

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of
DTE Gas Company for authority to Case No. U-21291
increase its rates, amend its rate
schedules and rules governing the Volume No. 4
distribution and supply of natural
gas, and for miscellaneous accounting PUBLIC RECORD
authority.

CROSS-EXAMINATION

Proceedings held via Microsoft Teams in the
above-entitled matter before Jonathan F. Thoits, J.D.,
Administrative Law Judge with MOAHR, for the Michigan
Public Service Commission, Lansing, Michigan, on
Monday, June 24, 2024, at 9:01 a.m.

APPEARANCES:

CARLTON D. WATSON, J.D.
BREANNE K. REITZEL, J.D.
ANDREA E. HAYDEN, J.D.
DTE Energy
One Energy Plaza, 1635 WCB
Detroit, Michigan 48226

On behalf of DTE Gas Company

STEPHEN A. CAMPBELL, J.D.
Clark Hill, PLC
500 Woodward Avenue, Suite 3500
Detroit, Michigan 48226-3485

On behalf of Association of Businesses
Advocating Tariff Equity

(Continued)

Penn Reporting, LLC - lori.penn@yahoo.com

1 APPEARANCES (Continuing):

2 JENNIFER UTTER HESTON, J.D.
3 Fraser Trebilcock Davis Dunlap & Cavanaugh, P.C.
4 124 W. Allegan Street, Suite 1000
5 Lansing, Michigan 48933

6 On behalf of Retail Energy Supply Association
7 and Michigan Power Limited Partnership

8 VALERIE J.M. BRADER, J.D.
9 Rivenoak Law Group
10 3331 West Big Beaver Road, Suite 109
11 Troy, Michigan 48084

12 On behalf of City of Ann Arbor

13 CHRISTOPHER M. BZDOK, J.D.
14 Troposphere Legal, PLC
15 420 East Front Street
16 Traverse City, Michigan 49686

17 On behalf of Michigan Environmental Council,
18 Natural Resources Defense Council, Sierra Club,
19 Citizens Utility Board of Michigan

20 DANIEL H.B. ABRAMS, J.D.
21 Environmental Law & Policy Center
22 35 E. Wacker Drive, Suite 1600
23 Chicago, Illinois 60601

24 On behalf of Environmental Law & Policy Center,
25 Ecology Center, Union of Concerned Scientists,
and Vote Solar

MARK N. TEMPLETON, J.D.
SAMUEL HEPPELL, J.D.
JACOB R. SCHUHARDT, J.D.
AMANDA URBAN, J.D.
University of Chicago
Abrams Environmental Law Clinic
6020 S. University Avenue
Chicago, Illinois 60637

On behalf of Urban Core Collective, Soulardarity,
and We Want Green, Too

(Continued)

Penn Reporting, LLC - lori.penn@yahoo.com

1 APPEARANCES (Continuing):

2 SEAN P. GALLAGHER, J.D.
3 Fraser Trebilcock Davis & Dunlap, P.C.
4 124 West Allegan, Suite 1000
5 Lansing, Michigan 48933

6 On behalf of Dearborn Industrial Generation, LLC

7 JOEL B. KING,
8 Assistant Attorney General
9 525 West Ottawa, Sixth Floor
10 G. Mennen Williams Building
11 Lansing, Michigan 48913

12 On behalf of Attorney General Dana Nessel

13 ANNA B. STIRLING,
14 Assistant Attorney General
15 7109 W. Saginaw Highway, Floor 3
16 Lansing, Michigan 48917

17 On behalf of Michigan Public Service
18 Commission Staff

19 - - -

20 REPORTED BY: Lori Anne Penn, CSR-1315

I N D E XWITNESS:PAGE

ERIC D. JANNESS

Direct Examination by Mr. Watson
Cross-Examination by Mr. Bzdok579
653

CEO

BRADLEY CEBULKO

Direct and Rebuttal Testimony Bound In

708

SAAD SIDDIQUE

Direct Testimony Bound In

777

MPLP

BRIAN C. COLLINS

Direct and Revised Rebuttal Testimony Bound In

788

MNSC

DR. ASA S. HOPKINS

Direct Testimony Bound In

824

ALICE NAPOLEON

Direct Testimony Bound In

890

CUB

RAM VEERAPANENI

Direct Testimony Bound In

936

MATT BANDYK

Direct Testimony Bound In

947

I N D E XWITNESS:PAGE

FLO

JACKSON KOEPPPEL

Direct and Rebuttal Testimony Bound In

968

JUSTIN SCHOTT

Direct Testimony Bound In

1053

SERGIO CIRA-REYES

Public Direct Testimony Bound In

1146

Confidential Direct Testimony Bound In

1190

TOYIA WATTS

Direct Testimony Bound In

1235

ABATE

JESSICA A. YORK

Direct and Rebuttal Testimony Bound In

1255

COLIN T. FITZHENRY

Direct Testimony Bound In

1310

CHRISTOPHER C. WALTERS

Direct and Rebuttal Testimony Bound In

1332

AG

SEBASTIAN COPPOLA

Direct Testimony Bound In

1420

I N D E X

<u>WITNESS:</u>	<u>PAGE</u>
STAFF	
DANIELLE R. ROGERS	
Direct Testimony Bound In	1596
JOSEPH E. UFOLLA	
Direct Testimony Bound In	1608
MADISON S. TODD	
Revised Direct Testimony Bound In	1635
SHANNON RUECKERT	
Direct Testimony Bound In	1645
NICHOLAS M. REVERE	
Direct and Rebuttal Testimony Bound In	1656
CHARLES E. PUTNAM, CPA	
Direct Testimony Bound In	1676
ROBERT F. NICHOLS, II, CPA	
Direct Testimony Bound In	1687
THERESA McMILLAN-SEPKOSKI	
Direct Testimony Bound In	1694
JAMES E. LaPAN	
Direct Testimony Bound In	1705
KEVIN S. KRAUSE	
Revised Direct and Rebuttal Testimony Bound In	1714
JUSTIN J. HECHT	
Direct Testimony Bound In	1742

I N D E X

<u>WITNESS:</u>	<u>PAGE</u>
ELAINA M. BRAUNSCHWEIG	
Direct and Rebuttal Testimony Bound In	1756
CYNTHIA L. CREISHER	
Direct Testimony Bound In	1782
NYRHE U. ROYAL	
Direct Testimony Bound In	1801
KEVIN P. SPENCE	
Direct Testimony Bound In	1816
DTE	
RAJAN M. TELANG	
Direct and Rebuttal Testimony Bound In	1834
KELLY M. FEDELE	
Direct and Rebuttal Testimony Bound In	1879
SCOTTY N. KEHOE	
Direct and Rebuttal Testimony Bound In	1993
CHRIS A. BENCE	
Direct and Rebuttal Testimony Bound In	2056
JAISON J. BUSBY	
Revised Direct and Rebuttal Testimony Bound In	2079
TIMOTHY J. KRYSINSKI	
Revised Direct and Rebuttal Testimony Bound In	2141
TIMOTHY J. LEPCZYK	
Direct and Rebuttal Testimony Bound In	2183

I N D E X

<u>WITNESS:</u>	<u>PAGE</u>
JASON E. SPARKS	
Direct and Public Rebuttal Testimony Bound In	2213
Confidential Rebuttal Testimony Bound In	2250
THERESA M. UZENSKI	
Direct and Rebuttal Testimony Bound In	2266
KIRK M. VANGILDER	
Direct and Rebuttal Testimony Bound In	2346
SHERRI L. WISNIEWSKI	
Revised Direct and Rebuttal Testimony Bound In	2372
MICHAEL A. BRENNAN	
Direct Testimony Bound In	2398
MICHAEL J. HATSIOS	
Direct and Rebuttal Testimony Bound In	2418
DR. BENTE VILLADSEN	
Direct and Revised Rebuttal Testimony Bound In	2444
MICHAEL S. COOPER	
Revised Direct and Rebuttal Testimony Bound In	2600

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
A-1	Sch. A1 (VANGILDER) Sch. A2 (LEPCZYK)	2344 2181	2344 2182
A-2	Sch. B1 (VANGILDER) Sch. B2, B3, B4, B4.1, B4.2 (UZENSKI)	2344 2264	2344 2265
A-3	Sch. C1, C1.1, C3, C4, C5, C6, C11, C14, C15, C16, C17, C18 (UZENSKI) Sch. C2, C12, C13 (VANGILDER) Sch. C7, C8, C9, C10 (WISNIEWSKI)	2264 2344 2381	2265 2344 2371
A-4	Sch. D1 (VANGILDER) Sch. D2, D3, D4, D5 (LEPCZYK)	2344 2181	2344 2182
A-11	Sch. A1 (VANGILDER) Sch A2 (LEPCZYK)	2344 2181	2344 2182
A-12	Sch. B1 (VANGILDER) Sch. B2, B3, B4, B4.1, B4.2, B4.3 (UZENSKI) Sch. B5, B5.2, B5.6, CONFIDENTIAL B5.7, B5.8, CONFIDENTIAL B5.9, B5.14 (FEDELE) Sch. B5.3, B5.20, B5.6, B6.1, B6.2, B6.3, B6.4, B6.5 (JANNES) Sch. B5.4.1, B5.15, B5.16, B5.17, B5.18, REVISED B.7, CONFIDENTIAL B9 (BUSBY) Sch. B5.5 (FEDELE/ABONA/JANNES/BUSBY)	2344 2264 1877 581 2077 581	2344 2265 1878 706 2078 706
A-13	Sch. C1, C1.1, C3, C3.1, C3.4, C5, C5.2.2, C5.6, C6, C11, C12, C14 (UZENSKI) Sch. C2, C15, C16 (VANGILDER) Sch. C4 (KRYNSKI) Sch. C5.1, C5.2, C5.3 (KEHOE) Sch. C5.4 (HATSIOS) Sch. C5.7 (SPARKS) Sch. REVISED C5.9, C5.9.1, C5.9.2, C5.9.3, C5.10, C5.11 (COOPER) Sch. C7, C7.1 REVISED, C8, C8.1, C9, C10 (WISNIEWSKI) Sch. C13.1, C13.2, C13.3, C13.4 (BRENNAN)	2264 2344 2139 1991 2417 2212 2598 2371 2396	2265 2344 2140 1992 2417 2212 2599 2371 2397

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
A-14	Sch. D1 (VANGILDER)	2344	2344
	Sch. D2, D3, D4 (LEPCZYK)	2181	2182
	Sch. D5, D5.1, D5.2, D5.3, D5.4, D5.5, D5.6, D5.7, D5.8, D5.9, D5.10, D5.11, D5.12, D5.13, D5.14, D5.15, D5.16, D5.17, D5.18 (VILLADSEN)	2442	2443
A-15	Sch. E8, E9, E10, E11, E12, E13 (BENCE)	2054	2054
A-16	Sch. F1, F1.1, F1.2, F2, F3, F4, F5, F5.1, F6 (KRYSENSKI)	2139	2140
A-17	Sch. G1, G2, G3 (LEPCZYK)	2181	2182
A-18	Sch. H1, H2, H3, H6, H7 (VANGILDER)	2344	2344
	Sch. H4, H5 (KRYSENSKI)	2139	2140
A-19	Sch. I1, I2, I3, I4, I5 REVISED (COOPER)	2598	2599
A-20	Sch. J1, J2 (KEHOE)	1991	1992
A-21	Sch. K1, K2 (KEHOE)	1991	1992
A-24	Sch. N1 REVISED (KRYSENSKI)	2139	2140
A-25	Sch. O1 (SPARKS)	2212	2212
A-27	Sch. Q1 (KEHOE)	1991	1992
A-29	Sch. S1, S2, S3, S4, S5, S6 (COOPER)	2598	2599
A-32	Sch. V1, V2 (JANNESS)	581	706
A-33	Sch. W1, W2 (SPARKS)	2212	2212
A-34	Sch, X1, X2, X3 (UZENSKI)	2264	2265
A-35	Sch. Y1, Y2 (LEPCZYK)	2181	2182
A-36	Sch. Z1 (WISNIEWSKI)	2371	2371
A-37	Sch. AA1 (VANGILDER)	2344	--
A-38	Sch. BB1, BB2, BB3 (VILLADSEN)	2442	2443

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
AB-1	Referenced Responses to Discovery Requests (York)	1253	1253
AB-2	Design Day Demand Class Cost of Service Study (York)	1253	1253
AB-3	Referenced Responses to Discovery Requests (Fitzhenry)	1309	1309
AB-4	Electric Utilities (Valuation Metrics) (Walters)	1331	1331
AB-5	Proxy Group (Walters)	1331	1331
AB-6	Consensus Analysts' Growth Rates (Walters)	1331	1331
AB-7	Constant Growth DCF Model (Consensus Analysts' Growth Rates) (Walters)	1331	1331
AB-8	Payout Ratios (Walters)	1331	1331
AB-9	Sustainable Growth Rate (Walters)	1331	1331
AB-10	Constant Growth DCF Model (Sustainable Growth Rate) (Walters)	1331	1331
AB-11	Multi-Stage Growth DCF Model (Walters)	1331	1331
AB-12	Common Stock Market/Book Ratio (Walters) Equity Risk Premium - Treasury Bond (Walters)	1331	1331
AB-13	Equity Risk Premium - Treasury Bond (Walters)	1331	1331
AB-14	Equity Risk Premium - Utility Bond (Walters)	1331	1331
AB-15	Bond Yield Spreads (Walters)	1331	1331
AB-16	13-Week Treasury and Utility Bond Yields (Walters)	1331	1331

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
AB-17	Beta (Walters)	1331	1331
AB-18	CAPM Return (Walters)	1331	1331
AB-19	Referenced Responses to Discovery Request (York)	1253	1253
AB-20	DTE Discovery Responses	1418	1418
	- - -		
AG-1	DTE Energy Investor Presentation April 2024	1418	1419
AG-2	CONFIDENTIAL Blue Chip Report March 2024	1418	1419
AG-3	Main Renewals DRs	1418	1419
AG-4	Actual Distribution Capex	1418	1419
AG-5	Public Improvements	1418	1419
AG-6	System Reliability Units and Costs	1418	1419
AG-7	Communications & Controls Meters	1418	1419
AG-8	Leak Detection & Repair LDAR Costs	1418	1419
AG-9	Fort Street Replacement	1418	1419
AG-10	Van Born Project Write-off	1418	1419
AG-11	PRA Risked Project List	1418	1419
AG-12	MRP MMO and IRM Spending with Miles	1418	1419
AG-13	Cathodic Spending in or out of IRM	1418	1419
AG-14	Transmission Premature Projects	1418	1419
AG-15	ILI Premature Projects	1418	1419
AG-16	TCARP Overruns and Billings to DTMLC	1418	1419
AG-17	Storage & Compression Projects	1418	1419

Penn Reporting, LLC - lori.penn@yahoo.com

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
AG-18	Transportation Vehicle and Equipment Purchases	1418	1419
AG-19	IT Capex Savings Gas Schedule Optimz.	1418	1419
AG-20	Capital Expenditures, Rate Base Reductions and Depr.	1418	1419
AG-21	Working Capital	1418	1419
AG-22	Overall Cost of Capital	1418	1419
AG-23	Equity Cost of Capital	1418	1419
AG-24	Equity Cost of Capital - DCF	1418	1419
AG-25	Equity Cost of Capital - CAPM	1418	1419
AG-26	Equity Cost of Capital -Risk Premium	1418	1419
AG-27	Peer Group Capitalization	1418	1419
AG-28	Market to Book	1418	1419
AG-29	ROE Decisions	1418	1419
AG-30	Cash Flow to Debt Coverage Ratio	1418	1419
AG-31	Value Line - Volatility vs. Risk	1418	1419
AG-32	Gas Sales Analysis	1418	1419
AG-33	Adjustments to DTE Forecasting Model and Usage Trend	1418	1419
AG-34	Gas Sales Revenue	1418	1419
AG-35	EUT Power Generation Load	1418	1419
AG-36	Off-System Transportation, Storage and Park & Loan	1418	1419
AG-37	Midstream Revenue Adjustments	1418	1419
AG-38	HPP Appliance Service Program Revenue	1418	1419

Penn Reporting, LLC - lori.penn@yahoo.com

E X H I B I T S

	<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
1				
2				
3	AG-39	O&M Summary Adjustments	1418	1419
4	AG-40	Co. Use and LAUF	1418	1419
5	AG-41	Revised Cost of Gas Rate	1418	1419
6	AG-42	Uncoll Accts Expense	1418	1419
7	AG-43	O&M Inflation Adjustment	1418	1419
8	AG-44	O&M Cost Reductions 2023	1418	1419
9	AG-45	2023 O&M Reductions Normalized	1418	1419
10	AG-46	O&M Cost Reductions Headcount Reduction	1418	1419
11	AG-47	Active Health Care O&M Expense	1418	1419
12	AG-48	Rents Adjustment	1418	1419
13	AG-49	Incentive Comp Performance Measures	1418	1419
14	AG-50	MAOP O&M Cost and TVC Records Review	1418	1419
15	AG-51	OPEB Regulatory Liability Amortization	1418	1419
16	AG-52	Customer Payment Transaction Cost Options	1418	1419
17	AG-53	Corporate Jet Travel	1418	1419
18	AG-54	DTE Gas Deferred Incentive Comp Calc	1418	1419
19	AG-55	Revenue Deficiency Calculation	1418	1419
20	AG-56	DR AGDG-8.207 to 8.213	1418	1419
21	AG-57	DR AGDG-8.214a, 8.215, 8.216	1418	1419
22	AG-58	DR AGDG-8.117a-b, 8.218a	1418	1419
23	AG-59	DR AGDG-8.218a, 8.218bi, 8.218bii with	1418	1419
24		Revised Exhibit AG-32, 8.218ci-ii,		
25		8.219a-b, 8.220, 8.221		

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
AG-60	DR AGDG-8.223, 8.225, 8.226 w/attachment, 8.227, 8.228a, 8.228d	1418	1419
AG-61	CONFIDENTIAL and PUBLIC versions DR AGDG-8.229a-c, 8.230	1418	1419
AG-62	DR AGDG-8.231a-d, 8.232a-c, 8.233a-c with DR AGDG-4.96c, 8.234a-d	1418	1419
AG-63	DR AGDG-8.235, 8.236	1418	1419
AG-64	DR AGDG-8.237a-b, 8.238a-b, 8.239, 8.240a	1418	1419
AG-65	DR AGDG-8.241, 8.242a-b, 8.243, 8.244	1418	1419
AG-66	DR AGDG-8.246a, 8.247, 8.248	1418	1419
AG-67	DR AGDG-8.250a, 8.250b with attachment, 8.250c with attachment	1418	1419
AG-68	DR AGDG-8.251b-c, 8.252b	1418	1419
AG-69	DR AGDG-9.255, 9.256, 9.257a-c	1418	1419
AG-70	DR AGDG-9.258a-b	1418	1419
AG-71	DR AGDG-9.259b, 9.262c, 9.264, 9.265, 9.269b	1418	1419
AG-72	DR AGDG-9.266a-b, 9.267, 9.268a-cc	1418	1419
AG-73	DR AGDG-9.272c	1418	1419
- - -			
CEO-1	Resume of Bradley Cebulko	707	707
CEO-2	DTE Response to CEODG-2.4j, Figure 65 Data	707	707
CEO-3	DTE Response to CEODG-1.16	707	707
CEO-4	DTE Response to MNSCDG-2.1b, Annual Billed Sales Volumes	707	707

Penn Reporting, LLC - lori.penn@yahoo.com

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
CEO-5	DTE Response to CEODG-1.27a, Historical Peak Day Demand	707	707
CEO-6	DTE Response to CEODG-1.24a, Five Year Forecast	707	707
CEO-7	Brattle, "The Future of Gas Series Utilities Series, Transitioning Gas Utilities to a Decarbonized Future." Part 1 of 3. August 21.	707	707
CEO-8	DTE Response to CEODG-2.1	707	707
CEO-9	DTE Response to CEODG-1.15a	707	707
CEO-10	DTE Response to MNSCDG-2.1a, Annual Emissions from Customer Gas Consumption	707	707
CEO-11	Modification to DTE Response to MNSCDG-2.1a, Annual Emissions from Customer Gas Consumption	707	707
CEO-12	DTE Response to CEODG-1.30a	707	707
CEO-13	DTE Response to CEODG-1.30b	707	707
CEO-14	DTE Response to CEODG-1.30c	707	707
CEO-15	DTE Response to CEODG-1.30d	707	707
CEO-16	DTE Response to CEODG-2.6c	707	707
CEO-17	DTE Response to CEODG-2.6d	707	707
CEO-18	DTE Response to CEODG-2.7b, BWEC Hydrogen Blending Pilot	707	707
CEO-19	DTE Response to CEODG-2.7c	707	707
CEO-20	DTE response to CEODG-2.8a	707	707
CEO-21	DTE Response to CEODG-2.8b	707	707
CEO-22	DTE Response to CEODG-2.8c	707	707

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
CEO-23	DTE Response to CEODG-2.9a	707	707
CEO-24	B. Cebulko, A Regulators Blueprint for 21st Century Gas Utility Planning (December 2023)	707	707
CEO-25	R. Nelson, Non-Pipeline Alternatives to Natural Gas Utility Infrastructure, An Examination of Existing Regulatory Approaches	707	707
CEO-26	DTE Response to CEODG-1.3a	707	707
CEO-27	DTE Response to CEODG-1.8c	707	707
CEO-28	DTE Response to CEODG-3.7a	707	707
CEO-29	DTE Response to CEODG-3.7b	707	707
CEO-30	DTE Response to CEODG-3.7c	707	707
CEO-31	DTE Response to CEODG-3.7d	707	707
CEO-32	DTE Response to CEODG-3.7e	707	707
CEO-33	DTE Response to CEODG-3.7f	707	707
CEO-34	DTE Response to CEODG-3.8a	707	707
CEO-35	DTE Response to CEODG-3.8b	707	707
CEO-36	DTE Response to MNSCDG-2.6d, Gas DR Pilot Results Season 2 ("Gas Demand Response Winter 2022-23 Results" June 16, 2023)	707	707
CEO-37	DTE Response to CEODG-3.12	707	707
CEO-38	DTE Response to CEODG-1.4a	707	707
CEO-39	DTE Response to CEODG-1.5a	707	707
CEO-40	DTE Response to CEODG-1.3c	707	707

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
CEO-41	DTE Response to MNSCDG-2.6d, Gas DR Pilot Results Season 1 ("Gas Demand Response Results - Year 1" May 11, 2022)	707	707
CEO-42	DTE Response to CEODG-4.1bi	707	707
CEO-43	DTE Response to CEODG-4.1di	707	707
CEO-44	Resume of Saad Siddique	776	776
CEO-45	DTE Gas Company's Response to the Ecology Center, the Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar's First Discovery Request; CEODG 1.31a	776	776
- - -			
CUB-1	Resume of Ram Veerapaneni	935	935
CUB-2	Capital Expenditures	935	935
CUB-3	Capital Expenditures - Adjustments	935	935
CUB-4	Resume of Matt Bandyk	935	935
CUB-5	Public Utility Fortnightly, "Nice Work If You Can Get It" by Steve Huntoon	935	935
CUB-6	Energy Institute at Haas, "Rate of Return Regulation Revisited", Werner & Jarvis	935	935
CUB-7	CAPM Analysis	935	935
CUB-8	Equity Risk Premium Estimates	935	935
CUB-9	Cost of Capital	935	935
- - -			
DIG-1	DTE Gas Co. Discovery Response No. DIGDG-1.1 (S. N. Kehoe)	2694	2695

