source: Cols.(g), (h), and (i): Exhibit No.: A-152 (HLR-58)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Income Tax Effect of Interest
For the Projected 12-Month Period Ending October 31, 2026
$(000)

Case No.: U-21806
Exhibit No.: A-154 (HLR-60)
Page: 1 of 1
Witness: Heather L. Rayl
Date: May 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Rate Base	Exhibit No.: A-147 (HLR-53)	11,567,432
2	Weighted Cost of Debt, Excluding JDITC	Exhibit No.: A-14 (MRB-1)	0.0182
3	Allowable Interest Expense	Line 1 * Line 2	210,830
4	Projected Pro-Forma Interest Expense - Initial Filing	Exhibit No.: A-12 (HLR-49)	214,171
5	Increase/ (Decrease) In Allowable Interest Deduction	Line 3 - Line 4	(3,341)
6	Impact on Taxable Income	Line 5 * -1	3,341
7	Impact on Local Income Taxes	Line 6 * Local Income Tax Rate	5
8	Impact on State Income Taxes	Line 6 * State Income Tax Rate	175
9	Impact on Federal Taxable Income	Line 6 - Line 7 - line 8	3,161
10	Impact on Federal Income Tax	Line 9 * Federal Income Tax Rate	664
11	Impact on Net Operating Income	(Line 7 + Line 8 + Line 10) *-1	(844)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Interest Synchronization Adjustment
For the Projected 12-Month Period Ending October 31, 2026
$(000)

Case No.: U-21806
Exhibit No.: A-155 (HLR-61)
Page: 1 of 1
Witness: Heather L. Rayl
Date: May 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Rate Base	Exhibit No.: A-147 (HLR-53)	11,567,432
2	JDITC Debt-Related Portion of the Capital Structure	Exhibit No.: A-14 (MRB-1)	0.0018
3	Portion of Rate Base Funded by JDITC	Line 1 * Line 2	21,196
4	Cost of JDITC - Debt Portion	Exhibit No.: A-14 (MRB-1)	0.0435
5	Allowable JDITC Interest Expense	Line 3 * Line 4	923
6	Projected Pro-Forma Interest Expense - Initial Filing	Exhibit No.: A-12 (HLR-50)	937
7	Increase/ (Decrease) in Allowable JDITC Interest Expense	Line 5 - Line 6	(15)
8	Impact on Taxable Income	Line 7 * -1	15
9	Impact on Local Income Tax	Line 8 * Local Income Tax Rate	0
10	Impact on State Income Tax	Line 8 * State Income Tax Rate	1
11	Impact on Federal Taxable Income	Line 8 - Line 9 - line 10	14
12	Impact on Federal Income Tax	Line 11 * Federal Income Tax Rate	3
13	Impact on Net Operating Income	(Line 9 + Line 10 + Line 12) *-1	(4)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

REBUTTAL TESTIMONY

OF

MUSTAFA A. SHERWANI

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Q. Please state your name and business address.

A. My name is Mustafa A. Sherwani, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. Are you the same Mustafa A. Sherwani who filed written direct testimony in this proceeding?

A. Yes. My name appears differently now (previously Mustafa Ahmed). There was an error in certain documents when I immigrated that temporarily required me to use my middle name as my last name for official business. The error has now been corrected.

Q. Please explain the purpose of your rebuttal testimony in this proceeding.

A. I am responding to the portion of the direct testimony filed by Paul R. Ausum and Elaina M. Braunschweig on behalf of the Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") and rebutting the portion of direct testimony filed by Alice Napoleon on behalf of Michigan Environmental Council ("MEC") and Sierra Club ("SC") (collectively, "MEC") and Sebastian Coppola on behalf of Attorney General Dana Nessel ("Attorney General").

Q. Are you sponsoring any exhibits supporting your rebuttal testimony in this case?

A. No.

PART I – RESPONDING TO STAFF WITNESS AUSUM

Q. On page 4, lines 13 through 19 of his direct testimony, Staff witness Ausum recommends that the Commission order the Company to include all raw data and inputs used to construct forecast models. Do you agree with this recommendation?

A. Yes, the Company agrees to include this raw data as part of workpapers for future filings.

PART II – RESPONDING TO STAFF WITNESS BRAUNSCHWEIG

Q. On page 6, line 20 and page 7, lines 1 and 2 of her direct testimony, Staff witness Braunschweig suggests that the Company should work with Staff to improve exhibits and testimony related to Residential Income Assistance ("RIA") credits for the next filing. Do you agree with this statement?

A. The Company acknowledges that there are some opportunities to improve the quality of its filing in this area. The Company plans to work with Staff and make changes to its presentation going forward to address Ms. Braunschweig's concerns.

Q. On page 18, lines 2 through 4 of her direct testimony, Staff witness Braunschweig proposes to base RIA count projections on three-year historical averages. Do you agree?

A. The Company agrees with this approach.

PART III – REBUTTAL OF MEC WITNESS NAPOLEON

Q. On page 6, lines 1 through 3 of her direct testimony, MEC witness Napoleon states that the Company should explain and document the relationship of the new connections forecast to the load forecast. Would it be appropriate to compare the two forecasts?

A. No, new service connections represent work associated with the installation of new services; the customer load forecast, on the other hand, is a forecast of the numbers of customers for which a bill for natural gas consumption is expected. The customer forecast that is part of the load forecast is based on regression analysis (a Commission approved methodology), as noted in my direct testimony on page 4, lines 10 through 14. It is possible for some period of time to elapse after completing a new service connection before any customer begins being billed on it. Likewise, an existing connection might remain active even if no customer is currently occupying the location. Similarly, if the Company has 1,000 new customers, it doesn't necessarily translate to 1,000 new gas connections. For example, a service installation may provide gas service to a single customer in a single-family home, or it may provide service to multiple customers in an apartment or condominium building. In theory, new service connections are a subset of the gas load customer forecasts. Given that the number of customers billed is a different measure of business activity than the number of new service installations, it is possible for there to be differences in the rate of growth over any particular time period. Therefore, it should be noted that the customer connection forecast and the customer forecast that is part of the gas load forecast each represent a different measure of business activity and should not be conflated by relating the two in terms of historical growth and trend.

Q. On page 33, lines 4 through 6 of her direct testimony, Ms. Napoleon states, "the Company should clarify why it does not incorporate information from its new customer connection forecast into its total customer load forecast". Why does the Company forecast total customer counts the way it does?

A. Customer counts fluctuate monthly and often follow a cyclical pattern of move ins and move outs. A regression that looks at the most recent 12 months does a better job than a model that uses multiple other variables. For the total Company forecast Consumers Energy is much less concerned about which customers are new and much more concerned about accurately forecasting total customers.

Q. On page 31, lines 3 through 5 of her direct testimony, Ms. Napoleon expresses concern with the regression model not incorporating the effects of Public Act 229 of 2023 ("Act 229"). Do you agree?

A. No, Act 229 creates a framework for electric utilities to encourage electrification by adopting an electrification program but does not mandate utilities to have an electrification program. Consumers Energy anticipates greater adoption of electrification by customers in the future, regardless of the impact of Act 229, and plans to assess possible projected impacts of electrification in future gas rate cases. However, the Company has no information available at the time of this rate case to indicate that Act 229 has had any impact on customer electrification behavior or that it will have any measurable impact during the test year of this case. At the time of filing the rate case the Company felt that it

was too premature to include any new assumptions about electrification attributable to Act 229 or for any other reason in this rate case.

Q. On page 32, lines 10 through 11 of her direct testimony, Ms. Napoleon claims that "customers should be able to save more gas" through the incorporation of the effects of Act 229. Do you agree?

A. In theory, customers would use less natural gas if they invested in electrifying their appliances. However, Act 229 does not mandate that customers electrify any natural-gas-fueled appliances that they currently use. As discussed above, it does not even mandate that electric utilities adopt an electrification program. The Company needs to see data supporting the savings through an electrification program adopted under Act 229 to be able to accurately forecast reductions in deliveries to customers as a result of that new statute.

Q. Does Act 229 quantify targets for reduction of natural gas service due to space heating electrification?

A. No, it does not.

Q. What does incorporation of out-of-sample data mean?

A. This means that the Company should have evaluated whether its regression model, based on the most recent 11 years of data, would have yielded accurate predictions for results from earlier periods.

Q. On page 31, lines 3 through 5 of her direct testimony, Ms. Napoleon expresses concern with the lack of incorporation of out-of-sample data in the regression model. Do you agree with this belief?

A. No, the Company uses the most current data that is available. In this case, I used the most recent eleven years of data. Out-of-period testing would only test the model's ability to

accurately forecast data from over a decade ago and would not necessarily be useful for testing the validity of the model for the future. The most current data is often the most relevant for making predictions. Using the latest data ensures that the model is trained on the most up-to-date information, which can improve its accuracy and relevance.

Q. On page 31, lines 18 through 20 of her direct testimony, Ms. Napoleon states that the regression models do not "demonstrate great performance relative to actual historical data as it is within the regression data sample". Do you agree?

A. No, as noted in my direct testimony on pages 6 through 8, the regression is built using historical data and tested against historical data and has proven to be an effective and accurate model. Arguing that a model can't be good at forecasting actual data because it uses historical data is illogical.

PART IV – REBUTTAL OF ATTORNEY GENERAL WITNESS COPPOLA

Q. On page 158, lines 6 through 8 and page 160, lines 2 through 5 of his direct testimony, Attorney General witness Coppola proposed an increase of 1.3 Bcf over the Company's commercial transport forecasted deliveries, do you agree with that proposal?

A. No, I disagree that an increase to the Company's commercial transport forecasted deliveries is appropriate.

Q. Did Mr. Coppola use MPSC-approved methodologies for forecasting deliveries?

A. No, Mr. Coppola used a very simplistic approach that takes one data point and applies a historical Compound Average Growth Rate ("CAGR") to forecast the future. On page 156, lines 2 through 8 of his direct testimony, Mr. Coppola details how he calculated the three-year CAGR and applied it to the 2024 calculated average use per customer to derive

the forecasted test year commercial transport deliveries as shown in his Exhibit AG-54, line 15.

Q. Is the methodology of using one historical year and applying a historical CAGR to derive a forecasted year a reasonable approach?

A. No, this is an unsound approach to forecasting. This oversimplified methodology assumes that customers' future behavior will be identical to behavior during the last three years. Mr. Coppola's approach applied a simple historical CAGR to the 2024 historical results without consideration for any econometric data. Mr. Coppola did not provide any information about forecasted conditions that would explain the need for these adjustments to the proposed forecast that used the long-standing regression modeling methodology. As described on pages 5 through 10 of my direct testimony, the Company used the standard approach of regression modeling and incorporating economic data to develop a robust forecast that has typically resulted in accurate forecasts.

Q. On page 157, line 3 through 9 of his direct testimony, Mr. Coppola compares the commercial transport decline of 0.5% with the increase in industrial transport of 2.6% and states that the same economic indicators apply to both classes of transport. Do you agree with this statement?

A. No, commercial transport should not be compared to industrial transport as they are different classes of customers and behave differently. For example, a gas station or convenience store does not respond to the economy in the same way as a large auto manufacturer does. More importantly the model variables are different for commercial and industrial transport and work independently of each other.

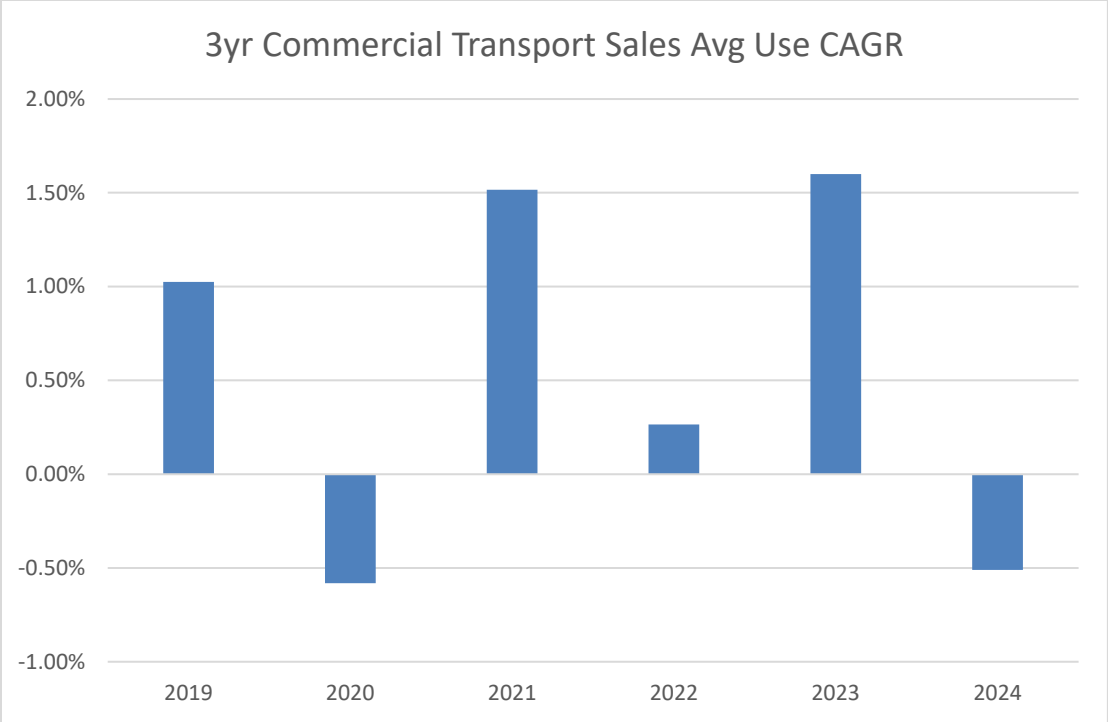
Q. On page 159, line 19 of his direct testimony, Mr. Coppola claims that the regression models use "stale customer usage data from 11 years ago." Do you agree with this claim?

A. No, it is important to use an adequate amount of historical data when training a regression model as too few datapoints can generate unrealistic forecasts. Eleven years of data is adequate to develop the formula while maintaining data that is current.

Q. Are there other factors that give you pause in using Mr. Coppola's suggested methodology?

A. Yes, Mr. Coppola's simplistic approach not only deviates from the historically reviewed and approved methodology, it also completely rejects the validity of the regression modeling process and accuracy. Most utilities in the country use regression modeling to forecast their deliveries. Furthermore, Itron's MetrixND (the software that Consumers Energy uses for regression analysis) is considered an industry standard, as more than 150 utilities, Independent System Operators, municipal utilities, cooperatives, and other energy service providers use Itron's MetrixND.[1] Mr. Coppola's approach also discounts the value and impact of Energy Waste Reduction ("EWR") by ignoring the Company's EWR filings and the impact of EWR on natural gas deliveries. There's also the high likelihood that using Mr. Coppola's methodology would cause the forecasts to fluctuate substantially from year to year causing possible rate instability. The three-year CAGR for commercial transport sales for the years 2019 through 2024 can be seen below. The fluctuation in CAGR and the lack of EWR inclusion makes the Attorney General's proposed approach inferior to the MPSC-accepted regression methodology.

[1] https://na.itron.com/o/commerce-media/accounts/-1/attachments/3828543



Q. On page 156, line 19 through page 157, line 7 of his direct testimony, Mr. Coppola refers to discovery responses U21806-AG-CE-0313 and U21806-AG-CE-0746 and states that the Company's explanation for the decline in transportation deliveries does not fit the evidence shown in his Exhibit AG-53. Do you agree with this comparison?

A. No. As I discussed above, Mr. Coppola's CAGR methodology fails to account for any econometric data and uses an insufficient number of years of data to be reliable. In contrast, the test year transportation deliveries shown in Exhibit A-15 (MA-14), Schedule E-10 on line 13, column (h) results from the Company's regression calculation using 11 years of data. This figure essentially captures the impact by economic indicators and usage patterns. The Company provided all of the inputs used in the regression model in this case, so Mr. Coppola could have used the data to answer his own question about what inputs drove the Company's test year transportation deliveries forecast. Instead, Mr. Coppola focused

on the "change in determinants" value shown on line 13, column (e) of that exhibit. He asked the Company to explain how that value was calculated. That value was simply calculated by taking the weather-normalized 2023 transportation deliveries (Exhibit A-15 (MA-14), line 13, column (a) plus column (d)) and subtracting the Company's regression results from line 13, column (h) to show the difference between those values. Mr. Coppola appears to believe the Company independently calculated the "change in determinants" value in order to subsequently use it as an input to determine its test year forecast, but it was done exactly the other way around. As a result, asking how the "change in determinants" number was calculated would tell you nothing about how the Company's test year transportation deliveries forecast was determined or what the drivers of that forecast were. If that's what Mr. Coppola meant to do, he asked the wrong question in discovery. The Company answered the question he asked and did not recognize until Mr. Coppola filed his testimony what he thought he was asking. In any case, the Company has already explained in detail how the test year forecast was calculated, so there was no reason Mr. Coppola could not have determined the driver of the test year forecast despite the clear confusion caused by his poorly stated discovery question. Mr. Coppola's comparison between the reduction in commercial transportation deliveries suggested by his simplistic CAGR method calculated in Exhibit AG-53 and the Company's regression approach is inappropriate because the Company's method takes econometric data into account and uses an appropriate number of years of data while the three-year CAGR method fails to do either.

Q. On page 159, lines 5 through 11 of his direct testimony, Mr. Coppola notes that the Company forecast accuracy was within 0.6% with a 2.6 Bcf standard deviation over the last eight years and implies that the model is not sufficiently accurate. Do you agree with this assessment?

A. No. The gas forecast has been incredibly accurate over the last eight years. The accuracy is better than it was ten years ago. Over the past eight years, the standard deviation decreased to 2.6 Bcf and the Mean Absolute Percentage Error ("MAPE") decreased to 0.6%. MAPE is a statistical test used to measure model errors in which smaller values suggest better model performance. From a statistical perspective, these are very accurate model results, which have provided very accurate sales and deliveries forecasts for the gas business through many rate cases.

Q. On page 158, lines 6 through 8 and lines 15 through 18 of his direct testimony, Mr. Coppola proposes an increase to the Company's commercial transportation forecast of 1.3 Bcf, citing the use of three-year CAGR as a suitable metric for projecting future performance. On page 159, lines 5 through 15, he also cites the standard deviation ranges to support his adjustment. Do you accept this logic?

A. No, the 1.3 Bcf increase to the forecast is inappropriate. Mr. Coppola arrived at this number by using a very simplistic approach and justified it, in part, by noting the standard deviation limits. It is important to note that the standard deviation limits mentioned in my direct testimony are for all classes combined and should not be used exclusively for commercial transport sales. More importantly, it should not be used to justify the increase in commercial transport volumes based solely on a three-year CAGR.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

REBUTTAL TESTIMONY

OF

S. AUSTIN SMITH

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Q. Please state your name and business address.

A. My name is S. Austin Smith, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same S. Austin Smith who previously submitted testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to rate design proposals raised in the direct testimony of Michigan Public Service Commission ("MPSC" or "the Commission") Staff ("Staff") witness Nancy C. Rademacher, Association of Businesses Advocating Tariff Equity ("ABATE") witness Jessica A. York, Attorney General witness Sebastian Coppola, and Citizens Utility Board of Michigan ("CUB") witness Joshua W. Denzler.