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
DIG-2	DTE Gas Co. Discovery Response No. DIGDG-1.2 (T. J. Krysinski)	2694	2695
DIG-3	DTE Gas Co. Discovery Response No. DIGDG-1.3 (T. J. Krysinski)	2694	2695
DIG-4	DTE Gas Co. Discovery Response No. DIGDG-1.4 (H. J. Decker)	2694	2695
DIG-5	DTE Gas Co. Discovery Response No. DIGDG-1.5 (H. J. Decker)	2694	2695
DIG-6	DTE Gas Co. Discovery Response No. DIGDG-1.6 (H. J. Decker)	2694	2695
- - -			
FLO-1	DTE Energy Co., Annual Report (Form 10-K) (Feb. 8, 2024) (excerpt)	966	967
FLO-2	Karlee Weinmann, Amid controversies, DTE Energy continues to spend big in Michigan and nearly every lawmaker accepts, ENERGY AND POLICY INSTITUTE (Sept. 28, 2022), https://energyandpolicy.org/dte-energy-political-contributions-michigan/ .	935	935
FLO-3	David Anderson, et al., Strings Attached: How utilities use charitable giving to influence politics and increase investor profits, ENERGY AND POLICY INSTITUTE (Dec. 2019), https://energyandpolicy.org/strings-attached-how-utilities-use-charitable-giving-to-influence-politics-increase-investor-profits-dte-energy/ .	935	935
FLO-4	Energy and Policy Institute, Michigan Energy First (last accessed May 2, 2024), https://energyandpolicy.org/michigan-energy-first/ .	935	935

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
FLO-5	Laura Frier, Delia Mayor, & Brett Zeuner, Assessing the State of Environmental Justice in Michigan (May 2019), https://deepblue.lib.umich.edu/bitstream/handle/2027.42/149105/AssessingtheStateofEnvironmentalJusticeinMichigan_344.pdf?sequence=1&isAllowed=y .	935	935
FLO-6	EMILY GRUBERT & SARA HASTINGS-SIMON, DESIGNING THE MID-TRANSITION: A REVIEW OF MEDIUM-TERM CHALLENGES FOR COORDINATED DECARBONIZATION IN THE UNITED STATES (2022) .	935	935
FLO-7	KARIN KIRK, WHICH STATE IS WINNING AT RENEWABLE ENERGY PRODUCTION? (Feb. 23, 2022) .	935	935
FLO-8	THROWING SHADE: 10 SUNNY STATES BLOCKING DISTRIBUTED SOLAR DEVELOPMENT (2018) .	935	935
FLO-9	VIBRANT CLEAN ENERGY, LLC, ELECTRIFICATION AND DECARBONIZATION PATHWAYS FOR MICHIGAN (2022) .	935	935
FLO-10	Andy Balaskovitz, Utility-linked group seeks to dismantle net metering in Michigan (Mar. 4, 2019), https://energynews.us/2019/03/04/utility-linked-group-seeks-to-dismantle-net-metering-in-michigan/ .	935	935
FLO-11	Erik Pohl, et al., Distribution Grid Impact Study in Highland Park, Michigan: Understanding Rooftop Solar, Behind-the-Meter Energy Storage, Electric Vehicle Charging, and Building Electrification, U.S. DEP'T OF ENERGY, (2024), https://www.nrel.gov/docs/fy24osti/87916.pdf) .	935	935

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
FLO-12	Weiwei Lin, et al., Meta-analysis of the effects of indoor nitrogen dioxide and gas cooking on asthma and wheeze in children, 42 INT. J. EPIDEMIOLOGY 1724 (2023).	935	935
FLO-13	Prudence Kunyangna & Beth Anderson, Detroit:The Current Status of Asthma Burden (2021).	935	935
FLO-14	DTE Gas's Response to FLO's Third Discovery Request, FLODG-3.12.	935	935
FLO-15	DTE Gas's Response to FLO's Third Discovery Request, FLODG-3.13. FLODG-3.15.	935	935
FLO-16	DTE Gas's Response to FLO's Third Discovery Request, FLODG-3.17.	935	935
FLO-17	DTE Gas's Response to FLO's Third Discovery Request, 3.19.	935	935
FLO-18	Courtney Lindwall, Decarbonization: Why We Must Electrify Everything Even Before the Grid Is Fully Green (Dec. 1, 2022), https://www.nrdc.org/stories/why-we-must-electrify-everything-even-grid-fully-green .	935	935
FLO-19	Arjun Makhijani, The Trouble with STRIDE: Meeting climate goals and addressing natural gas system stranded costs (Dec. 2023), https://ieer.org/wp/wp-content/uploads/2024/01/Natural-gas-stranded-costs-and-climate-A-Maryland-case-study-2023-12.pdf .	935	935
FLO-20	Isaac Sevier, Building Decarbonization has a Natural Gas Pipeline Problem (May 17, 2023), https://www.climateandcommunity.org/building-decarb-natural-gas-problem .	935	935

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
FLO-21	DTE Gas's Response to FLO's Third Discovery Request, FLODG-3.9.	935	935
FLO-22	DTE Gas's Response to CEO's First Discovery Request, CEODG-1.15a.	935	935
FLO-23	DTE Gas's Response to MNSC's Fifth Discovery Request, MNSCDG-5.10b.	935	935
FLO-24	DTE GAS COMPANY, LOW CARBON ENERGY INFRASTRUCTURE ENHANCEMENT AND DEVELOPMENT GRANT PROPOSAL: EXPANSION OF NATURAL GAS DISTRIBUTION SYSTEMS IN BENZIE, MANISTEE, AND WEXFORD COUNTIES (2023).	935	935
FLO-25	DTE GAS COMPANY, LOW CARBON ENERGY INFRASTRUCTURE ENHANCEMENT AND DEVELOPMENT GRANT PROPOSAL: EXPANSION OF NATURAL GAS DISTRIBUTION SYSTEMS IN NEWAGO COUNTY (2023).	935	935
FLO-26	DTE GAS COMPANY, LOW CARBON ENERGY INFRASTRUCTURE ENHANCEMENT AND DEVELOPMENT GRANT PROPOSAL: EXPANSION OF NATURAL GAS DISTRIBUTION SYSTEMS IN DELTA COUNTY (2023).	935	935
FLO-27	DTE GAS COMPANY, LOW CARBON ENERGY INFRASTRUCTURE ENHANCEMENT AND DEVELOPMENT GRANT PROPOSAL: EXPANSION OF NATURAL GAS DISTRIBUTION SYSTEMS IN OSCEOLA COUNTY (2023).	935	935
FLO-28	DTE GAS COMPANY, LOW CARBON ENERGY INFRASTRUCTURE ENHANCEMENT AND DEVELOPMENT GRANT PROPOSAL: EXPANSION OF NATURAL GAS DISTRIBUTION SYSTEMS IN OCEANA COUNTY (2023).	935	935
FLO-29	DTE Gas's Response to CEO's First Discovery Request, CEODG-1.17.	935	935

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
FLO-30	DTE Gas's Response to FLO's Fifth Discovery Request, FLODG-5.1b, 5.1c(i)-(iii), 5.2b, 5.2c(i)-(iii), 5.3b, 5.3c(i)-(iii).	935	935
FLO-31	DTE Gas's Response to FLO's Fifth Discovery Request, FLODG-5.1a, 5.2a, 5.3a.	935	935
FLO-32	Trustwell. Standard Definitional Document, IES (Sep. 1, 2020).	935	935
FLO-33	MIQ Standard, MIQ (last accessed May 1, 2024), https://miq.org/the-technical-standard/ .	935	935
FLO-34	NRDC et al., Comments to the MPSC on the Renewable Natural Gas Study Draft and June 29 Presentation (Aug. 3, 2022).	935	935
FLO-35	DTE Gas's Response to FLO's Third Discovery Request, FLODG-3.10a.	935	935
FLO-36	DTE Gas's Response to FLO's Third Discovery Request, FLODG3-10b.	935	935
FLO-37	Brian Allnutt, U.S. Senators accuse DTE-chaired American Gas Association of Using Customer Money to Mislead Public, PLANET DETROIT (May 1, 2024), https://planetdetroit.org/2024/05/natural-gas-dte-american-gas-association/ .	935	935
FLO-38	DTE 501(c)(6) CONTRIBUTIONS AND LOBBYING EXPENSES (2023), https://www.dteenergy.com/content/dam/dteenergy/deg/website/common/about-us/company-information/corporate-governance/political-participation/DTE501Expenditures.pdf .	935	935
FLO-39	DTE, POLITICAL PARTICIPATION (last accessed May 1, 2024), https://www.dteenergy.com/us/en/residential/about-dte/corporate-governance/political-participation.html .	935	935

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
FLO-40	About Us, THE COALITION FOR RENEWABLE NATURAL GAS (last accessed May 6, 2024) https://www.rngcoalition.com/thecoalitionforrng .	935	935
FLO-41	Karl Dunkle Werner & Stephen Jarvis, Energy Inst. at Haas, Rate of Return Regulation Revisited (Energy Inst. Working Paper No. 329R, Revised Aug. 2023).	935	935
FLO-42	BEN STACY & TONY REAMES, URBAN ENERGY JUST. LAB, UNIVERSITY OF MICHIGAN, SOCIAL EQUITY IN STATE ENERGY POLICY: INDICATORS FOR MICHIGAN'S ENERGY EFFICIENCY PROGRAMS (2017).	935	935
FLO-43	HOME ENERGY AFFORDABILITY GAP REPORT 2022: MICHIGAN (2023).	935	935
FLO-44	AMERICAN COUNCIL FOR AN ENERGY EFFICIENT ECONOMY, UNDERSTANDING ENERGY AFFORDABILITY (Sep. 9, 2019).	935	935
FLO-45	DTE Gas's Response to FLO's Sixth Discovery Request, FLODG-6.11, 6.12, 6.13.	935	935
FLO-46	ELECTRICITY CONSUMERS RESOURCE COUNCIL, REVENUE DECOUPLING AND ITS ALTERNATIVES: AN INTERVENER'S GUIDE TO RETAIL RATEMAKING AND POLICIES ON DECOUPLING (2009).	935	935
FLO-47	MPSC Approves \$50M in Low-Carbon Energy Infrastructure Grants, MICH. PUB. SERV. COMM'N (June 9, 2023), https://www.michigan.gov/mpsc/commission/news-releases/2023/06/09/mpsc-approves-\$50m-in-low-carbon-energy-infrastructure-grants .	935	935
FLO-101	Justin Schott CV & Summary of Qualifications	1052	1052

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
FLO-102	SHALANDA BAKER, SUBIN DEVAR & SHIVA PRAKASH, INITIATIVE FOR ENERGY JUST., THE ENERGY JUSTICE WORKBOOK (2019)	1052	1052
FLO-103	Diana Hernandez, Understanding gEnergy Insecurity h and Why It Matters to Health, SOC. SCI. & MED., no. 167, 2016 Household Energy Insecurity (Indiana U, 2022)	1052	1052
FLO-104	In 2020, 27% of U.S. Households Had Difficulty Meeting Their Energy Needs, U.S. ENERGY INFO. ADMIN. (Apr. 11, 2022)	1052	1052
FLO-105	Workgroups, MICH. PUB. SERV. COMM'N (last accessed May 5, 2024)	1052	1052
FLO-106	MICH. PUB. SERV. COMM'N, EQUITY AND ENVIRONMENTAL JUSTICE TECHNICAL ASSISTANCE, REQUEST FOR QUOTES (2024)	1052	1052
FLO-107	ENERGY EQUITY PROJECT, SCH. FOR ENV'T & SUSTAINABILITY, UNIV. OF MICH., ENERGY EQUITY PROJECT REPORT (2022)	1052	1052
FLO-108	Low-Income Self-Sufficiency Plan, DTE (last accessed Apr. 30, 2024)	1052	1052
FLO-109	Justin Schott, JS FLO Working Paper 1	1052	1052
FLO-110	DTE's Response to FLO's First Discovery Request, FLODG-1.18a	1052	1052
FLO-111	DTE's Response to FLO' First Discovery Request, FLODG-1.17	1052	1052
FLO-112	Low-Income Programs, DTE (last accessed May 4, 2024)	1052	1052
FLO-113	Billing: Frequently Asked Questions, DTE (last accessed May 4, 2024)	1052	1052
FLO-114	Sarah Alvarez, The Obscure Utility Tax Detroiters Pay Each Month to Fund the Police, OUTLIER Media (Mar. 24, 2022)	1052	1052

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
FLO-115	DTE' Response to FLO' First Discovery Request, FLODG-1.2a & U-21291 FLODG-1.2a 10 Sample Residential Invoices	1052	1052
FLO-116	Sheri McWhirter, DTE, Consumers Win \$231M in Approvals Despite Reliability Woes, MLIVE (Mar. 4, 2024)	1052	1052
FLO-117	Sarah Alvarez & Emily Hopkins, She Didn't Know She Still Owed Money to Her Utility. Then 25% of Her Paycheck Was Gone, PROPUBLICA (Aug. 19, 2022)	1052	1052
FLO-118	Dominic J. Bednar & Tony G. Reames, Recognition of and Response to Energy Poverty in the United States, NATURE ENERGY	1052	1052
FLO-119	Janjala Chirakija, Seema Jayachandran & Pinchuan Ong, Inexpensive Heating Reduces Winter Mortality (Nat'l Bureau of Econ. Rsch., Working Paper No. 25681, 2019)	1052	1052
FLO-120	Michelle Graff, David M. Konisky, Sanya Carley & Trevor Memmott, Climate Change and Energy Insecurity: A Growing Need for Policy Intervention, 15 ENV'T JUST, no. 2, 2022	1052	1052
FLO-121	Sonal Jessel, Samantha Sawyer & Diana Hernandez, Energy, Poverty, and Health in Climate Change: A Comprehensive Review of an Emerging Literature, 7 FRONTIERS IN PUB. HEALTH, Dec. 2019	1052	1052
FLO-122	Michigan, CTRS. FOR DISEASE CONTROL & PREVENTION (last updated Sept. 12, 2023)	1052	1052
FLO-123	Heart Disease Mortality by State, CTRS. FOR DISEASE CONTROL & PREVENTION (last updated Feb. 25, 2022)	1052	1052

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
FLO-124	Jeremiah Bohr & Anna C. McCreery, Do Energy Burdens contribute to Economic Poverty in the United States? A Panel Analysis, 99 SOC. FORCES, no. 1, Sept. 2020	1052	1052
FLO-125	Gopal K. Singh & Hyunjung Lee, Marked Disparities in Life Expectancy by Education, Poverty Level, Occupation, and Housing Tenure in the United States, INT'L J. OF MATERNAL & CHILD HEALTH & AIDS, no. 10, 2021	1052	1052
FLO-126	Justin Schott, JS FLO Working Paper 2	1052	1052
FLO-127	ARIEL DREHOBL & LAUREN ROSS, AM. COUNCIL FOR AN ENERGY-EFFICIENT ECON., LIFTING THE HIGH ENERGY BURDEN IN AMERICA'S LARGEST CITIES: HOW ENERGY EFFICIENCY CAN IMPROVE LOW INCOME AND UNDERSERVED COMMUNITIES (2016)	1052	1052
FLO-128	MARILYN A. BROWN, ANMOL SONI, MELISSA V. LAPSA & KATIE SOUTHWORTH, OAK RIDGE NAT'L LAB'Y, LOW-INCOME ENERGY AFFORDABILITY: CONCLUSIONS FROM A LITERATURE REVIEW (2020)	1052	1052
FLO-129	SANYA CARLEY, DAVID KONISKY & TREVOR MEMMOTT, ENERGY JUST. LAB, IND. UNIV., HOUSEHOLD ENERGY INSECURITY SURVEY, WINTER 2021.2022 (2022)	1052	1052
FLO-130	Trevor Memmott, Sanya Carley, Michelle Graff & David M. Konisky, Sociodemographic Disparities in Energy Insecurity Among Low-Income Households Before and During the COVID-19 Pandemic, 6 Nature Energy, no. 2, 2021	1052	1052
FLO-131	Ill. Com. Comm'n Docket Nos. 23-0068 & 23-0069, Colton Direct Testimony (May 9, 2023)	1052	1052

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
FLO-132	Rahul Agrawal Bejarano CV & Summary of Qualifications	1052	1052
FLO-133	Quick Facts: Michigan, U.S. CENSUS BUREAU (last accessed May 5, 2024)	1052	1052
FLO-134	Justin Schott, FLO JS Workpaper 3	1052	1052
FLO-135	Justin Schott, FLO JS Workpaper 4	1052	1052
FLO-136	Shuchen Cong, Destenie Nock, Yueming Lucy Qiu & Bo Xing, Unveiling Hidden Energy Poverty Using the Energy Equality Gap, 13 NATURE COMM'NS, 2022	1052	1052
FLO-137	Introduction, HOME ENERGY AFFORDABILITY GAP (last accessed May 5, 2024)	1052	1052
FLO-138	Justin Schott, FLO JS Workpaper 5	1052	1052
FLO-139	REVISED QUARTERLY REPORT FOR 1ST, 2ND, AND 3RD QUARTERS OF 2023, DTE (2023)	1052	1052
FLO-140	DTE's Response to FLO's First Discovery Request, FLODG-1.3	1052	1052
FLO-141	Sarah Alvarez, Lights Out: Profitable Utility Company Shut Off Electricity to Homes Hundreds of Thousands of Times, PROPUBLICA (Mar. 18, 2022)	1052	1052
FLO-142	FACT SHEET: Biden Administration Deploys American Rescue Plan Funds to Protect Americans from Rising Home Heating Costs; Calls on Utility Companies to Prevent Shut Offs This Winter, WHITE HOUSE (Nov. 18, 2021)	1052	1052
FLO-143	Justin Schott, FLO JS Workpaper 6	1052	1052
FLO-144	DTE's Response to FLO's First Discovery Request, FLODG 1.2.b	1052	1052
FLO-145	DTE's Response to FLO's Fourth Discovery Request, FLODG-4.6b	1052	1052

Penn Reporting, LLC - lori.penn@yahoo.com

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
FLO-146	Justin Schott, FLO JS Workpaper 7	1052	1052
FLO-147	Justin Schott, FLO JS Workpaper 8	1052	1052
FLO-148	DTE's Response to FLO's Fourth Discovery Request, FLODG-4.8a	1052	1052
FLO-149	DTE's Response to FLO's First Discovery Request, FLODG-1.9	1052	1052
FLO-150	DTE's Response to FLO's Sixth Discovery Request, FLODG-6.1, 6.2a, 6.2c, 6.3, 6.5a, 6.8a, and 6.9a	1052	1052
FLO-151	Lebel et al., Methane and NOx Emissions from Natural Gas Stoves, Cooktops, and Ovens in Residential Homes, 56 ENVIRON. SCI. TECHNOL. 2529 (2022)	1052	1052
FLO-152	Krasner et al. Cooking with Gas, Household Air Pollution, and Asthma: Little Recognized Risk for Children, 83 J. ENVIRON. HEALTH 14 (2021)	1052	1052
FLO-153	MICH.N DEP'T OF HEALTH & HUM. SERVS., DETROIT: THE CURRENT STATUS OF ASTHMA BURDEN (2021)	1052	1052
FLO-154	Excerpt from Ill. Com. Comm'n No. 23-0067, Order (Nov. 16, 2023)	1052	1052
FLO-155	NAT'L ENERGY ASSISTANCE DIRECTORS' ASS'N, SUMMARY OF STATE UTILITY SHUT-OFF MORATORIUMS (2021)	1052	1052
FLO-156	Low-Income Energy Policy Board, MICH. PUB. SERV. COMM'N (last accessed May 6, 2024)	1052	1052
FLO-157	AFFORDABILITY, ALIGNMENT, AND ASSISTANCE SUBCOMMITTEE, MICH. PUB. SERV. COMM'N, PRESENTATION (Oct. 3, 2023)	1052	1052
FLO-158	AFFORDABILITY, ALIGNMENT, AND ACCESSIBILITY SUBCOMMITTEE GOALS (2022)	1052	1052

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
FLO-159	AFFORDABILITY, ALIGNMENT, AND ACCESSIBILITY SUBCOMMITTEE KICK-OFF (2021)	1052	1052
FLO-160	AFFORDABILITY, ALIGNMENT, AND ACCESSIBILITY SUBCOMMITTEE 11-10-2022 MEETING (2022)	1052	1052
FLO-161	AFFORDABILITY, ALIGNMENT, AND ACCESSIBILITY SUBCOMMITTEE 9-9-2021 MEETING (2021)	1052	1052
FLO-162	Credits, Collections, and Arrearages Reports Monthly Dashboard, ILL. COM. COMM'N (last accessed May 6, 2024)	1052	1052
FLO-163	ACEVES GUZMAN, DECISION ADOPTING INTERIM RULES TO REDUCE RESIDENTIAL CUSTOMER DISCONNECTIONS FOR CALIFORNIA- JURISDICTIONAL ENERGY UTILITIES (2018)	1052	1052
FLO-164	Phase I Decision Adopting Rules and Policy Changes to Reduce Residential Customer Disconnections for the Larger California-jurisdictional Energy Utilities, Decision 20-06-003 (June 11, 2020)	1052	1052
FLO-165	Winter and Covid-19 Shut-Off Moratoriums, NATL ASS'N OF ENERGY ASSISTANCE DIRECTORS (Mar. 15, 2021)	1052	1052
FLO-166	L.A. DEP'T OF WATER & POWER, MOTION TO DISCONTINUE SHUT-OFFS AS AN ACCOUNT MANAGEMENT COLLECTION TOOL FOR CUSTOMERS ENROLLED IN LADWP EZ-SAVE AND LIFELINE DISCOUNT PROGRAMS (2022)	1052	1052
FLO-167	SANYA CARLEY AND DAVID KONISKY, UTILITY DISCONNECTIONS DASHBOARD (2023)	1052	1052
FLO-201	About the Collective, URB. CORE COLLECTIVE (last updated Apr. 6, 2018), https://www.urbancorecollective.org/about .	1144	1144

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
FLO-202	C4, ZERO CITIES PROJECT & HEZERO: MPSC EWR . LI MEETING (2021).	1144	1144
FLO-203	C4 PLANNING TEAM, COMMUNITY COLLABORATION ON CLIMATE CHANGE (C4) (2021).	1144	1144
FLO-204	GRIDWORKS, CALIFORNIA'S GAS SYSTEM IN TRANSITION: EQUITABLE, AFFORDABLE, DECARBONIZED, AND SMALLER (2019), https://gridworks.org/wp-content/uploads/2019/09/CA_Gas_System_in_Transition.pdf .	1144	1144
FLO-205	Michelle Graff, Addressing Energy Insecurity: Policy Considerations for Enhancing Energy Assistance Programs, HELIYON, Feb. 2024, https://www.ncbi.nlm.nih.gov/pmc/articles/PMC10850901 .	1144	1144
FLO-206	U.S. Energy Insecure Households Were Billed More for Energy Than Other Households, U.S. ENERGY INFORMATION ADMIN. (May 30, 2023), https://www.eia.gov/todayinenergy/detail.php?id=56640 .	1144	1144
FLO-207	FISHER, SHEEHAN & COLTON, MICHIGAN 2022: HOME ENERGY AFFORDABILITY GAP (2023), available as "Michigan 2022 HEAG Fact Sheet" at http://www.homeenergyaffordabilitygap.com/downloads/2022_Released_Apr23/ZIP_Archives/2022_Michigan.zip .	1144	1144
FLO-208	QuickFacts: Grand Rapids City, Michigan, U.S. CENSUS BUREAU (2023), https://www.census.gov/quickfacts/fact/table/grandrapidscitymichigan/IPE120222#IPE120222 .	1144	1144
FLO-209	URB. CORE COLLECTIVE, EQUITY ASSESSMENT TOOL: ZERO CITIES PROJECT 5 (2020).	1144	1144