Q. Are you sponsoring any exhibits in connection with your rebuttal testimony?

A. Yes. I am sponsoring Exhibit A-156 (SAS-9), which is a discovery response from CUB witness Denzler.

Q. Staff witness Rademacher, on page 4, lines 4 through 8, of her direct testimony supports updating the Excess Peak Demand threshold from 45 Mcf to 92 Mcf for Rate A-1 customers. Do you agree?

A. Yes.

Q. Staff witness Rademacher, on page 5, line 20, through page 6, line 5, of her direct testimony proposes adjusted rate stability targets. Do you find these adjusted rate stability targets to be reasonable?

A. Yes.

Q. Staff witness Rademacher, on page 5, lines 1 and 2, of her direct testimony testified that the Company's proposed Transmission-Only Transportation Service rates do not reflect the breakeven points of the associated rate schedules. Do you agree?

A. No. This appears to mirror the stance Staff witness Rademacher took in the last case, when the Company did fail to include Customer Charges and associated breakeven points with the four proposed rate schedules. But in the instant case, the rates are set according to the same breakeven point thresholds used by the Transportation class rate schedules. This is discussed on page 15, line 23, through page 16, line 3, of my direct testimony.

Q. Staff witness Rademacher, on page 5, lines 3 through 8, of her direct testimony testified that the service provided to Transmission-Only Transportation Service customers has not been shown to differ in a way that supports separate rates for the breakeven-based classes. Do you agree?

A. No, I do not agree. In the last gas rate case, Case No. U-21490, the Company did not fully align its Transmission-Only Transportation Service rate design with the breakeven methodology used for other transportation classes. The Company has now developed and applied breakeven points for Transmission-Only customers consistent with how rates are designed for end-use transportation customers. This approach ensures internal consistency across all transportation rate classes and better reflects cost-causation principles. The use of breakeven analysis in designing these rates helps determine appropriate fixed and variable components while supporting rate stability for customers.

Q. What do you make of Staff witness Rademacher's argument on page 5, lines 6–8, of her testimony that the Company should design rates for Transmission-Only customers consistent with DTE?

A. Other regulated utilities' rate designs should not prevent the Commission from approving a different rate structure for Consumers Energy, where justified by the Company's cost-of-service analysis and customer usage patterns.

Q. Attorney General witness Coppola, on page 196, line 13, through page 198, line 3, of his direct testimony, recommended the Company not increase the residential and GS-1 customer charges. Do you agree with this recommendation?

A. No. The Attorney General's recommendations regarding the customer charges are not based on any cost study. If the final Commission-approved Cost-of-Service Study supports a residential customer charge greater than $15.00 and a GS-1 customer charge greater than $21.00, then these customer charges should be designed to reflect that higher cost. Both the Company and Staff have independently calculated the residential customer charge using a methodology that limits the charge to costs directly associated with supplying service, such as metering, service laterals, and customer billing. These calculations support a higher charge than currently assessed, and the Company's calculation is even higher than it has proposed, indicating that the increase is justified by the actual Cost-of-Service Study. Further, as expressed by Staff witness Krause in his direct testimony, previous rate cases have resulted in smaller increases or no increase in customer charges due to settlements, which has widened the gap between calculated and approved charges over time. The proposed increase aims to address this growing disparity.

Q. Does an increase in the Customer Charge negatively impact low-income customers on the residential income assistance ("RIA") provision?

A. No. A higher customer charge is beneficial for low-income customers on the RIA provision. As I noted in my direct testimony, the customer charge is completely offset by the RIA credit. Further, when a larger portion of the proposed revenue is collected via a fixed charge (i.e. customer charge), a smaller portion of the proposed revenue is collected via a variable charge (i.e. distribution charge). A lower variable charge results in a lower monthly bill for the most vulnerable customers; especially during the winter when customer use is at its highest. The following example illustrates how a low-income residential customer on the RIA provision would have a *lower* monthly bill with a $20.00 customer charge using the proposed rate design methodology as compared to a $15.00 customer charge using the same proposed methodology.

Table 1
Customer Charge Impact to RIA Customers

			$20.00 Customer Charge		$15.00 Customer Charge	
Description	**Quantity**	**Units**	**Rates**	**Revenue**	**Rates**	**Revenue**
Delivery						
Customer	12	Mthly	$ 20.00	$ 240.00	$ 15.00	$ 180.00
Distribution Mcf/mth[1]	78	Mcf	5.8140	453.49	6.4430	502.55
Provisions						
Income Assistance - RIA	12	Mthly	(20.00)	(240.00)	(15.00)	(180.00)
Total Delivery				453.49		502.55
Fuel						
GCR Sales	78	Mcf	3.296	257.09	3.296	257.09
Total Annual Expense				$ 710.58		$ 759.64
Average Monthly Expense				$ 59.21		$ 63.30
Percent Increase/(Decrease)						6.9%

Notes
[1] Based on the 2023 average annual use for RIA customers of 78 Mcf

Q. CUB witness Denzler, on page 32, line 12, through page 35, line 14, of his direct testimony, has said he opposes increasing the customer charge for four reasons: 1) customer charges are regressive and harm low-to-moderate income ("LMI") customers; 2) higher customer charges do not send good price signals; 3) customers prefer lower customer charges; and 4) the Company's current fixed charge is high compared to other Michigan utilities. How do you respond to Mr. Denzler's first reason?

A. The assertion that fixed customer charges are inherently regressive and harms LMI customers oversimplifies both the nature of utility cost recovery and the broader tools available to support affordability. As provided in Table 1 above, low-income customers receiving the RIA credit benefit from a higher customer charge. The Company acknowledges that all low-income customers may not receive the RIA credit and recognizes that affordability is a valid consideration, particularly for LMI customers, but affordability issues are better addressed through targeted low-income assistance programs (e.g. RIA and LIAC) and energy efficiency investments provided by the Company's Energy Waste Reduction programs.

Q. What is the impact to customers who do not receive the RIA provision credit?

A. Even without the RIA provision credit, this means that any customer (LMI or otherwise) paying a $20.00 Customer Charge and consuming 8 Mcf or more per month actually experiences a *lower* bill. In addition, usage is not a reliable proxy for income, as many LMI households (e.g. those with larger families or in less efficient homes) may have higher usage than financially advantaged, single-occupant households.

Q. How do you respond to Mr. Denzler's second reason?

A. By removing fixed costs from the volumetric rate, the remaining usage-based rate more closely reflects the marginal cost of delivering gas. This allows customers to see the real cost of additional usage, improving the accuracy and efficiency of the price signal for conservation or behavioral response. Customer Charges do not eliminate price signals that prompt conservation, as a majority of a residential customer's typical bill is composed of a volumetric rate for gas delivery and commodity supply. Therefore, even with a higher Customer Charge, those volumetric charges and commodity prices have a consequential influence on energy efficiency programs, weatherization, and consumption-based decisions.

Q. How do you respond to Mr. Denzler's third reason?

A. Mr. Denzler's testimony relies on the position of the National Association of State Utility Advocates ("NASUCA"), but it is not clear if they have conducted a survey of Consumers Energy's customers. NASUCA's position represents a broad policy stance and does not seem to account for the unique circumstances of individual utilities or regions. It does not reflect a detailed analysis of Consumers Energy's specific cost structures or regional characteristics.

Q. How do you respond to Mr. Denzler's fourth reason?

A. Comparing fixed charges across utilities without examining the underlying cost-of-service studies, system configurations, and customer demographics is an oversimplification that can lead to flawed conclusions. Each utility's customer charge is based on the unique costs it incurs to serve a residential customer—such as meter installation and maintenance, service lines, billing, call center operations, and customer information systems. In response

to discovery, Mr. Denzler conceded that he has not evaluated whether other Michigan utilities' service areas or customer demographics contributed to their different customer charges. Exhibit A-156 (SAS-9). Rate design should be based on the utility's actual cost to serve its customers, not on simplistic benchmarking against other utilities whose cost structures may differ. The Company's fixed customer charge is based on its own cost-of-service study, which reflects the actual costs incurred to maintain safe and reliable service for each customer.

Q. ABATE witness York, on page 13, line 12, through page 17, line 6, of her direct testimony, proposes a revenue apportionment methodology to design rates. Do you agree with this approach?

A. No. ABATE witness York proposes a revenue apportionment methodology to adjust rate design outcomes to reflect her preferred Version 3 cost-of-service study, which utilizes an Average and Excess Demand ("AED") allocator. However, she simultaneously concedes that if the Commission adopts the Company's Version 2 COSS, her apportionment approach could be used to approximate the results of her Version 3 COSS. Rather than using a COSS to guide revenue allocation, witness York is relying on revenue apportionment—essentially shifting revenue between classes without a supporting cost basis. Revenue apportionment that shifts cost recovery between rate schedules to reflect a rejected cost-allocation method undermines the very purpose of conducting a COSS in the first place.[1]

[1] In Case No. U-21291, the Commission rejected ABATE's proposed AED allocation method. See MPSC Case No. U-21291, November 7, 2024 Order, pages 224, 228-229.

Q. ABATE witness York, on page 37, line 8 through line 19, of her direct testimony, opposed the Company's transportation service rate design, which is based on economic breakeven points. Ms. York argues that the Company has not provided evidence to show that frequent rate shifting and revenue volatility would occur if rates for all Transportation rate schedules were based on the class COSS rather than a desire to maintain economic breakeven points. How do you respond?

A. The Company is justifiably concerned about rate shifting—a concern grounded in both experience and sound ratemaking principles. Current approved breakeven points reflect economic thresholds that guide how customers evaluate their rate class alignment. If the Company were to abruptly shift transportation rates to align precisely with the current class COSS without considering these breakeven points—or without re-running the full forecasting and cost-allocation process—there is a material risk of distorting cost recovery. Specifically, the Company could experience customer migration between rate classes or changes in usage patterns, leading to either over-recovery or under-recovery of authorized revenues. Rate design and customer class assignment are part of a cyclical, iterative process. If these thresholds were altered midstream—without adjusting load forecasts, usage patterns, and cost allocations accordingly—it would invalidate the assumptions embedded in the class COSS and result in rates that no longer align with actual cost causation.

Q. ABATE witness York, on page 37, lines 10 and 11, of her direct testimony, notes that minimal rate shifting has occurred over the last several years. What does this show?

A. This shows that the Company has appropriately set breakeven points.

Q. ABATE witness York, on page 39, line 8 through line 16, of her direct testimony, describes her proposed rate design calculated in Exhibit AB-4, which recommends the Commission set LT & XLT Customer Charges at the cost of service and establish new breakeven thresholds. Do you agree with this proposed rate design?

A. No. Exhibit AB-4 does not consider the impact that changing the breakeven points has on sales determinants—and the related rate revenue. A much more thorough analysis would be needed to properly calculate rate impacts with ABATE witness York's proposed breakeven points. Modifying the breakeven points requires a new forecast of sales determinants. This is a cyclical process in that the Company would need to develop the cost of service and rate design using today's breakeven points, calculate the new breakeven points, and then reforecast the sales to align with the new breakeven points and rerun the cost of service and rate design. Additionally, changing breakeven points provides an incentive for customers to switch rates. The Company would need to communicate to customers that they may be better off on a different rate, and if customers do not shift to the most economical rate in response, it could lead to an over- or under-recovery of costs. The Company has engaged in collaborative discussions with ABATE and Staff to explore options for studying breakeven points, alternative rate designs, and aligning customer charges with the cost of service. This collaborative approach ensures that any changes to rate design are informed by stakeholder input and aligned with broader regulatory objectives.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

EXHIBIT

OF

S. AUSTIN SMITH

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

21806-CE-MNSC-0005

On pages 34-35 of Mr. Denzler's direct testimony, he compares Consumers Energy's customer charge with other Michigan utilities' customer charges.

a. Does Mr. Denzler agree that a utility's service area and customer demographics (e.g., the number of urban and rural customers in the utility's service territory) can affect its costs of providing service to customers?

Response:

I agree that the service area and customer demographics are among many factors that can influence the cost of service and note that what "can" affect cost of service and what actually *does* affect cost of service are two different things.

b. Concerning the utilities that Mr. Denzler named on pages 34-35 of his testimony, did he evaluate whether these utilities' service areas or customer demographics contributed to the different customer charges? If so, what did his evaluation show? Please produce all documents and communications supporting the evaluation if one was performed.

Response:

I did not complete this analysis.

Respondent: Joshua W. Denzler

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

REBUTTAL TESTIMONY

OF

BRIAN M. SNYDER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Q. Please state your name and business address.

A. My name is Brian M. Snyder, and my business address is 11801 Farmington Road, Livonia, Michigan 48150.

Q. In what capacity are you employed?

A. I am employed as Principal Mechanical Engineer for Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your educational background?

A. I earned a Bachelor of Science in Mechanical Engineering from the University of Michigan – Dearborn. I am a licensed engineer in the state of Michigan.

Q. What have your job responsibilities entailed with Consumers Energy?

A. I began working for Consumers Energy in 2009 on the Facilities Engineering and Design Team. In 2016, I accepted the Assessment Planning Engineer role in the Transmission Integrity Management Program ("TIMP"). I am currently in this same role. The role entails managing the TIMP work plan, aligning that plan with both federal regulation and risk prioritization, selection of assessment methodology, and long term financial planning.

Q. Please summarize your experience with Probabilistic and Relative risk models.

A. I have been working with the risk models utilized by the Company since I started in this role in 2016. I am responsible for the post-modeling results analysis and work plan alignment. I worked with the relative risk model through 2022 and then moved to working with the current Transmission Probabilistic Risk Model upon the retirement of the relative model.

Q. Please summarize your experience with the use of, administration, and development of the Company's Transmission Probabilistic Risk Model.

A. I was one of the supporting team members from the beginning of the Transmission Probabilistic Risk Model adoption. I worked on the team which selected the vendor and model as well as helping to establish the Company's requirements for the project. I work with the Company's risk engineer during the data upload process, through the modeling process, and support and develop most of the post modeling analytics for work planning alignment.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. No, I have not.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibit:

Exhibit A-157 (BMS-1)	Response to Discovery Requests U21806-MNSC-CE-80, and U-21806-MNSC-CE-218 through 285.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to provide rebuttal testimony concerning proposals around the inclusion of cost effective calculations in the Company's risk modeling brought forth by Michigan Environmental Council ("MEC") and Sierra Club ("SC") (collectively, MEC) witness Dr. Sol deLeon.

I. MEC WITNESS DELEON

Q. Beginning on page 28, line 6, through page 42, line 6 of her direct testimony, MEC witness deLeon discusses risk modeling and cost-effectiveness to maximize safety impacts of ratepayer expenditures. Do you have an overall comment to make concerning her analysis?

A. Yes, I do. The Company provided to MEC in discovery request U21806-MNSC-CE-0080 the uses and limitations of the Company's current risk models. I am including that response as Exhibit A-157 (BMS-1). As stated in her direct testimony, the Company has a probabilistic risk model in place for certain transmission assets and is in the process of making use of a probabilistic risk model on more assets in the future. Overall, the Company agrees with Dr. deLeon that they are a valuable tool. However, the fundamental problem with Dr. deLeon's analysis and recommendation is her lack of acknowledgment of the nature and limitations of the Company's current Transmission Probabilistic Risk Model and risk models in general.

Q. At page 29 of her direct testimony, MEC witness deLeon discusses how utilities can utilize probabilistic risk models and calculate the cost effectiveness of various safety investments. Do you agree with her assessment?

A. No, I do not. The Transmission Probabilistic Risk Model was developed for the TIMP with the purpose of calculating the total risk of an asset, the threats of which are listed in ASME B31.8S, which are driving that risk, and the consequence of a failure (nine different failure modes) at any location along those pipe assets. The work plan developed within TIMP first must comply with federal regulation for assessment compliance dates, assessment methodology, and remediation. The plan is built first to comply with the

assessment compliance dates and then prioritized by the results from the risk model. Any cost analysis must be done outside the model and would require substantial further development of the model, using Artificial Intelligence to predict the future repairs, where they are, how many, and the cost of remediation. That functionality is not likely to be available in the near future.

Q. Can you explain the annual time frame cadence of the risk model?

A. Yes, I can. The probabilistic risk model is run once per year. The data Extract, Transformation, and Load ("ETL") process takes up to 90 days to complete and commences in the first quarter of the year. This is the Company's process of updating the data information on the transmission system in preparation for the Company's vendor to upload into their software. After this is completed, the model requires up to three months to configure and then perform the analysis on the vendor servers. Results are returned to the Company during the third quarter. Those results are then reviewed in the Geospatial Information System, and other Company systems, and a thorough quality assurance review is performed by Company subject matter experts ("SMEs"). The risk model results are targeted for acceptance for use by the fourth quarter and then the TIMP work plan is adjusted based on findings from the model. The work plan is prioritized by compliance with federal regulation and by risk. The TIMP work planning engineers next selects an assessment methodology, which is the process or technology utilized to assess the threats on the segment. The federal code is prescriptive as to which methods can be utilized to assess each threat and options include Direct Assessment ("DA"), In-Line Inspections ("ILI"), and Pressure Testing. It is well known in the industry that some methodologies provide greater risk reduction than others. ILI is generally regarded as the most effective

method of assessing threats on a pipe asset. The Company utilizes ILI where feasible and supplements with DA where a segment is not ILI capable. Hydrostatic Pressure Testing is not typically utilized by the Company because it creates environmentally hazardous waste to dispose of, is very costly, and provides no information about the defects present on the segment.

Upon completion of the inspection, an assessment of the results is performed and dig locations are selected. The remediation team uncovers the pipe segment and performs a field inspection of the defect, and a decision is made as to the best option for remediation. Options include a cut-out, a mechanical sleeve, or a recoat and return to service. Customer impact, system resilience, reassessment intervals/methodology, permanent verses temporary repair, and cost are considered when determining which mitigation to implement. This occurs in the summer and fall of the year.

Results from the inspection, assessment, and remediation are gathered and prepared for the ETL process for the next risk model run in the last quarter of the year. The modeling process is performed, and when results are returned, the Company can analyze the actual reduction in risk achieved based on the actions performed. Part of the TIMP requirements is to ensure that the work performed is effectively lowering the risk for each segment. Pipe assets which continue with favorable risk trending support that the TIMP work is effective for that asset. An asset with trending that is less favorable can then be investigated for other work such as retirement, replacement, pressure lowering, or other operational changes. Design options for these projects consider cost, effectiveness, deliverability, system resilience, and customer impact.

The probabilistic risk model is designed to calculate current state risk. To calculate mitigation effectiveness, the model requires the data collected post project to perform the analysis. This data is not available during the design phase so the model cannot calculate a mitigation effectiveness value. This is not unique to the model used by the Company. What some models use for an effectiveness value is industry averages. These values are not accurate for analysis on individual assets which leads to over or understating of mitigation effectiveness. The Company uses the model to understand the risk and threats to an asset and then selects the methodology to mitigate that threat based on industry knowledge, cost, system reliability, and customer impact.