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
FLO-210	QuickFacts: Kent County, Michigan, U.S. CENSUS BUREAU (2023), https://www.census.gov/quickfacts/fact/table/kentcountymichigan/PST045223 .	1144	1144
FLO-211	FISHER, SHEEHAAN & COLTON, MICHIGAN 2022: HOME ENERGY AFFORDABILITY GAP (2023), available as "Michigan HEAG2022 XL Detail" at http://www.homeenergyaffordabilitygap.com/downloads/2022_Released_Apr23/ZIP_Archives/2022_Michigan.zip .	1144	1144
FLO-212	SELAH GOODSON BELL ET AL., CTR FOR BIOLOGICAL DIVERSITY, ENERGY & POL'Y INST. & BAILOUTWATCH, POWERLESS IN THE UNITED STATES: HOW UTILITIES DRIVE SHUTOFFS AND ENERGY INJUSTICE (2021).	1144	1144
FLO-213	Nicole Goodkind, Predatory Lenders are Making Money off Rising Gas and Food Prices, CNN (June 30, 2022), https://www.cnn.com/2022/06/23/business/money/payday-predatory-lending-inflation-gas/index.html .	1144	1144
FLO-214	Payday Lending in America: Who Borrows, Where They Borrow, and Why, PEW. (July 19, 2012), https://www.pewtrusts.org/en/research-and-analysis/reports/2012/07/19/who-borrows-where-they-borrow-and-why .	1144	1144
FLO-215	Predatory Lending, NAT'L ASS'N OF CONSUMERS ADVOCATES (July 19, 2012), https://www.consumeradvocates.org/for-consumers/predatory-lending/ .	1144	1144
FLO-216	Quality of Housing, U.S. DEP'T OF HEALTH & HUM. SERVS. (last updated Aug. 6, 2022), https://health.gov/healthypeople/priority-areas/social-determinants-health/literature-summaries/quality-housing .	1144	1144
FLO-217	Rohith Teja Mittakola et al., Drivers of Natural Gas Use in U.S. Residential Buildings, 10 SCI. ADVANCES 6 (2024).	1144	1144

Penn Reporting, LLC - lori.penn@yahoo.com

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
FLO-218	Midwest Homes, Notably Older Homes, Consumer More Natural Gas Than Most Other States, U.S. ENERGY INFORMATION ADMIN. (Aug. 7, 2023), https://www.eia.gov/todayinenergy/detail.php?id=57321&src=%E2%80%B9%20Consumption%20%20%20%20%20%20Residential%20Energy%20Consumption%20Survey%20(RECS)-b2 .	1144	1144
FLO-219	U.S. ENERGY INFORMATION ADMIN., TABLE HC11.1 HOUSEHOLD ENERGY INSECURITY, 2020 (2023), https://www.eia.gov/consumption/residential/data/2020/hc/pdf/HC%2011.1.pdf	1144	1144
FLO-220	WORLD HEALTH ORGANIZATION, WHO HOUSING AND HEALTH GUIDELINES (2018), https://www.ncbi.nlm.nih.gov/books/NBK535293/pdf/Bookshelf_NBK535293.pdf .	1144	1144
FLO-221	Diana Hernandez, Understanding "Energy Insecurity" and Why It Matters to Health, 167 SOC. SCI. & MED. 1 (2016).	1144	1144
FLO-222	DTE's Response to FLO's Second Discovery Request, FLODG-2.3b.2.4b.	1144	1144
FLO-223	DTE's Response to FLO's First Discovery Request, FLODG-1.18c.	1144	1144
FLO-224	DTE's Response to FLO's First Discovery Request, FLODG-1.18a.	1144	1144
FLO-225	DTE's Response to FLO's First Discovery Request, FLODG-1.17.	1144	1144
FLO-226	DTE's Response to FLO's Second Discovery Request, FLODG-2.1.	1144	1144
FLO-227	DTE's Response to FLO's Third Discovery Request, U-21291 FLODG-3.5d 03 Payment Assist Bill Insert 2023-24.	1144	1144
FLO-228	Low-Income Programs, DTE (last accessed May 4, 2024), https://perma.cc/AX5K-FGYX .	1144	1144

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
FLO-229	DTE's Response to FLO's Third Discovery Request, FLODG-3.4b.3.4c.	1144	1144
FLO-230	DTE's Response to FLO's Third Discovery Request, U-21291 FLODG-3.6a Gas_LIA-LSP and non-LSP.	1144	1144
FLO-231	DTE's Response to FLO's Third Discovery Response, FLODG-3.1a.3.1b.	1144	1144
FLO-232	DTE's Response to FLO's Third Discovery Response, FLODG-3.2.	1144	1144
FLO-233	DTE's Response to FLO's Second Discovery Request, FLODG 2.6a.	1144	1144
FLO-234	DTE's Response to FLO's First Discovery Request, FLODG-1.19.	1144	1144
FLO-235	DTE's Response to FLO's First Discovery Request, FLODG-3.3a.3.3b.	1144	1144
FLO-236	DTE's Response to FLO's Seventh Discovery Request, FLODG-7.1b.	1144	1144
FLO-237	What Is Average Speed of Answer? Strategies and Calculation, CALL CTR. STUDIO (Jan. 5, 2024), https://callcenterstudio.com/blog/what-is-average-speed-of-answer-strategies-and-calculation/ .	1144	1144
FLO-238	Michigan Energy Assistance Program Frequently Asked Questions, MICH. PUB. SERV. COMM'N (last accessed May 4, 2024), https://www.michigan.gov/-/media/Project/Websites/mpsc/consumer/meap/MEAP_FAQs.pdf?rev=2ba17357b585490195c365457037102c .	1144	1144
FLO-239	CONFIDENTIAL . DTE's Response to FLO's Third Discovery Request, NDA U-21291 FLODG 7.1f Customer Call Handling JA-CS-COLL-035 v.2.	1144	1144

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
FLO-240	DTE's Response to FLO's Third Discovery Request, U-21291 FLODG-3.5a-c 2021-2024 CAD CRF POP UPS.	1144	1144
FLO-241	BudgetWise Billing, DTE (last accessed Apr. 19, 2024), https://www.dteenergy.com/us/en/business/billing-and-payments/payment-programs/bwb.html .	1144	1144
FLO-242	DTE Gas's Response to FLO's Fourth Discovery Request, FLODG-4.1d.	1144	1144
FLO-301	DTE Gas's Response to FLO's Third Discovery Request, U-21291 FLODG-3.5d 03 Payment Assist Bill Insert 2023-24.	1234	1234
FLO-302	Customer Resource Fairs, DTE (last accessed 5/2/2024), https://perma.cc/NLS3-BMTY .	1234	1234
FLO-303	DTE Gas's Response to FLO's Third Discovery Request, U-21291 FLODG3.5-a-c 2024-2024 CAD CRF POP UPS.	1234	1234
FLO-304	DTE Gas's Response to FLO's Second Discovery Request, FLODG-2.3b.	1234	1234
FLO-305	DTE Gas's Response to FLO's Second Discovery Request, FLODG-2.4a.	1234	1234
FLO-401	U-21291 FLODG 5.1a 2022 Clarington RSG CONFIRMATION.	1252	1252
FLO-402	U-21291 FLODG 5.2a 2022 Falcon RSG CONFIRMATION.	1252	1252
FLO-403	U-21291 FLODG 5.3a 2022 PEPL RSG CONFIRMATION.	1252	1252
FLO-404	OIL CHANGE INT'L, CERTIFIED DISASTER: HOW PROJECT CANARY & GAS CERTIFICATION ARE MISLEADING MARKETS & GOVERNMENTS (2023).	1252	1252

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
FLO-405	GLOB. WITNESS, US GAS CAN'T CERTIFY AWAY ITS CLIMATE AND ENVIRONMENTAL JUSTICE PROBLEMS: A CASE STUDY ON MIQ AND EXXON (2022) .	1252	1252
FLO-406	DTE Gas's Response to AG's Eighth Discovery Request, AGDG-8.237a-b.	1252	1252
FLO-407	DTE Gas's Response to AG's Eighth Discovery Request, AGDG-8.239.	1252	1252
FLO-408	DTE Gas's Response to FLO's Eighth Discovery Request, FLODG-8.2a.	1252	1252
FLO-409	DTE Gas's Response to FLO's Eighth Discovery Request, FLODG-8.3d & U-21291 FLODG- 8.3d Invoices.	1252	1252
FLO-410	American Gas Association, ENERGY & POL'Y INST. (last accessed June 15, 2024), https://energyandpolicy.org/american-gas-association/ .	1252	1252
FLO-411	DTE Gas's Response to FLO's Eighth Discovery Request, FLODG-8.4-8.6 & U-21291 FLODG-8.5 RM&P Actuals and Projections.	1252	1252
FLO-412	DTE Gas's Response to FLO's Eighth Discovery Request, FLODG-8.7b-8.9b.	1252	1252
FLO-413	CONFIDENTIAL - DTE Gas's Response to FLO's Eighth Discovery Request, NDA U-21291 FLODG-8.8d Bill Analysis after LSP.	1252	1252
FLO-414	DTE Gas's Response to FLO's Eighth Discovery Request, FLODG-8.10.	1252	1252
	- - -		
MEC-1	Resume of Asa S. Hopkins	822	823
MEC-2	ICF RNG Report	822	823

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
MEC-3	LETI, "Hydrogen: A decarbonisation route for heat in buildings?"	822	823
MEC-4	Leibreich Hydrogen Ladder	822	823
MEC-5	Net Zero America Data	822	823
MEC-6	Brattle Future of Gas	822	823
MEC-7	Comparison of Customer Economics	822	823
MEC-8	DPU Order 20-80	822	823
MEC-9	MNSCDG-6.1a	822	823
MEC-10	MNSCDG-2.10c	822	823
MEC-11	MNSCDG-5.11gi	822	823
MEC-12	MNSCDG-1.8h	822	823
MEC-13	MNSCDG-1.8fi	822	823
MEC-14	MNSCDG-1.8b	822	823
MEC-15	MNSCDG-1.9, 4.4bi, and 4.4ai	822	823
MEC-16	MNSCDG-4.6f Attachment, DTE Low Carbon Energy Infrastructure Enhancement and Development Grant Proposal	822	823
MEC-17	Resume of Alice Napoleon	822	823
MEC-18	MNSCDG-5.12 and Attachment	822	823
MEC-19	MNSCDG-5.3a	822	823
MEC-20	MNSCDG-5.2e and f	822	823
MEC-21	DTE 2023 Year-end Earnings Conference Call (Feb. 8, 2024)	822	823
MEC-22	MNSCDG-5.10a	822	823
MEC-23	MNSCDG-3.16b	822	823

Penn Reporting, LLC - lori.penn@yahoo.com

E X H I B I T S

	<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
1				
2				
3	MEC-24	MNSCDG-3.13	822	823
4	MEC-25	MNSCDG-2.4f	822	823
5	MEC-26	DTE Gas Co's CleanVision Natural Gas Balance 2023 Annual Impact Report	822	823
6				
7	MEC-27	MNSCDG-6.3b	822	823
8	MEC-28	MNSCDG-2.6e	822	823
9	MEC-29	ACEEE, "Winter Demand Response Using Baseboard Heaters"	822	823
10	MEC-30	MNSCDG-5.5ai, bi, ci	822	823
11	MEC-86	MNSCDG-5.17	672	672
12	MEC-87	MNSCDG-5.489	676	676
13	MEC-88	MNSCDG-5.18b	688	689
14	MEC-89C	CONFIDENTIAL Att. to MNSCDG-5.18b	688	688
15	MEC-90	MNSCDG-5.19	693	694
16	MEC-91	MNSCDG-5.20	695	695
17	MEC-92	MNSCDG-5.21a-b	698	698
18	MEC-93	MNSCDG-5.22, 5.23, 5.24	704	704
19	MEC-97	MNSCDG-10.4	676	676
20	MEC-98	MNSCDG-10.5a-b	691	691
21	MEC-99	MNSCDG-10.6	693	694
22	MEC-101	MNSCDG-10.8 and AGDG-54.51	704	704
23	MEC-104	MNSCDG-5.14	704	704
24	MPL-1	(BCC-1) Load Factor Calculation for the Projected Test Year Ending 9/30/2025	786	787
25		With and Without Rate XXLT		

Penn Reporting, LLC - lori.penn@yahoo.com

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
MPL-2	(BCC-2) Summary of Projected Test Year Ending 09/30/2025, Proposed Gas Revenue Increase, Peak Day Demand, Distribution Plant-Other Allocated Using Low-Pressure Distribution Usage for XXLT	786	787
MPL-3	(BCC-3) Discovery Responses MPLPDG-1.1, 1.2 & 1.3	786	787
MPL-4	(BCC-4) Summary of Projected Test Year Ending 09/30/2025, Proposed Gas Revenue Increase, 75% Demand and 25% Throughput, Distribution Plant-Other Allocated Using Low-Pressure Distribution Usage for XXLT	786	787
MPL-5	(BCC-5) Summary of Projected Test Year Ending 09/30/2025, Proposed Gas Revenue Increase, Company Study Modified for Distribution Plant-Other Allocated Using Low-Pressure Distribution Usage for XXLT	786	787
MPL-6	(BCC-6) Usage Characteristics by Customer Class for the Projected Test Year Ending 9/30/2025	786	787
MPL-7	REVISED (BCC-7) Summary of Projected Test Year Ending 09/30/2025, Proposed Gas Revenue Increase, REVISED Staff Study	786	787
MPL-8	REVISED (BCC-8) Calculation of the Projected Test Year Ending 09/30/2025, Current and Proposed Revenues by Rate Schedule, Transportation Service Rate ST, LT, XLT and XXLT, (\$000), REVISED Staff Study	786	787
MPL-9	REVISED (BCC-9) Summary of Projected Test Year Ending 09/30/2025, Proposed Gas Revenue Increase, REVISED Staff Study with No Distribution Plant-Other Allocated to Rate XXLT	786	787

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
MPL-10	REVISED (BCC-10) Calculation of the Projected Test Year Ending 09/30/2025, Current and Proposed Revenues by Rate Schedule, Transportation Service Rate ST, LT, XLT and XXLT, (\$000), REVISED Staff Study with No Distribution Plant-Other Allocated to Rate XXLT	786	787
	- - -		
S-1	Sch. A-1 (NICHOLS)	1686	1686
S-2	Sch B-1, B-4 (HECHT)	1741	1741
S-3	Sch. C-1, C-1.1, C-15, C-16 (NICHOLS)	1686	1686
S-3.0	Sch. C5 (RUECKERT) Sch C3, C4 (TODD)	1644 1634	1644 1634
S-4	Sch D-1, D-2, D-3, REVISED D-4, D-5 (UFOLLA)	1607	1607
S-6	REVISED Sch F-1.1, F1.2 (KRAUSE)	1713	1713
S-6.0	REVISED Sch F2, F3, F4, F6 (TODD)	1634	1634
S-8.0	Restricted Stock/Incentive Compensation in Revenue Requirement - Co. Response TMS-4.1a	1693	1693
S-8.1	DTE Energy Company Long-Term Incentive Plan Booklet	1693	1693
S-9.0	Employee Savings Plan & Active Healthcare Expenses for the 12 Month Period Ending September 30, 2025	1644	1644
S-9.1	Employee Savings Plan & Active Healthcare Expense Projections for the 12 Month Period Ending September 30, 2025	1644	1644
S-9.2	Employee Savings Plan Expense:2018-2023	1644	1644
S-9.3	Active Healthcare Expense and Employee Headcount:2018-2023	1644	1644

Penn Reporting, LLC - lori.penn@yahoo.com

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
S-9.4	Uncollectible Accounts Expense for the 12 Month Period Ending September 30, 2025	1644	1644
S-9.5	REVISED Uncollectible Accounts Expense for the 12 Month	1644	1644
S-10.0	Staff Adjustments to Capital Expenditure - Routine Distribution	1781	1781
S-10.1	Staff Adjustments to Capital Expenditure - Infrastructure Recovery Mechanism	1781	1781
S-10.2	DTE Gas Company's Response to Staff Audit Request CLC-3.1	1781	1781
S-10.3	DTE Gas Company's Response to Staff Audit Requests CLC-3.6, CLC-3.7, CLC-3.8, CLC-3.9, CLC-3.10, and CLC-3.11	1781	1781
S-10.4	DTE Gas Company's Response to Staff Audit Request CLC-2.2	1781	1781
S-10.5	DTE Gas Company's Response to Staff Audit Request CLC-2.3	1781	1781
S-10.6	DTE Gas Company's Response to AGDG-7.195	1781	1781
S-10.7	DTE Gas Company's Response to Staff Audit Request CLC-1.6	1781	1781
S-10.8	DTE Gas Company's Response to Staff Audit Request CLC-5.2	1781	1781
S-11.1	DTE Gas' Audit Responses to NUR-1.1a, NUR-1.1b, and NUR-1.4	1800	1800
S-11.2	The September 2024 through September 2025 Average Costs and Volumes of Natural Gas in Underground Storage Reservoirs	1800	1800
S-11.3	DTE Gas' Supplemental Audit Responses to NUR-1.3 and NUR-1.4	1800	1800

E X H I B I T S

<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
S-11.4	The October 2024 through September 2025 Jurisdictional Average Cost of Natural Gas	1800	1800
S-11.5	DTE Gas' Audit Responses to NUR-1.7 through NUR-1.10 and NUR-1.18 through NUR-1.20	1800	1800
S-11.6	DTE Gas' Audit Responses to NUR-2.2 and NUR-2.3	1800	1800
S-12.0	Company Response to MPSC Staff Audit Request JJH-3	1741	1741
S-12.1	Company Response to MPSC Staff Audit Request JJH-5	1741	1741
S-12.2	Company Response to MPSC Staff Audit Request JJH-6	1741	1741
S-12.3	Company Response to MPSC Staff Audit Request JJH-7	1741	1741
S-13.1	DTE Gas Company Projected IT O&M	1595	1595
S-13.2	Staff's Recommended IT Adjustments	1595	1595
S-13.3	Company Audit Response of Projects with Level 2 Cost Estimates	1595	1595
S-13.4	Company Audit Responses for Shared Assets	1595	1595
S-13.5	Company Discovery Response to the AG for Shared Assets	1595	1595
S-13.6	Company Updated Exhibit A-13 Schedule C5.6 pg 3	1595	1595
S-14.0	"Affordability, Alignment, and Assistance Subcommittee 12/4/2023"	1755	1755
S-15	Sch. 1 (KRAUSE)	1713	1713
	REVISED Sch. F-1, F-1.1, F-1.2 (KRAUSE)	1713	1713

Monday, June 24, 2024

At 9:01 a.m.

- - -

JUDGE THOITS: All right. We are on the record in Case U-21291, which is DTE Gas, Natural Gas rate case. This is the continuation of the hearing in this matter. We have scheduled one witness, as I understand it, by the parties' agreement for this morning. My name Jon Thoits, I'm the presiding officer for this matter.

Could we have appearances, please, first on behalf of DTE Gas.

MR. WATSON: Thank you, your Honor.
Carlton Watson on behalf of DTE Gas Company.

JUDGE THOITS: All right. Do we have an appearance on behalf of the Public Service Commission Staff?

MS. STIRLING: Good morning, your Honor.
Anna Stirling on behalf of the Public Service Commission Staff.

JUDGE THOITS: Thank you. Do we have an appearance on behalf of the Michigan Attorney General?

MR. KING: Good morning, your Honor.
Joel King appearing this morning on behalf of Attorney General Dana Nessel.

Penn Reporting, LLC - lori.penn@yahoo.com

1 JUDGE THOITS: Thank you. Do we have an
2 appearance on behalf of ABATE?

3 MR. CAMPBELL: Good morning, your Honor.
4 Steve Campbell of Clark Hill, PLC, on behalf of the
5 Association of Businesses Advocating Tariff Equity.

6 JUDGE THOITS: Thank you. Mr. Bzdok,
7 could you enter your appearance, please?

8 MR. BZDOK: Good morning, your Honor.
9 Christopher Bzdok on behalf of the Michigan Environmental
10 Council, Natural Resources Defense Council, Sierra Club,
11 and Citizens Utility Board of Michigan.

12 JUDGE THOITS: Thank you. Do we have an
13 appearance on behalf of what's referred to as the Clean
14 Energy Organizations?

15 MR. ABRAMS: Good morning, your Honor.
16 Daniel Abrams appearing on behalf of the Ecology Center,
17 the Environmental Law & Policy Center, the Union of
18 Concerned Scientists, and Vote Solar, collectively the
19 Clean Energy Organizations.

20 JUDGE THOITS: Thank you. Do we have an
21 appearance on behalf of a group referred to as
22 Frontlines?

23 MR. TEMPLETON: Good morning, your Honor.
24 Mark Templeton on behalf of Soulardarity, Urban Core
25 Collective, and We Want Green, Too, collectively known as
Penn Reporting, LLC - lori.penn@yahoo.com

1 the Frontline Organizations, or FLO, in this proceeding.
2 Also entering an appearance on behalf of my colleagues
3 Jacob Schuhardt, Sam Heppell, and Amanda Urban. Thank
4 you.

5 JUDGE THOITS: Thank you. Do we have any
6 other appearances?

7 MS. HESTON: Yes, your Honor. Good
8 morning. This is Jennifer Heston of the law firm of
9 Fraser Trebilcock Davis & Dunlap appearing on behalf of
10 Michigan Power Limited Partnership.

11 JUDGE THOITS: Thank you.

12 MS. BRADER: Valerie Brader appearing on
13 behalf of the City of Ann Arbor.

14 JUDGE THOITS: All right. Thank you.
15 All right. As I indicated, I understand that examination
16 today starting off will be of Mr. Janness. It's also my
17 understanding that this examination may involve
18 discussions of confidential testimony or confidential
19 exhibits, so I would ask that the attorneys give us a
20 heads-up when we might be going there so that we can take
21 appropriate steps to ensure that the confidential
22 testimony and exhibits remains confidential.

23 All right. Mr. Watson.

24 MR. WATSON: Thank you, your Honor. The
25 Company calls Eric D. Janness.

1 E R I C D. J A N N E S S

2 was called as a witness on behalf of DTE Gas Company and,
3 having been duly sworn to testify the truth, was examined
4 and testified as follows:

5 JUDGE THOITS: Mr. Janness, do you have
6 any documents or notes with you today other than filed
7 testimony, exhibits, or discovery responses in this case?

8 THE WITNESS: That's all I have, your
9 Honor.

10 JUDGE THOITS: All right. Thank you.
11 Mr. Watson.

12 DIRECT EXAMINATION

13 BY MR. WATSON:

14 Q Thank you. Good morning, and please state your name and
15 business address for the record.

16 A Yes. My name is Eric Daniel Janness, my business address
17 is One Energy Plaza, Detroit, Michigan 48226.

18 Q Did you file with the Commission a document entitled the
19 Qualifications and Direct Testimony of Eric D. Janness,
20 consisting of a cover sheet and 51 pages of questions and
21 answers?

22 A Yes.

23 Q Do you have any changes you wish to make to your direct
24 testimony?

25 A No.

1 Q Is that, then, the direct testimony that you are adopting
2 today?

3 A Yes.

4 Q Are you sponsoring any exhibits associated with your
5 direct testimony in this case?

6 A Yes.

7 Q For purposes of identification, are these nine direct
8 exhibit -- I'm sorry -- direct exhibits designated as
9 A-12 Schedule B5.3, consisting of one page; A-12 Schedule
10 B5.5, consisting of 45 pages; Exhibit A-12 Schedule
11 B5.20, consisting of one page; Exhibit A-12 Schedule B6,
12 consisting of one page; Exhibit A-12 Schedule B6.1,
13 consisting of one page; Exhibit A-12 Schedule B6.2,
14 consisting of one page; Exhibit A-12 Schedule B6.3,
15 consisting of one page; Exhibit A-12 Schedule B6.4,
16 consisting of one page; and Exhibit A-12 Schedule B6.5,
17 consisting of one page?

18 A Yes.

19 Q Were these exhibits prepared by you or at your direction?

20 A Yes.

21 Q Do you have any changes to make to these nine direct
22 exhibits?

23 A No.

24 Q Did you also file with the Commission a document entitled
25 Rebuttal Testimony of Eric D. Janness, consisting of a

Penn Reporting, LLC - lori.penn@yahoo.com

1 cover sheet and 17 pages of questions and answers?

2 A Yes.

3 Q Do you have any changes you wish to make to your rebuttal
4 testimony?

5 A No.

6 Q Is that, then, the rebuttal testimony that you are
7 adopting today?

8 A Yes.

9 Q Are you sponsoring any exhibits associated with your
10 rebuttal testimony in this case?

11 A Yes.

12 Q For purposes of identification, are these two rebuttal
13 exhibits designated as Exhibit A-32 Schedule V1,
14 consisting of eight pages; Exhibit A-32 Schedule V2,
15 consisting of one page?

16 A Yes.

17 Q Were these exhibits prepared by you or at your direction?

18 A Yes.

19 Q Do you have any changes you wish to make to your two
20 rebuttal exhibits?

21 A No.

22 MR. WATSON: Your Honor, at this time the
23 Company moves to bind into the record the Qualifications,
24 Direct Testimony, and Rebuttal Testimony of Eric D.
25 Janness, and we also move for the admission at the end of
Penn Reporting, LLC - lori.penn@yahoo.com

1 cross-examination of the aforementioned exhibits, and
2 tenders the witness for cross-examination.

3 JUDGE THOITS: Mr. Watson, just a
4 clarification. None of the testimony nor the referenced
5 exhibit schedules are confidential; is that correct?

6 MR. WATSON: Correct, your Honor.

7 JUDGE THOITS: All right. Thank you.
8 Are there any objections to the admission of the
9 testimony of this witness? (No response.)

10 Hearing none, the Direct and Rebuttal
11 Testimony of Eric Janness is bound into the record.

12 (Testimony bound in.)

13 - - -
14
15
16
17
18
19
20
21
22
23
24
25

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE GAS COMPANY)
for authority to increase its rates, amend)
its rate schedules and rules governing the)
distribution and supply of natural gas, and)
for miscellaneous accounting authority.)

Case No. U-21291

QUALIFICATIONS
AND
DIRECT TESTIMONY
OF
ERIC D. JANNESS

DTE GAS COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF ERIC D. JANNESS

Line
No.

1 **Q1. What is your name, business address and by whom are you employed?**

2 A1. My name is Eric D. Janness (He/Him/His). My business address is One Energy
3 Plaza, Detroit, Michigan 48226. I am employed by DTE Gas Company, a
4 subsidiary of DTE Energy Company (DTE Energy).

5

6 **Q2. On whose behalf are you testifying?**

7 A2. I am testifying on behalf of DTE Gas Company (DTE Gas or Company).

8

9 **Q3. What is your educational background and business experience?**

10 A3. I graduated from Western Michigan University with a Bachelor of Science degree
11 in Geology and from Lawrence Technological University with a Master of Science
12 in Civil Engineering. I hold a Lean Six-Sigma Black Belt Certification from the
13 University of Michigan College of Engineering, and a Project Management
14 Professional certification from the Project Management Institute. Prior to joining
15 DTE Energy, I was a General Manager for a construction contractor, Commercial
16 Contracting Corporation, managing capital projects for DTE Energy, Consumers
17 Energy, General Motors, Ford, and Chrysler/Stellantis. I joined DTE in 2011 and
18 held progressive roles in DTE's Project Management Office (PMO) before moving
19 into Gas Operations.

20

21 **Q4. What are your responsibilities as Director – Gas Operations – Construction?**

22 A4. As Director – Gas Operations – Construction, I am responsible for overseeing the
23 strategy, planning, and operations of construction activities in Southeast and
24 Greater Michigan including Main Renewal, Meter Move Out and MAC MMO.

25

1 **Q5. Have you previously sponsored testimony before the Michigan Public Service**
2 **Commission?**

3 A5. No. However, I have previously provided witness support and developed testimony
4 and exhibits as a subject matter expert in several other MPSC case proceedings.

1 **Q6. What is the purpose of your testimony?**

2 A6. My testimony supports DTE Gas's Infrastructure Renewal Program. Specifically, I
3 support:

- 4 1. Consolidation of Meter Assembly Check / Meter Move-Out (MAC/MMO)
5 program and Gas Renewal Program (GRP);
- 6 2. The need to increase Infrastructure Recovery Mechanism (IRM) capital
7 expenditures;
- 8 3. Utilization of a revised risk-ranking methodology and project selection criteria
9 as a result of implementation of DTE Gas's new Probabilistic Risk Assessment
10 (PRA) model;
- 11 4. Formalization of a degree of flexibility in yearly GRP unit goals;
- 12 5. The Pipeline Integrity (PI) program capital expenditures;
- 13 6. The inclusion of Distribution Integrity Management - Corrosion Work Order
14 capital expenditures and unit goals within the scope of the IRM; and
- 15 7. The introduction of a strategy to remediate legacy service lines and cathodically
16 protected bare steel mains not currently supported for replacement in the 18-year
17 main renewal plan.

18

19 **Q7. Are you sponsoring any exhibits in this proceeding?**

20 A7. Yes, I am supporting the following exhibits:

21	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
22	A-12	B5.3	Capital Expenditures – Infrastructure Recovery
23			Mechanism
24	A-12	B5.5	DTE Gas Highest Cost Top 25 Capital Projects

Line
No.

1	A-12	B5.20	Detailed Pipeline Integrity Capital Project List for 2020 -
2			2022
3	A-12	B6	Infrastructure Recovery Mechanism Target Capital
4			Expenditures
5	A-12	B6.1	Actual Capital Cost of IRM Compared to Targeted Levels
6	A-12	B6.2	Inside Meter Move Out History and Projections
7	A-12	B6.3	Main Renewal History and Projections
8	A-12	B6.4	IRM Report Contents and Proposed Changes
9	A-12	B6.5	Investment Recovery Mechanism Expenditures History
10			and Projections
11			
12	Q8.		Were these exhibits prepared by you or under your direction?
13	A8.		Yes, they were.
14			

Line
No.

1 **Investment Recovery Mechanism (IRM)**

2 **Q9. What is the IRM?**

3 A9. The IRM is the program name for a series of capital expenditures that support long-
4 term improvements to DTE Gas's infrastructure. Three processes make up the IRM
5 capital expenditures:

6 1. Gas Renewal Program (GRP – formerly two separate programs, MRP and
7 MMO),

8 2. Meter Assembly Check Meter Move-Out (MAC/MMO) and

9 3. Pipeline Integrity (PI).

10

11 DTE Gas is currently making substantial investments in these areas and will
12 continue to do so beyond the Company's projected test period in this proceeding.

13 As part of this proceeding, the Company seeks to recover its cost related to IRM
14 capital expenditures from January 2025 through 2029 using a new IRM surcharge.

15

16 **Q10. What is the purpose of DTE Gas's infrastructure renewal programs?**

17 A10. IRM programs are necessary to ensure the safety of DTE Gas's customers and the
18 public and to allow the Company to provide reliable utility service. The
19 Commission has stated that ensuring safe and reliable utility service is an obligation
20 it takes seriously (page 25, Commission order in Case No. U-16999, April 15,
21 2013). The Commission has stated, "that the safety and reliability of DTE Gas's
22 gas distribution system is not a goal but rather a necessity..." (Case No. U-16407
23 Order, page 7). The IRM expenditures proposed in this case continue supporting
24 DTE Gas's and the Commission's goal of safe and reliable service. The proposed

Line
No.

1 IRM expenditures are necessary to achieve goals established in the Commission's
2 September 13, 2018, order in Case No. U-18999, at page 33.

3

4 **Q11. Is DTE Gas proposing any changes to its IRM programs?**

5 A11. Yes. DTE is proposing to (1) combine the GRP and MAC MMO programs after
6 2024 to support main renewal and meter move-out after the elimination of the
7 current MAC backlog; (2) increase capital expenditure included in the IRM to
8 levels that reflect more recent spending levels; (3) implement a degree of year-to-
9 year flexibility for meter move out and main renewal unit goals to support
10 accelerated risk mitigation projects identified by the new Probabilistic Risk
11 Assessment (PRA) Model and to utilize some GRP resources to proactively move
12 out inside meters with an approaching MAC expiration while maintaining stable
13 yearly capital expenditures and resources; and (4) the inclusion of Corrosion Work
14 Order capital expenditures within the IRM.

15

16 **Q12. What are the GRP and MAC MMO programs?**

17 A12. The GRP is a focused effort to upgrade DTE Gas's distribution system through
18 replacement of legacy mains and the relocation of meters from the inside to the
19 outside of customer homes and businesses. "Legacy mains" refers to mains
20 constructed of cast iron or steel that does not have cathodic protection from
21 corrosion. GRP currently has a goal to replace 206 miles of legacy mains and move
22 out 14,790 inside meters annually. The program is on pace to conclude in 2035
23 upon elimination of all legacy mains and the moving outside of all feasibly possible
24 inside meters. The MAC MMO program is a supplementary meter move-out effort
25 that specifically targets and prioritizes relocation of inside meters that have an

Line
No.

1 overdue MAC (Meter Assembly Check) inspection. Every inside meter is required
2 to have a MAC inspection documented in the last three years not to exceed 39
3 months. The MAC MMO program focuses on addressing two specific issues: first,
4 the Company's challenge in accessing inside meters to perform MACs, and second,
5 the declining number of inside meter relocations resulting from customer-initiated
6 (routine) construction activities. This program, supported in Case No. U-18999,
7 has targeted 8,000 inside meters annually.

8

9 **Q13. Did DTE Gas attain the meter move target of 229,750 from 2012 through 2021**
10 **as ordered in Case No. U-16407?**

11 A13. DTE Gas moved out 209,991 inside meters from 2012 to 2021 excluding MAC
12 MMO against a goal of 229,750 ordered in Case No. U-16451. With MAC MMO,
13 DTE Gas moved out 227,682 inside meters from 2012 to 2021. Cumulative MMO
14 totals are included in Exhibit A-12 Schedule B6.2, Inside Meter Move-Out History
15 and Projections.

16

17 **Q14. Why is DTE Gas proposing to combine the GRP and MAC MMO programs**
18 **in 2024?**

19 A14. DTE Gas has reduced the backlog of inside meters with overdue MACs from
20 129,305, when the MAC MMO program was initiated in 2018, to 22,148 at the end
21 of 2022. The Company expects to be current with meter assembly checks by the
22 end of 2024, eliminating the need to specifically target 8,000 inside meters on the
23 MAC backlog list yearly past 2024. However, to proactively reduce the yearly
24 volume of required MACs resulting from meters becoming continually due for
25 MACs, DTE Gas will redeploy the resources and yearly capital expenditures

Line
No.

1 currently performing 8,000 MAC MMOs to complete supplemental MMOs based
2 on risk prioritization for the GRP. A forecast of GRP MMOs by component are
3 included in Exhibit A-12 Schedule B6.2, Inside Meter Move-Out History and
4 Projections.

5

6 **Q15. What have the IRM expenditure targets and unit goals been historically?**

7 A15. A history of capital expenditures, beginning in 2013, used to calculate IRM
8 surcharges is included in Exhibit A-12 Schedule B6, Infrastructure Recovery
9 Mechanism Target Capital Expenditures. This exhibit also includes the
10 corresponding unit goals. Target expenditures are not limits on expenditures. These
11 expenditure targets are the amounts used to calculate the revenue requirements that
12 determine the IRM surcharges. Any spend in excess of these amounts is recovered
13 in subsequent general rate cases.

14

15 **Q16. Has DTE Gas achieved IRM expenditure targets?**

16 A16. Yes. A history of IRM actual expenditures and units is included in Exhibit A-12
17 Schedule B6.1, Actual Capital Cost of IRM Compared to Targeted Levels. DTE Gas
18 exceeded the IRM expenditure target in 2021 by \$19.9 million and in 2022 by \$27.7
19 million.

20

21 **Q17. What IRM capital expenditures is the Company proposing?**

22 A17. The Company's total IRM capital expenditures are as follows:

Line
No.

1

Table 1. Total IRM Proposed Capital Expenditures through 2029

Year	Proposed Spend (\$ Millions)
2023	\$336.1
2024	\$349.1
2025	\$354.2
2026-2027	\$344.5
2028-2029	\$311.4

2

3

A forecast of IRM capital expenditures by program is included in exhibit A-12 B6.

4

These amounts are used by Company Witness Vangilder to develop the IRM

5

revenue requirement and Company Witness Krysinski to develop the cost of

6

service.

7

8

Q18. Does the Company intend to allow for flexibility in the capital expenditure of

9

the IRM based on economic conditions and customer rate affordability?

10

A18. Yes, as stated in Company Witness Harris's testimony in Case No. U-18999, the

11

Company intends to maintain the IRM capital expenditure as ordered in Case No.

12

U-17999 as the minimum spend for the program and the proposed additional spend

13

in this request for 2025-2029 as the maximum spend.

14

15

Q19. What GRP capital expenditures is the Company proposing?

16

A19. See Table 2 below for DTE Gas proposed GRP capital expenditures through 2029

17

compared to expenditures settled in case No. U-20940.

Line
No.

1 **Table 2. Comparison of Proposed GRP & MAC MMO Expenditures & Units**
 2 **to U-20940 Levels**

	2022	2023	2024	2025-2027	2028-2029
GRP	\$ 255.1	\$ 255.1	\$ 255.1	\$ 255.1	Surcharge not supported beyond 2025
MAC MMO	\$ 21.0	\$ 21.0	\$ 21.0	\$ 21.0	
GRP U-20940 (\$M)	\$ 276.1	\$ 276.1	\$ 276.1	\$ 276.1	
GRP	\$ 272.5	\$ 290.3	\$ 329.1	\$ 321.5	\$ 290.7
MAC MMO	\$ 23.2	\$ 22.4	\$ -	\$ -	\$ -
GRP U-21291 (\$M)	\$ 295.7	\$ 312.7	\$ 329.1	\$ 321.5	\$ 290.7
Addl. Expenditures	\$ 40.6	\$ 57.6	\$ 74.0	\$ 70.5	\$ 298.4
Reduced MMO Units				\$ (4.1)	\$ (7.7)
Net Increase	\$ 40.6	\$ 57.6	\$ 74.0	\$ 66.4	\$ 290.7
Legacy Main Miles remediated	222	206	206	206	206
Main Miles Installed	258	260	264	261	261
MMO's	22,918	22,790	22,790	20,500	8,500

3

4 **Q20. Why is DTE Gas proposing to increase the capital spending for the Gas**
 5 **Renewal Program from Case No. U-20940 levels?**

6 A20. The Company is projecting additional costs to execute the Main Renewal Program
 7 in both the Southeast and Greater Michigan service territories from 2020 through
 8 2025. There are three primary drivers of this cost increase:

- 9 1. Increasing contractor and material costs;
- 10 2. Municipal permit requirements for design, third party inspection, temporary and
 11 final restoration, as well as flowable fill; and
- 12 3. A change in the scale and scope of projects as identified by the Probabilistic
 13 Risk Assessment.

14

15 **Q21. Why are Contractor costs increasing?**

Line
No.

1 A21. Distribution underground construction, trucking, and property restoration unit price
2 contracts were bid in 2020 and negotiated in 2021 with a 2-year effective term. The
3 new pricing for contracts effective in March 2023 reflects two years of cost
4 inflation. PowerAdvocate, a third-party provider of industry market and cost
5 intelligence, estimates that market prices have increased 25% from 2020 levels for
6 gas distribution construction work. According to PowerAdvocate, the pricing
7 increases are primarily driven by rising construction wages year over year and
8 competition in the market as capital investment in infrastructure increases at
9 utilities across the country and within the state. The DTE Gas Renewal Program is
10 experiencing construction contractor cost increases of approximately 10% in
11 Southeast Michigan and approximately 15% in Greater Michigan, resulting in total
12 increases as shown in Table 3 below:

Table 3. Construction Contractor Costs

	2024	2025-2029
Total incremental cost from construction contractor pricing	\$25M	\$35M Avg

14

15 **Q22. How have municipal permit requirements changed since U-20940?**

16 A22. Some municipalities have adopted or reference Michigan Department of
17 Transportation (MDOT) specifications as a requirement for underground
18 construction permit activities. For GRP, this primarily affects the engineering
19 design, restoration, and flowable fill of pipe. Some municipalities have also
20 contracted out permit processing and drawing review to professional engineering
21 contractors, adding more requirements. For design, DTE is often required to
22 provide a survey and a plan and profile drawing prepared and stamped by a
23 professional engineer in lieu of DTE's standard internal planning and investigating

Line
No.

1 work. GRP is also experiencing a requirement to restore minor or residential
2 roadways from “joint to joint” meaning that a small excavation may require over
3 1,000 square feet of concrete restoration. Upon completion of gas main
4 replacement, a municipality may require the filling or removal of all abandoned
5 pipes. Historically DTE Gas has only been required to fill larger mains under
6 MDOT or County roadways. This requirement adds significant costs for additional
7 excavation, restoration, and contractor-installed flowable fill material.

8

9 **Q23. How has the implementation of a new risk assessment affected the**
10 **characteristics of projects?**

11 A23. In 2023, GRP began construction on 40 miles of mains identified by the
12 Probabilistic Risk Assessment (PRA) as a pilot to understand the cost implications
13 of increased risk mitigation. The Company estimates the costs for these grids to be
14 20-30% more than GRP’s 2022 average cost per mile of abandonment. This is
15 primarily due to the density of active services and population, a concentration in
16 areas with hardscape across the totality of the right of way, as well as a focus on
17 the replacement of larger diameter mains. Further, many of these areas contain main
18 thoroughfares which often cross railroad tracks and highways. These mains must
19 be installed with costly directional drilling and hydro-excavating processes. I will
20 discuss project selection criteria later in the testimony.

21

22 **Q24. What has the Company done to reduce cost pressure?**

23 A24. The Company has deployed several capital efficiency initiatives since U-20940 to
24 gain efficiencies and reduce cost:

Line
No.

- 1 1. Rigorous negotiation with 5 construction, 4 restoration, and 6 cross bore
- 2 inspection contractors to reduce bid price increases approximately 50%;
- 3 2. Diversifying the design, cross bore inspection, and restoration contractor base;
- 4 3. Re-balancing of the volume of work to each contractor based on the scope of
- 5 each project;
- 6 4. Reallocation of 6 miles per year from 2024 onward from Southeast Michigan
- 7 scope to greater Michigan regions, which have a lower average cost per unit;
- 8 5. Limiting high-complexity mileage to approximately 13% of yearly main miles
- 9 to be replaced;
- 10 6. Improving project design to reduce restoration impacts (e.g., installing new main
- 11 in soft surface versus hard surface and in alleys whenever possible in
- 12 commercial districts);
- 13 7. Successfully negotiating with some municipalities to limit the extent of
- 14 restoration and minimize mains to be filled with flowable concrete;
- 15 8. Implementation and usage of a new cost control application (EcoSys) as
- 16 supported in Witness Busby's testimony in U-20940 to calculate earned value
- 17 and monitor and control costs with detailed visibility.
- 18 Overall, our cost reduction efforts have resulted in approximately \$17 million in
- 19 savings over the past two years. While these efforts have mitigated some of the cost
- 20 increases, the magnitude of the increases described above still requires additional
- 21 capital.

22

23 **Q25. Is the Company proposing any changes to the IRM yearly unit goals that were**
24 **approved in U-20940?**

Line
No.

1 A25. Yes. The Company is proposing to adjust the Gas Renewal Program yearly inside
2 meter move-out goals to align with the pace of main renewal between 2024 and
3 2035 as indicated in Exhibit A-12 Schedule 6.2 Inside Meter Move-Out History
4 and Projection. GRP would set goals of 22,790 inside meters in 2024, 20,500 in
5 2025-2027 and 8,500 in 2028-29 compared to 22,790 approved in Case No. U-
6 20940, and the Company forecasts meter move-outs to occur within GRP grid
7 projects through 2035. A forecast for future routine meter move-outs was not
8 performed due to the significant variability in yearly actuals.

9 The Company is not changing the current average pace of main renewal (target of
10 replacing all legacy mains by 2035) as indicated in Exhibit A-12 Schedule B6.3
11 Main Renewal History and Projection, but the Company has updated the forecast
12 to reflect the yearly goals in each region (Southeast and Greater Michigan).

13 As the Company completes the replacement of cast iron and unprotected steel
14 mains in each region at an accelerated pace, DTE intends to continue assessing risk
15 within the distribution system and propose the continuation of replacement work
16 on assets not currently supported in GRP including:

- 17 1) 60 miles of cathodically protected bare steel prone to corrosion,
18 2) 54,000 copper and unprotected steel service lines with an outside meter
19 connected to plastic or cathodically protected mains,
20 3) Vintage plastic mains and services requiring mechanical couplings
21 subject to corrosion.

22

23 **Q26. Is the Company proposing a reduction in GRP spending levels due to the**
24 **revised annual inside meter goals in 2025-2029?**

Line
No.

1 A26. No. The Company is not proposing a reduction in the IRM surcharge capital
2 expenditure target for GRP. DTE estimates that the reduction in MMOs provides a
3 spending reduction of approximately \$28M during 2025-2029, but it is offset by
4 forecasted increases in main replacement costs as calculated in exhibit A12 B6.5.
5 Further, performing MMOs as a part of GRP projects in 2029-2035 avoids
6 approximately \$85.0 million in costs associated with reconnecting the previously
7 impacted services to new mains installed by GRP. As mentioned previously in this
8 testimony, DTE Gas has consistently achieved capital expenditures in excess of
9 minimum spending levels currently supported in the IRM surcharge.

10

11 **Q27. Is DTE Gas on pace to the accelerated 18-year main renewal goal approved in**
12 **U-18999?**

13 A27. Yes. DTE Gas is ahead of pace on the 18-year main renewal goal, having exceeded
14 the projected pace by a cumulative 72 miles since 2018 as displayed in Table 1
15 Actual Main Renewal Miles Achieved. As of January 1, 2023, DTE Gas has 2,442
16 miles of legacy mains remaining (See Exhibit A-12 Schedule B6.3). At the
17 currently supported pace of main renewal per year (excluding non-IRM renewal
18 such as unplanned or public improvement), approximately 31 miles of legacy main
19 will be completed in 2035 compared to 141 miles as forecasted in Case No. U-
20 20642. Including non-IRM legacy main renewal, DTE Gas is 179 miles ahead of
21 the approved 18-year pace to remove all legacy mains from the distribution system.

22

23

24

25

Line
No.

1

Table 4. Actual Main Renewal Miles Achieved 2018-2022 (1)

2

Year	Annual Main Renewal Goal	Actual Main Renewal Miles (2)	Variance
2018	149	157	8
2019	178	183	5
2020	206	220	14
2021	206	222	16
2022	206	235	29
Total	945	1017	72

3

(1) Mileage retired less plastic as detailed in annual IRM filings.

4

(2) Excludes unplanned renewal, public improvement and special project renewal.

5

6 Meter Move-Out

7

Q28. What is DTE Gas's progress towards reducing the 2022 inside meter remaining balance of 176,138, as forecast in Case No. U-20940?

8

9

A28. As of January 2023, DTE Gas has an inside meter balance of 148,403 putting the Company 3,143 inside meters ahead of the forecast established in U-20940. DTE Gas completed 72,854 meter move-outs between 2020 and 2022 compared to the forecast of 81,970. Over this period, IRM programs *exceeded* the inside meter move-out goal by 3,533, while routine meter move-out completions were 9,016 less than forecasted as indicated in Table 5 below. The annual actuals and projections by component are included in Exhibit A-12 Schedule B6.2, Inside Meter Move-Out History and Projections.