Q. Does the Company compare risk results to understand the impact of work performed?

A. Yes, it does. The Company compares previous year risk results to current year risk results to understand the full impact of work performed in the previous year. Multiple years of risk cannot be compared at this point because of the migration from a relative to a new probabilistic risk model. Comparing long-term risk results for overall reduction values is not appropriate with integrity related asset models because the threats in the model are time dependent. Upon the completion of a project and the data being loaded into the model from that point forward the risk due to time dependent threats increases until another mitigation is performed. This aligns with federal regulation requiring the assessment of these assets on a prescriptive interval.

Q. Beginning on page 28, line 9, through page 29, line 2 of her direct testimony, MEC witness deLeon discusses the definition of cost-effectiveness in relation to safety related programs. Do you agree with her analysis?

A. No, I do not. Cost-effectiveness and risk reduction are just two of several factors that need to be considered when evaluating various mitigative measures. Additional items like customer impact, system resilience, reassessment intervals/methodology, and permanent verses temporary repair all need to be considered when determining which mitigation to implement.

Q. Does the Company undertake efforts to ensure its project spending is reasonable?

A. Yes, it does. In the Pipeline Integrity Program, which is primarily O&M expense, the Company competitively bids materials, sets up multi-year fixed rate contracts to ensure lower costs, and utilizes one contractor for multiple projects in order to lower mobilization/demobilization costs. Additionally, for capital projects being conducted for other purposes outside of the federally mandated Pipeline Integrity Program, (i.e., for customer requested work and to ensure reliability and deliverability), the Company also competitively bids materials and contractors and has a system planning group that aligns projects within common time frames to limit outages, blowdowns, and methane emissions.

Q. At page 29 of her direct testimony, Dr. deLeon proposes how a utility could calculate the cost-effectiveness of various safety investments. Is this an effective way to calculate cost-effectiveness?

A. No, not for the Company, nor the models the Company is familiar with. What some models use for an effectiveness value is industry averages. These values are not accurate for analysis on individual assets which leads to over or understating of mitigation

effectiveness. The Company's model is used to understand the risk and threats to an asset and then selects the methodology to mitigate that threat based on industry knowledge, cost, system reliability, and customer impact. For Pipeline Integrity inspections, the Company has a seven-year mandated inspection cycle, so even in the case of a low risk scored project, the Company must perform the work to comply with regulations.

Q. Could cost-effectiveness be included in the Company's probabilistic risk model in the manner suggested by MEC witness deLeon?

A. It could not. The risk model is intended to provide insight into threats on the system and is not intended to be a financial evaluation tool. Further, it is neither prudent nor practical for the reasons stated above.

Q. Does the Company agree with Dr. deLeon, on page 30 of her direct testimony, that the value in risk modeling is to "allow stakeholders to examine the level of risk reduction expected from Consumers' proposed remediations, the cost to achieve this, and an ability to assess alternatives that could better maximize risk reduction and minimize costs."?

A No, it does not. The Transmission Probabilistic Risk Model was developed with the purpose of calculating the total risk of an asset, the threats listed in ASME B31.8S which are driving that risk, and the consequence of a failure (nine different failure modes) at any location along those pipe assets. The model can help provide insight into the threats on segments as a tool to validate the correct inspection methods and mitigative measures are part of the mandated pipeline assessments. This tool was not intended to be a financial tool used to evaluate project selection and does not have the capabilities or the years of historical data to do so with meaningful results. The risk model is an important tool used

to ensure we take the appropriate actions from a pipeline integrity perspective to provide safe and reliable gas service.

Q. On page 30, line 15 of her direct testimony, MEC witness deLeon discusses the relationship between risk modeling, cost effectiveness, and the energy transition. Considering the "energy transition," she argues that the Company should minimize spending on irreversible and long-lived investments. Does the Company agree with these ideas?

A. No, it does not. Please see the rebuttal testimony of Company witness Neal P. Dreisig, describing how the Company's gas system infrastructure is becoming more critical.

Q. Beginning at page 31, line 16, of her direct testimony, MEC witness deLeon provides examples of how utilities use risk modeling and cost-effectiveness in their decision-making. Are these examples relevant to this case?

A. No, they are not. As described in Dr. deLeon's testimony concerning Washington Gas, the ranking is *a basic prioritization* and then may *be modified* with SME input based upon various factors. Further, Washington Gas only utilizes their model on distribution assets and primarily for that utility's distribution main replacement program, which is vastly different from utilization of the probabilistic risk model on transmission assets as done by Consumers Energy. As I have previously stated, the probabilistic risk model used by the Company indicates the threat, consequence, and risk of the asset allowing companies to prioritize the integrity projects. Cost-effectiveness and Risk Spend Efficiency ("RSE") would be calculated outside the model. It is worth noting that enhanced risk modeling, integrity measures, and stricter enforcement of pipeline regulations were a result of

incidents like that at San Bruno. Cost-effectiveness is not a part of the Pipeline and Hazardous Materials Safety Administration's recommendation around risk modeling.

Q. Do these examples demonstrate that risk modeling and cost-effectiveness should be adopted in the manner proposed by Dr. deLeon?

A. No, they do not. I have described the purpose and limitations of probabilistic risk models. There are other limitations with risk modeling. This was acknowledged in a presentation concerning risk modeling for utility investments by Synapse Energy.[1] These include the need for a history of data collection (which the Company does not currently possess), the sharing of confidential and critical information, the fact that they do not directly address affordability, and that they do not address what is an acceptable level of risk. In the Company's case, given the recent and emerging implementation of probabilistic risk models, there is not any significant history. Further, there is an inherent vulnerability and security risk with providing this type of information in the public domain. Not to mention the financial and reputational liability the Company could face were it not to address a known threat for financial reasons.

Q. Beginning on page 34, lines 6 through 16 of her direct testimony, MEC witness deLeon discusses her understanding of` relative risk models compared to probabilistic models. Do you agree with her assessment?

A. No. The definitions used by Dr. deLeon are blending multiple types of models together as opposed to properly describing each type of model. The first definition concerning a relative model is not accurate. The description given is that of a qualitative model which

[1] https://www.nasuca.org/wp-content/uploads/2023/03/Risk-Presentation_Eric Borden_Synapse_NASUCA_6.18.23.pdf

does not calculate a numerical score for likelihood, consequence, or risk. A relative model can be qualitative, semi-quantitative, or quantitative. The defining characteristic of a relative model is that the failure calculation is a likelihood and not a probability. The relative model can use these numerical scores to compare one asset within the model to another or to the system as a whole which is a relative comparison. A probabilistic model calculates a probability of failure based on the confidence of the data provided. This probability is independent of anything else within that model and does not rely on being compared to other assets to determine the severity of the threat or the resulting risk. Neither of these models inherently calculates mitigation effectiveness values but instead are run with new data to calculate a new risk score after project completion. Models that do calculate mitigation effectiveness do so using industry averages that make individual asset evaluation for risk mitigation and cost benefit unreliable.

Q. Beginning on page 40, lines 5 through 8 of her direct testimony, MEC witness deLeon recommends that the Company report on a regular basis transmission-level projects that demonstrate how Consumers Energy utilizes cost-effectiveness, where applicable, to maximize safety impacts for the ratepayer dollars spent. Calculations and assumptions should be available to stakeholders upon request. Do you agree with this recommendation?

A. No, I do not. I have explained above how the Company uses the probabilistic risk model and how the other projects in the transmission programs are selected. The Company has provided an explanation as to why it is not practical to provide the results of the relative risk model along with other information pertaining to the model to MEC in discovery

requests that are included in Exhibit A-157 (BMS-1). The Company offered MEC an opportunity to review the Company's models. They did not respond to this offer.

Q. On page 41, lines 1 and 2, MEC witness deLeon recommended that the Company's future rate case applications should utilize probabilistic risk modeling and cost-effectiveness calculations to a much greater extent for all asset classes. Is this possible?

A. No, it is not. As acknowledged by Dr. deLeon, the Company is in the process of rolling out probabilistic risk modeling for the different asset classes. Developing the models is a tremendous undertaking and the Company will in all likelihood not have probabilistic models for all asset classes prior to its next rate case. The Company is developing a model for storage wells which it expects to begin utilizing in 2025 and the Company expects to develop a probabilistic distribution asset risk model by 2027. However, as I have explained the problems with cost-effectiveness calculations and further, these models are not developed with cost-effectiveness capabilities.

Q. Beginning on page 41, lines 1 through 21 of her direct testimony, MEC witness deLeon makes recommendations concerning future rate case applications. Do you agree with this recommendation?

A. No, I do not. As I have explained above, the Company will not have probabilistic risk models on all assets prior to its next rate case filing. Further Dr. deLeon's recommendation that the Company calculate the risk reduction, cost, and RSE for all of its expenditures is not possible for the reasons I have stated above. The Company has and will continue to provide robust rate case filings that comply with all MPSC filing requirements, which do not include the proposals made by MEC. Dr. deLeon's recommendations are not possible

with the risk model currently in use and the results would not be obtainable. I have described above how the Company uses the current model. These recommendations would be unduly burdensome and unnecessary as the Company currently operates the system in a safe and effective manner taking into consideration safety and affordability.

Q. Beginning on page 41, line 13, MEC witness deLeon suggests the Commission should order the Company to provide an estimate of the impact prior year's expenditures have had to reduce risk on the system. Do you agree with this recommendation?

A. No, I do not. As I have explained above, the Company compares previous year risk results to current year risk results to understand the full impact of work performed in the previous year. Multiple years of risk cannot be compared at this point because of the migration from a relative to a new probabilistic risk model. Comparing long-term risk results for overall reduction values is not appropriate with integrity related asset models because the threats in the model are time dependent. Upon the completion of a project and the data being loaded into the model from that point forward the risk due to time dependent threats increases until another mitigation is performed.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

EXHIBIT

OF

BRIAN M. SNYDER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Question:

75. Witness Griffin testimony at page 14 states "The Company is updating its risk ranking methodology and transitioning its current relative risk model into a probabilistic risk model to ensure investments are concentrated on the right assets." Regarding the most current version of the inputs and results of the probabilistic risk model used by Consumers to develop its testimony:
a. Is this risk model used only to assess risk of Consumers' transmission pipe?
i. If yes, why doesn't Consumers have a similar risk model for the distribution system or specific assets (e.g. regulators)? Please explain.
b. Please provide an explanation of how the probabilistic model estimates risk including but not limited to the likelihood of failure, consequence of failure, and mitigation effectiveness.
i. Please provide all documents and presentations that explain how the risk model derives key inputs, assumptions, and results (e.g. likelihood/probability, consequence/impact, and total risk score).
ii. Please explain what level of granularity is assessed by this risk model. For example, how does Consumers' determine the number of miles of each pipeline or pipeline segment on which it assesses the probability and consequence of failure? Please explain.
iii. Please provide mitigation effectiveness descriptions and calculations specific to the activities discussed in Witness Griffin's testimony.
c. In Excel with supporting data, calculations, and assumptions, please provide the annual risk reduction (in percentage and risk units) accomplished by safety-related activities from 2018-2024. Please provide separately for the transmission system, distribution system, and asset-specific risk models.
i. Please provide a general explanation of how risk reduction was calculated.
ii. Please explain how prior year risk reduction informs Consumers investment and mitigation plan for 2026.
d. In Excel with supporting data, calculations, and assumptions, please provide the forecast annual risk reduction expected to be accomplished by safety-related activities in 2025 and 2026. Please provide separately for the transmission system, distribution system, and asset-specific risk models, which may or may not be supported by Witness Griffin.
e. In Excel with supporting data, calculations, and assumptions, please provide the forecast annual risk reduction expected to be accomplished by safety-related activities from 2027-2035. Please provide separately for the transmission system, distribution system, and asset-specific risk models, which may or may not be supported by Witness Griffin.
f. In Excel, please provide all primary data, assumptions, inputs, and results of the probabilistic risk model for all transmission pipeline segments with working formulas where applicable, including but not limited to the following information. Each row should contain information for one transmission pipeline segment, with corresponding columns containing the following information:
i. Pipeline segment ID.
ii. Miles of pipeline segment.
iii. Likelihood of failure (including supporting data and calculations in separate tabs).
iv. Consequence of Failure (including supporting data and calculations in separate tabs).
v. Total risk score of the pipeline segment.
vi. Mitigation proposed (if any) in 2025, 2026, 2027, 2028, and/or 2029 (e.g. asset relocation).
vii. Mitigation effectiveness of the proposed mitigation(s).
viii. Total risk reduction from the proposed mitigation(s).
ix. Total estimated cost of the proposed mitigation(s).

g. In Excel, please provide the data provided in part (f) for all other risk models (distribution system, asset-based risk models, etc.).
i. Please explain whether the risk scores of these models can be directly compared.
ii. If not, please explain why the model has correctly calculated a risk score.
h. Please demonstrate and explain how the risk model provided above utilized the probabilistic risk model to determine what pipeline to remediate in 2025 and 2026, respectively.
i. Does Consumers seek to prioritize the highest risk assets first?
1. Where it has not, why is this the case?
ii. Please describe any practical or logistical challenges in mitigating other pipe segments than the ones indicated in the response above.

Response:

a. Currently only the Transmission and Transmission Operated by Distribution ("TOD") pipe are included in the probabilistic risk model. A model for Storage Wells is scheduled for use in 2025 and a distribution model is under development and is scheduled for use in 2027. These assets currently utilize a relative risk model.
b. The risk model uses collected data from the Company as well as industry established equations for calculating the magnitude of threats on the pipeline assets. The model the uses Bayesian Statics to calculate a failure rate per unit of length and year. This provides a probability of failure projected out ten years from the date of the model run. The consequence of failure is calculated using building and population data around the assets along with federal insurance equations for consequence. Risk is these two values multiplied. The risk is analyzed across 28 different threats and 9 different modes of failure. The risk models don't currently calculate mitigation effectiveness.
    i. ii. The risk model is run on the entire transmission system annually for the likelihood of failure and consequence of failure. The inspections scheduled are determined by federal regulatory requirements and prioritized by the model results.
    iii. Post assessment analysis by inline inspection and direct assessment analysts determines the effectiveness of the mitigation. This data is then an input to the risk model to inform the model of the overall asset health to provide a future risk profile for the system by asset.
c. This model is not used on the other assets so it is not possible to compare with distribution and other asset groups.
    i. The Company utilizes likelihood of failure thresholds and overall risk to prioritize work. The inputs and results are too large to utilize or view in Excel. CE uses graphical visualization software to monitor risk. Inputs are updated to include new data from projects which impacts the overall risk results. Changes in risk can be seen in the visualization. The threats are time dependent, so these results constantly change. The data visualization allows CE engineers to track the overall risk of each asset.
    ii. Post assessment analysis by inline inspection and direct assessment analysts determines the effectiveness of the mitigation. This data is then an input to

the risk model to inform the model of the overall asset health to provide a future looking risk profile.

d. The risk model currently cannot forecast mitigation due to work performed. Pipeline inspections are required by federal regulation so the work must be completed regardless of the risk mitigation.
e. The risk model currently cannot forecast mitigation due to work performed. Pipeline inspections are required by federal regulation so the work must be completed regardless of the risk mitigation.
f. The confidential attachment U21806-MNSC-CE-0080-CONF_ATT_1 provides the primary data inputs including current risk results that are currently in the model. The consequence of failure can only be viewed within the model and cannot be exported to excel. The model doesn't recommend mitigation measures. The Company selects the mitigation method depending upon the threats.
g. Currently only the Transmission and TOD pipe are included in the probabilistic risk model. The other asset classes are relative risk models.
    i. As these are different types of risk models, they cannot be compared. The assets are prioritized within each asset classification.
    ii. The risk model calculates the best risk score based on inputs and information provided. It is a tool used to prioritize work and requires consistent tuning and updating.
h. The model does not determine remediation but informs the Company on which segments to inspect. The results of the inspection will determine if or where remediation is required on that asset. The is model is only one factor in determining which segments require assessment. Federal regulation is the first guideline utilized. The risk model ensures that they are prioritized correctly and that the correct threats are being assessed.
    i. Yes. The Company's baseline assessment plan was developed in conformance with PHMSA requirements which required ranking from highest to lowest risk
    ii. The Company has inspected most of the gas transmission system. This is a cyclic work; segments are reassessed based on federal regulatory requirements and escalating risk in the risk model. The Company uses competitive bidding to manage project costs.

Witness: MICHAEL P. GRIFFIN

Date: February 3, 2025

U21806-MNSC-CE-0281
Page **1** of **1**

Question:

1. Witness Griffin's response to U21806-CE-0080 (question 75) part (a), states "A model for Storage Wells is scheduled for use in 2025 and a distribution model is under development and is scheduled for use in 2027. These assets currently utilize a relative risk model."

a. Please define "scheduled for use" – how will these models be used?

b. Please provide explanations and supporting documentation for information contained in the "relative risk models" in use for storage wells and distribution assets.

c. Please describe in detail how Consumers utilizes the relative risk models for distribution assets and storage wells.

d. Please provide all results of the relative risk models in Excel, including pipe segment ID, risk rank, total risk score, and other major outputs. Please include all supporting data and calculations, with assumptions and inputs clearly documented and formulas intact (if applicable).

   i. Please add a column for the assets targeted in 2024-2025 for remediation, and the forecast or actual cost of this work for each pipeline segment.

Response:

a. Scheduled for use is the "go live" date for these models transition from the current risk models to the new probabilistic models. These models are still in development with the vendor. These models will be used to identify threats, risk, and prioritize work plans for storage wells and the gas distribution system.

b. Relative Risk Model is a modeling type which uses industry trends to calculate risk on an asset. The scores are unitless numbers which are used to compare assets within the model. These models use similar data as a probabilistic model but usually require less information and is a less detailed analysis.

c. The relative risk models calculate risk scores to compare assets within the model. The distribution model compares grids of distribution pipe and the storage model compares storage wells. It allows a risk-based prioritization for work planning.

d. The comprehensive information request cannot be adequately shared in the format requested. The Company is willing to schedule a meeting and review the information at one of Consumers Energy's office locations.

   i. The risk model will indicate the riskiest segments and assets which could lead to projects in the future but does not categorize projects and the costs of prospective projects.

Witness: MICHAEL P. GRIFFIN
Date: March 10, 2025

U21806-MNSC-CE-0282
Page **1** of **1**

Question:

2. Regarding Witness Griffin's response to U21806-CE-0080 (question 75) part (b) states "the risk models don't currently calculate mitigation effectiveness." Consumers also did not provide any mitigation effectiveness information in part (f) of this question. Please provide mitigation effectiveness (percent risk reduction) estimates or calculations in Consumers possession for each type of mitigation in Witness Griffin's testimony, at minimum for replacement, repair, and asset relocation. This may include historical estimates of mitigation effectiveness or any other applicable data. Please provide in Excel with supporting calculations and workpapers if applicable, with assumptions and inputs clearly documented and formulas intact (if applicable).

Response:

The risk model is used to identify risk and threats to our pipe segments. It is an aid in project selection and prioritization. The risk models do not calculate a mitigation effectiveness. The results from the inline inspection and post inspection remediation work determines the overall health of that pipe segment and ensures it can operate safely until it is scheduled for reassessment.

The Company focuses on analyzing the health of an asset instead of the mitigation effectiveness. Knowing that the asset is safe for operation is the primary driver for the integrity actions taken on an asset. The risk model calculation will show that the overall risk of that asset due to threats has lowered due to the work performed. Some threats to a gas asset are time dependent so that asset is continuously monitored for risk and assessment compliance dates to ensure safe operation.