15

16

17

18

19

Line
No.

1

Table 5. Inside Meter Completions vs U-20940 Goals (2020-2022)

	Actual	Total Goal	Variance
Gas Renewal Program	45,968	44,370	1,598
MAC Meter Move-Out	24,507	24,000	507
IRM Programs	70,475	68,370	2,105
Routine Activities	2,379	13,500	(11,121)
Total Inside Meters	72,854	81,970	(9,016)

2

3 **Q29. Why is the Company revising the yearly inside meter move-out goals**
4 **presented in Case No. U-20940?**

5 A29. There are two primary drivers for the Company's proposed change in annual meter
6 move-out goals.

7 (1) First, DTE is adjusting its forecast to reflect the reduction it is seeing in 'routine'
8 move-outs (work that is not planned or budgeted for as part of the IRM but is instead
9 driven by unplanned or emergent Company- or customer-generated needs). The
10 goals developed in U-20940 included a forecast of routine inside meter completions
11 that are no longer realistic. The annual pace of 22,790 meter move-outs assumed
12 4,500 per year due to 'routine' activity, but routine actuals from 2020-2022 were
13 fewer than 1,000 each year. Drivers of this decrease are described later in this
14 testimony.

15 (2) Second, DTE can improve outcomes for infrastructure risk reduction, customer
16 satisfaction, and efficiency/affordability by avoiding the duplicative work that
17 would be required if we maintained the current pace for IRM meter move-outs. At
18 the current pace, approximately 32,000 customer meters would have to be impacted
19 twice, first for meter move-out and again later for main renewal.

20

21 **Q30. Why were routine meter completions lower than forecasted?**

Line
No.

1 A30. Routine work is not a dedicated program with specific funding or resources. It is
2 based on the incoming supply of customer- and Company-generated work
3 including demo or vacant cuts, revenue protection cuts, idle cuts or renewals for
4 leak each year that are unplanned and may or may not have an inside meter. Case
5 No. U-20940 projected that DTE Gas would achieve 4,500 routine completions
6 through 2028 based on an historical 3-year average (2017-2019). Since 2019, actual
7 routine completions have fallen each of the past four years. This variance results
8 from multiple factors including: (1) a reduction of inside meters as a percentage of
9 total DTE Gas meters from 21% in January 2019 to 12% in December 2022 (see
10 Exhibit A-12 B6.2), reducing the likelihood that any routine job impacts an inside
11 meter and (2) a significant reduction in inside meter cuts generated through the city
12 of Detroit's demolition and neighborhood stabilization program.

13

14 **Q31. How does the new proposed pace of inside meter move-outs avoid duplicative**
15 **meter work?**

16 A31. At the current approved GRP MMO pace and in order to complete meter move-
17 outs by 2028, approximately 32,000 inside meters would need to be moved out
18 between 2024-2028 and impacted again during risk-prioritized main renewal grid
19 projects between 2029-2035, with a tie-in to the new main. Completing all inside
20 meter move-outs prior to the completion of main renewal activities would be
21 disruptive to customers who would be impacted multiple times. It also would add
22 significant unnecessary and wasteful cost to total program expenditures, as a result
23 of duplicative design, permitting, customer notification and communication,
24 mobilization, construction and property restoration, and mapping processes. The
25 Company has estimated that acceleration of MMO to offset the reduction in routine

Line
No.

1 MMO's and the double impacting of the associated service lines would add
2 approximately \$85M of cost to GRP during 2024-2028 as mentioned previously.

3

4 **Q32. Are there any other factors leading to the change in meter move-out timing?**

5 A32. Yes. In addition to avoidance of duplicative work, the implementation of the
6 probabilistic risk model will change meter move-out timing. The Company is
7 finding that the probabilistic risk assessment has increased the priority of some high
8 complexity projects. Higher complexity projects are more expensive to complete.
9 Under the relativistic risk model, these projects were prioritized later in the
10 program. This higher priority will result in their being completed sooner than
11 previously planned. These higher complexity projects will start being remediated
12 as early as 2024. The adjustment down in the yearly inside meter goal is estimated
13 to help offset increased costs of higher complexity projects as well as avoid future
14 inefficiencies that would be incurred by a continuation of the 22,790 goal through
15 2028.

16

17 **Q33. When does DTE Gas plan to have completed legacy main renewal and meter**
18 **move-out?**

19 A33. DTE Gas estimates it will complete both legacy main renewal and inside meter
20 move-out by 2035 as shown in Exhibit A-12 Schedule B6.3, Inside Meter Move-
21 Out History and Projections. As of January 1, 2023, inside meters comprise
22 approximately 12 percent of DTE Gas meters. This percentage will continue to
23 decrease as the Company dedicates GRP resources to yearly MMO (along with
24 some ongoing move-out of inside meters through routine activities).

Line
No.

1 With the current approved IRM capital expenditures and dedicated resource levels,
2 the Company proposes to move out all feasible inside meters on non-legacy mains
3 in Southeast Michigan by the end of 2028, leaving only 3% of total DTE Gas meters
4 inside by that point. The remaining inside meters in both SEMI and GRMI, as
5 feasible, will be removed in conjunction with GRP risk-prioritized grids through
6 2035.

7

8 **Q34. Does the extension of the inside meter move-out pace impact total system risk?**

9 A34. The extension of the inside meter move-out efforts through 2035 does not increase
10 risk. Under the Probabilistic Risk Assessment model, inside meters are found to
11 have relatively low system risk compared to legacy main. DTE's work to perform
12 timely MAC inspections will contribute to the mitigation of inside meter risk.

13

14 Main Renewal

15 **Q35. What is a probabilistic risk model and what benefits does it provide?**

16 A35. A probabilistic risk model is a type of model that calculates risk by multiplying the
17 frequency of failure by the consequence of failure and presents the risk output in a
18 monetary unit of dollars per year. DTE Gas views the use of probabilistic risk
19 models as a leading practice in pipeline integrity management.

20

21 **Q36. Why is DTE Gas implementing a new probabilistic risk model?**

22 A36. In the Final Order for Case No. U-17999, the Commission recommended that DTE
23 Gas seek the services of a risk expert with a background in risk analysis as applied
24 to cast iron and steel pipes to perform a review of DTE's Distribution Integrity
25 Management Program (DIMP) risk model and main renewal/abandonment priority

Line
No.

1 selection procedures. DTE Gas reviewed and agreed with the risk expert's
2 recommendation to adopt a single, comprehensive framework for risk assessment
3 (probabilistic risk model) and began implementation in 2019. Further, the MPSC
4 issued the Michigan Statewide Energy Assessment (SEA) final report on
5 September 11, 2019. In this report, as part of the Natural Gas Recommendations,
6 specifically section 9.3.1.2 Natural Gas, Natural Gas Recommendation G-2, the
7 Commission recommends "utilities work towards incorporating the use of
8 probabilistic risk models to prioritize system investments".

9

10 **Q37. How has GRP traditionally selected main renewal candidates prior to the**
11 **implementation of the PRA?**

12 A37. Prior to the implementation of the probabilistic risk assessment, DTE Gas identified
13 risk candidates as defined below:

14

15 **Risk Ranked:** Risk Rank main abandonment projects, which are the highest-risk
16 segments of legacy distribution main as determined by the prior "relative risk"
17 model. The goal has been to renew 15 miles of the highest risk mains on an annual
18 basis. DTE Gas has selected the top 15 miles (10 SEMI, 5 GRMI) from a segment-
19 based risk list (referred to as "risk-rank").

20

21 **Municipal Coordination and Field-recommended:** GRP solicits input from
22 various regions throughout the Company to accelerate the replacement of legacy
23 mains that have increased maintenance activity. We also coordinate the selection
24 and timing of some GRP projects with the municipalities in which we perform
25 construction, to minimize the impact of our projects to newly paved roads,

Line
No.

1 sidewalks and streetscapes. These efforts have contributed to our cost savings
2 initiatives, further reducing maintenance and construction costs.

3

4 **Grids:** The service territory is segmented into Grids based upon leak survey areas
5 in SEMI and 1 mile x 1 mile grids in GRMI. Grids are ranked based on risk as
6 determined by the “relative risk” model. Renewal projects are then created based
7 on a Grid’s prioritization rank. Performing work based on Grids allows for more
8 efficiencies than localized Risk Rank segments.

9 Performing projects as Grids also allows for use of the Modified Grid Approach,
10 which focuses on replacing lower pressure distribution systems with a new higher-
11 pressure plastic system, starting in one area, and systematically working into the
12 next adjacent area while eliminating inside meters. The Modified Grid Approach
13 allows for the use of smaller diameter pipes which helps reduce construction costs.

14

15 **Regional Considerations:** As of January 1, 2023, DTE Gas has 2,442 miles of
16 legacy distribution main. There are 1,800 miles in Southeast Michigan (SEMI) and
17 642 miles in Greater Michigan (GRMI). Historically, DTE Gas has set yearly
18 regional goals of 156 and 50 miles in each, respectively, as approved in U-20642.

19 DTE Gas is proposing to maintain an average annual renewal of 206 miles (150
20 SEMI, 56 GRMI) as referenced in exhibit A12 B6.4 Main Renewal History and
21 Projections. Performing a relatively consistent scope in each region ensures DTE
22 Gas stays on track with main renewal and meter move-outs by allowing the
23 Company to develop and maintain resources (both internal to DTE and contracted
24 support) in respective regions throughout the lifetime of the program as well as
25 provides increased accuracy in expenditure and productivity forecasts.

Line
No.

1

2 **Q38. Is DTE Gas proposing any changes to GRP project selection criteria?**

3 A38. Yes. DTE Gas is proposing to use a single “grid-based” risk prioritization model in
4 lieu of selecting projects from separate segment and grid rankings, eliminating the
5 yearly goal of replacing 15 miles of “risk ranked” segments. In 2023, GRP is
6 performing 40 miles of higher risk mitigating grids from the PRA in lieu of “risk
7 rank” segments from the current relative model.

8

9 **Q39. What are the benefits of risk-ranked grid replacement in lieu of risk-ranked**
10 **segment replacement?**

11 A39. DTE Gas’s proposal to follow a singular, probabilistic, grid-based model between
12 2024 and 2035 will eliminate the need to return to segments of previously renewed
13 main in the future when a grid becomes a candidate for replacement and raise the
14 pressure and connect to the upgraded grid. This approach significantly reduces
15 multiple customer impacts as well as duplicative restoration, design, permitting,
16 and traffic control costs resulting in an estimated \$12 million cost avoidance over
17 the lifetime of the program.

18

19 **Q40. Does the implementation of the Probabilistic Risk Assessment (PRA) affect**
20 **distribution system risk mitigation?**

21 A40. Yes. DTE Gas has analyzed the results of the PRA for 2024-2035 in comparison to
22 the current relative risk model. The implementation of the PRA approach to system
23 risk mitigation is estimated to remediate three times as much risk during the first 4
24 years of implementation (2024-2027) compared to the prior model.

25

Line
No.

1 **Q41. Is the Company continuing to replace segments of legacy mains in addition to**
2 **grids?**

3 A41. Yes. The Company is proposing to continue the practice of pulling forward select
4 segments of legacy main renewal for a few reasons, including:

- 5 1. Municipal Coordination
- 6 2. Field Recommended
- 7 3. Corrosion Recommended

8

9 **Q42. What are corrosion recommended projects?**

10 A42. DTE Gas intends to perform remedial action on some main segments that have
11 active corrosion pursuant to NC-418725. If a segment of gas pipe is identified as
12 having active corrosion and is a legacy gas main, DTE Gas will try to design and
13 plan the project as a GRP project and remediate the active corrosion segment(s)
14 through main renewal within the specified remediation period. Active corrosion
15 service lines identified outside of GRP projects planned within the compliance
16 period will be remediated by non-IRM programs.

17

18 **Q43. Beyond the Probabilistic Risk Assessment rankings, what criteria will the**
19 **Company consider in selection of renewal projects?**

20 A43. DTE Gas has historically and will continue to consider and work to balance many
21 factors when selecting projects for a construction year including:

- 22 1. Risk mitigation
- 23 2. Legacy main mileage
- 24 3. Inside meter goals
- 25 4. Capital expenditure levels

Line
No.

- 1 5. Hydraulic reliability
- 2 6. Municipality and customer impact
- 3 7. Resource availability
- 4 8. Complexity

5

6 **Q44. What changes is DTE Gas making in how it selects its grid due to the PRA?**

7 A44. DTE Gas is introducing a complexity variable when it selects grids based on the
8 PRA. The PRA methodology differs from the current relative model by placing
9 more risk value on population density and building occupancy. This change results
10 in a risk ranking including grids located entirely within densely populated areas and
11 along heavily traveled main thoroughfares. GRP's intent is to balance risk
12 mitigation, unit goal levels, and capital expenditures to prevent significant year-
13 over-year capital expenditure variation and regional shifts in resource requirements,
14 geographic shifts by a consideration of project complexity, as well as the quantity
15 of legacy mains and meters remaining in each region.
16 Complexity assessment is not new to the Gas Renewal Program. As established in
17 Case No. U-17999 Testimony of A. Sandberg (ADS-57 & 58) regarding annual
18 mileage goals: "There are numerous variability factors that drive the complexity.
19 Given this variability, assessing the performance of the program based on mileage
20 targets established in advance of the work execution may not accurately reflect the
21 true efficiency of the program." And: page 58 "In lieu of establishing annual
22 mileage targets, DTE Gas will submit the current estimate of the cost for each
23 project with the annual planning report for Staff's review based on known
24 complexity and contractor unit pricing by October 31st of each year."

Line
No.

1 For project selection criteria under the PRA, however, DTE Gas is proposing to
2 classify grids as high or medium complexity and set an average annual mileage goal
3 for high-complexity projects to maintain relatively consistent capital expenditure
4 and mileage.

5 DTE has estimated that approximately 209 miles of remaining legacy mains are
6 considered “high complexity” equating to an average of 19 miles per year (13
7 SEMI, 6 GRMI) as indicated in Table 6.

8 **Table 6. GRP Average Yearly Planned Legacy Miles by Project Type**

	SEMI	GRMI	Total Goal
High Complexity Miles	13	6	19
Medium Complexity Miles	137	46	183
Total PRA Miles	150	52	202
Muni/Field/Corr Recom.	2	2	4
Total GRP Miles	152	54	206

9
10 At the beginning of 2024 (the start of full PRA implementation), DTE estimates
11 that it will have about 2,285 miles of legacy main (1,665 SEMI, 620 GRMI). In the
12 12 years 2024-2035, DTE needs to retire an average of 190 miles of main each year
13 to meet the 18-year pace approved in Case No. U-18999.

14 The Company maintains that a degree of flexibility in yearly main and inside meter
15 unit goals is necessary and prudent to maintain the accelerated pace of the Gas
16 Renewal Program. As DTE Gas is currently 43 miles ahead of the 18-year pace
17 approved in U-18999, the Company is proposing a yearly ‘minimum goal’ mileage
18 of 190 miles for GRP, allowing DTE Gas to perform fewer miles annually than the
19 206 miles approved in Case No. U-20940. Unit goal flexibility will allow the
20 Company to continue to mitigate the highest risk mains (as ranked in the PRA) at

Line
No.

1 an accelerated pace, while also accounting for anticipated variation in complexity
2 of the prioritized mains. With this strategy, DTE Gas can ensure relatively
3 consistent capital expenditure levels and dedicated resources in defined geographic
4 areas and mitigate significantly more risk from the distribution system each year
5 starting in 2024.

6 **Table 7. Probabilistic Risk Assessment (PRA) Risk/Cost/Mileage Balance**

7 **Analysis (Illustrative Example)**

	W/ Complexity Balance(1)	W/O Complexity Balance(2)
Legacy Main Mileage	206	206
Yearly Cost	\$280 M	\$390 M
Risk Mitigation	\$16 M	\$23 M

8 (1) Balance assumes a limit of 19 miles of high complexity grid projects

9 (2) Scenario assumes selection of projects in SEMI and GRMI based on PRA
10 results from May 2022

11

12 **Q45. Are any projects supported by the GRP expenditures part of DTE Gas's**
13 **highest cost projects?**

14 A45. Yes. The East Jefferson project has expenditures large enough to fall into DTE
15 Gas's highest cost projects and are supported in detail in Exhibit 12, Schedule B5.5
16 DTE Gas Highest Cost Top 25 Capital Projects and the testimony of Witness
17 Abona.

18

19 Pipeline Integrity

20 **Q46. What is pipeline integrity work?**

Line
No.

1 A46. Pipeline integrity is the program used by DTE Gas to manage and ensure the
2 integrity of the gas transmission system as prescribed in Subpart O of the Michigan
3 Gas Safety Standards (MGSS), Pipeline Integrity Management. The regulatory
4 requirements contained in Subpart O of MGSS prescribe minimum requirements
5 for a transmission pipeline integrity management program. The sub-programs of
6 DTE Gas's Pipeline Integrity Management Program are:

7 (i) Pipeline Integrity Assessments

8 (ii) In-Line-Inspection (ILI) Expansion

9 (iii) Remote Control Valves (RCV)

10 (iv) Records Management System Development

11 Item (i) is an operations and maintenance (O&M) expense covered in Company
12 Witness Kehoe's testimony. This testimony will address the capital expenditures,
13 items (ii – iv).

14

15 **Q47. Why is it appropriate to include PI expenditures in the IRM?**

16 A47. As pointed out by the MPSC in Case U-16999, "The PI program is required under
17 federal and state safety standards and is an integral part of the Company's overall
18 effort to improve the safety and reliability of its system." Similar to the GRP
19 program, the PI program involves significant long-term infrastructure expenditures.
20 DTE Gas sought recovery for the cost of service for PI capital expenditures in Case
21 No. U-16999, and the Commission authorized the capital spending plan in its final
22 order.

23

24 **Q48. What is the Pipeline Integrity Assessment Program?**

Line
No.

1 A48. Pipeline assessments are conducted to identify any potential anomalies on the
2 facilities. After evaluating these anomalies and depending on their severity,
3 remediation methods vary from simply reapplying protective coating, to removal
4 and replacement of a section of pipe containing the anomaly with new, coated and
5 pressure tested pipe, and tie-in joints successfully tested by non-destructive method.
6 Accepted assessment methods are In-Line Inspection (ILI) (i.e., smart pigging),
7 Pressure Testing, and Direct Assessment (DA). Once the initial baseline
8 assessment is completed using any of the accepted assessment methods in
9 accordance with regulatory schedule, each covered segment must be reassessed at
10 intervals as specified in Subpart O, generally every seven years.

11

12 **Q49. How is the cost of pipeline integrity assessments and remediation treated?**

13 A49. The cost of pipeline integrity assessments and remediation was capitalized through
14 year 2012, as authorized in a prior DTE Gas rate case, Case No. U-15985. As
15 authorized in DTE Gas's prior depreciation case, Case No. U-15699, beginning in
16 2013, the costs associated with transmission pipeline integrity assessments and
17 remediation, pipe repair or replacement 50 feet in length or less, are expensed as
18 routine O&M transmission pipeline maintenance and are supported in Witness
19 Kehoe's testimony. The following assessment related costs associated with the ILI
20 Expansion or pipeline integrity assessment sub-programs under the transmission
21 integrity management program are capitalized and supported in this testimony:

- 22 (i) Pipeline retrofits required to prepare the lines for ILI assessment (ILI
23 Expansion), and
24 (ii) Replacement of sections of pipeline that are greater than 50 feet in length
25 (under the standard retirement unit policy authorized in Case No. U-15699).

Line
No.

1 Although pipeline assessments are an O&M expense supported in Witness Kehoe's
2 testimony, the assessment methods are described in this testimony to provide
3 background supporting the capital ILI Expansion program.

4

5 In-Line-Inspection

6 **Q50. What is the ILI method for assessing integrity of pipelines?**

7 A50. ILI involves inserting an electronic instrumented module into the pipeline at one
8 end and typically propelling it to the other end utilizing the velocity of the gas,
9 while recording metal loss data and other information about the pipeline. The
10 instrument is often referred to as a "smart pig" and the process is described as
11 launching and receiving a pig. In addition, for short segments, usually less than one
12 mile long, when there is not enough gas to propel the "smart pig" down the pipeline,
13 tethered or robotic type "smart pigs" are utilized to record metal loss data and other
14 information about the pipeline.

15

16 **Q51. What is the direct assessment method for assessing integrity of pipelines?**

17 A51. Direct assessment is a process for external, internal and stress corrosion cracking
18 (SCC) assessment that involves the use of above ground surveys to look for
19 indications of a coating defect and potential locations for corrosion. These areas
20 are then excavated and evaluated to determine the need for any pipeline
21 remediation.

22

23 **Q52. What is ILI Expansion program?**

24 A52. ILI Expansion is the program implemented by DTE Gas to increase the coverage
25 of transmission integrity assessments beyond the minimum requirements specified

Line
No.

1 in MGSS, Subpart O, Pipeline Integrity Management. Under this program,
2 pipelines previously assessed by methods other than ILI will be retrofitted with
3 appropriate bends, barred tees, launchers, receivers, and valves to permit passage
4 of ILI tools to assess the integrity of the pipelines not only in High Consequence
5 Areas (HCAs) but also Moderate Consequence Areas (MCAs) and other areas
6 outside of HCAs/MCAs. HCA and MCA are defined in Title 49 of the Code of
7 Federal Regulations, parts 192.903 and 192.3, respectively. Selection of expansion
8 candidate lines is based on a combination of risk ranking from risk assessments,
9 and timing of reassessment schedules.

10

11 **Q53. Why did DTE implement the ILI Expansion program?**

12 A53. DTE Gas started implementing the ILI Expansion program following completion
13 of required baseline assessments in 2012. The ILI method was chosen for the
14 integrity assessment expansion program because ILI gathers the most
15 comprehensive data about pipelines and is the most versatile method in terms of
16 coverage of pipeline threats, making it the method preferred by most operators.
17 Further, assessment by ILI provides information beyond HCA to get a full picture
18 of the integrity of the assessed segment for continued service.

19

20 **Q54. Are there regulatory drivers that support the ILI expansion program?**

21 A54. Yes, there are regulatory drivers described below for the ILI expansion program.

22 (1) A January 2015 safety report by the National Transportation Safety Board
23 NTSB (NTSB/SS-15/01, PB2015-102735) on “Integrity Management of
24 Gas Transmission Pipelines in High Consequence Areas” stated that “ILI
25 yields the highest per-mile discovery of pipe anomalies and the use of direct

Line
No.

1 assessment as the sole integrity assessment method has numerous
2 limitations.” The NTSB recommends (i) expanding the use of ILI
3 especially for intrastate pipelines and (ii) eliminating the use of DA as the
4 sole integrity assessment method for pipelines.

5 (2) The Interstate Natural Gas Associate of America (INGAA), in response to
6 the NTSB recommendation, in April 2012 responded with a white paper
7 titled “Historical and Future Development of Advanced In-Line Inspection
8 (ILI) Platforms for Natural Gas Transmission Pipelines”. In this document
9 INGAA stated that “INGAA members recognize that improving technology
10 is critical to achieving our commitments by making more of the [pipeline]
11 system conducive to ILI”. In addition, “ILI is our most predictive and
12 preferred tool for determining fitness for service.”

13

14 **Q55. What is the result of the ILI expansion program since inception?**

15 A55. From 2012 to 2022, DTE Gas has retrofitted a total of 518 miles for assessment by
16 ILI. Coverage of DTE Gas’s transmission system assessable by ILI through 2022
17 has increased to 66.8% for total miles, and 95.4% for HCA miles.