Witness: MICHAEL P. GRIFFIN
Date: March 10, 2025

U21806-MNSC-CE-0283
Page **1** of **1**

Question:

3. Witness Griffin's Direct Testimony at page 11 states "Federal Regulation, 49 CFR Part 192, Subpart O, specifies how pipeline operators must identify, prioritize, assess, evaluate, repair, and validate the integrity of natural gas transmission pipelines that could, in the event of a leak or failure, affect High Consequence Areas ("HCA")."

a. Does Consumers apply the requirements from 49 CFR part 192 to non-HCA pipelines? Please explain.

b. What PHMSA regulations are applicable to non-HCA pipelines? Please list and explain.

c. Please explain whether Consumers has discretion of when, whether, and how to remediate non-HCA pipelines according to federal regulations.

d. Please explain whether Consumers has discretion of when, whether and how to remediate HCA pipelines according to federal regulations.

Response:

a. Yes, the Company follows the requirements in 49 CFR 192 for segments non-HCA.

b. Regulations contained within 49 CFR 192 outline requirements to design, construct, operate, test, inspect, and maintain pipe segments in HCA and non-HCA areas. Subpart O outlines requirements for an integrity program within HCA segments. One example of additional requirements is to perform inspections on pipe segments considered "Outside of HCA" in 49 CFR 192.710. The segments in the work plan contain a mix of HCA, 49 CFR 192.710 miles, and non-covered pipe. The Company applies the appropriate regulations to the pipe segment to ensure safe operation.

c. The Company must remediate all "HCA" and "Outside of HCA" covered pipe segments per regulation. The Company performs remediation on all non-covered pipelines to ensure safe operation. This work is typically performed within a single outage to optimize efficiency. The Company performs remediation in accordance with 49 CFR 192.933 and 49 CFR 192.714.

d. See response to Part c.

Witness: MICHAEL P. GRIFFIN
Date: March 10, 2025

U21806-MNSC-CE-0284
Page **1** of **3**

Question:

4. Regarding Witness Griffin's response to U21806-CE-0080 (question 75), attachment U21806-MNSC-CE-0080-CONF_ATT_1.

a. Please provide a definition and description of each column header other than column A. This should include, for applicable column headers, how the values are calculated and what units they are in.

b. Please explain why some high-risk pipeline segments are not in an HCA. For example, the first segment, 2800-1, is not in an HCA. Why is this segment so high risk?

c. It appears there is a calculation of residual risk in column K. Does this indicate the amount of risk remaining after a mitigation? If yes, how was the mitigation determined? If not, how is this defined?

d. In Excel, please add the following information to this attachment in separate columns for each pipeline segment where there is forecast work:

   i. Pipeline program where the cost is included (e.g. TIMP, Pipeline Integrity, Capacity/Deliverability etc.);

   ii. Mitigation proposed or forecast (e.g. repair (please specify), replacement, etc.);

   iii. Cost (Estimated or actual).

e. Please explain why Consumers forecasts remediation of pipelines with near-zero risk, such as row 234,131, and some of the least risky pipeline segments above this last pipeline segment row.

f. Please explain whether Consumers prioritizes transmission and TOD segments for inspection (and/or remediation) by total risk or risk per mile. Please explain this choice and provide supporting documentation.

Response:

a. Name: Pipe segment designation
HCA: 0=No, 1=Yes
FromMeasureFT: odometer reading down the pipe where that data set starts. Measured in Feet
ToMeasureFT: odometer reading down the pipe where that data set ends. Measured in Feet
Length_Ft: The physical length of the data set (to – from) measured in feet
Length_miles: The physical length of the data set (to – from) measured in miles
FromForecastYear: The start of the time period of that risk score (Sets the integral time period for the risk analysis. This is a Bayesian statics model)
ToForecastYear: The start of the time period of that risk score (Sets the integral time period for the risk analysis. This is a Bayesian statics model)

RiskTotal_RU_YR: the total risk score for this year. The model calculates a probability and a consequence per threat. That is the risk per threat and then each risk per threat is aggregated into a total risk. This is a unitless score.
RiskTotal_Ru_yr_Actionable: Risk due to threats which can be mitigated via inspection and remediation or an engineering in-ditch replacement project. This is a unitless score.
RiskTotal_Ru_yr_Residual: Risk due to threats which cannot be mitigated. These are environmental risks which cannot be lowered with an inspection, remediation or in-ditch replacement. This is a unitless score.
Risk___External_Corrosion__Ru_yr: Risk value for external corrosion. This is a unitless score.
Risk___Internal_Corrosion__Ru_yr_: Risk value for internal corrosion. This is a unitless score.
Risk___Stress_Corrosion_Cracking__Ru_yr_: Risk value for Stress Corrosion Cracking. This is a unitless score.
Risk___Manufacturing_Defects__Ru_yr_: Risk value for manufacturing defects. This is a unitless score.
Risk___Construction_Defects__Ru_yr_: Risk value for construction defects. This is a unitless score.
Risk___Third_Party___Mechanical_Damage__Ru_yr_: Risk value for third party damage. This is a unitless score.
Risk___Equipment_Failure__Ru_yr_: Risk value for equipment failure. This is a unitless score.
Risk___Incorrect_Operations_Procedure__Ru_yr_: Risk value for incorrect operations. This is a unitless score.
Risk___Weather_Related_and_Outside_Force__Ru_yr_: Risk value for weather related and outside forces. This is a unitless score.

b. Total Risk = Probability of Failure x Consequence of Failure. Some segments have risk driven by probability and other segments by consequence. HCA could indicate a higher consequence of failure but has no impact on the probability of a failure. The first row, 2800-1, the elevated risk score is driven by probability of failure due to threats present and not consequence.

c. The probabilistic models do not calculate a mitigation effectiveness, and this is not a mitigation calculation. The residual risk in column K is calculated by combining the threats: 3rd Party Damage, Weather and Outside Force, and Incorrect Operations. These threats are managed with operational preventative measures.

d. The information from the risk results cannot be organized into the categories suggested in this interrogatory. The risk model analyzes segments of pipelines though dynamic segmentation, so when there is any change in a data property the risk model will perform segmentation for all the data points provided on a given line segment. Thus, the risk model will indicate the riskiest segments which could lead to projects, primarily in Pipeline Integrity or Asset Relocation in the future but does not categorize projects and costs such that they would translate to the capital projects and programs. Further, besides not indicating specific projects, the model does not calculate the cost of prospective projects.

e. This row is a piece of Dx1087b pipe segment. In this pipe system there are areas which are HCA which requires assessment and those of higher risk score. The model calculates risk scores on the entire transmission system. A row of data does not indicate work or remediation is being performed at that location.

f. The Company prioritizes segments for planning based upon total risk. Risk per mile will over-inflate the prioritization of smaller assets and skew the modeling results. That value is used for generalized mapping and not for work planning. Inspection Segments are ranked by total risk. The threats contributing to the risk score are evaluated to determine the type of inspection and the technology selected to inspect that asset. Additionally federal regulation provides requirements for the timing and methodology of these assessments.

Witness: MICHAEL P. GRIFFIN
Date: March 10, 2025

U21806-MNSC-CE-0285
Page **1** of **1**

Question:

5. Regarding Witness Griffin's response to U21806-CE-0081(question 76):

a. Please explain why Consumers does not consider cost-effectiveness or RSE metrics to evaluate different mitigations for transmission or TOD projects.

b. Please explain why Consumers does not consider cost-effectiveness or RSE metrics to evaluate different mitigations for distribution projects.

c. Please explain whether Consumers believes cost-effectiveness is a relevant criterion for choosing what mitigation to deploy for pipeline remediation, including why or why not.

Response:

a. The Company's current processes prudently address system risk in a cost-effective manner. The probabilistic model is designed to inform the operator of the overall risk of an asset and the threats that are present on that asset. This allows for the selection of the proper method and technology to assess those threats. The results from the inspection and post inspection remediation work determines the overall health of that pipe segment and ensures it can operate safely until it is scheduled for reassessment. The risk model is used to identify risk and threats to our pipe segments. It is an aid in project selection and prioritization. Cost effectiveness is factored into the remediation methodology selected for each individual project as well as complying with all applicable regulations and industry standards.

b. The Company's current processes prudently address system risk in a cost-effective manner. The distribution relative model is designed to inform the operator of the overall risk of the asset and the threats that are present on that asset. This allows for the selection of grid-based projects to address those threats. The risk model is used to identify risk and threats to our pipe segments. It is an aid in project selection and prioritization. Cost effectiveness is factored into the remediation methodology selected for each individual project as well as complying with all applicable regulations and industry standards.

c. The Company inspects the pipe anomalies found during the inspection process. There are multiple permanent repair options available. The Company selects the most appropriate method of remediation based on multiple considerations (i.e. cost effectiveness, operational considerations, system demand, and environmental constraints).

Witness: MICHAEL P. GRIFFIN
Date: March 10, 2025

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

REBUTTAL TESTIMONY

OF

LINCOLN D. WARRINER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2025

Q. Please state your name and business address.

A. My name is Lincoln D. Warriner, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. Are you the same Lincoln D. Warriner who previously submitted direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to formally accept certain capital expenditure adjustments recommended by Attorney General witness Sebastian Coppola related to New Business and Asset Relocation capital expenditures, and to rebut certain assertions and recommendations made by the following witnesses regarding Consumers Energy Company's ("Consumers Energy" or the "Company") gas distribution capital investments:

a. Michigan Environmental Council and Sierra Club ("MEC") witness Alice Napoleon's proposed disallowance of projected New Business program capital expenditures and various recommendations regarding the Company's Energy Waste Reduction ("EWR") programs, line extension policies, and new connection forecasts;

b. Citizens Utility Board of Michigan ("CUB") witness Ram Veerapaneni's proposed disallowance of projected test year capital expenditures for the Company's distribution system capital expenditures related to New Business, Asset Relocation, Regulatory Compliance, and Capacity/Deliverability program capital expenditures;

c. MEC witness Sol deLeon's proposal to limit projected capital expenditures to 2024 levels;

d. Association of Businesses Advocating Tariff Equity ("ABATE") witness Colin T. Fitzhenry's proposal to disallow $15.8 million of 2023 capital expenditures for Asset Relocation – Civic Improvement projects; and

e. Attorney General witness Coppola's proposed disallowance of distribution system capital expenditures related to Large New Business projects, and Regulatory Compliance project capital expenditures.

Q. Are you sponsoring any exhibits in connection with your rebuttal testimony?

A. No, I do not have any exhibits in connection with this rebuttal testimony.

Q. Please summarize the proposed adjustments in capital expenditures that you are accepting on behalf of the Company?

A. I am accepting capital expenditure adjustments totaling approximately $46 million in the Company's New Business and Asset Relocation programs. The amounts that I am accepting by sub-program are detailed in Table 1 below:

Table 1: Gas Distribution Programs and Sub-Programs: Accepted Capital Expenditure Adjustments

Line No.		2024 Adjustment	1/1/25-10/31/25 Adjustment	Test Year Adjustment	Total Adjustment
	New Business				
1	Mains Services & Meter Stands - Dist	(3,067,000)	(5,714,000)	(8,018,000)	(16,799,000)
2	Large New Business Projects - Dist	(1,948,000)	(685,000)	(4,819,000)	(7,452,000)
3	Customer Attachment Program - Dist				
4	**Total New Business**	**(5,015,000)**	**(6,399,000)**	**(12,837,000)**	**(24,251,000)**
	Asset Relocation				
5	Asset Relocation - Civic Improvement		(9,408,000)	(9,913,000)	(19,321,000)
6	Asset Relocation - Reimbursable		(203,000)	(1,919,000)	(2,122,000)
7	**Total Asset Relocation**	-	(9,611,000)	(11,832,000)	(21,443,000)
8	**Total Capital Expenditure Adjustments**	**(5,015,000)**	**(16,010,000)**	**(24,669,000)**	**(45,694,000)**

I. MICHIGAN ENVIRONMENTAL COUNCIL AND SIERRA CLUB WITNESS NAPOLEON

Q. On page 11, line 6 of her direct testimony, Ms. Napoleon indicates that it is puzzling that the Michigan decarbonization study does not include demand-side measures such as demand response to reduce emissions. Can you explain the reasons for the Company not planning for demand response programs at this time?

A. Yes, the Company conducted demand response program pilots during the 2020/2021 and 2021/2022 winter seasons. The results of the Company's pilots indicate that a full-scale customer program for natural gas demand response would not provide enough benefits to be cost effective. The results of the Company's natural gas demand response pilots are

documented in evaluation reports, specifically (1) the Smart Thermostat Winter Pilot Program Evaluation Report, 2021 Program Year, dated August 27, 2021, and (2) the Smart Thermostat Winter Pilot Program Evaluation Report, 2022 Program Year, dated October 5, 2022.

Q. On page 34, lines 2-3 of her direct testimony, Ms. Napoleon's testimony indicates that the Company's forecast of new customer connections contradicts the historical trend of customer connections. Is this an accurate assessment of the Company's service installation forecast?

A. No, there is no contradiction between the Company's service installation forecast and the historical trend. Ms. Napoleon's analysis of the historical trend is inaccurate because she did not account for Customer Attachment Program service connections that were installed by the Company in 2014. During 2014, the Company was actively marketing natural gas service to households using propane for space heating. 3,028 services were installed in 2014 for these propane conversions. Reducing the 2014 historical installations for these propane conversions results in a comparable service installation count of 8,515 service installations in 2014. Compared to the 2023 actual service installation count of 6,870 units, the actual annual average decline in service installations from 2014 to 2023 is 183 services per year. Over this period, the construction of new homes in Michigan has not kept pace with demand, resulting in shortages of available and affordable housing options. The Company's projection starts with the 2023 actual value of 6,870 units and grows to 7,800 units. Over the course of 10 years (2024-2033), the Company's projected growth in service installations ranges from -70 installations to +200 installations and averages out to a growth rate of 93 service installations per year. It is reasonable to anticipate modest long-term

growth in annual new service connections given the ongoing shortage of available and affordable housing units.

Q. On page 35, line 5 through page 37, line 5 of her direct testimony, Ms. Napoleon indicates that the Company's forecast of new customer connections does not reflect market trends or policies as reported by the U.S. Census Bureau's American Community Survey. Do you agree with Ms. Napoleon's analysis of the American Community Survey?

A. No. As I explain in detail below, the American Community Survey data does not logically support Ms. Napoleon's conclusions regarding electric space heating and gas space heating growth between 2014 and 2023.

Q. Please explain your analysis of the American Community Survey data.

A. The raw data reported for Michigan estimates of house heating fuel is displayed in Table 2 below. The data for house heating fuels are only estimated for occupied housing units. The American Community Survey does not provide house heating fuel estimates for vacant housing units.

Table 2: American Community Survey house heating fuel estimates for Michigan

	2023 Estimate	2014 Estimate	Change	Percent Change
Occupied Housing Units	**4,107,809**	**3,834,574**	**273,235**	**7%**
Utility Gas	3,039,167	2,942,704	96,463	3%
Bottled, tank, or LP gas	372,796	314,434	58,362	19%
Electricity	523,137	342,353	180,784	53%
Fuel oil, kerosene, etc.	32,099	47,572	-15,473	-33%
Coal or coke	1,733	1,408	325	23%
Wood	88,484	129,455	-40,971	-32%
Solar energy	1,302	906	396	44%
Other fuel	28,300	38,130	-9,830	-26%
No fuel used	20,791	17,612	3,179	18%

Q. Is the exclusion of vacant housing units significant in understanding the trends reported in Table 2?

A. Yes, I believe that it is significant for this analysis. The American Community Survey estimates that vacant housing units declined by 170,366 units, from 705,514 vacant units in 2014 to 535,148 vacant units in 2023. Given that occupied housing units increased by 273,235 units over that same time period, it is logical to conclude that a good portion of the increase in occupied housing units after 2014 were previously existing vacant units. Total housing units are estimated to have grown by 2%, but occupied housing units are estimated to have grown by 7% and vacant housing units are estimated to have declined by 24% as shown in Table 3.

Table 3: American Community Survey housing occupancy estimates for Michigan

	2023 Estimate	2014 Estimate	Change	Percent Change
Total Housing Units	**4,642,957**	**4,540,088**	**102,869**	**2%**
Occupied Housing Units	4,107,809	3,834,574	273,235	7%
Vacant Housing Units	535,148	705,514	-170,366	-24%

When viewed within the context of the American Community Survey housing occupancy estimates for Michigan (in Table 3), the following observations can be made regarding the house heating fuel estimates (in Table 2):

1. The increase in occupied houses heated by electricity of 180,784 units is very similar to the 170,366 reduction in vacant housing units, therefore I believe that a large portion of the increase in electrically heated occupied housing units were classified as existing vacant housing units in 2014. Other sources of increase in houses heated by electricity are likely wood, fuel oil/kerosene, and other fuel categories.

2. The increase in occupied housing units heated by utility gas of 96,463 units (in Table 2) is similar to the 102,869 increase in total housing units (in Table 3), therefore I believe that a very large portion of the total housing unit additions since 2014 are heated by utility gas.

Q. Have you reviewed any additional data when evaluating Ms. Napoleon's conclusion that the Company's forecast of new customer connections does not reflect market trends or policies?

A. Yes, I have reviewed MPSC Form P-522 Annual Reports available for each natural gas utility on the Michigan Public Service Commission's website to see if any growth or decline in natural gas residential customer counts is apparent from 2014 through 2023. The results of that review are summarized in Table 4 below:

Table 4: MPSC Form P-522 Average Number of Customers per Month for Michigan Natural Gas Utilities

	2023 Actual	2014 Actual	Change	Percent Change
Total Residential Customers	**3,302,335**	**2,984,296**	**318,039**	**11%**
Consumers Energy Company	1,683,982	1,595,561	88,421	6%
DTE Gas Company	1,148,660	964,491	184,169	19%
SEMCO Energy Gas Co	275,632	253,584	22,048	9%
Michigan Gas Utilities	152,191	131,736	20,455	16%
Seven Other Gas Utilities	41,870	38,924	2,946	8%

It is interesting that the growth of 318,039 Michigan gas utility residential customers exceeds the American Community Survey's estimates of both total housing unit growth

(102,869) and occupied housing unit growth (273,235) in Table 3. These reports further support the conclusion that a large portion of housing unit additions are heated by utility gas.

Q. What is your conclusion regarding the use of the American Community Survey data by Ms. Napoleon?

A. I have concluded that Ms. Napoleon's statement on page 36, line 7 through line 10, that "… the number of gas-heated homes increased by approximately 96,000, while electric-heated homes increased by about 180,000…" is based on an incomplete analysis of the American Community Survey data and does not accurately reflect actual trends in household selection of space heating fuels. It appears more logical to conclude that natural gas continues to be the preferred heating fuel for residential utility customers in Michigan.

Q. Does the American Community Survey provide any data that would be useful for the Commission to consider in determining whether the Company's tariff Rule C.8. "Customer Attachment Program" 20-year net present value calculation is unfair to existing natural gas customers as discussed by MEC witness Napoleon at pages 24 through 25 of her direct testimony?