18

19 **Q56. What is DTE Gas’s plan for ILI expansion beyond 2022?**

20 A56. From 2023 through 2025, DTE Gas’s ILI expansion plan includes retrofit of an
21 additional 276 miles of pipeline for inspection by ILI, increasing coverage of the
22 total transmission system assessable by ILI from 66.8% in 2022 to 83.6% in 2025.
23 Correspondingly, DTE forecasts that HCA assessable by ILI will increase from
24 94.5% in 2022 to 97% in 2025.

25

Line
No.

1 **Q57. What is DTE Gas's plan for ILI expansion beyond 2025?**

2 A57. After 2025, 97% of DTE Gas' HCA miles will be assessable by ILI, the best
3 available technology to assess the condition of pipelines. The remaining
4 approximately 3% of HCA miles will not be assessed by ILI for various reasons
5 including the lack of availability of commercial tools for the smaller pipeline
6 diameters, gas flow rate that is too low to keep the tool moving, or the HCA miles
7 being in a station where ILI assessments are impractical. For this mileage, Direct
8 Assessment will be used to assess the condition of these pipelines to ensure the
9 Company is assessing 100% of HCA as required by regulations. Starting in 2026,
10 DTE Gas plans to address a total of seven pipelines that do not currently have
11 permanent ILI launcher and receiver facilities and install this piping to reduce risks
12 and eliminate annual costs associated with transportation, retesting, and installation
13 of the portable traps.

14

15 Remote Control Valve

16 **Q58. What is the Remote Control Valve (RCV) program?**

17 A58. The RCV program is the automation of transmission pipeline sectionalizing valves
18 (aka Main Line Valves-MLV) in pipeline HCAs, to permit remote closure of the
19 valves in the event of a pipeline emergency.

20

21 **Q59. Why did DTE Gas implement a RCV program?**

22 A59. DTE Gas implemented its RCV program to (i) provide quick indication of a
23 pipeline emergency at the Company's Gas Control, (ii) enable faster response and
24 containment of an emergency, and (iii) reduce the consequences of an emergency
25 to life and property in the riskiest segments of the pipelines (HCA areas). Prior to

Line
No.

1 implementing the program, all MLVs in HCA were locally operated.
2 Consequently, an emergency required a call-out to a trained pipeline technician, a
3 process that could result in a response time of several minutes to hours depending
4 on the location of the pipeline technician relative to the incident.
5

6 **Q60. What are the regulatory drivers for the RCV program?**

7 A60. The regulatory drivers are:

- 8 (i) The MGSS, Subpart O, Pipeline Integrity Management, requires installation
9 of Automatic Shut Off Valves (ASV) or Remote Control Valves (RCV) if an
10 operator determines based on risk analysis that an ASV or RCV would be an
11 efficient means of adding protection to an HCA in the event of a gas release.
12 (ii) The Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011
13 requires pipeline owners and operators to install RCV, ASV or equivalent
14 technology in HCAs of newly constructed or entirely replaced pipeline
15 segments where economically, technically, and operationally feasible.
16 DTE Gas determined from a risk evaluation conducted in 2008 that automation of
17 MLVs in HCAs with remote control capability will provide faster response time in
18 the event of a gas release and, thereby, reduce the impact of the release on life and
19 property.
20

21 **Q61. What is the result of the RCV program since inception?**

22 A61. The RCV program commenced in 2011 and by year-end 2018, 181 MLVs and
23 critical connector valves in HCA were automated with remote control capability.
24

25 **Q62. What are DTE Gas's future plans for RCVs?**

Line
No.

1 A62. As new HCAs are identified outside the limits of existing RCVs, DTE will evaluate
2 the need to install RCVs to permit remote closure. DTE will also evaluate and
3 prioritize the need to automate valves in Moderate Consequence Areas (MCA)
4 based on risk.

5

6 **Q63. Why are total Pipeline Integrity expenditures not decreasing since RCV**
7 **installations have decreased since 2018?**

8 A63. To meet DTE Gas's goal of having 97% of HCAs assessed by ILI by 2025, DTE
9 Gas has increased capital expenditures to retrofit transmission pipelines as part of
10 its ILI expansion program, offsetting the reduction in RCV installations. DTE Gas
11 believes this is an appropriate decision because it recognizes the importance of the
12 In-Line Inspection (ILI) method as the industry preferred and more robust method
13 of detecting pipeline anomalies.

14

15 MAOP Records Review

16 **Q64. What is the MAOP Records Review program?**

17 A64. MAOP Records Review is the review of pipeline records to ensure that the records
18 are traceable, verifiable and complete (TVC), and substantiate Maximum
19 Allowable Operating Pressure (MAOP).

20

21 **Q65. Why did DTE Gas implement the MAOP Records Review program?**

22 A65. DTE Gas implemented the MAOP Records Review program in response to the
23 Advisory Bulletin issued by PHMSA on January 10, 2011. The bulletin advised
24 pipeline operators of their obligations to ensure that data used to establish pipeline
25 MAOP are reliable. Further to the advisory bulletin, the Pipeline Safety, Regulatory

Line
No.

1 Certainty and Job Creation Act of 2011 requires pipeline owners and operators to
2 verify that records for gas transmission pipelines in HCA and class 3 and 4 locations
3 (1) accurately reflect pipeline physical and operational characteristics and (2) can
4 substantiate MAOP.

5

6 **Q66. What is the coverage of DTE Gas's MAOP Records Review program?**

7 A66. DTE Gas's MAOP Records Review program exceeds the requirements of the
8 Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011. Specifically,
9 the program covers all DTE Gas facilities operating at or above 100 psig as follows:
10 (i) 1,881 miles of transmission pipelines, including MLV sites regardless of
11 class location
12 (ii) 208 transmission gate stations
13 (iii) 7 compressor stations
14 (iv) 1,367 miles of high-pressure steel distribution pipelines
15 (v) 92 district pressure regulating stations

16 The wide coverage of the DTE program is in recognition of the risks inherent in
17 pipeline operation. Although pipeline failures triggered by material defects can
18 result in rupture of transmission lines, distribution pipelines tend to leak under
19 similar circumstances. A leak from a high-pressure distribution pipeline in a
20 populated area can have greater consequences than a failure on a transmission line
21 in a less populated area.

22

23 **Q67. What is the result of the MAOP Records Review program since inception?**

24 A67. By year end 2020, records review to substantiate MAOP has been completed for
25 1,881 miles of transmission lines, 208 gate stations, 7 compressor stations, 428

Line
No.

1 miles of high-pressure steel distribution mains and 92 district regulating stations.
2 In addition, we performed a second level review in 2019 and 2020 of the HCA and
3 class 3 and class 4 miles to ensure we captured all record defects to develop a
4 comprehensive MAOP Reconfirmation plan.

5

6 **Q68. What is DTE Gas's plan for the MAOP Records Review program regarding**
7 **transmission records in the future?**

8 A68. Since all transmission records have been reviewed, we will continue to focus our
9 attention and resources on the remediation of the records defects as required by the
10 new rules, in class 3 and class 4 and HCA. This remediation work began in 2021.
11 DTE Gas plans to perform a second level review of the class 1 and 2 miles and
12 stations in the future to ensure we captured all record defects for any potential
13 remediation.

14

15 **Q69. Why is an MAOP Reconfirmation plan required?**

16 A69. The revision to the Federal Pipeline Safety Regulations by PHMSA, titled Safety
17 of Gas Transmission Pipelines (MAOP Reconfirmation, Expansion of Assessment
18 Requirements and Other Related Amendments,) that was finalized on October 1,
19 2019, and became effective on July 1, 2020, requires operators to develop an
20 MAOP reconfirmation plan by July 1, 2021 for piping in HCA and class 3 and 4
21 without traceable, verifiable and complete (TVC) records. MAOP Reconfirmation
22 of 50% of defects is required to be completed by 7/3/2028 with the remaining 50%
23 to be completed by 7/2/2035. DTE Gas has developed this detailed MAOP
24 Reconfirmation plan and is currently executing this plan to remediate defects much
25 earlier than the timeline required by the new rules.

Line
No.

1

2 **Q70. What is DTE Gas's plan for the MAOP Records Review program regarding**
3 **distribution records in the future?**

4 A70. Given the importance of ensuring adherence to the new rules from PHMSA
5 requiring new projects have TVC records and to focus our attention and resources
6 on the remediation of the records defects as required by the new rules, starting in
7 2021 we paused our legacy high pressure steel distribution records review efforts
8 to focus our efforts on process improvements to prevent record defects in the future.

9

10 **Q71. Why are IRM expenditures not decreasing since the legacy high pressure steel**
11 **distribution records review was paused at the end of 2020?**

12 A71. Similar to the RCV funding, to meet DTE Gas's goal of having 97% of HCAs
13 assessed by ILI by 2025, DTE Gas will utilize the capital expenditures for
14 distribution records review to retrofit transmission pipelines as part of its ILI
15 expansion program. DTE Gas believes this is an appropriate decision because it
16 recognizes the importance of the In-Line Inspection (ILI) method as the industry
17 preferred and more robust method of detecting pipeline anomalies.

18

19 Records Management System

20 **Q72. What is the Records Management System?**

21 A72. DTE Gas's Records Management System is a multi-faceted program to develop an
22 electronic system for managing pipeline risks and records. It ensures safe archiving
23 and quick retrieval of records and automatic and frequent updates of threats and
24 relative risks for pipeline segments. Implementation includes (i) mapping of
25 transmission lines in ESRI-GIS utilizing GPS coordinates, (ii) creating an

Line
No.

1 electronic records repository in Documentum, (iii) uploading and linking repository
2 of MAOP records, construction records, assessment records, cathodic protection
3 (CP) records, and routine O&M records to pipeline segments in ESRI, (iv) updating
4 pipeline probabilistic risk models, and (v) updating of legacy construction records
5 to reflect current installation (as-built).

6

7 **Q73. Why did DTE Gas implement a Records Management System?**

8 A73. DTE Gas implemented an electronic records management system as described
9 above for a number of reasons: (i) the development of an electronic repository of
10 pipeline records replaces current paper records susceptible to loss or degradation
11 over time and ensures compliance with MGSS, which requires records retention for
12 the life of certain facilities, (ii) to comply with the positional accuracy and
13 significant increase in pipeline attribute data required in the proposed National
14 Pipeline Mapping System (NPMS) information collection issued by PHMSA, and
15 (iii) to ensure that pipeline integrity risk mitigation through assessments and
16 preventive and mitigative (P&M) measures is based on risk ranking reflecting
17 current threats.

18

19 **Q74. What is the result of DTE Gas Records Management System since inception?**

20 A74. From 2012 through 2022, DTE Gas (i) completed mapping of 1,881 miles of
21 transmission pipelines, (ii) scanned data for 1,881 miles of transmission pipelines
22 to create an electronic data repository, (iii) completed linkage of MAOP data with
23 segments in ESRI-GIS, (iv) developed a database for pipeline integrity digs (DA
24 and ILI), (v) completed as-built of legacy gas piping drawings at Belle River Mills,
25 Columbus, Kalkaska, Alpena and Reed City compressor stations, (vi) updated the

Line
No.

1 distribution and transmission risk models from the relative to the probabilistic risk
2 model to improve prioritization of risk mitigation efforts, (vii) completed
3 conversion from a paper-based process for class and HCA determination to an
4 electronic process, and (viii) created an electronic records repository in
5 Documentum.

6

7 **Q75. What is the plan for DTE Gas Records Management System in 2023 through**
8 **2025?**

9 A75. From 2023 through 2025, DTE Gas plans to:

- 10 1) complete the implementation of the new probabilistic risk model for the
- 11 underground storage integrity management program (UNGSIMP),
- 12 2) locate and scan station records into an electronic data repository,
- 13 3) develop and implement a conversion plan to migrate distribution and
- 14 transmission pipeline data models into a new Utility and Pipeline Data
- 15 Model (UPDM) and investigate merging the two models into one network
- 16 for automatic and seamless extraction of data to calculate relative risks,
- 17 4) continue the as-built of legacy piping drawings at the remaining compressor
- 18 stations and begin gate station updates, and
- 19 5) perform a second level review of the class 1 and 2 stations.

20

21 **Q76. What level of PI capital expenditures does the Company support in this**
22 **proceeding for 2023 through September 2025?**

23 A76. From December 31, 2022, the end of the historical test year, through-September 30,
24 2025, the end of the projected test year, DTE Gas will have incurred \$50.0 million
25 of PI capital expenditures. These expenditures are illustrated in Exhibit A-12,

Line
No.

1 Schedule B5.3, line 6, columns (e) and (f). Detailed project list for Pipeline
2 Integrity projects is identified in Exhibit A-12, Schedule B5.20 DTE Gas Detailed
3 Pipeline Integrity Project List for 2023-2025.

4

5 **Q77. Did the Company's Pipeline Integrity expenditures in 2021 and 2022 vary**
6 **from projections in Case U-20940?**

7 A77. While the timing of expenditures in the two years varied from plan, the total amount
8 was \$29.7 million, approximately \$1 million more than forecasted. See Table 8
9 below.

10 **Table 8. Pipeline Integrity Capital Expenditures in '000s**

	2021	2022 (a/e)	Average
Base Rates	\$14,250	\$3,380	\$17,630
IRM Surcharge	0	11,120	11,120
Total	\$14,250	\$14,500	\$28,750
Actual	\$11,726	\$18,000	\$29,726

11

12 **Q78. Is DTE Gas implementing any changes in the Pipeline Integrity portion of**
13 **IRM capital expenditures reflected in its IRM surcharge?**

14 A78. Yes. The IRM surcharge, which will commence January 1, 2025, will be based on
15 PI capital expenditures shown in the table below. Overall, PI spending for 2024,
16 both IRM and expenditures in excess of IRM, will total \$22.3 million.

17 **Table 9. Pipeline Integrity Capital Expenditures**

	2025	2026	2027	2028	2029	Total
Expenditures	\$23.1	\$13.4	\$13.4	\$11.1	\$11.1	\$72.1

18

Line
No.

1 These higher expenditures will be used to:

2 (1) Complete the implementation the probabilistic risk models. The
3 implementation of the probabilistic risk model across distribution, transmission
4 and storage assets is a one-time multi-year project that will put the Company at
5 the forefront of risk management in the integrity management space. The costs
6 associated with this project are not included in the proposed IRM expenditures
7 and therefore higher costs are expected for IRM.

8 (2) Retrofit the Alpena 12", Alpena 16", Powers Gladstone, Belle River Field
9 Headers 12"/16", Menominee Powers, Trufant 12" and Austin Taggart. These
10 projects require additional funding above the Commission approved total
11 amount due to accelerating the ILI Expansion projects in order to achieve 97%
12 of HCA's assessed by ILU by 2025.

13

14 **Q79. Why are 2025 expenditures more than the historical \$11.1 million?**

15 A79. To meet DTE Gas's goal of having 97% of HCAs assessed by ILI by 2025, DTE
16 Gas will retrofit a total of five pipelines as part of its ILI expansion program. This
17 includes the Belle River Field Headers 24", Muskegon Ludington 10", Petoskey
18 8", Lincoln Traverse City 12" and the Escanaba Paper pipeline. DTE Gas believes
19 this is an appropriate decision because it recognizes the importance of the In-Line
20 Inspection (ILI) method as the industry preferred and more robust method of
21 detecting pipeline anomalies.

22

23 **Q80. Are any other projects supported by the PI expenditures part of DTE Gas's**
24 **highest cost projects?**

Line
No.

1 A80. Yes. Six PI projects have expenditures large enough to fall into DTE Gas's highest
2 cost projects and are supported in detail in Exhibit 12, Schedule B5.5 DTE Gas
3 Highest Cost Top 25 Capital Projects. Specifically, the projects are Alpena 16",
4 Powers Gladstone (Powers Junction to Escanaba Paper Tap), Belle River Field
5 Headers (12/16), Trufant 12, Belle River Field headers 24 and Muskegon
6 Ludington 10 (Ludington Gate – Scottville Tie In).

7

8 **Q81. Did PHMSA issue new Pipeline Integrity regulation?**

9 A81. Yes. On October 1, 2019, PHMSA released "Pipeline Safety: Safety of Gas
10 Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment
11 Requirements, and other Related Amendments" effective July 1, 2020.

12 The final rule addresses:

13 (i) MAOP Reconfirmation

14 A MAOP reconfirmation plan must be developed by July 1, 2021, with 50% of the
15 remediation completed by July 3, 2028, and 100% by July 2, 2035, for the following
16 transmission pipeline segments without traceable, verifiable, and complete (TVC)
17 records:

18 a. HCA or Class 3 or 4 locations

19 b. Piggable segments that have MAOP established in accordance with
20 102.619(c) ("Grandfather Rule") and the pipeline has an MAOP greater
21 than or equal to 30% SMYS and is located in an HCA, Class 3 or 4 or
22 Moderate Consequence Area (MCA)

23

24 (ii) Expansion of Integrity Assessments

Line
No.

1 Initial integrity assessments must be completed by July 2034 and reassessments
2 completed every ten years for the following transmission pipelines outside of HCAs
3 operating at an MAOP greater than or equal to 30% SMYS:

4 a. located in a Class 3 or 4 non-HCA location

5 b. located in moderate consequence areas (MCA) if the pipeline is
6 assessable by ILI

7

8 **Q82. What is the impact of the new PHMSA regulation on DTE Gas expenditures?**

9 A82. In this rate case, DTE Gas has included Capital expenditures to address MAOP
10 reconfirmation as it pertains to pipelines currently operating under the “grandfather
11 clause”, 192.619(c). Under the new ruling, the grandfather clause can only be used
12 to establish the MAOP of pipelines that operate under 30% specified minimum
13 yield strength (SMYS) or pipelines that operate in a Class 1 or Class 2 area. This
14 new ruling pertains to two pipelines in our system and based on accounting
15 guidelines from the Federal Energy Regulatory Commission (FERC), Docket No.
16 AI20-3-000, capitalization of MAOP reconfirmation of these pipelines is prudent
17 since these pipelines were allowed to operate under the “grandfather clause” prior
18 to the new rules but now do not meet the requirements of the new federal rules and
19 therefore require MAOP reconfirmation.

20

21 **Cathodic Protection**

22 **Q83. What are cathodic protection expenditures?**

23 A83. Cathodic protection is installed on the metallic components of DTE’s gas
24 infrastructure from external, internal, and atmospheric corrosion. There are two
25 components to this expenditure: Corrosion Work Order (CWO), unit-based work

Line
No.

1 and Cathodic Engineering, which consists of larger projects. Corrosion work orders
2 for remediation of defects identified through yearly surveys are integral to the
3 management of the integrity of both distribution and transmission pipelines.
4 Corrosion work orders (CWOs) are for remediation of defects identified through
5 annual surveys that are integral to the management of the integrity of pipelines.
6 These CWOs could call for impressed current system rectifier and ground bed
7 replacements and additions, as well as galvanic anode system for isolation fittings
8 needed to sustain cathodic protection on existing underground transmission and
9 distribution piping systems. Corrosion (Engineering) capital projects are for new
10 construction requiring corrosion protection such as new impressed current systems
11 rectifier and ground bed. Capital expenditures for cathodic protection were
12 supported within routine plant expenditures in case no. U-20940 by Witness
13 Brudzynski.

14

15 **Q84. Why is DTE proposing to recover cathodic protection expenditures through**
16 **the IRM rather than as part of routine capital?**

17 A84. As of 2022, approximately 25% of DTE's Gas distribution system is cathodically
18 protected steel and is not included in the scope of the GRP for replacement by 2035.
19 DTE's long term strategy includes consistent capital investment in corrosion
20 control and protection to reduce the risk of distribution leaks. By including these
21 expenditures within the scope of the IRM, DTE Gas can (1) assure our customers
22 and MPSC Staff that these expenditures are reasonable and prudent with increased
23 transparency to costs, unit completions, and projects, (2) ensure sufficient
24 minimum expenditure levels will be dedicated to cathodic protection through 2029,
25 and (3) formalize a holistic, programmatic approach to the Company's continued

Line
No.

1 reduction of gas leaks in line with DTE's commitment to the safety of the public
2 and the reduction of methane emissions.

3

4 **Q85. What level of cathodic protection capital expenditures is DTE Gas proposing**
5 **to include in the IRM?**

6 A85. From January 1, 2023, through September 30, 2025, the end of the projected test
7 year, DTE Gas will have incurred \$23.7 million of cathodic protection capital
8 expenditures. These expenditures are illustrated in Exhibit A-12, Schedule B5.1,
9 page 2 of 2, line 10, columns (f) and (g).

10

11 **Q86. How do the Company's 2023 through 2025 cathodic protection expenditures**
12 **compare to historical average spend?**

13 A86. On average, DTE Gas expects 2023-2025 cathodic protection capital expenditures
14 to be \$3 million higher per year than the 2020-2022 \$5.6 million three-year average.

15

16 **Table 10. Cathodic Protection Expenditures 2020-2029**

	2020	2021	2022	2023	2024-29
	Actual	Actual	Actual	Forecast	Forecast
CWO (Corrosion Work Orders)	\$5.69	\$5.26	\$5.70	\$8.61	\$6.80
CE (Corrosion Engineering)	\$1.38	\$1.03	\$1.66	\$2.78	\$2.78
Total	\$7.07	\$6.29	\$7.36	\$11.40	\$9.60

17

Line
No.

1 The increase is related to the unit-based work. On average, corrosion work order
2 unit costs have increased from \$3,056 per unit in 2020 to \$4,624 in 2023 and the
3 Company is forecasting a unit cost of \$4,012 for 2024-2029. The Company
4 forecasts 1,695 Corrosion Work Orders per year starting in 2024 based on a 4-year
5 historical average of units completed 2020-2023.

6

7

Table 10 - Corrosion Work Order Costs and Units

	2020 Actual	2021 Actual	2022 Actual	2023 Forecast	2024-29 Forecast
Corrosion Work Orders	1,862	1,699	1,359	1862	1,695
Total (\$Millions)	\$5.69	\$5.26	\$5.702	\$8.61	\$6.80
Cost Per Unit	\$3,056	\$3,093	\$4,196	\$4,624	\$4,012

8

Table 11 – CP Engineering Costs and Units

	2020 Actual	2021 Actual	2022 Actual	2023 Forecast	2024-29 Forecast
CP Engineering	5	5	10	12	12
Total (\$Millions)	\$1.38	\$1.03	\$1.66	\$2.78	\$2.78
Cost Per Unit	\$0.36	\$0.206	\$0.166	\$0.232	\$0.232

9

10 **Q87. What are the factors contributing to the increase in corrosion work order**
11 **costs?**

12 **A87.** There are 3 major factors contributing to the increase in corrosion work order costs.
13 First, remediations involving impressed current system rectifier and ground bed
14 replacements and additions, as well as galvanic anode system isolation fittings
15 needed to sustain cathodic protection on existing underground transmission and
16 distribution piping systems are higher complexity corrosion work orders. Higher
17 complexity corrosion work order remediation contributes to the planned increases.
18 Second, contractor costs have been increasing since 2020 for typical galvanic anode
19 and test station work along with higher restoration cost in general for roadway hard

Line
No.

1 surface areas. DTE Gas secured bids reflecting higher cost with contract prices set
2 through February 2025. This increase is reflected in the increase for cathodic
3 protection capital expenditures. The existing contracts are included in Confidential
4 Exhibit A-12 B5.19.