A. Yes. The Census Bureau tracks an indicator named "Median Year Structure Built," and that indicator is available for the state of Michigan. The American Community Survey data indicates that the median year of structures built during the 2014 survey was the year 1969. This would mean that the approximate median age of Michigan housing structures in 2014 was about 45 years. The 2023 survey reported that the median year of structures built was 1972. Therefore, the approximate median age of Michigan housing structures in 2023 was about 51 years. Given that residential structures exceed a median age of 50 years,

and appear to be trending older over time, the use of 20-year revenue and cost projections in the net present value calculation does not seem to create a subsidy for new customer connections.

Q. Does Ms. Napoleon make any statements in the content of her testimony that contradict her criticism of the 20-year revenue and cost projections used in the net present value calculation that are used to determine new customer connection contributions?

A. Yes. On page 15, lines 6 through 9, her testimony states "Many gas appliances, and many of the gas energy efficiency measures incentivized by the EWR programs, have long useful lives. For example, a new natural gas furnace typically lasts 20 or more years. For some existing heating equipment such as boilers, the useful life is longer." This statement seems to support the C8. Customer Attachment Program assumption that new gas customers will remain customers on our system for more than 20 years.

Q. On page 5, lines 21 and 22 of her direct testimony, Ms. Napoleon recommends that the "Commission should order the Company to set the growth rate in new connections to zero…" Do you agree with that recommendation?

A. No, this request of the Commission is unusual and vague and should not be adopted for several reasons, including:

1. The Company's Customer Energy Management department provides the estimates for new service connections and manages the creation and completion of capital expenditure work orders to connect new customers. Within the Customer Energy Management department, staff members have regular interaction with builders in our service territory and are therefore the most logical source for projections related to the service connection workload for the Company.

2. The Company's forecast in this proceeding included projections of 6,800 units in 2024 and 2025, which reflect no growth between the two projected years, and are less than the 6,870 service installations installed during 2023.

3. The Company has evaluated recent trends within the New Business Mains, Services, and Meter Stands sub-program and has decided to adopt the recommendation of Attorney General witness Coppola, which projects 2025 and 2026 service installation volumes with no growth from 2024 actual.

4. The determination of longer-range forecasts as used within the Natural Gas Delivery Plan are reviewed by the Company periodically for changes in actual activity and future expectations and should remain the responsibility of the Company to monitor and adjust.

Q. What proposal has MEC witness Napoleon made regarding the Company's investments in New Business Mains, Services, and Meter Stands?

A. Ms. Napoleon has recommended New Business capital expenditures in the test year of $35.947 million dollars, which she claims includes a recommended customer contribution of 50% of total construction costs and the elimination of projected growth in service installations. Given that the Company is accepting a $12.837 million test year adjustment for New Business proposed by Attorney General witness Coppola, Ms. Napoleon is recommending an additional reduction in the test year of $17.861 million.

Q. What decision should the Commission make regarding MEC witness Napoleon's proposal to reduce the projected test year Gas Distribution capital expenditures?

A. I recommend that the Commission find that Ms. Napoleon's reduction is unreasonable given her unsupported claims that residential customers prefer electric heating options over natural gas. Her claim that existing natural gas customers are subsidizing new service connections should also be rejected as new buildings that connect to the Company's gas system will likely remain natural gas customers well beyond the 20-year projection embedded in the Company's Net Present Value model. Ms. Napoleon has not made any specific recommendation on what adjustments to the customer contribution calculation could actually achieve the 50% level of contribution she is seeking, so there is considerable doubt that her recommended outcome can actually be realized. Therefore, I recommend

that the Commission disregard Ms. Napoleon's recommendation to reduce capital expenditures by increasing customer contributions. The revised capital expenditure projections included in the rebuttal exhibits of Company witness Heather L. Rayl should be adopted.

II. CUB WITNESS VEERAPANENI

Q. Please summarize the overall reductions to the Company's projected capital expenditures that are proposed by CUB witness Veerapaneni.

A. CUB witness Veerapaneni presents one paragraph of testimony concerning the Gas Distribution New Business, Asset Relocation, Regulatory Compliance, and Capacity/Deliverability programs presented in my direct testimony and exhibits. He recommends that test year capital expenditures be set at the average of 2023 and 2024 actual capital investments and recommends a test year value of $206.716 million.

Q. How does the test year capital expenditure amount proposed by Mr. Veerapaneni compare to the test year capital expenditure supported by your testimony and exhibits in this proceeding?

A. The Company's original test year projection in this proceeding was $321.119 million, which I am revising to $296.450 million as part of my rebuttal testimony to reflect certain acceptable adjustments recommended by Attorney General witness Coppola. Mr. Veerapaneni's recommended test year value of $206.716 million is $89.734 million, or 30.3%, lower than the revised capital expenditure projection for the 12 months ending October 31, 2026.

Q. What is your response to the adjustment to the Company's projections that Mr. Veerapaneni has proposed in his direct testimony?

A. CUB's proposed methodology of projecting test year expenditures using two years of historical actual investments for Gas Distribution capital projects is unreasonable. Mr. Veerapaneni did not review the reasonableness of the individual Gas Distribution programs and projects proposed during the test year or the benefits that customers would experience from the Company's investment in those projects. For example, on page 9, starting on line 13, through page 10, line 2, my testimony identifies five specific projects that make up the difference between the projected test year and the 2023 historical year and 2019 to 2023 historical average Gas Distribution capital projects. Forecasted expenditures for the Company's Regulatory Compliance program are necessary to comply with recently adopted Pipeline and Hazardous Materials Safety Administration ("PHMSA") regulations regarding pipeline safety. My direct testimony explaining the planned Maximum Allowable Operating Pressure ("MAOP")-Distribution projects begins on page 46, line 17 and concludes on page 60, line 8, yet Mr. Veerapaneni claims I have provided no valid explanation for the increases in capital expenditures. Mr. Veerapaneni's testimony is contradictory because he claims on page 14, line 6 that these projects have no valid explanation, then states on page 14, line 7 that these projects are required to comply with federal and state pipeline safety regulations. He also claims that the Company is "long overdue" in compliance with these safety regulations. This claim specifically contradicts my testimony on page 47, lines 6 through 11, that identifies the specific compliance milestones required by 49 CFR 192.624. The Company is planning to comply with the required compliance milestones and is not overdue. The Company has an obligation to

operate its gas distribution system in a manner that complies with existing PHMSA gas safety regulations and the Company's customers also expect the gas distribution system to be operated in a manner that provides reliable service. As a result, the Company does not believe the recommended adjustment to the test year capital expenditures proposed by Mr. Veerapaneni is prudent.

Q. What decision should the Commission make regarding CUB witness Veerapaneni's proposal to reduce the projected test year Gas Distribution capital expenditures?

A. I recommend that the Commission include the Company's revised projected test year Gas Distribution capital investments when determining customer rates in this proceeding. The revised capital expenditure projections are included in the rebuttal exhibits of Company witness Rayl.

III. ABATE WITNESS FITZHENRY

Q. Please summarize the overall reductions to the Company's 2023 actual capital expenditures that are proposed by ABATE witness Fitzhenry.

A. ABATE witness Fitzhenry presents approximately three pages of testimony concerning the Asset Relocation – Civic Improvement projects completed during the calendar year 2023. He recommends that the Commission disallow $15.8 million of actual capital expenditures for the Mound Road project, the Atlas Iron Belle Trail Project, and the 9 Mile Road Eastpoint projects. These three projects are highlighted on page 29 of my direct testimony, as well as in Table 9, which appears on page 30 of my direct testimony. Mr. Fitzhenry's rationale for recommending this disallowance is that the Company disclosed a variance from the Company's 2023 budget, and he alludes that these variances are associated with poor project management and the Company was therefore imprudent in the execution of

projects. He indicates the variances could be due to reasons such as extended project duration, poor project planning, labor cost overruns, or project scope creep.

Q. On page 12, lines 5 through 16, Mr. Fitzhenry claims that the Company's response to requests for cost variance explanations during discovery is limited. Do you agree with that assessment of the response?

A. No, Mr. Fitzhenry's assessment of the response provided by the Company is not accurate. The Company's response as reflected on Exhibit AB-5, pages 6 and 7, begins with a quantification of budget program level actual and budget values, then provides additional detail on the variances for Asset Relocation – Civic Improvement and for the Enhanced Infrastructure Replacement Program. The cover sheet associated with those two pages of Exhibit AB-5, which was not included in Mr. Fitzhenry's exhibit, provided a link to the 2023 Gas Enhanced Infrastructure Replacement (EIRP) - Annual Performance Report. Attachment 9 of the 2023 EIRP Annual Performance Report details the work completed for 122 individual Asset Relocation – Civic Improvement projects. These details include the number of services replaced for each project and the footage of plastic main and footage of steel main installed.

Q. What is your response to Mr. Fitzhenry's claims that the cost variances are associated with poor project management, imprudent execution of projects, extended project duration, poor project planning, labor cost overruns, or project scope creep?

A. I do not believe those claims to be true. My understanding of the replacement of utility infrastructure associated with civic improvement projects is that these projects can be complex, involving the coordination of work scope and schedules with municipal project administrators and construction crews who may have project requirements that are specific

to their local community. The Company rarely has complete information to compile a detailed project estimate for civic improvement projects at the time our annual budget projections are developed. The large civic improvement project estimates used for our 2023 budget were not intended to be precise estimates that would allow for the specific quantification of the root cause of variances. Also, it should be noted that the Company's actual 2023 Civic Improvement expenditures of $83.5 million is only slightly higher than the 2019 to 2023 annual average capital expenditure of $81.6 million. This would be an indicator that the Company was reasonable and prudent in managing its investments in Civic Improvement projects during 2023.

Q. What decision should the Commission make regarding ABATE witness Fitzhenry's proposal to reduce the 2023 actual calendar year Asset Relocation – Civic Improvement capital expenditures?

A. I recommend that the Commission find that the Company's variances disclosed on page 6 of 12 in Exhibit AB-5 do not support a disallowance of the actual capital expenditures incurred during the historical year of 2023, and that those capital expenditures were prudently incurred.

IV. MEC WITNESS DELEON

Q. What capital expenditure recommendations are proposed by MEC witness deLeon?

A. On page 7, Ms. deLeon recommends that the Commission should cap additions to plant in service in the projected test year at 2024 investment levels.

Q. What is your assessment of Ms. deLeon's recommendation?

A. I am concerned that capping the additions to plant in service would severely restrict the Company's ability to comply with MAOP reconfirmation requirements as described on page 46, line 17 through page 60, line 8 of my direct testimony. The annual capital

additions for the MAOP program are provided on page 48 of my direct testimony in Table 17. The 2024 projected amount of $9.3 million is followed by projections of $69.1 million in 2025 and $127.9 million in 2026. The Company has an obligation to operate its gas distribution system in a manner that complies with existing PHMSA gas safety regulations and the Company's customers also expect the gas distribution system to be operated in a manner that provides reliable service. As a result, the Company does not believe the recommended cap to the test year capital expenditures proposed by Ms. deLeon is prudent.

IV. ATTORNEY GENERAL WITNESS COPPOLA

Q. What are the capital expenditure adjustments proposed by Mr. Coppola with respect to the Company's New Business program?

A. Mr. Coppola discusses the New Business capital expenditure program starting on page 19 and concluding on page 25 of his direct testimony. His discussion includes two sub-programs: (1) Mains, Services, and Meter Stands on page 19 through line 10 of page 23, and (2) Large New Business Projects starting on page 23, line 12 through the end of page 25.

For the Mains, Services, and Meter Stands sub-program, Mr. Coppola recommends that the Company's 2024 projection be reduced to match the actual capital expenditures incurred by the Company in 2024, and that the 2025 and 2026 capital expenditures projections be reduced so that the number of projected service installations are the same as what the Company installed in 2024.

For the Large New Business Projects sub-program, Mr. Coppola recommends that the Company's 2024 projection be reduced to match the actual capital expenditures incurred by the Company in 2024; that the 2025 capital expenditures be reduced for the

Lansing Board of Water & Light Delta Energy Park project and the industrial site redevelopment project in Flint; and that the 2026 capital expenditures be fully eliminated from the Company's projections.

Q. Do you agree with the New Business program adjustments proposed by Mr. Coppola?

A. I have reviewed Mr. Coppola's New Business capital expenditures program testimony and the supporting documentation provided in Exhibit AG-2. I did note what appears to be a typographical error on page 23, line 13 that states the Company projected $8.7 million for 2024 Large New Business Projects. Mr. Coppola identifies the correct amount of $9.7 million on page 25, line 7. Therefore, I think the $8.7 million amount on page 23 was a simple typographical error that had no impact on his analysis of the Company's projections. I have also reviewed additional external sources of current economic activity, including the NAHB/Wells Fargo Housing Market Index ("HMI") for April 2025, and have also discussed the adjustments proposed by Mr. Coppola with the Company's new business subject matter experts. The results of this analysis confirm that 2025 calendar year service connections are tracking closely with 2024 and there is no evident growth to support the Company's original projections for service connection volumes. I have also confirmed that the industrial site redevelopment project in Flint is currently on hold awaiting a decision from the customer that requested service on the Company's contract. Currently, the Company still anticipates the development of large projects in 2026 but does not have contracts with specific projects to support the projected capital expenditures for 2026. The only specific adjustment that the Company strongly disagrees with is the proposed adjustment related to the contract status of the Lansing Board of Water & Light Delta Energy Park project. Exhibit AG-2, page 6, indicates that contract signatures were in

progress at the time of my response to AG-CE-0346. Contract signatures were completed in mid-April and construction is expected to be completed by November 1, 2025. As a result, the only proposed adjustment that the Company is not including in the rebuttal exhibits of Company witness Rayl, and in Table 1 on page 3 of my rebuttal testimony, is the proposed adjustment for the Lansing Board of Water & Light Delta Energy Park project.

Q. What decision should the Commission make regarding Attorney General witness Coppola's proposal to reduce the 2024, 2025, and 2026 New Business program projections?

A. I recommend that the Commission accept Mr. Coppola's New Business program capital expenditure projection adjustments, except for the adjustment related to the Lansing Board of Water & Light Delta Energy Park project. The Company's revised projections for the New Business program are summarized as follows:

Mains, Services, and Meter Stands – Distribution
1. 12 Months Ending 12/31/2024: $52.271 million (a reduction of $3.067 million)
2. 10 Months Ending 10/31/2025: $43.882 million (a reduction of $5.714 million)
3. 22 Months Ending 10/31/2025: $96.153 million (a reduction of $8.781 million)
4. 12 Months Ending 10/31/2026: $53.664 million (a reduction of $8.018 million)

Large New Business Projects – Distribution
1. 12 Months Ending 12/31/2024: $7.761 million (a reduction of $1.948 million)
2. 10 Months Ending 10/31/2025: $2.517 million (a reduction of $0.685 million)
3. 22 Months Ending 10/31/2025: $10.278 million (a reduction of $2.633 million)
4. 12 Months Ending 10/31/2026: $0.143 million (a reduction of $4.820 million)

Q. What are the capital expenditure adjustments proposed by Mr. Coppola with respect to the Company's Asset Relocation program?

A. Mr. Coppola discusses the Asset Relocation capital expenditure program starting on page 26 through page 31, line 6. His discussion includes two sub-programs: (1) Civic Improvement projects, and (2) Reimbursable projects.

For Civic Improvement projects, Mr. Coppola concludes that the 2025 capital expenditures should be reduced to $65.0 million and 2026 capital expenditures should be reduced to $73.7 million. He estimates a reduction for the 10 months ending October 31, 2025 of $9.4 million and a reduction for the 12 months ending October 31, 2026 of $9.9 million.

Q. Do you agree with the Asset Relocation program adjustments proposed by Mr. Coppola?

A. I have reviewed Mr. Coppola's Asset Relocation capital expenditures program testimony and the supporting documentation provided in Exhibit AG-3 and Exhibit AG-4. Page 4 and page 5 of Exhibit AG-3 describe how the estimates of Civic Improvement workload were determined for my original testimony and page 3 of Exhibit AG-4 describes how the projections of Reimbursable program investments were determined. Asset Relocation projects do represent a substantial portion of the Company's annual capital investments in the natural gas distribution system, and projects are performed at the request of federal, state, and local governmental units as well as at the request of the Company's natural gas customers. Numerous projects are completed over the course of a calendar year, and can range from very small meter stand and service upgrades to the relocation of large distribution mains and are generally not known far enough in advance to provide extensive footage and unit cost details in support of the Company's capital expenditure programs. The projections of workload provided in my direct testimony are indicative of the corresponding projected capital expenditures included in my original testimony and exhibits. Mr. Coppola's analysis reflects that there are some unknowns regarding the actual work that will be accomplished in 2025 and 2026, and he makes assumptions about activity

and costs that result in a lower capital expenditure estimate than what has been provided by the Company. I have evaluated the adjusted sub-program dollar projections that result from his calculations against historical Asset Relocation capital expenditures and have consulted subject matter experts within the Company on Asset Relocation program capital expenditures. Mr. Coppola's 2025 and 2026 projections are comparable to average annual expenditures for Asset Relocation projects from 2020 through 2024, and the Company accepts those projections for the purpose of determining customer rates in this proceeding.

Q. What decision should the Commission make regarding Attorney General witness Coppola's proposal to reduce the 2025 and 2026 Asset Relocation program projections?

A. I recommend that the Commission accept Mr. Coppola's Asset Relocation program capital expenditure projection adjustments. The Company has reflected those adjustments in the rebuttal exhibits of Company witness Rayl, and included those adjustments in Table 1 on page 3 of this rebuttal testimony. The Company's revised projections for the Asset Relocation program are summarized as follows:

Asset Relocation – Civic Improvement
1. 12 Months Ending 12/31/2024: $64.148 million (no reduction)
2. 10 Months Ending 10/31/2025: $54.204 million (a reduction of $9.408 million)
3. 22 Months Ending 10/31/2025: $118.352 million (a reduction of $9.408 million)
4. 12 Months Ending 10/31/2026: $72.249 million (a reduction of $9.913 million)

Asset Relocation – Reimbursable
1. 12 Months Ending 12/31/2024: $22.690 million (no reduction)
2. 10 Months Ending 10/31/2025: $12.023 million (a reduction of $0.203 million)
3. 22 Months Ending 10/31/2025: $34.713 million (a reduction of $0.203 million)
4. 12 Months Ending 10/31/2026: $14.728 million (a reduction of $1.919 million)

Q. What are the disallowances proposed by Mr. Coppola with respect to the Regulatory Compliance program?

A. Mr. Coppola recommends $93.340 million of capital expenditure reductions for the Company's Regulatory Compliance program. This recommended adjustment includes the following components:

Table 5: Regulatory Compliance Program Recommended Adjustments	
Reference: S. Coppola direct testimony page 35, line 1	**Amount**
MAOP Distribution – 2023 Actual	-$0.804 million
MAOP Distribution – 2024 Forecast	-$4.648 million
MAOP Distribution – 10 Months Ending October 31 2025	-$29.982 million
MAOP Distribution – 12 Months Ending October 31 2026	-$57.906 million
Total proposed reduction	**-$93.340 million**

Q. Please summarize the rule changes that caused the Company to evaluate existing pressure test records for compliance with PHMSA traceable, verifiable, and complete compliance standards.

A. Mr. Coppola's Exhibit AG-6 on page 2 of 79 indicates that PHMSA revised the existing Federal Pipeline Safety Regulations to address congressional mandates, National Transportation Safety Board recommendations, and public input. The requirements include required actions for pipeline operators to reconfirm the MAOP of natural gas transmission pipelines. These requirements are outlined as follows:

a. Reconfirmation of the MAOP for pipeline segments installed after implementation of test record requirements in 1970 is required if original construction test records are not traceable, verifiable, and complete (or "TVC"). The TVC standard is a new requirement that did not exist prior to the 2020 rule amendment.

b. Pipeline segments installed prior to test record requirements implemented in 1970 were previously "grandfathered," or exempt, from original construction pressure test documentation requirements and allowed to operate at the highest actual operating pressure observed between 1965 and 1970. The updated 2020 rules limited this exemption to pipelines operating below 30% of the specified

minimum yield strength (or "SMYS"). The requirement to substantiate the MAOP with records that meet the revised TVC standard for pipelines operating above 30% SMYS is identified on page 3 of 79 of Exhibit AG-6.

As a result, the Company must reconfirm the MAOP for all pre-1970 pipelines operating above 30% SMYS.

Q. Does Exhibit AG-6 support the Company's conclusion that the TVC record documentation standard is a new requirement compared to prior record keeping requirements.

A. Yes. Exhibit AG-6, page 4 of 79, states that the final rule "clarifies and expands recordkeeping requirements to ensure operators have and retain the basic physical and operational attributes and characteristics of their pipelines."

Q. What is the purpose of the rule changes that caused the Company to evaluate existing pressure test records for compliance with PHMSA traceable, verifiable, and complete compliance standards?

A. Mr. Coppola's Exhibit AG-6 identifies the purpose of the rule changes on page 3 of 79, where it states that "The purpose of this final rule is to increase the level of safety associated with the transportation of gas."

Q. Are there other aspects of the new TVC documentation requirement for line segments subject to pressure test records requirements that need to be factored into the Company's determination that existing documents comply with the new standards?

A. Yes. In addition to the minimum pressure test record requirements instituted in 1970, the Company now needs to evaluate if each test record is TVC.

a. For a test record to be considered traceable, it must be able to be linked to a specific pipeline segment. If the test record cannot be traced to a specific pipeline segment, then it cannot be considered TVC.

b. For a test record to be considered verifiable, there must be complementary, but separate documentation available that confirms the test record for that specific pipeline segment. If a test record is not verifiable by other records or documentation, it cannot be considered TVC.

These are two examples of additional record requirements that did not exist prior to the 2020 rule amendment requiring that pressure test and material properties records be TVC. Examples of projects that are planned to replace segments to establish TVC test records include:

a. Line 1009 Huron Park to I-94
b. Line 1022f Vermontville
c. Line 1009/1009c I-94 to Little Mack, 10 Mile to 11 Mile
d. Line 1002f Macomb ITC Corridor
e. Line 1020 Greenfield Rd.
f. Line 1087b E Isabella Rd.
g. Line 1009c, 9 Mile to 10 Mile
h. Line 1041 Lapeer Rd.
i. Line 1026f Mt. Hope
j. Line 1026i MSU PP
k. Line 1090n Davis St.

Q. Are there operational benefits associated with the replacement of pipeline segments that have their MAOP grandfathered and operate above 30% SMYS?

A. Yes, pipeline segments are going to be replaced by thicker and stronger pipeline materials in order to operate below 20% SMYS and will be subject to distribution pipeline integrity management requirements after replacement. Examples of projects that are planned to replace line segments that have their MAOP grandfathered and are currently operated above 30% SMYS include:

a. Line 1002c Coolidge to 11 Mile & Dequindre

b. Line 1022 Airport CG to State Rd & State Rd to W Grand River

c. Line 1093 Shattuck Rd

d. Line 1006 Groebel Dr to Mound Rd.

Q. On page 31, line 18, through page 32, line 2, Mr. Coppola claims that "the genesis of the problem requiring the replacement or remediation of pipelines to re-establish the MAOP is the lack of traceable, verifiable, and complete (TVC) records that should have been maintained by the Company." Do you agree with that claim?

A. No. As indicated previously, the TVC records standard was published in 2019. The Company has several pipeline segments that were constructed prior to test record requirements implemented in 1970 and had their MAOP grandfathered. Grandfathered pipeline segments that operate above 30% of SMYS are now required to have the MAOP reconfirmed because of the new PHMSA rules. Pressure test records for line segments constructed after 1970 are now required to be TVC, which wasn't required previously. The Company was required to thoroughly review its available records and identify line segments that don't have test records that meet the standards defined by the 2019 published rule. The Company's plan to replace various pipeline segments, as opposed to other reconfirmation options, best balances the need to maintain service to customers while complying with the new requirements.

Q. On page 33, line 1 through line 5, Mr. Coppola restates his claim that MAOP replacement projects are "the direct result of the Company not having the appropriate records to verify that the pipelines can operate at the designed pressure level and not knowing their material properties and attributes that would assist in that verification. These are basic records that the Company should have in its possession from when the pipeline was installed." Do you agree with that claim?

A. No. As described above, the Company was required to review its historical records and evaluate compliance considering the new PHMSA standards. The new TVC requirements revise the minimum standard for MAOP records.

Q. On page 33, line 13 through line 16, Mr. Coppola states that "The PHMSA rules enacted in 2019 simply require that pipeline operators do now what they should have been doing all along." Do you agree with that claim?

A. No. Exhibit AG-6 indicates that pipelines installed before 1970 had been operating under "grandfathered" MAOP documentation provisions based on actual operations during the 1965 to 1970 period. Pipelines operating above 30% SMYS are required to now have MAOP records that meet the new TVC standards. Therefore, Mr. Coppola's statement is inaccurate because it does not recognize the new requirement placed on pipeline operators to obtain TVC MAOP records after the rule change.

Q. On page 34, line 3 through line 6, Mr. Coppola claims that the Company is unable to pressure test Line 1080 due to "the lack of records to allow it to establish the pipeline design MAOP" and that the project "would not exist but for the Company's lack of traceable, verifiable, and complete records for Line 1080." Do you agree with that claim?

A. No. Mr. Coppola does not provide any source reference for these statements, and they are contradicted by the information contained in my direct testimony. On page 51 of my direct testimony, I describe how the Line 1080 segment does not require reconfirmation of MAOP. Because the line segment was constructed prior to 1970, and operates at less than 30% SMYS, the new requirements for TVC records do not apply to this line segment. The available records support the operation of this line segment at 325 psi but the line has operated for several years at 400 psi. In order to comply with regulations that require pipeline segments to be operated at their documented MAOP, the Company must reduce the operating pressure on that segment. Reducing the operating pressure on that line creates risk that some of the customers in that area would be unable to receive enough gas volume to operate their natural gas appliances. The Company plans to enhance the gas volume available to the customers on that line to prevent customer outages. The Line 1080 project will also enhance the resilience of that line segment by adding additional gas volume capacity.

Q. Are the revised PHMSA TVC record requirements a root cause for the need for the Line 1080 project?

A. No. Line 1080 record requirements are grandfathered and do not need to be reconfirmed as TVC records because the line was constructed before 1970 and operates below 30% SMYS. Because Line 1080 currently operates at 400 psi, but has a documented MAOP of 325 psi, the Company would need to reduce the pressure on that line segment independent of any the rule changes published by PHMSA in 2019. The Line 1080 project enables the Company to reduce the operating pressure to 325 psi while balancing the need to plan for adequate supply volume on that line segment.

Q. Does Exhibit AG-6 document any reasons why a pipeline operator would find pressure testing to be an undesirable approach to reconfirming MAOP on existing pipelines?

A. Yes. On page 7 of Exhibit AG-6, the content of the exhibit indicates that "Hydrostatic pressure testing can result in substantial costs, occasional disruptions of service, and substantial methane emissions due to the routine evacuation of natural gas from pipelines prior to tests. Further, many operators prefer not to use hydrostatic pressure tests because it can be destructive."

Q. Does the pipeline replacement option offer any additional benefits that merit consideration beyond compliance with new TVC record standards?

A. Yes. The Company plans to upgrade the pipelines on all the MAOP projects using thicker and stronger materials such that pipeline segment replacements will be operated below 20% SMYS, which will enhance the safety of the line segments replaced.

Q. On page 35, line 2 to line 5, Mr. Coppola recommends a capital expenditure disallowance of $93.340 million, or 50% of the Company's 2023 through the test year ending October 31, 2026 expenditures for MAOP-Distribution projects. His testimony claims that a 50% recovery of these projects is reasonable given the age of the pipelines being replaced. Do you agree with his recommended disallowance for those projects?

A. No, I do not agree that Mr. Coppola's recommended 50% recovery of MAOP compliance expenditures is reasonable. The Company is reasonably planning for investments in distribution MAOP projects prior to and during the projected test year in this proceeding to comply with PHMSA regulations. Mr. Coppola's recommendations are based on

assumptions regarding the Company's historical pipeline records and PHMSA's 2019 rule changes that are factually incorrect. The Line 1080 project accounts for approximately $17.359 million[1] of the total recommended disallowance, and the need for additional main in that area has nothing to do with TVC MAOP records requirements as claimed on page 34 of his direct testimony. Excluding or delaying the inclusion of 50% of all projected expenditures for MAOP-Distribution projects in the Company's projected rate base is not a reasonable recommendation. I recommend the Commission adopt the Company's projections as reasonable and prudent investments to include in capital expenditures for the projected test year.

Q. On page 38, line 1 to line 9, Mr. Coppola claims his recommended disallowance of 50% of MAOP project capital expenditures is reasonable because it is not clear how thorough the Company's review process was that led to the conclusion that replacement is the best reconfirmation method. Do you agree with his claim that the Company's discovery response in AG-5, page 2 of 7, is vague about the review process?

A. No, I do not agree that the Company's response to discovery regarding the decision making process is vague. The Company has a process to evaluate all the reconfirmation methods and select the option that is most appropriate for compliance depending on the circumstances of each line segment. The evaluation process for MAOP-Distribution projects is the same as the evaluation process for MAOP-Transmission projects and involved multiple subject matter experts in the decision. Replacement is the is the best compliance option for the Company given the goal of also maintaining or improving

[1] Line 1080 from Exhibit AG-5 page 6 of 7: (383 + 3,829 + 29,945 + 561) = 34,698 x 50% recommended adjustment = 17,359.

deliverability for customers. The other compliance methods are either infeasible or introduce risk to system operations which could result in customer outages or project execution failures. The Company believes the planned replacements are reasonable and recommends that the Commission disregard Mr. Coppola's proposed 50% disallowance.

Q. What are the disallowances proposed by Mr. Coppola with respect to the Tracking and Traceability technology project?

A. Mr. Coppola provides testimony regarding the proposed disallowances for the Company's Tracking and Traceability technology project on page 85, line 11, through page 87, line 6, of his direct testimony. He proposes disallowances of $7.513 million of capital expenditures and $0.509 million of O&M expense from the projected test year as detailed on page 87, lines 4 through 6, of his direct testimony.

Q. What is your response to Mr. Coppola's recommendations regarding the Company's Tracking and Traceability technology project?

A. The Company still expects to incur the Tracking and Traceability amounts provided in this case. The project is required to meet PHMSA proposed regulatory requirements (PHMSA-2014-0098), also known as the Plastic Pipe rule, as described in my direct testimony on pages 76 and 77. As a part of the Investment Planning phase of this project, the Company conducted a Request for Information process and received nine responses. This information was used to estimate the cost for this project. Please reference the rebuttal testimony of Company witness Stacy H. Baker for further details on the strict business case process followed for a project to get to the Investment Planning phase.

Q. Does this conclude your rebuttal testimony in this proceeding?

A. Yes.

Consumers Energy Company's
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Category	Intervenor	Intervenor Witness	Intervenor Position	Disagree?	CE Witness
Accumulated Depreciation	Staff	Witt	Correction for Company using incorrect depreciation rates.	No	Rayl
Affordability	AG	Coppola	Dramatic increase in customer bills	Yes	Neal Dreisig
Affordability	CUB	Bunch	Spending plan leads to affordability issues for Customers Customers want safety and reliability but those are empty desires when they cannot afford the service to begin with. Past rate increases have created the situation 1 I detail above, and a further 12.1% increase can only exacerbate this dangerous trend	Yes	Byrom
Affordability	CUB	Bunch	Capital spending is not affordable for customers	Yes	Neal Dreisig
Affordability	CUB	Denzler	Future rate increases are not affordable for customers	Yes	Neal Dreisig
Capital	ABATE	Fitzhenry	Recommending a disallowance of $15.8m in 2023 Capital Expenditures for Asset Relocation - Civic Improvement	Yes	Warriner
Capital	AG	Coppola	AG is recommending disallowances based on a three-year historical average due to variability in spending on the program.	Yes	Baker
Capital	AG	Coppola	AG is recommending disallowance based on the conclusion that this project is not a priority. That the issues with the equipment are routine problems and do not require replacement.	Yes	Baker
Capital	AG	Coppola	AG is recommending adjusting 2024 capital expenditures by $5,668,000 to reflect actual 2024 capital spend attributed to the gas business.	No	Baker
Capital	AG	Coppola	Asset Relocation Trans: Reduce test year expenditures for certain projects based upon status in March of 2025	Yes	Griffin
Capital	AG	Coppola	City Gates: Utilized historical project costs to get an "average" cost and inflated that to get to test year cost	Yes	Griffin
Capital	AG	Coppola	Deliverability Base Field Measurement Prog: Reduce test year expenditures for certain projects based upon status in March of 2025. Cuts to other projects based upon purported lack of evidence	Yes	Griffin
Capital	AG	Coppola	Deliverability Base Pipeline Prog: Reduce test year expenditures for certain projects based upon status in March of 2025. One project was cancelled but we pulled ahead a project from 2026.	Yes	Griffin
Capital	AG	Coppola	MAOP PL: Removal of a canceled project, an un-identified project and 50% reduction to rest of projects.	Yes/No	Griffin
Capital	AG	Coppola	Pipeline Integrity TOD: Rejects company increase in expenditure to do hazard assessemnts of non-HCA/MCA adjacent pipeline segments	Yes	Griffin
Capital	AG	Coppola	TED-I RCVs: Reduce test year expenditures for certain projects based upon status in March of 2025	Yes	Griffin
Capital	AG	Coppola	(1) AG examined Fleet replacements planned for the bridge and test periods (2) AG calculated an average cost per vehicle for replacements planned in the bridge and test periods (3) AG calculated an average cost per vehicle for replacements made in previous years (4) AG argues the increase over previous years in average cost per vehicle for replacements planned in the bridge and test periods exceeds the inflation factor (5) AG argues therefore the average cost per vehicle should increase by no more than the inflation factor.	Yes	Guinn
Capital	AG	Coppola	Disallowance based on the timing and duration of the engineering window reported during discovery.	Yes	Joyce

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Category	Intervenor	Intervenor Witness	Intervenor Position	Disagree?	CE Witness
Capital	AG	Coppola	Project has Act 9 filing that is pending; funding that is contingent upon the approval should be disallowed.	Yes	Joyce
Capital	AG	Coppola	Disallowance base on lack of justification for the project	Yes	Joyce
Capital	AG	Coppola	New Business capital expenditures reduction of $5,714,000 in bridge period; $8,018,000 in test year	Yes	Warriner
Capital	AG	Coppola	New Business capital expenditures reduction of $3,067,000 for 2024 due to actual expenditures less than projected	No	Warriner
Capital	AG	Coppola	Large New Business capital expenditure reduction of $4,778,000 for the test year (unknown projects), $684,676 in bridge periods and $82,722 in projected test year for projects that have not finalized contracts	No	Warriner
Capital	AG	Coppola	Large New Business capital expenditure reduction of $1,452,073 for bridge period and $82,722 in projected test year for LBWL projects that do have not finalized contracts	Yes	Warriner
Capital	AG	Coppola	Large New Business capital expenditure reduction of $1,948,000 for 2024 actual expenditures less than projection.	No	Warriner
Capital	AG	Coppola	Asset Relocation - Civic Improvement and Asset Relocation - Reimburseable reductions summarized on page 31 lines 4-6 as $9,611,000 reduction for the 10 months ending October 2025 and $11,832,000 for the projected test year	No	Warriner
Capital	AG	Coppola	MAOP-Distribution 50% disallowance ($804,000 in 2023; $4,648,000 in 2024; $29,982,000 in 10 months ending October 2025; $57,906,000 in test year).	Yes	Warriner
Capital	CUB	Bunch	CUB is recommending that the Commission limit O&M and capitalized labor costs to 2023 - 2024 historical average levels plus compounded 2025 - 2026 labor productivity-adjusted inflation. CUB indicates that the IT and Security capital labor for the projected test year more than doubling over 2023-2024 historical average.	Yes	Baker
Capital	CUB	Denzler	CUB is recommending a disallowance of $6,524,840 due to defects in both its planning and overall merit and therefore would not be reasonable and prudent to recover additional costs above total allowed capital approved in U-21490.	Yes	Baker
Capital	CUB	Denzler	CUB is recommentding that the unit costs be adjusted by applying PAI factor for applicable items to historical unit costs, as the Company did not provide justification for the difference in costs.	Yes	Baker
Capital	CUB	Denzler	CUB is recommentding that the unit costs be adjusted by applying PAI factor for applicable items to historical unit costs, as the Company did not provide justification for the difference in costs.	Yes	Baker
Capital	CUB	Denzler	CUB is recommending a 20% ROM adjustment on the remaining ARP spend due to insufficient justification of cost estimation.	Yes	Baker
Capital	CUB	Denzler	Gas SCADA Software Solution - CUB is recommending a total of 40% ROM adjustment, which is an incremental 20% over the Company's 20% ROM adjustment due to the history of the Company's significant over-estimation.	Yes	Baker/Warriner