5 Third, new regulatory requirements were released under Pipeline and Hazardous
6 Material Safety Administration (PHMSA), docket item PHMSA-2011-0023 for
7 Repair Criteria, Integrity Management Improvements, Cathodic Protection,
8 Management of Change, and Other Related Amendments. The additional Cathodic
9 Protection requirements listed in this new regulation include coating fault tests,
10 close interval survey (CIS), Alternating Current (AC) mitigation, Medium
11 Consequence Areas (MCAs), and cathodic protection remediation. This will impact
12 the transmission survey, requiring additional in-depth CIS troubleshooting when
13 survey readings do not meet the required criteria. Once CIS is completed and
14 remediation is performed, CIS is repeated to ensure survey readings are adequate.
15 In addition, Alternating Current Density Monitoring will be required. This is a new
16 practice that requires interference monitoring from other utilities, expanded
17 monitoring requirements, and additional troubleshooting / remediation. While the
18 number of work units fluctuate annually based on survey findings and
19 troubleshooting, the forecast is an increase in number of work units due to these
20 additional regulatory requirements, hence incremental costs relative to current
21 number of work units.

22

23 **Q88. How would DTE Gas handle cathodic protection capital if approval was not**
24 **granted for these expenditures to be included in the IRM?**

Line
No.

1 A88. If cathodic protection capital expenditures are not approved to be included in the
2 IRM, these costs must be included in routine capital plant expenditures as they were
3 in case no. U-20940, as these are investments required to ensure the continued safe
4 operation of our gas system.

5

6 **IRM Review**

7 **Q89. How will the MPSC monitor DTE Gas's performance to ensure that the capital**
8 **expenditures related to the IRM are incurred prudently?**

9 A89. Consistent with the current IRM program requirements, the Company will continue
10 to file, by March 31st annually, the results of the previous year's activity including
11 footage, units and cost information on a variety of task components. The Company
12 will continue to provide the MPSC a summary report of the total dollars spent
13 during the previous year compared to the target levels for each of the IRM
14 programs. Under the current approved IRM, the surcharges that will be established
15 in this proceeding cannot increase but will be reduced if the combined spending
16 level of the IRM infrastructure programs is less than the annual amount approved.
17 The Company will also continue to provide the 'Main Renewal Candidate List' by
18 October 31st in the year prior to construction. This report contains estimated project
19 costs and legacy main and inside meter units in comparison to yearly program
20 goals. Detailed commentary will be provided if yearly unit goals are different than
21 from the goals detailed in exhibits A-12 B6.2 and B6.3.

22

23 **Q90. Is DTE Gas proposing any changes to the reconciliation and reporting of IRM**
24 **capital expenditures and units established previously?**

Line
No.

1 A90. Yes. To align with the combination of MRP and MMO programs (now GRP)
2 approved in Case No. U-20940 and the incorporation of MAC MMO resources
3 starting in 2025, DTE Gas is proposing to consolidate yearly IRM reporting
4 currently comprised of 6 separate reports and 1 exhibit into 3 standardized reports
5 as detailed in Exhibit A-12 B6.4 IRM Report Contents and Proposed Changes. The
6 company is proposing the following IRM report structure to be implemented in
7 2026 for the 2025 IRM results:

8

9 IRM Report

10 1) Gas Renewal Program Report

11 (a) Pipe installation, retirement, retest, services and meters, and
12 costs by project

13 2) Pipeline Integrity Management Report

14 (a) Pipeline Integrity scope of work and expenditures by project

15 (b) Cathodic Protection expenditures and units

16 3) IRM Capital Expenditure Summary

17 (a) Gas Renewal Program units and expenditures

18 (b) Unplanned main renewal / public improvement / routine units
19 and expenditures

20 (c) Pipeline Integrity total expenditures

21 (d) Cathodic Protection total expenditures

22

23 The company expects that the changes will afford DTE Gas and its reporting
24 audience efficiencies by eliminating unnecessary and redundant data and removing
25 opportunities for misalignment.

Line
No.

1 The Company is proposing the elimination of the DTE Gas Main Retirement
2 Summary referenced in exhibit A-12 B6.4. This summary is a monthly breakout of
3 GRP main retirement by pipe type, by month and is submitted with the yearly IRM
4 reconciliation. As yearly retirement units are currently summarized by pipe type
5 and project in the GRP Report, the Company feels that a rearward-looking monthly
6 breakout is not relevant. The Company does not track main replacement by pipe
7 type on a monthly basis throughout the year, but instead classifies main retirement
8 units as legacy (CI, WI, C/W Steel, Bare Steel) or non-legacy pipes (CP Steel,
9 Plastic) against the yearly plan. The Company will continue providing monthly
10 status updates for inside meters move out to staff on a monthly basis. Resources
11 dedicated to preparing this report may be utilized to further support ongoing GRP
12 projects or other programs within DTE Gas.

13 The Company plans to continue providing a Gas Renewal Candidate List by
14 October 31st in the year prior to construction. This report will detail estimated
15 project costs and legacy main and inside meter units in comparison to program
16 goals and commentary will be provided if yearly unit goals are different than
17 approved.

18

19 **Q91. Does this complete your direct testimony?**

20 A91. Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
DTE GAS COMPANY for authority)
to increase its rates, amend its rate)
schedules and rules governing the)
distribution and supply of natural gas,)
and for miscellaneous accounting authority)
_____)

Case No. U-21291

REBUTTAL TESTIMONY

OF

ERIC D. JANNESS

DTE GAS COMPANY
REBUTTAL TESTIMONY OF ERIC D. JANNESS

**Line
No.**

1 **Q1. Are you the same Eric D. Janness who previously offered testimony in this**
2 **proceeding?**

3 A1. Yes, I am.

4

5 **Purpose of Testimony**

6 **Q2. What is the purpose of your rebuttal testimony?**

7 A2. The purpose of my rebuttal testimony is to rebut:

8 1. The arguments made by the Attorney General Witness Coppola's testimony
9 regarding the current pace and spending of GRP, inclusion of Cathodic
10 Protection in the IRM, and a proposed disallowance for ILI Expansion program.

11 2. The arguments made by MNSC Witness Napoleon's testimony regarding the
12 pace and spending of IRM programs, more stringent guidelines for IRM,
13 investment evaluations, and overall disapproval of the IRM.

14 3. The arguments made by ABATE Witness Fitzhenry's testimony regarding the
15 pace of the GRP.

16 4. The arguments made by Ann Arbor Witnesses Stults' and Stewart's testimony
17 regarding municipal coordinate in the GRP and a proposed disallowance for
18 main replacement in Ann Arbor.

19 The absence of a discussion of other matters in my rebuttal testimony should not
20 be taken as an indication that I agree with other aspects of any Staff or intervenor
21 testimony.

22

23 **Q3. Are you sponsoring any rebuttal exhibits?**

24 A3. I am sponsoring the following rebuttal exhibits:

E. D. JANNES
U-21291

**Line
No.**

1	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
2	A-32	V1	Ann Arbor Gas System Overview & GRP Summary
3	A-32	V2	IRM Expenditures for 2020-2029

4

5 Q4. Were these exhibits prepared by you or under your direction?

6 A4. Yes, they were.

7

8 Rebuttal to the Attorney General

9 IRM

10 Q5. What is AG Witness Coppola's recommendation regarding annual IRM
11 expenditures beginning on page 38, line 10 of his testimony?

12 A5. Witness Coppola believes that DTE Gas is expanding its IRM too quickly and not
13 operating within the annual expenditures included in the IRM surcharge. Witness
14 Coppola recommends that the Commission should set a maximum level or a cap of
15 \$240 million for the MRP, \$48 million for the combined MMO programs and \$15
16 million for Pipeline Integrity. In total, Coppola recommends that the Commission
17 approve a spending level of \$303 million for 2025 and allow the Company to
18 increase that amount by an inflation factor of 2.5% annually beginning in 2026 and
19 in subsequent years.

20

21 Q6. Is the Company expanding the IRM too quickly?

E. D. JANNES
U-21291

Line
No.

1 A6. Beginning in Case No. U-15985¹ and continuing through every DTE Gas rate case
2 since, the Commission has emphasized the importance of ensuring the safety of
3 DTE Gas's system through elimination of cast iron and other poor performing
4 mains and elimination of inside meters. Specifically, in Case No, U-16999, the
5 Commission, in its April 16, 2013 order, stated:

6 The Commission takes very seriously its obligation to assure safe
7 and reliable utility service and finds that the MRP and MMO and
8 PI programs are of critical importance in achieving this end.
9 These programs, coupled with funding from the IRM, will permit
10 Mich Con to accelerate the replacement or retirement of those
11 pipelines most likely to endanger public safety.

12 In Case No. U-18999, the Commission ordered an expansion of the MRP scope and
13 spend on the basis that a rapid replacement and retirement of poor performing,
14 unprotected mains would stabilize our distribution system and reduce the threat of
15 major failure. DTE believes its actions reasonably and prudently manage the timing
16 of these replacements and the associated capitals expenditures. DTE believes it
17 balances the need to eliminate these items and capital expenditures needed to
18 perform work to meet that timing.

19

20 **Q7. Should the IRM amounts used to calculate the surcharge be considered**
21 **budgets, as Witness Coppola states on page 38, lines 16 through 20 of his**
22 **testimony?**

¹ U-15985 June 3, 2010 order, page 102.

E. D. JANNES
U-21291

**Line
No.**

1 A7. No. The IRM was established because the Staff and Commission felt DTE Gas was
2 not committed to completing this important safety work. Through the IRM, DTE
3 Gas makes a minimum commitment to eliminating these safety risks. To
4 accomplish the work it needs to annually, DTE may need to spend more than the
5 minimum commitment. Expenditures in excess of the minimum commitment may
6 be needed due to project complexity or the work needed to be completed in one
7 year to allow work planned for the next year to take place. The IRM amounts are
8 not “budgets”, they are the amounts DTE Gas knows, at the time it files, it will
9 spend, at a minimum. As with any capital investment, any reasonable and prudent
10 expenditures greater than the IRM amounts are subject to regulatory lag.

11

12 **Q8. Does the Company agree with Witness Coppola’s set spending levels for each**
13 **component of the IRM in 2025 and a 2.5% inflation factor beginning in 2026?**

14 A8. No, the proposed spend by Witness Coppola is significantly lower than the actual
15 spend for the last 2 years of the IRM. This expenditure level would result in a
16 reduction of the legacy retirement pace established in U-18999, and it would
17 jeopardize the goal of stabilizing the distribution system and reducing the threat of
18 major failure. Current projections for program spend beyond 2025 do not include
19 an inflation factor because DTE Gas sets its expenditure levels based on a minimum
20 capital expenditure commitment.

21

22 Cathodic Protection

23 **Q9. What does Witness Coppola propose regarding cathodic protection beginning**
24 **on page 42, line 1 of his testimony?**

E. D. JANNES
U-21291

Line
No.

1 A9. Witness Coppola states that the Company has not made a convincing case that
2 capital expenditures for cathodic protection should be included in the IRM and
3 recommends that \$7.4 million of cathodic protection capital expenditures be added
4 to the \$2.2 million already included in routine capital expenditures in the projected
5 test year for total routine cathodic protection capital expenditures of \$9.6 million.

6

7 **Q10. Why does Witness Coppola recommend not including Cathodic Protection in**
8 **the IRM?**

9 A10. Witness Coppola believes that the Company should make prudent spending
10 decisions irrespective of how cost recovery occurs and should allocate sufficient
11 resources to cathodic protection regardless of the cost recovery methodology.

12

13 **Q11. Do you agree with Witness Coppola's proposal to not include Cathodic**
14 **Protection in the IRM?**

15 A11. No. Cathodic Protection is appropriate to be included in the IRM because it is a
16 strategic capital improvement and the IRM will ensure the dollars included in rates
17 will be spent for this purpose as well as provide greater long-term certainty on
18 recovery of these reasonable and prudent costs expended to improve the safety and
19 reliability of the gas distribution system. By including these expenditures within
20 the scope of the IRM, DTE Gas can assure our customers and MPSC Staff that
21 these expenditures are: (1) reasonable with increased transparency to costs, unit
22 completions, and projects, (2) that the minimum expenditure levels are dedicated
23 to cathodic protection through 2029, and (3) the reduction of gas leaks in line with
24 DTE's commitment to the safety of the public and the reduction of methane

E. D. JANNES
U-21291

Line
No.

1 emissions. Furthermore, Cathodic Protection is an integral part of Pipeline
2 Integrity which is already part of IRM.

3

4 Pipeline Integrity

5 **Q12. What does Witness Coppola recommend regarding pipeline integrity's In-**
6 **Line Inspection (ILI) Projects beginning on page 44, line 11 of his testimony?**

7 A12. Witness Coppola recommends a disallowance of \$3.6M of capital expenditures for
8 the 9 months ending September 2024, and \$8.6M for the 12 months ending
9 September 2025 for a total disallowance of \$12.2 million.

10

11 **Q13. Why does Witness Coppola recommend the disallowance of capital**
12 **expenditures for In-Line Inspection (ILI) Projects?**

13 A13. Witness Coppola assumes that Muskegon-Ludington 10 Scottville Tie-In, and the
14 Belle River Field Headers 24 projects are still in the early phase of development
15 with no assured timeline and therefore are premature to include in the rate base in
16 this proceeding.

17

18 **Q14. Do these programs have an assured timeline?**

19 A14. Yes, they do.

20

21 **Q15. Does the Company agree with the recommendation to disallow the capital**
22 **expenditures for these In-Line Inspection Projects?**

23 A15. DTE Gas is utilizing a two-year project cycle for capital projects, including ILI
24 projects, with engineering to be completed in year 1 and construction in year 2.

E. D. JANNES
U-21291

**Line
No.**

1 Therefore, the timing for these ILI projects will be (1) project engineering having
2 occurred in 2023 or occurring in 2024, and (2) construction occurring during the
3 2024 or 2025 construction season. The construction season typically begins in the
4 spring and has an anticipated completion timing of early Q4 of the same year, ahead
5 of the heating season. This construction timeline aligns with the projected test year.

6

7 **Q16. Why might Witness Coppola believe that these projects are in an early phase**
8 **of development, rather than the engineering phase?**

9 A16. In Exhibit AG-15, the AG's discovery request asking for details of the project
10 development phase. DTE Gas used the term "Conceptual Design" in describing the
11 current phase. This term was used in error. All of these projects, except for Belle
12 River Field Header 24, were in the engineering phase of the project. The Belle River
13 Field Header 24 is also now in the engineering phase.

14

15 **Rebuttal to MNSC**

16 **Q17. What is Witness Napoleon proposing regarding the IRM program on page 22**
17 **Line 17 of her testimony?**

18 A17. Witness Napoleon recommends four main changes: (1) more stringent guidelines
19 for IRM program eligibility; (2) community involvement; (3) no expansion of IRM
20 scope or spending; and (4) evaluation of non-pipeline alternatives (NPAs).

21

22 **Q18. Why does Witness Napoleon claim that IRM guidelines should be more**
23 **stringent?**

E. D. JANNES
U-21291

Line
No.

1 A18. On page 13, lines 8-10, and page 16, lines 10-11 of Witness Napoleon's direct
2 testimony, she claims that the criteria for what projects qualify for the IRM are not
3 clear. She assumes DTE Gas may be applying vague criteria to investments that do
4 not warrant special treatment.

5

6 **Q19. Does the Company agree with Witness Napoleon's recommendation for more**
7 **stringent guidelines for the IRM program eligibility?**

8 A19. No. The investments included in the IRM are strategic capital improvements. The
9 IRM ensures that the spending on these capital improvements is made a priority.
10 IRM projects have recurrent investment and are long term (See Commission Order
11 in case proceeding U-20836, Page 77). IRM investments are required under federal
12 and state safety standards and are an integral part of the Company's overall effort
13 to ensure the safety and reliability of its system. The genesis of the IRM was the
14 Commission's concern, in case No. U-15985, regarding DTE Gas's investment, or
15 lack thereof, in eliminating cast iron main and inside meters. The Commission
16 decides which programs can be included in the IRM in each rate case.

17

18 **Q20. Why does Witness Napoleon claim that the IRM should have open**
19 **collaborative proceedings to consider and revise purpose, requirements,**
20 **process, and structure?**

21 A20. On page 18, lines 5-6, and page 15, lines 11-14, in Witness Napoleon's direct
22 testimony, she claims the IRM process lacks meaningful review and an opportunity
23 for contestation. She states that there is no opportunity for stakeholders to

E. D. JANNES
U-21291

Line
No.

1 participate in the review of the IRM reconciliation filing and that there is little threat
2 the Commission will disallow IRM expenditures.

3

4 **Q21. Does the Company agree with Witness Napoleon's recommendation to not**
5 **approve the IRM, but instead to have open collaborative proceedings to**
6 **consider and revise purpose, requirements, process and structure?**

7 A21. No, rate cases are an open collaborative opportunity for the IRM. The Commission
8 set the purpose in case U-15985 where it clearly laid out the infrastructure issues it
9 found and ordered DTE Gas to file cases addressing these issues directly². The
10 cases addressing these issues were U-16451 (MMO) and U-16407 (MRP). These
11 cases set the initial process and structure for the IRM. Then, in Case No. U-16999,
12 the Commission further clarified how cost recovery would work and approved the
13 first increase in the program's approved expenditures thereby allowing DTE Gas to
14 eliminate these safety issues more quickly.³

² U-15985 June 3, 2010 Order, page 104-105 "The Commission wholeheartedly agrees with the Staff, ... It is time for Mich Con to commit to addressing these problems. ... the Commission directs the company to do the following:

1) Within 30 days of the date of this order, Mich Con shall file in a new docket a detailed plan for main renewal, including a long term plan to significantly reduce the amount of cast iron main in Mich Con's system. The plan will be reviewed by the Commission and made available for public comment.

...

4) Within 120 days of the date of this order, Mich Con shall file in a new docket a detailed plan for moving inside meters to outside locations. The plan will be reviewed by the Commission and made available for public comment.

5) In its next general rate case, Mich Con shall provide information addressing the capital expenditure amount required for continuing and completing improvements to its natural gas system, and shall file a report analyzing the effectiveness of its capital expenditures during the previous 12 months in preventing leaks."

³ U-16999 April 16, 2013 Order, Page 25, "The Commission takes very seriously its obligation to assure safe and reliable utility service and finds that the MRP and MMO and PI programs are of critical importance in achieving this end. These programs, coupled with funding from the IRM, will

E. D. JANNES
U-21291

Line
No.

1

2 **Q22. Why does Witness Napoleon recommend that the expansion of IRM scope**
3 **and/or spending not be approved?**

4 A22. On page 13, lines 16-22, and page 14, lines 1-13, in Witness Napoleon's direct
5 testimony, she claims the IRM provides a reduced incentive to minimize costs and
6 expressed concern that the IRM budget has been increasing over the past seven
7 years. Witness Napoleon's claims are not founded in fact. In Exhibit A-32 V2, line
8 9, the cost per legacy mile retired has remained within 7% of the 2020 cost, even
9 as complexity and restoration requirements have increased. In 2023, the Company
10 projected a unit cost of \$1.27 million per mile but it was \$1.18 million per mile.
11 DTE Gas has not tempered its unit goals even with these increasing cost pressures.
12 If its expenditures exceed the amounts used to calculate the IRM surcharge, DTE
13 Gas carries the cost of those amounts until the next rate case.

14

15 **Q23. Does the Company agree with Witness Napoleon's recommendation to not**
16 **approve expansion of the IRM scope and/or spending?**

17 A23. No. The purpose of the IRM is to ensure spending on these capital improvements
18 is a priority. Most of the increased IRM expenditures over its history was tied to
19 increased unit goals. In recent years, based on historical actuals, the spend required
20 to hit targets and keep pace has been higher than the current IRM expenditure
21 amount. In order to ensure DTE meets its annual goals on critical infrastructure
22 replacement, DTE Gas is requesting an increase in the annual amount included in

permit Mich Con to accelerate the replacement or retirement of those pipelines most likely to endanger public safety. In addition, Mich Con will be able to relocate indoor meters and undertake service renewals, all with the assurance of timely cost recovery."

E. D. JANNES
U-21291

Line
No.

1 the surcharge as the work becomes more complex and market and inflation
2 pressures increase costs.

3

4 **Q24. Why does Witness Napoleon claim that all investments should be evaluated**
5 **against Non-pipeline Alternatives (NPAs)?**

6 A24. On page 18, lines 1-18, and page 19, lines 1-15, in Witness Napoleon's direct
7 testimony, she claims that the IRM increases the incentive to replace pipe, even
8 when that action might not be the most prudent course of action. In contrast, utilities
9 have far less incentive to invest in NPAs that would avoid spending on pipeline
10 replacements and allow for pipe retirement while saving ratepayers money.

11

12 **Q25. Does the Company agree with Witness Napoleon's recommendation to require**
13 **that all investments be evaluated against NPAs?**

14 A25. No. DTE Gas is committed to providing cost-effective options for customers to
15 manage their own fuel use. Since the goal of the GRP is to replace leak prone pipe,
16 energy efficiency or demand response would not change the need for that
17 investment. The Company believes it is in the best interest of the customers to
18 allow them to determine which sources of energy they wish to use for which
19 applications while providing safe and reliable service for those who use our service.
20 Customers who find NPAs to be more cost effective or otherwise preferable can
21 make that choice for themselves.

22

E. D. JANNES
U-21291

Line
No.

1 **Rebuttal to ABATE**

2 **Q26. What is Witness Fitzhenry proposing regarding the IRM program from his**
3 **testimony starting on page 7, line 2 of his testimony?**

4 A26. Witness Fitzhenry is proposing to reduce the pace of legacy main retirement to 190
5 miles per year to reduce impact to customer rates, while still maintaining the end
6 goal of completing work by 2035.

7
8 **Q27. Why does Witness Fitzhenry recommend that the IRM pace be slowed to 190**
9 **miles of main each year?**

10 A27. On page 6, lines 1-12, and page 7, lines 1-7 of Witness Fitzhenry's direct testimony,
11 he claims that due to a notable reduction in leaks from 2018 – 2022, the main
12 replacement program demonstrated it could make system improvements prior to
13 the elevated levels in 2022. And if spread evenly until 2035, the remaining miles
14 needed would average to 190 a year compared to the current pace of 206 miles.
15 This would allow for an approximate 8% reduction in capital expenditures per year.

16

17 **Q28. Does the Company agree with Witness Fitzhenry's recommendation to retire**
18 **an average of 190 miles of main each year to meet the 18-year pace approved**
19 **in Case No. U-18999, which is less than the 206 miles being proposed by the**
20 **Company to reduce the impact to customer rates?**

21 A28. No. Case U-18999 ordered an expansion of the MRP scope and spend on the basis
22 that a rapid replacement and retirement of poor performing, unprotected mains
23 would stabilize our distribution system and reduce the threat of major failure. While
24 the program has pulled ahead of the original projections, to slow the pace just to

E. D. JANNES
U-21291

Line
No.

1 hold the 2035 completion would jeopardize that goal. DTE is always evaluating its
2 goals and expenditures to balance the amount of work needed to be completed for
3 safety and reliability with the cost passed on to the customers in rates.

4

5 **Rebuttal to Ann Arbor**

6 **Q29. Why does Ann Arbor Witness Stults believe that the Commission should put**
7 **the Company on notice that project costs be excluded from recovery?**

8 A29. On page 19, starting at Line 14, Witness Stults believes that lack of coordination
9 likely creates wastes. She further believes that the Commission should signal to the
10 Company that failure to remedy its coordination could have serious economic
11 implications if not addressed.

12

13 **Q30. Does the Company agree with Ann Arbor Witness Stults' recommendation to**
14 **put DTE Gas on notice that project costs may be excluded from recovery if**
15 **there is a failure to coordinate work?**

16 A30. No. While DTE Gas believes that work coordination is preferable, it does not agree
17 that costs should be excluded from recovery if work coordination does not occur.
18 There are many reasons it would not be possible to coordinate work. For example,
19 the work may need to be done sequentially and the timing cannot be worked so that
20 cost savings would be possible. Additionally, there may be regulatory requirements
21 that do not allow for timeline adjustments.