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Category	Intervenor	Intervenor Witness	Intervenor Position	Disagree?	CE Witness
Capital	CUB	Denzler	Witness questions use of the Blended Factor Model in replacement plan decisions and alleges the Company has not proven its efficacy. Witness cites discovery responses noting the Company has had vehicles fail with a Blended Factor rating of 0 and less. Hence, recommends a 20% disallowance of all Replacement Plan capital requests in this case arguing these asks are based in part on the Blended Factor which the witness alleges is not reliable.	Yes	Guinn
Capital	CUB	Denzler	Witness cites the Commission disallowance in ERC U-21585 of the Lansing Service Center project and recommends the same disposition apply in this instance given the proximity of this testimony to the order in ERC U-21585.	Yes	Guinn
Capital	CUB	Denzler	Witness cites the Commission disallowance in ERC U-21585 of the Hastings Service Center project and recommends the same disposition apply in this instance given the proximity of this testimony to the order in ERC U-21585.	Yes	Guinn
Capital	CUB	Denzler	Witness cites the Commission disallowance in ERC U-21585 of the Kalamazoo Service Center project and recommends the same disposition apply in this instance given the proximity of this testimony to the order in ERC U-21585. In addition, witness suggests the Kalamazoo Project is being overbuilt by 40 percent.	Yes	Guinn
Capital	CUB	Veerapaneni	Transmission : Recommending the use of the adjusted two-year average for the test year	Yes	Griffin
Capital	CUB	Veerapaneni	Recommending the use of the adjusted two-year average for the test year	Yes	Warriner
Capital	MEC	deLeon	The Commission should cap addtions to plant in service in the projected test year at no more than 2024 investment levels as illustrated in Table 1. (Page 7, line 21-22)	Yes	Warriner
Capital	MEC	Napoleon	The Commission should order the Company to set the growth rate in new connections to zero and reduce its capital expenditures for New Business (page 5, line 21-page 6, line 3)	Yes	Warriner
Capital	MEC	Napoleon	The Company's 3% increase in gas connections is not supported by historical data	Yes	Warriner
Capital	MEC	Napoleon	The Commission should order the Company to reduce the allowance for new customer line extension costs to no more than 50% of total costs and reduce test year capital expenditures for New Business (page 5, lines 12-20)	Yes	Warriner/Bonner
Capital	MEC	Napoleon	The Company's line extension policies incentivize new customer connections by subsidizing the true cost of gas line extensions (page 26, lines 11-20)	Yes	Warriner/Bonner
Capital	MEC	Napoleon	The Commission should require the Company to explain and document the relationship of the new connections forecast to the load forecast (page 6, lines 1-3)	Yes	Warriner/Sherwani
Capital	MPSC Staff	Klocke	Disallowance for LMI project--benefit does not yield the cost, there has been no proof of success	Yes	Byrom

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Category	Intervenor	Intervenor Witness	Intervenor Position	Disagree?	CE Witness
Capital	MPSC Staff	Klocke	Disallowances for Click to Chat Enhancement	Yes	Byrom
Capital	MPSC Staff	Klocke	Disallowances for Web Chat AI Enhancement	Yes	Byrom
Capital	MPSC Staff	Klocke	Disallowances for Mobile App Enhancement	Yes	Byrom
Capital	MPSC Staff	Klocke	Consistent with Staff's position in Case No. U-21490 and U-21585, Staff is recommending a full disallowance of costs requested for the Click to Chat project because Staff finds that the project does not offer any new technology or features that are innovative, nor does it represent any cost savings. Additionally, Staff recommends disallowance because there no anticipated reduction in calls to the call center and will still require assistance from a live customer agent.. Staff also has concerns that there have been only 314 for the three years it's been available.	Yes	Byrom/Baker
Capital	MPSC Staff	Zichi	Staff is recommending a partial disallowance to correct an error identified related to a cost breakdown for auditorium refresh. The current quote is lower than projected.	No	Baker
Capital	MPSC Staff	Zichi	Staff is recommending this adjustment because the Company has not provided clear evidence in support of the new purchases. And that the Company provided conflicting rationale in testimony as to how the costs were projected.	Yes	Baker
Capital	MPSC Staff	Zichi	Staff is recommending this adjustment because the Company has not provided clear evidence in support of the new purchases. And that the Company provided conflicting rationale in testimony as to how the costs were projected.	Yes	Baker
Capital	MPSC Staff	Zichi	Staff is recommending this adjustment to correct an error discovered during audit. The Company identified that AFUDC and employee benefits overheads were inadvertently applied.	No	Baker
Capital	AG	Coppola	Dissallowance based on 2024 program underspend versus what was submitted in the case	Yes	Joyce
Capital	AG	Coppola	Disallowance is based on using an average cost per well drilled based on historical expense	Yes	Joyce
Capital	CUB	Veerapaneni	Recommending the use of the adjusted two-year average for the test year	Yes	Joyce
Capital	MPSC Staff	Spence	Three storage projects have Act 9 filings that are pending; funding that is contingent upon the approval should be disallowed.	Yes	Joyce
Capital	ABATE	Fitzhenry	The Company completed 15% less miles of distribution main replacement in 2023 than originally projected. Further investment in the Companies' Enhanced Infrastructure Replacement Distribution Program ("EIRP – Distribution") would not likely yield customer benefits commensurate with the level of customer costs.	Yes	Pascarello

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Category	Intervenor	Intervenor Witness	Intervenor Position	Disagree?	CE Witness
Capital	AG	Coppola	AMD is too expensive. There has been no evidence presented by the Company that the existing leak detection is missing serious and dangerous gas leaks that is placing customers and the public in danger or that large quantities of natural gas are escaping into the atmosphere that pose a large financial loss or environmental hazard.	Yes	Pascarello
Capital	AG	Coppola	Reduce test year expenditures for seven EIRP projects based upon status of not meeting the 30% design completed status in March of 2025. Additionally proposes a cap on EIRP spend of $197 million in TY with futire years being adjusted for CPI rate of inflation	Yes	Pascarello
Capital	AG	Coppola	Makes separate agruments on the Company initiated projects: Wrought Iron - agrues Company is expanding CINC to include vintage and this should be done in EIRP, HP Waterways are not far enough along in design process, Leaks and Obsolete meters are devoid of explanation and evidence to justify spending. Line 1010 should have 50% of costs disallowed due to Copany's responsibilty of record keeping	Yes	Pascarello
Capital	AG	Coppola	The higher number of service replacements is not adequately supported and should be scaled back. Increased number related to effort to complete program by 2035. Uses 2024 level of VSR replacements.	Yes	Pascarello
Capital	AG	Coppola	n/a	n/a	Pascarello
Capital	AG	Coppola	Wants disallowance for implentation of Devonway software. Stares it's not clear what problems exist that the Company is trying to resolve by implementing a new system to gather information it should already have.	Yes	Pascarello
Capital	AG	Coppola	The marginal improvement in functionality and lack of a cost/benefit analysis do not support undertaking the Utility Network project	Yes	Pascarello
Capital	AG	Coppola	The additional $1.51M added to address leak backlog should be disallowed due to delay of LDAR rule	Yes	Pascarello
Capital	CUB	Veerapaneni	Recommending the use of the adjusted two-year average for the test year	Yes	Pascarello
Capital	CUB	Veerapaneni	Recommending the use of the adjusted two-year average for the test year	Yes	Pascarello
Capital	MEC	Deleon	EIRP reporting should include risk-ranking information (risk rank of asset remediated and total number of assets) and narrative descriptions regarding the use of risk-ranking driving remediation for a particular project. Recommends capping EIRP at 2024 level	Yes	Pascarello
Capital	MEC	Deleon	The MCNM program spend increases 47 percent from $38.3 million in 2024 to a projected $56.2 million for the test year. Recommends capping at 2024 level	Yes	Pascarello

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Category	Intervenor	Intervenor Witness	Intervenor Position	Disagree?	CE Witness
Capital	MEC	Deleon	Consumers' projects an increased number of vintage service replacements in 2024, 2025, and 2026, and through 2035. The VSR program spend increases 128 percent from $18.6 million in 2024 to a projected $42.5 million for the test year. Recommends capping at 2024 level.	Yes	Pascarello
Capital	MPSC Staff	Creisher	Disallowance due to reduced projected costs for 2025 AMD capital expenditures provided by audit/discovery	No	Pascarello
Capital	MPSC Staff	Creisher	Disallowance due to reduced projected costs for Line 1010 provided by audit/discovery	No	Pascarello
Capital Structure	ABATE	Walters	ABATE recommends a 50% equity ratio versus the 50.75% proposed by the Company consistent with prior Commission orders.	Yes	Marc Bleckman
Capital Structure	AG	Coppola	AG recommends that the equity ratio should be set at 50.0% consistent with the Commission's order in the Company's most recent rate cases.	Yes	Marc Bleckman
Capital Structure	MPSC Staff	Megginson	Staff recommends a 50% equity ratio versus the 50.75% proposed by the Company. Staff references prior Commission orders which reflect its desire for the Company to reach a 50/50 equity ratio.	Yes	Marc Bleckman
Capital Structure	MPSC Staff	Megginson	Staff recommends a lower cost of long-term debt (4.33% versus 4.35%) as a result of assuming a lower credit spread on projected long-term debt issuances (1.00% versus 1.36%).	Yes	Marc Bleckman
Capital/O&M	AG	Coppola	SAP S/4HANA - AG is recommending disallowance of this project as it sees this project being forced obsolecence by the vendor in order to sell new software, services, and technology. Additionally, the project is not financially justified. Indicating that the current ERP system still functions well and meets the operating need of the Company and could continue to operate the system into 2030 and potentially . In reference to the O&M disallowance, the AG indicates that these costs should be disallowed as the projec is premature and unnecessary.	Yes	Baker
Capital/O&M	AG	Coppola	AG is recommending disallowance based on the conclusion that new software is not necessary due to the service improvement in the past year.	Yes	Baker
Capital/O&M	AG	Coppola	AG is recommending disallowance based on the project being in the investment planning phase and indicating that resolving the water infiltration risk and and aging climate equipment would be a lower cost.	Yes	Baker
Capital/O&M	AG	Coppola	AG is recommending disallowance based on the project not providing any cost savings or financial benefits.	Yes	Baker
Capital/O&M	AG	Coppola	Gas Facilities Tracking and Traceability - AG is recommending disallownce of this project indicating that the project is not economically justified and the project is the preliminary stage of development.	Yes	Warriner/Baker
Capital/O&M	CUB	Veerapaneni	Not evaluating projects on merits but instead relying on historical	Yes	Myers

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Category	Intervenor	Intervenor Witness	Intervenor Position	Disagree?	CE Witness
Capital/O&M	MPSC Staff	Klocke	Staff recommends disallowance as they feel the project offers technology that is redundant and nor worth the cost. Additionally, Staff is concerned that the Company's website redsign has been put on hold and that the website updates would essentially provide the same kind of information and accessibility the Web Chat AI tool would provide. Staff also thinks that the examples of things that the chat bot would provide are things that should already easily be found on the Company's website. Additionally, Staff takes issue with the fact that no reduction in overall costs is anticipated from the Web Chat AI.	Yes	Byrom/Baker
Capital/O&M	MPSC Staff	Klocke	Consistent with positions in prior cases, Staff is recommending full disallowance of costs for Self-Service Mobile Application enhancements. Additionally, Staff has concerns for requested costs for 2025 and 2026 are unspecified and classified as emergent and makes comparison to contingency, specifically the App Support Center and App Login enhancements.	Yes	Byrom/Baker
Capital/O&M	MPSC Staff	Klocke	Staff is recommending full disallowance of the LMI Customer Support project and the associated enhancements. Staff feels strongly that the Company update their website to make information such as this standard.	Yes	Byrom/Baker
Capital/O&M	MPSC Staff	Zichi	Staff is recommending this adjustment to correct an error that was found through discovery.	No	Baker
Capital/O&M	MPSC Staff	Zichi	Staff is recommending this adjustment to correct for an error that was identified through discovery.	No	Baker
Capital/O&M	MPSC Staff	Zichi	Staff is recommending this adjustment to correct for a change in the project that was discovered during audit of the Company's projects.	No	Baker
Capital/O&M	Staff	Rueckert	Staff position is to disallow the LIBA benefit awards for rate recovery including O&M and Capital. The Staff is also wanting the 2024 capitalization amount disallowed. Shannon Rueckert testimony page 3 to 5.	Yes	Grob
Cost of Service	ABATE	York	Reccomends replacing the current Average and Peak allocation with an Average and Excess Demand ("AED") allocation because it prevents double counting of peak day volumes and better reflects cost causation principles by recognizing the variability in load between customer classes	No	Geller
Cost of Service	ABATE	York		No	Geller
Cost of Service	CUB	Bunch	reccomends allocating uncolectibles based on Cost of servce plus gas rather than the current approved method, because it better reflects each rate class's contribution to uncollectible expenses	Yes	Geller
Cost of Service	LWBL-MSU	Lyons	Recommended functionalizing Other Distribution Plant accounts 773, 375 and 378 between High Pressure and Non-High Pressure before allocating to each rate class because it more accurately allocates costs to Rate XXLT. End result would be using existing allocator 217.	Yes	Geller
Cost of Service	MPSC Staff	Krause	Staff recommends allocating uncollectible expenses based on revenue rather than the current approved method, because it better reflects each rate class's contribution to uncollectible expenses	No	Geller

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Category	Intervenor	Intervenor Witness	Intervenor Position	Disagree?	CE Witness
Cost of Service	MPSC Staff	Krause	Staff reccomends creating a new composite allocator for FERC Account 378 expenses that weighs costs associated with serving each pressure level rather than using the current allocator based on annual and peak usage for customers served at all pressure levels.	No	Geller
Cost of Service	MPSC Staff	Revere	Sponsors the exhibit the Account 378 allocator is based on	No	Geller
Depreciation Expense	MPSC Staff	Witt	Correction for Company using incorrect depreication rates.	No	Rayl
Inflation	ABATE	Fitzhenry	Use different index for inflation	Yes	Myers
Inflation	AG	Coppola	Recommends the Commisison direct the Company to clearly disclose by operating unit and cost function the forecasting inflationary cost increase it has included in the bridge period and the projected test year for specific expense items if they are different than CPI	Yes	Myers
NGDP	CUB	Denzler	Future of gas demand is uncertain	Yes	Neal Dreisig
NGDP	MEC	DeLeon	Future of gas demand is uncertain	Yes	Neal Dreisig
NGDP	MEC	DeLeon	Non-pipe alternative analysis	Yes	Neal Dreisig
NGDP	MEC	DeLeon	RNG Program	Yes	Neal Dreisig
NGDP	MEC	DeLeon	Decarb plans	Yes	Neal Dreisig
NGDP	MEC	Napoleon	The Company is not pursuing all decarbonization pathways	Yes	Neal Dreisig
NGDP	MEC	Napoleon	Decarbonization study is flawed and does not align with other studies	Yes	Neal Dreisig
NGDP	MEC	Napoleon	EWR is not found within the decarbonization study	Yes	Neal Dreisig
NGDP	MEC	Napoleon	The Company is not investigating non-pipe alternatives	Yes	Neal Dreisig
NGDP	MEC	Napoleon	Electrification growth is greatly outpacing gas growth in Michigan	Yes	Neal Dreisig
NGDP	MEC	Napoleon	The Company's NGDP does not address the potential for gas demand response as way to realize decarbonization goals	Yes	Warriner
O&M	AG	Coppola	AG is recommending disallowance in amoritization expense related to cloud computing costs.	Yes	Baker
O&M	AG	Coppola	O&M for Analytics and Outreach is not justified--no evidence of efficacy or customer contact	Yes	Byrom
O&M	AG	Coppola	O&M for DCO is not justified--no evidence of efficacy or customer contact	Yes	Byrom
O&M	AG	Coppola	Using the 66% average performance goal achievement rate, the most that the Company should be allowed to recover in this rate case is $1,020,000 ($1,546,000 x 66%). The remaining amount of $526,000 should be disallowed.	Yes	Conrad
O&M	AG	Coppola	Corporate O&M: VSP Savings AG recommends that the Commission remove the entire $7,989,000 (Corporate=$3,921,000)of VSP cost savings from the Company's forecasted O&M expense for the projected test year to ensure that the cost savings are appropriately reflected in rates in this rate case	Yes	Foster

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Category	Intervenor	Intervenor Witness	Intervenor Position	Disagree?	CE Witness
O&M	AG	Coppola	AG position is to decrease active healthcare by $2,754,000 pages 183 to 183 of S. Coppola testimony	Yes	Grob
O&M	AG	Coppola	Employee Safety performance has a negative trend and associated costs from safety inicidents has been erratic.	Yes	Meschke
O&M	AG	Coppola	SAIDI targets and costs savings have been set on a 4 year historical average as opposed to year over year improvements and customer benefits have not been achieved	Yes	Meschke
O&M	AG	Coppola	Culture Index customer benefits show cost savings associated with turnover, and turnover performance shows a negative trend.	Yes	Meschke
O&M	AG	Coppola	No additional information was provided from where those costs were reclassified, and no showing was made that a comparable decrease in expense was included in the function where those costs previously resided.	Yes	Pascarello
O&M	AG	Coppola	The marginal improvement in functionality and lack of a cost/benefit analysis do not support undertaking the Utility Network project. He included this is IT sectionof his testimony though the dollars are in GE&S O&M	Yes	Pascarello
O&M	AG	Coppola	Recommends that the commission not approve the staking deferral	Yes	Pnacek
O&M	CUB	Denzler	CUB is recommending disallowance due to the Company not evaluating other software options and does not even understand the capabilities of other technologies and recommend requiring the Company to provide suitable evaluation of alternative as preprequisite to being granted recovery in a future case. In addition, if the Commission does not support full disallowane, they recommend a 20% ROM adjustment.	Yes	Baker
O&M	CUB	Denzler	CUB is recommending disallowance due to not sufficiently demonstrating the reasonableness and prudence of the enhancement worklist and inclusion of many large-cost projects, which should not be included in Enhancements and instead be standalone projects. In addition, they are recommending that enhancements be projected based on three-year historical average plus PAI factor.	Yes	Baker
O&M	CUB	Denzler	Witness cites the Company's statements concerning savings from total cost of ownership in ICE to EV conversions but alleges the Company has not expressly incorporated these savings into any financial exhibits in this case. Witness alleges the Company is therefore "over-recovering" in its requests for Fleet Responsibility allowance in this case.	Yes	Guinn

Consumers Energy Company's
Table of Disputed Issues
MPSC Case No. U-21806

Category	Intervenor	Intervenor Witness	Intervenor Position	Disagree?	CE Witness
O&M	CUB	Denzler	Witness alleges insufficient detail is provided concerning Fleet Responsibility costs, how they are derived, and where they settle in the business. Witness recommends a 20% disallowance of all Responsibility costs basically on the notion that no one within the Company can confirm where these costs manifest and therefore they should simply be taken out of Fleet since this is the only specific place these expenses are recognized as existing. The witness' logic continues . . . because no one can demonstrate where these costs manifest and for what purpose they are ultimately expended no one therefore can definitely state that these costs are "reasonable and prudent" .	Yes	Guinn
O&M	CUB	Veerapaneni	Recommending the use of the adjusted two-year average for the test year	Yes	Griffin
O&M	CUB	Veerapaneni	Recommending the use of the adjusted two-year average for the test year	Yes	Joyce
O&M	CUB	Veerapaneni	Recommending the use of the adjusted two-year average for the test year	Yes	Pascarello
O&M	MPSC Staff	MCMILLAN-SEPKOSKI	Staff recommends disallowance of the operational measures portion of EICP for the top 5 officers.	Yes	Conrad
O&M	MPSC Staff	Zichi	Staff is recommending this adjustment to correct an error discovered during audit. The Company provided O&M costs that were inadvertently overstated and did not account for optimization in contractor costs.	No	Baker
O&M	MPSC Staff	Zichi	Staff is recommending this adjustment to correct an error discovered during audit. The Company provided O&M costs that were inadvertently overstated and did not account for optimization in contractor costs.	No	Baker
O&M	MPSC Staff	Zichi	Staff is recommending this adjustment to correct an error that was discoveryed during its audit of the Company's projects.	No	Baker
O&M	ABATE	Fitzhenry	Witness states the company doesn’t have a leak backlog.	Yes	Pnacek
O&M	ABATE	Fitzhenry	Proposed disallowance of $1.3M for leak backlog due to the LDAR rule not being published yet	Yes	Pnacek
O&M	ABATE	Fitzhenry	Do not approve the LDAR deferral mechanism because the rule is on-hold page 17	No	Pnacek
O&M	AG	Coppola	Corporate O&M: General Activities Labor is unusual and excessive	Yes	Foster
O&M	AG	Coppola	Increasing expense not supported	Yes	Griffin
O&M	AG	Coppola	Reduce MAOP records review (SEA) O&M by 50%	Yes	Griffin
O&M	AG	Coppola	Based on the Company's methane emission reduction goals, there should be a reduction in the LAUF.	Yes	Joyce
O&M	AG	Coppola	Recommends the Commission remove all VSP cost savings from the Company's projected O&M expense because the Company cannot provide certainty the cost savings were incorporated in the test year O&M exoebse for each of the affected departments.	Yes	Myers
O&M	AG	Coppola	AMD is too expensive. There has been no evidence presented by the Company that the existing leak detection is missing serious and dangerous gas leaks that is placing customers and the public in danger or that large quantities of natural gas are escaping into the atmosphere that pose a large financial loss or environmental hazard.	Yes	Pascarello

Consumers Energy Company's
Table of Disputed Issues
MPSC Case No. U-21806

Category	Intervenor	Intervenor Witness	Intervenor Position	Disagree?	CE Witness
O&M	AG	Coppola	Did not provide any evidence that the cost paid by customers for this function is having a significant beneficial impact, reducing costs or achieving other financial benefits. Without that information, it is not possible to assess the value created by the Quality Lean Office.	Yes	Pascarello
O&M	AG	Coppola	Mr. Pnacek's direct testimony does not explain this increase in expense for EIRP Training. And then discovery response is misrepresented	Yes	Pnacek
O&M	AG	Coppola	No evidence of a high turnover in employees has been presented to justify the training of a larger number of employees or contractors. Furthermore, as I proposed in the Capital Expenditures section of my testimony, the EIRP should be scaled back beginning with the projected test year to stay within a reasonable cost budget. This reduction in spending will require fewer resources, Therefore, I recommend that the Commission remove the increase of $1,656,000 from the Company's forecasted O&M expense.	Yes	Pnacek
O&M	AG	Coppola	Do not approve the LDAR deferral mechanism because the rule is on-hold page 195	No	Pnacek
O&M	AG	Coppola	Proposed disallowance of $1.3M for leak backlog due to the LDAR rule not being published yet	Yes	Pnacek
O&M	AG	Coppola	The word "typically, gas" implies it is the standard. We as no major gas utility uses the shared model. Page 167, line 14-18	Yes	Pnacek
O&M	AG	Coppola	Charactization as an experimental program to establish whether the incremental benefits justified the incremental cost of a dedicated program. Page 168, line 1-6	Yes	Pnacek
O&M	AG	Coppola	Company didn't attempted to work with the shared model staking and locating contractors to resolve whatever problems with performance existed and in turn minimize the cost of staking and location. Page 168, line 7-14	Yes	Pnacek
O&M	AG	Coppola	The Company did not provide any evidence that a serious problem with staking and locating exists in those counties that cannot be resolved in other ways. Page 168, line 15-19	Yes	Pnacek
O&M	AG	Coppola	Mr. Pnacek states that based on recent bids received from contractors the cost per unit is lower for the dedicated model than the shared model. This is counter to the historical evidence presented by the Company. Page 168, line 20 to Page 169 line 4	Yes	Pnacek
O&M	AG	Coppola	The bidding process that the Company went through in 2024 cannot be relied on. Page 169 line 4-9	Yes	Pnacek
O&M	AG	Coppola	Recommends that the Commission remove the incremental O&M expense of $11,184,000 included by the Company in the projected test year. Page 169 line 12 Page 170 line 2	Yes	Pnacek
O&M	CUB	Bunch	Limit O&M and capitalized labor costs to historic levels plus productivity adjusted inflation. Limit Other O&M and capital costs to inflation less productivity.	Yes	Myers
O&M	CUB	Veerapaneni	Use of his two-year historical average described in his summary and conclusions for Gas Ops Storage program O&M Expenses. Page 18, line 10-19	Yes	Pnacek

Consumers Energy Company's
Table of Disputed Issues
MPSC Case No. U-21806

Category	Intervenor	Intervenor Witness	Intervenor Position	Disagree?	CE Witness
O&M	CUB	Veerapaneni	Use of his two-year historical average described in his summary and conclusions for Gas Ops O&M Expenses. Page 16, line 2-10	Yes	Pnacek
O&M	CUB	Veerapaneni	Use of his two-year historical average described in his summary and conclusions for Field Ops services program O&M Expenses.	Yes	Pnacek
O&M	CUB	Veerapaneni	Use of his two-year historical average described in his summary and conclusions for Gas Ops - Other program O&M Expenses. Page 17, line 10-15	Yes	Pnacek
O&M	CUB	Veerapaneni	Use of his two-year historical average described in his summary and conclusions for Gas Ops O&M Expenses on Exhibit CUB-9 (Maybe duplicative). Page 18 line 21 to page 19 line 4	Yes	Pnacek
O&M	CUB	Veerapaneni	Use of his two-year historical average described in his summary and conclusions for $1.3M disallowance for leak backlog repair. O&M Expenses. Page 16, line 13-21	Yes	Pnacek
O&M	MPSC Staff	Martus	Do not approve the LDAR deferral mechanism because the rule is on-hold. Page 6	No	Pnacek
O&M	MPSC Staff	Martus	Approve staking deferral mechanism with limation to staking volume and apply a min and max cap to the request. Page 8	No	Pnacek
O&M	CUB	Veerapaneni	Use of his two-year historical average described in his summary and conclusions Gas Ops O&M Expenses on Exhibit CUB-11(Maybe duplicative) Combine with above. Page 19 line 6-8	Yes	Pnacek
O&M	AG	Coppola	Dissallowance based on updated information provided during discovery	Yes	Joyce
Other	AG	Coppola	AG is recommending the Commission not approve a deferred regualtory asset for the IT Investment costs related to the SAP S/4 HANA project, indicating the project is premature and inadequately justified.	Yes	Baker
Other	AG	Coppola	AG is recommending the Commission not approve a deferred regualtory asset for the cloud implementation costs related to the SAP S/4 HANA project, indicating the project is premature and inadequately justified.	Yes	Baker
Other	AG	Coppola	AG is recommending that the excess amount be removed from proposed working capital adjustment.	No	Baker/Rayl
Other	AG	Coppola	AG is recommending that projected working capital balance be reduced by $1,034,000 and remove $5,478,000 from the Company's forecasted amorization.	Yes	Baker/Rayl
Other	AG	Coppola	Remove Riverside regulatory asset because associated sale fell through	Yes	Myers
Other	AG	Coppola	Defferal should be denied because it is preliminary	Yes	Myers

Consumers Energy Company's
Table of Disputed Issues
MPSC Case No. U-21806

Category	Intervenor	Intervenor Witness	Intervenor Position	Disagree?	CE Witness
Other	CUB	Denzler	Supports COST project, but notes that the Company hasn't removed expected O&M savings from its calculations.	Yes	Byrom
Other	CUB	Denzler	Witness requests the Commission order the Company to produce a detailed study of the benefits of ICE to EV conversion complete with estimated savings and actual field data.	No	Guinn
Other	CUB	Denzler	Witness requests the Commission order the Company to produce more detail concerning Fleet Responsibility costs in rate cases moving forward including impact by business unit and a projected bridge period and test year request for allowance.	No	Guinn
Other	CUB	Denzler	Witness requests the Commission order the Company to produce detailed study concerning vehicle idling and its dollar costs. Witness suggests the Company may be overrecovering for Fuel expenses as a result of unneccesary idling.	No	Guinn
Other	MEC	Deleon	CE should provide transparency regardeing probabilistic risk modeling and calculation of cost-effectiveness	Yes	Griffin
Other	MEC	Napolean	The EWR plan savings and design are relevant in this rate case, since they inform Consumers' investment plan. The focus of the gas efficiency program should be on electrification measures as well as weatherization and building envelope measures.	Yes	Byrom
Other	MPSC Staff	McMillian-Sepkoski	Staff recommends approval of the 15-year amortization of thecloud implementation costs for SaaS for SAP S/4HANA Implementation project.	No	Baker
Other	MPSC Staff	Nichols	Staff supports the requested accounting treatment to defer SAP S/4HANA Implementaion project O&M expense. If commission approves, the additional incremental revenue deficiency reduction is not reflected in the Staff's $177, 351,000 revenue deficiency found in Exhibit S-1, Schedule A-1.	No	Baker
Other	MPSC Staff	Zichi	Staff is recommending that the Company meet with Staff quarterly to inform them on progress of the SAP S/4HANA Implementation project, including updates on any advancements and/or setbacks in project implementaion, budget adherence, changes to scope, timeline, expenses, and any problems the Company has experienced or anticipates experiencing with any operations or customer interactions	No	Baker
Other	MPSC Staff	Zichi	Staff is recommending that the Company include in the Company's future rate cases until implementation is complete and share at the quarterly meetings with Staff, on any over and under recovery of each projected expense in the SAP S/4HANA Implementation project compared to the 80% base (ROM Projected investment).	No	Baker
Rate Design	ABATE	York	Transportation rate design: set LT & XLT Customer Charge at COS, new breakeven thresholds	Yes	Smith
Rate Design	ABATE	York	Revenue apportionment	Yes	Smith
Rate Design	AG	Coppola	No increase to Customer Charges for Res and GS-1	Yes	Smith
Rate Design	CUB	Denzler	No increase to Customer Charges for Residential	Yes	Smith
Rate Design	MPSC Staff	Rademacher	Increase the Excess Peak Demand threshold from 45 Mcf to 92 Mcf	No	Smith
Rate Design	MPSC Staff	Rademacher	Rate stability targets that differ from Company's proposed	No	Smith
Rate Design	MPSC Staff	Rademacher	Rate TOT - one single volumetric rate schedule with one single volumetric rate	Yes	Smith
Rate Design	MPSC Staff	Rademacher, Krause	Residential Customer Charge of $19, which is $1 less than the Company's proposal	No	Smith

Consumers Energy Company's
Table of Disputed Issues
MPSC Case No. U-21806

Category	Intervenor	Intervenor Witness	Intervenor Position	Disagree?	CE Witness
Revenue Forecast	AG	Coppola	Increase forecasted deliveries for Commerical Transport Class (similar approach to prior case)	Yes	Sherwani
Revenue Forecast	MPSC Staff	Braunschweig	Use 3 year average for forecasting income assistance	No	Sherwani
ROE	ABATE	Walters	ABATE recommends a 9.45% ROE	Yes	Ann Bulkley
ROE	AG	Coppola	AG recommends a 9.75% ROE	Yes	Ann Bulkley
ROE	CUB	Bandyk	CUB recommends a 9.24% ROE	Yes	Ann Bulkley
ROE	MPSC Staff	Megginson	Staff recommends a 9.75% ROE	Yes	Ann Bulkley
Sales Forecast	MPSC Staff	Ausum	Recommending to include all raw data and inputs used to construct forecast models in all future rate cases	No	Sherwani
Tariff	MPSC Staff	Rademacher	Proposes a 14 calendar day review period before rates are effective to file corrections in the docket prior to implementation, if needed.	No	Myers?
Tax	MPSC Staff	Witt	Property tax should be lower due to proposed disallowed capital.	No	VanBlarcum
Tax	AG	Coppola	Property tax should be lower due to proposed disallowed capital.	No	VanBlarcum
Tax	MPSC Staff	Putnam	Correction for incorrect inflation rate applied to test year payroll taxes and inclusion of historical sales & use tax amounts in projected general taxes.	No	Rayl
Test Year	ABATE	York	Commission should require the Company to use a historical test year.	Yes	Myers
Test Year	ABATE	York	Commission should examine the issue of projected test years continuing to result in excess revenues being collected from customers	Yes	Myers
Unamortized MGP	MPSC Staff	LaPan / Hecht	Staff recommends updating the net unamortized MGP balance for 2024 actual remediation activities	No	Rayl
Working Capital	AG	Coppola	Cash balance should be $12.3 million based on a 3-year historical average. This is lower than the Company's $28.4 million cash balance.	Yes	Marc Bleckman
Working Capital	AG	Coppola	Correction of an error in the calculation of the S4/HAHA cloud implementation adjustment to working capital (original adjustment was total company, not gas only)	No	Rayl
Working Capital	MPSC Staff	Justin Hecht	Cash balance should be $23,130,000 rather than $28,393,000 (Company error)	No	Marc Bleckman
Working Capital	MPSC Staff & AG	Hecht / Coppola	Correction for Company error in calculating projected accrued taxes	No	Rayl
Working Capital	AG	Coppola	Correction of an error in the calculation of the prepaid cloud computing adjustment to working capital	No	Rayl
Working Capital	MPSC Staff	Hecht	Recommended removal of a non-utility account from working capital	No	Rayl

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

PROOF OF SERVICE

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Melissa K. Harris, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on May 14, 2025, she served an electronic copy of the **Rebuttal Testimony and Exhibits of Consumers Energy Company Witnesses**, pursuant to the Protective Order in this case, upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.

Melissa K. Harris

Subscribed and sworn to before me this 14th day of May, 2025.

Crystal L. Chacon, Notary Public
State of Michigan, County of Eaton
My Commission Expires: 05/25/30
Acting in the County of Jackson

ATTACHMENT 1 TO CASE NO. U-21806

Party	Mailing Address	Email Address
Administrative Law Judge		
Hon. James M. Varchetti	Michigan Public Service Commission 7109 West Saginaw Highway Lansing, MI 48909	varchettij@michigan.gov
Counsel for Consumers Energy Company		
Bret A. Totoraitis, Esq. Gary A. Gensch, Jr., Esq. Anne M. Uitvlugt, Esq. Spencer A. Sattler, Esq. Evan B. Keimach, Esq. Mark R. Ruszkiewicz	One Energy Plaza Jackson, MI 49201	Bret.Totoraitis@cmsenergy.com Gary.GenschJr@cmsenergy.com Anne.Uitvlugt@cmsenergy.com Spencer.Sattler@cmsenergy.com Evan.Keimach@cmsenergy.com Mark.Ruszkiewicz@cmsenergy.com mpsc.filings@cmsenergy.com
***Counsel for the Michigan Public Service Commission Staff**		
Michael J. Orris, Esq. Amit T. Singh, Esq. Anna B. Stirling, Esq. Alena Clark, Esq.	Public Service Division 7109 West Saginaw Highway Post Office Box 30221 Lansing, MI 48909	orrism@michigan.gov singha9@michigan.gov stirlinga1@michigan.gov clarka55@michigan.gov
Michigan Public Service Commission Staff		
Mike Byrne Bill Stosik David Chislea Bob Nichols Nick Revere Lori Mayabb*	Michigan Public Service Commission 7109 West Saginaw Highway Post Office Box 30221 Lansing, MI 48909	byrneM@michigan.gov stosikb@michigan.gov chislead@michigan.gov nicholsb1@michigan.gov reveren@michigan.gov mayabbl@michigan.gov
***Counsel for Attorney General Dana Nessel**		
Celeste R. Gill, Esq.	Michigan Department of Attorney General, Special Litigation Division 525 West Ottawa Street 6th Floor Williams Building Post Office Box 30755 Lansing, MI 48909	gillc1@michigan.gov AG-ENRA-Spec-Lit@michigan.gov
***Counsel for Citizens Utility Board of Michigan ("CUB"), Michigan Environmental Council ("MEC") and Sierra Club ("SC")**		
Christopher M. Bzdok, Esq. Holly L. Hillyer, Esq. Natasha Fowles	Troposphere Legal 420 East Front Street Traverse City, MI 49686	chris@tropospherelegal.com holly@tropospherelegal.com natasha@tropospherelegal.com
Counsel on behalf of Sierra Club ("SC")		
Nihal Shrinath, Esq.	2101 Webster St. Suite 1300 Oakland, CA 94612	Nihal.shrinath@sierraclub.org
Consultant for Citizens Utility Board of Michigan ("CUB"), Michigan Environmental Council ("MEC") and Sierra Club ("SC")		
Julielyn Gibbons* Douglas Jester* Rick Bunch* Josh Denzler* Ram Veerapaneni*	5 Lakes Energy 220 M.A.C. Ave., Apt. 218 East Lansing, MI 48823	jgibbons@5lakesenergy.com djester@5lakesenergy.com rbunch@5lakesenergy.com jdenzler@5lakesenergy.com ram@5lakesenergy.com
Matthew Bandyk* Alice Napoleon* Sol Deleon*	Synapse Energy Economics 485 Massachusetts Ave., Suite 3 Cambridge, MA 02139	mbandyk@synapse-energy.com anapoleon@synapse-energy.com sdeleon@synapse-energy.com

* Receives Confidential Materials

ATTACHMENT 1 TO CASE NO. U-21806

Sophie Schadler*		sschadler@synapse-energy.com
Nihal Shrinath	Sierra Club 2101 Webster St., Suite 1300 Oakland, CA 94612	Nihal.shrinath@sierraclub.org
***Counsel for the Association of Businesses Advocating Tariff Equity ("ABATE")**		
Stephen A. Campbell, Esq. Michael J. Pattwell, Esq. Benjamin J. Holwerda, Esq.	Clark Hill, PLC 500 Woodward, Suite 3500 Detroit, MI 48226	scampbell@clarkhill.com mpattwell@clarkhill.com bholwerda@clarkhill.com
Consultants for ABATE		
James Dauphinais Jessica York	Brubaker & Associates, Inc. P.O. Box 412000 St. Louis, MO 63141	jdauphinais@consultbai.com jyork@consultbai.com
Counsel for Retail Energy Supply Association ("RESA")		
Jennifer Utter Heston, Esq.	Fraser Trebilcock Davis & Dunlap, P.C. 124 West Allegan, Suite 1000 Lansing, MI 48933	jheston@fraserlawfirm.com
***Counsel for the Lansing Board of Water & Light ("LBWL") and Michigan State University ("MSU")**		
Nolan J. Moody, Esq. Cole V. Lussier, Esq.	Dickinson Wright PLLC 123 W. Allegan Street, Ste. 900 Lansing, MI 48933-1816	nmoody@dickinsonwright.com clussier@dickinsonwright.com
Counsel for LBWL		
Mark Matus, Esq.	Lansing Board of Water & Light 1201 S. Washington Avenue Lansing, MI 48910	mark.matus@lbwl.com
Counsel for Energy Michigan		
Timothy J. Lundgren, Esq. Laura A. Chappell, Esq. Justin K. Ooms, Esq.	Potomac Law Group 120 N. Washington Square, Suite 300 Lansing, MI 48933	tlundgren@potomaclaw.com lchappelle@potomaclaw.com jooms@potomaclaw.com
***Counsel for The Ecology Center, The Environmental Law & Policy Center ("ELPC"), Union of Concerned Scientists ("UCS"), and Vote Solar (collectively, "CEO")**		
Daniel Abrams, Esq. Alondra Estrada Carolyn Boyce	Environmental Law & Policy Center 35 East Wacker Drive, Suite 1600 Chicago, IL 60601	dabrams@elpc.org aestrada@elpc.org cboyce@elpc.org MPSCDocket@elpc.org

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