22

23 **Q31. What is Ann Arbor Witness Stewart's observation of DTE's coordination**
24 **practices with the City of Ann Arbor?**

E. D. JANNES
U-21291

Line
No.

1 A31. Witness Stewart's testimony, beginning on page 6, indicates that these efforts have
2 been inadequate from Ann Arbor's point of view. Witness Stewart believes there is
3 no predictable or established advanced notification of DTE's work in place.

4

5 **Q32. Do you agree with Ann Arbor Witness Stewart's characterization of DTE's**
6 **coordination efforts with Ann Arbor?**

7 A32. No. I am concerned with this characterization because DTE Gas has been actively
8 engaged in communication and coordination efforts with Ann Arbor. Since I
9 assumed this role 7 months ago, I, personally, have had two meetings with Ann
10 Arbor to discuss coordination of work:

- 11 • December 14, 2023, at 10:30 AM at Ann Arbor City Hall. Invited attendees
12 from Ann Arbor were Atleen Kaur, Skye Stewart, and Missy Stults. See
13 Exhibit V1 for DTE Gas's presentation at this meeting.
- 14 • April 26, 2024, at 3:30 PM via Teams Meeting, DTE met with the City of
15 Ann Arbor. The invitee list from the City of Ann Arbor included Brian
16 Steglitz, John Fournier, Andrea Wright, Nicholas Bayley, Nicholas
17 Hutchinson, and Skye Stewart.

18 In the meeting DTE Gas had with Ann Arbor in December, we provided a
19 presentation including a map, see Exhibit V1, page 5, which showed both 2024 and
20 2025 planned Gas Renewal work. Additionally, on page 8 of the presentation, DTE
21 Gas proposed regular meetings with Ann Arbor and timelines for providing work
22 plans to Ann Arbor. I plan to continue to schedule meetings with Ann Arbor at least
23 biannually.

24

E. D. JANNES
U-21291

Line
No.

1 **Q33. Are the efforts above the only communications channel DTE provides for Ann**
2 **Arbor?**

3 A33. No. DTE has a dedicated Regional Relations employee, whose responsibility is to
4 be a resource and contact for Ann Arbor. This dedicated employee resource works
5 directly with Ann Arbor's Chief of Staff, Skye Steward, and the city's engineer,
6 Nicholas Bayley. DTE has a yearly plan that includes bi-annual meetings to discuss
7 DTE's plans in the area and address concerns the city may have.

8

9 **Q34. Should the Commission require a report of changes made to improve**
10 **coordination with other utilities and local governments as recommended by**
11 **Ann Arbor Witnesses Stults on page 2, lines 2 and 3 of her testimony?**

12 A34. No. As I have explained above, DTE is actively engaging the City of Ann Arbor
13 regarding Capital Improvement Plans with the purpose of coordinating work efforts
14 and has plans to continue to do so.

15

16 **Q35. What is Witness Stults proposal for pipeline replacement in Ann Arbor**
17 **beginning on page 18 Line 1 of her testimony?**

18 A35. Witness Stults believes DTE Gas should be denied recovery of \$20.42 million for
19 replacement of distribution pipeline projects in Ann Arbor. Witness Stults identifies
20 these projects in her testimony as "AA6," "Ann Arbor Muni," "State Street and
21 Liberty," "I-94BL – Dexter St," "Huron St at 7th 2 Street," and "Washtenaw and
22 Geddes".

23

E. D. JANNES
U-21291

Line
No.

1 **Q36. Why does Witness Stults believe that main replacement in Ann Arbor is**
2 **unnecessary?**

3 A36. Witness Stults believes that these projects were/are not reasonable and prudent to
4 be replaced because the mains were/are coated steel or plastic with little history of
5 leak repairs. Witness Stults refers to fellow Ann Arbor Witness Robert Ackley's
6 testimony, which states that pipelines made of these materials should be able to
7 operate safely if the mains are monitored for leaks and repaired as necessary until
8 at least 2050, which is when Ann Arbor is forecasted to no longer require fossil gas
9 service. Witness Stults believes that the Company should invest only in repairing
10 these mains as the cost would be less than the cost to replace them.

11

12 **Q37. Does the Company agree that main replacement in Ann Arbor is unnecessary?**

13 A37. No. Ann Arbor Muni is a portion of a grid planned for 2025/2026 that was pulled
14 ahead into our 2024 plans to coordinate with the city of Ann Arbor due to road
15 resurfacing the city has planned. The segment of Ann Arbor Muni in question is
16 entirely coated steel that is not cathodically protected. Witness Ackley's assertion
17 regarding coated steel is inaccurate. Rather, with coated steel, the coating can fail
18 and, without cathodic protection and monitoring, can corrode. This is a legacy
19 material that is within the scope of the GRP.

20 Most of AA6 was also coated steel that was not cathodically protected, therefore
21 within the scope of the GRP. In instances where we replaced protected coated steel
22 or plastic, it was to raise the grid's operating pressure. Existing pipes that can
23 operate at the higher pressure would just be retested. Doing so efficiently improves

E. D. JANNES
U-21291

Line
No.

1 the reliability of the system as we are already renewing a significant portion of the
2 grid to eliminate legacy pipe.

3 The remaining listed projects are public improvement projects which were initiated
4 to resolve a utility conflict in coordination with the city of Ann Arbor.

5

6 **Q38. Does this conclude your rebuttal testimony?**

7 A38. Yes.

1 JUDGE THOITS: Is it you, Mr. Bzdok?

2 MR. BZDOK: Yes, your Honor.

3 JUDGE THOITS: Please proceed.

4 MR. BZDOK: Thank you.

5 CROSS-EXAMINATION

6 BY MR. BZDOK:

7 Q Good morning, Mr. Janness.

8 A Good morning.

9 Q I want to talk to you about, primarily about your
10 testimony regarding capital expenditures under the
11 infrastructure recovery mechanism, and projected
12 increases that you discuss in your direct and rebuttal
13 testimony in the costs of those programs, as well as the
14 addition of Cathodic Protection -- am I saying that
15 right?

16 A Correct, yes.

17 Q -- to the scope of the IRM programs.

18 So one of the subjects of your testimony,
19 just for context, is capital expenditures to be recovered
20 via the infrastructure recovery mechanism, correct?

21 A Yes.

22 Q And that's often referred to in this case, including by
23 you, as the IRM; is that right?

24 A Correct.

25 Q For context, at a high level, would you agree the IRM is

1 a ratemaking mechanism in which the revenue requirements
2 for certain capital expenditures are collected via a
3 surcharge in years that may include the projected test
4 year and may also include years to the future of the
5 projected test year, fair?

6 A Yeah. Can I ask you to please repeat that question?

7 Q Sure. At a high level and generally, just to set some
8 content, the IRM is a ratemaking mechanism in which the
9 revenue requirements for certain capital expenditures are
10 recovered via a surcharge in years that include the
11 projected test year and may also include in some
12 instances time periods beyond the projected test year,
13 fair?

14 A Fair.

15 Q O.K. In this case, you are supporting IRM expenditures
16 out to 2029; is that right?

17 A Correct.

18 Q What are the programs in which you are supporting those
19 expenditures?

20 A Programs in which I am specifically supporting is the
21 Main Renewal and the Meter Move Out.

22 Q Main Renewal has, is a program whose name has changed
23 over time; is that right?

24 A It has, yes.

25 Q It's now called what?

1 A We now refer to it as GRP or the Gas Renewal Program.

2 Q And tell me how Meter Move Out has changed in terms of
3 its classification and categorization.

4 A If you're asking how it has changed regarding from the
5 onset of the program up till now, I am unfamiliar with
6 the initial onset, I'm only familiar with the Meter Move
7 Out being classified as the Meter Move-Out Program.

8 Q O.K. Fair enough. There are two other IRM programs
9 proposed in this case; is that right?

10 A There are, yes.

11 Q What are those?

12 A Pipeline Integrity and Cathodic Protection.

13 Q What is your relationship to those programs as a witness?

14 A I --

15 Q Are you sponsoring those, are you involved in those? Go
16 ahead.

17 A I am merely sponsoring those.

18 Q O.K. Do you have access to the SharePoint site for this
19 case?

20 A Yes.

21 Q Within DTE's folder, there is a folder for you as a
22 witness; is that right?

23 A Correct.

24 Q And within that folder, there is an exhibit you're
25 sponsoring, Exhibit A-12 Schedule B6.5; is that right?

1 A Correct.

2 Q Are you able to access that?

3 A Yeah.

4 MR. WATSON: I'm sorry, Chris, did you
5 say 5.5?

6 MR. BZDOK: 6.5. So Janness's Exhibit
7 A-12 6.5, one-page exhibit.

8 MR. WATSON: Whatever is more comfortable
9 for you.

10 Q (By Mr. Bzdok): Are you there?

11 A Yes.

12 Q O.K. So there is a -- there's a program for Main Renewal
13 which comprises the first nine numbered lines; is that
14 right? Did you hear my question?

15 A Yes. I'm sorry. I said correct, yes.

16 Q Oh, I'm sorry, I didn't hear your answer. And then there
17 is a program category listed as Meter Move Out which
18 comprises numbered lines 10 through 18; is that right?

19 A Yes, correct.

20 Q And there is a subcategorization of Meter Move Out, MMO
21 and MAC MMO; do you see that?

22 A Correct. You're referring to line 11?

23 Q Yep, and also 14.

24 A Yes.

25 Q O.K. What's the difference between MMO and MAC MMO?

1 A MAC is Meter Assembly Check where MMO is Meter Move Out.

2 Q And what's the difference, in lay terms?

3 A DTE is required to do a Meter Assembly Check every three
4 years, no later than 39 months, that is what is your
5 Meter Assembly Check. Meter Move Out is the, more or
6 less the implementation of moving a meter that resides
7 inside a facility to outside the building.

8 Q Is the MAC a check of interior meters or exterior meters
9 or both?

10 A It could be both, yes.

11 Q O.K. So how is -- so explain to me why it's MAC MMO as
12 opposed to just MAC?

13 A So for me to explain this at a very high level, a Meter
14 Assembly Check, as I stated, is required, you know, every
15 three years. MMO is the implementation of moving a meter
16 outside. DTE during, or for the Gas Renewal Program, we
17 will -- we do not want to interrupt or disrupt customers
18 multiple times, so if we are planning on looking at a
19 grid or a facility a few years down the road where this
20 area is not scheduled but there may be facilities or
21 buildings that need a Meter Assembly Check, what we'll
22 try to do is try to coordinate the MMOs with the Meter
23 Assembly Check so we're not interrupting a grid or a
24 resident, you know, more than one time. If we're not
25 able to do that, then we are going to have to go in and

1 do a Meter Assembly Check once every three years.

2 Q O.K. Thank you. And then there is a subcategory in line
3 19 for Total GRP; is that right?

4 A Correct.

5 MR. BZDOK: Lori, did you get the
6 correct?

7 COURT REPORTER: Yes.

8 Q (By Mr. Bzdok): O.K. So the GRP is Gas Renewable
9 Program, Gas Renewal Program?

10 A Correct, yes.

11 Q O.K. So the Gas Renewable -- sorry -- Gas Renewal
12 Program is comprised of Main Renewal as well as the MAC
13 and MMO?

14 A There are, yes, there are some MACs associated with the
15 Gas Renewal Program.

16 Q O.K. And then the other two programs are listed there at
17 the bottom as Pipeline Integrity and Cathodic Protection,
18 correct?

19 A Yes.

20 Q In this exhibit -- O.K. Give me a second. Bear with me
21 just a moment, I've got to find an exhibit.

22 JUDGE THOITS: Let's go off the record.

23 (At 9:18 a.m., brief pause.)

24 JUDGE THOITS: All right. Back on the
25 record.

1 Q (By Mr. Bzdok): I'm going to ask you, Mr. Janness, to go
2 to the MEC, NRDC & SC folder, and within that folder
3 there's a folder for the witness named Alice Napoleon.
4 You filed rebuttal to, among other witnesses, Witness
5 Napoleon; is that right? You filed rebuttal to Witness
6 Napoleon, among others; is that right?

7 A Correct, yes. Sorry, are you not hearing me? I
8 apologize. I can try to speak up if you're not hearing
9 me.

10 Q Only occasionally.

11 A O.K.

12 Q O.K. Within the folder for Witness Napoleon, there is an
13 exhibit, prefiled Exhibit MEC-18, do you see that, it's
14 labeled 21291 MNSCDG-5.12. Could you open that one if
15 you find it.

16 A Yes.

17 Q O.K. And this exhibit, the first page of this exhibit is
18 a discovery request to you to provide information
19 included in the exhibit we were looking at a moment ago,
20 A-12 Schedule B6.5, going back to the initiation of the
21 IRM, correct?

22 A Uh-huh, yes.

23 Q Sorry. And then the second page of the exhibit is the
24 information that you provided in response to the request,
25 correct?

1 A Yes.

2 Q And so this is essentially formatted in the same manner
3 as your prior exhibit, but includes additional years
4 going backwards to 2012; is that right?

5 A Correct.

6 Q And this exhibit indicates that the total, the grand
7 total amount of expenditures responsive to this request
8 in the year 2012 was \$47,000,561; is that right? Sorry.
9 \$47,561,000, correct?

10 A Yeah. You're looking at column 2012, row 22?

11 Q Yep.

12 A Yes.

13 Q Now, the IRM started in 2015; is that right?

14 A I am unfamiliar when the IRM started.

15 Q O.K. This exhibit would indicate, then, that IRM
16 expenditures have grown from about \$47.6 million in 2012
17 to the last year of actuals, of pure actuals in the
18 exhibit is 2022 at \$337.6 million, give or take, correct?

19 A Correct.

20 Q And there's a combination of actuals and projected for
21 2023 of \$346,943,000; is that right?

22 A Correct.

23 Q The actual spend for 2023 was reported in the Company's
24 IRM, IRM report that it files annually, correct?

25 A If you're referring to our March 31 report which goes to
Penn Reporting, LLC - lori.penn@yahoo.com

1 the Commission, then yes.

2 Q O.K. And that amount was 345,893,000; is that right,
3 does that ring a bell?

4 A I don't recall.

5 Q Does that sound right or does that sound off?

6 A I don't recall.

7 Q O.K. Are you involved in any way in the filing of that
8 report?

9 A At a high level.

10 Q O.K. The same exhibit then projects total spending for
11 the IRM in the year 2024 of \$349,135,000, correct?

12 A Correct.

13 Q And then increasing in the projected test year of 2025 to
14 \$354.2 million, give or take, correct?

15 A Correct.

16 Q And then there are modest declines from that projected in
17 2026 and 2027, correct?

18 A Correct.

19 Q Now, in 2026 and 2027, as well as '28 and '29, the Main
20 Renewal costs are basically held level with the Main
21 Renewal costs for 2025; is that right?

22 A Correct.

23 Q That has not been the experience, however, correct?

24 A In regards to?

25 Q Main Renewal costs don't stay level year-to-year, they

1 increase, don't they?

2 A They do. They do, yes.

3 Q There are the decreases -- well, let me say it this way.
4 MAC MLO -- these acronyms are giving me a hard time
5 today. MAC MOO -- strike that.

6 Meter Assembly Check Meter Move Outs
7 phase out starting in 2024, correct?

8 A Correct.

9 Q Meter Move Outs phase down in 2028 and '29, correct?

10 A Correct.

11 Q And those two actions account for, in this exhibit, the
12 reductions in IRM spending projected for those out years;
13 is that right?

14 A That is correct.

15 Q But if the future resembles the past in terms of Main
16 Renewal spending, those declines due to the phase out and
17 phase down to the Meter Move Programs may be offset by
18 continued increases in Main Renewal costs, fair?

19 A Fair, yes.

20 Q And therefore, grand totals of IRM spending may be higher
21 than the grand total amounts listed at the bottom of this
22 exhibit, fair?

23 A Yes.

24 Q O.K. The addition of Cathodic Protection to the IRM
25 which is proposed in this case also contributes to the

1 near-term increase in IRM costs, fair?

2 A Yes.

3 Q In your direct -- let's look at your direct testimony.

4 MR. BZDOK: I'll note for the record that
5 my intention is to move to admit this prefiled exhibit as
6 part of the binding in and admission of Ms. Napoleon's
7 testimony and exhibits later today. Go ahead, Judge.

8 JUDGE THOITS: No, I was just going to
9 say, so noted, thank you.

10 Q (By Mr. Bzdok): So let's look at your direct testimony,
11 Mr. Janness, page 10. Actually, page 9, question and
12 answer 19.

13 A I'm there.

14 Q Here you make a statement -- well, the question is, "What
15 GRP capital expenditures is the Company proposing?", and
16 your answer is to, "See Table 2 for DTE Gas proposed GRP
17 capital expenditures through 2029 compared to
18 expenditures settled in Case No. U-20940," correct?

19 A Yes.

20 Q Bear with me a moment. And Case U-20940 was the
21 Company's last gas rate case before this one; is that
22 right?

23 A I believe so, but I would need to verify.

24 Q Was that -- O.K. In the hearing exhibits folder with
25 your name on it, the Janness folder, there is a copy of

Penn Reporting, LLC - lori.penn@yahoo.com

1 an order dated the December 9, 2021, in U-20940; do you
2 see that?

3 A Yes.

4 Q Could you open that up, please.

5 A It's open.

6 Q O.K. On the first page, the first page of text of the
7 order, which would be page 5 of the PDF, there is an
8 indication that -- well, let me just ask it. Do you know
9 what the projected test year was for the U-20940 levels
10 that you're comparing in this Table 2?

11 A I do not, no.

12 Q O.K. If you open -- if you look at page 5 of the PDF,
13 which is the first page of the order itself, the one that
14 starts: History of Proceedings, On February 12, 2021",
15 are you there?

16 A Yes.

17 Q Can you see about four to five lines down reference to a
18 projected test year commencing January 1, 2022, and
19 ending December 31, 2022?

20 A I see this.

21 Q Does that refresh your memory as to whether the 20940
22 levels you're comparing in your Table 2 were for a 2022
23 projected test year?

24 A It does not refresh my memory, no.

25 Q So you never knew what test year you were comparing in
Penn Reporting, LLC - lori.penn@yahoo.com

1 2022 to levels in this case?

2 A Sorry, can you repeat your question?

3 Q So you never knew what projected test year levels you
4 were comparing in your Table 2 to the levels proposed in
5 this case?

6 A I'm not familiar with those test years.

7 Q O.K. In your Table 2 you have, the first three rows, the
8 first three rows that include -- the first row is a set
9 of years, correct?

10 A Correct.

11 Q And then the next three rows are GRP and MAC MMO levels
12 that were projected or proposed in 20940, correct?

13 A Correct.

14 Q Along with a total for those; is that right?

15 A Correct. Can I ask which total line you're referring to?

16 Q So I'm looking at the third line, GRP U-20940 (\$M).

17 A I see, yes.

18 Q O.K. The row that is MAC MMO, is that -- does that
19 correspond, looking at either your Exhibit A-12 Schedule
20 B6.5 or that Alice Napoleon exhibit we were looking at,
21 does that correspond to just the MAC MMO line, or does
22 it -- is it both the MMO and the MAC MMO?

23 A Let me refer to back to 6.5, please.

24 Q Yep.

25 A So to verify, are you asking if the MAC MMO first row

1 which corresponds to 21 million per year from 2022, 2023,
2 2024, 2025 is referencing back to 6.5, or are you
3 referring back to the second row of MAC MMOs with a spend
4 of 23.2 million in 2020, 22.4 million, and zeros 2024 to
5 2029, which row are you referring to?

6 Q Thank you. Let me try to clarify. In your Exhibit A-12
7 B6.5, you present MAC MMO and MMO costs as separate rows,
8 correct?

9 A Yes.

10 Q And what I'm trying to understand is, are the MAC MMO
11 rows in your Table 2, are those just the MAC MMO, or are
12 they both the MMO and the MAC MMO?

13 A They're both.

14 Q O.K. The next three lines present the same information
15 as projected or proposed in this case, correct?

16 A Correct.

17 Q The projections in Table 2 for this case show a zeroing
18 out of MAC MMO costs in 2024, '25 through '27, and '28
19 through '29, correct?

20 A Correct.

21 Q However, in your A-12 B6.5, the MMO costs are not zeroed
22 out, only the MAC MMO costs are, agreed?

23 A Are you referring to line 11 on 6.5?

24 Q Yes.

25 A The line 11 on 6.5 starting in 2024, we are zeroed out.

1 Q MAC MMO is zeroed out, right?

2 A Correct.

3 Q MMO continues with positive spending, agreed?

4 A Correct.

5 Q Where is that spending reflected in your Table 2, if at
6 all?

7 A I don't recall. I would need to doublecheck because I
8 don't have that information in front of me to
9 doublecheck.

10 Q O.K. If that information -- if that spending was not
11 included in your Table 2 but it is in fact projected in
12 this case, then the net increase line, a few lines below
13 that, would be larger for 2024, '25 to '27, and '28 to
14 29; would you agree -- sorry -- '24 and '25 to '27; would
15 you agree?

16 A Are you referencing back to Table 2 or Table 6.5?

17 Q Table 2.

18 A O.K. Can you please repeat your question, then, for me?

19 Q Yes. If the MMO costs projected in A-12 Schedule B6.5
20 are not reflected anywhere in your Table 2, then the true
21 net increase in the overall Gas Renewal Program in your
22 Table 2 should be larger for 2024 and 2025 through '27
23 than is reflected in Table 2; would you agree?

24 A I would like to verify, but yes, I would agree.

25 Q Thank you. Toggling between your Table 2 and your direct
Penn Reporting, LLC - lori.penn@yahoo.com

1 testimony at page 14, would you agree with me that the
2 projected increases in costs in Table 2 are for the same
3 number of Main Renewal units in each year?

4 A I don't fully understand your question, could you please
5 repeat it?

6 Q O.K. So I'll repeat it, and if it's still unclear, then
7 I'll try to phrase it a different way. Looking,
8 referencing page 14 of your direct testimony, would you
9 agree that the increases in costs reflected in Table 2 as
10 to Main Renewal are for the same number of units each
11 year?

12 A Are you asking that the table is reflecting the same
13 amount of miles of Main Renewal?

14 Q Right.

15 A That's what you're asking? Yes, we did forecast or
16 estimate that as a levelized number of miles that will be
17 renewed per year.

18 Q O.K. And the increase in costs reflected in your Table 2
19 reflect a declining number of Meter Assembly Checks and
20 Meter Move Outs, correct?

21 A That is correct.

22 Q In your direct testimony, page 3, starting at line, page
23 3 on line 6, you indicate that one of the subjects of
24 your testimony is "The need to increase Infrastructure
25 Recovery Mechanism (IRM) capital expenditures," correct?

1 A Yes. Page 3 of my direct testimony, you said item 6 or
2 line 6?

3 Q Line 6, I think it was item 2 --

4 (Multiple speakers.)

5 COURT REPORTER: I'm sorry. I'm sorry.
6 You were talking over each other there. Can you start
7 your answer again, please.

8 A Yes. To verify the question, it is line 6, item 2, "The
9 need to increase Infrastructure Recovery Mechanism (IRM)
10 capital expenditures."

11 Q (By Mr. Bzdok): Thank you.

12 JUDGE THOITS: Mr. Bzdok, it might be
13 helpful when you're jumping between exhibits, et cetera,
14 to give the witness a moment to get there.

15 MR. BZDOK: Thank you, Judge, I
16 appreciate the note and will endeavor to do so.

17 Q (By Mr. Bzdok): Let's take a look at your rebuttal
18 testimony, starting at page 10.

19 A I'm on page 10.

20 Q In question and answer 23, just to paraphrase to save
21 time, you're offering rebuttal of MNSC Witness
22 Napoleon's, one of her recommendations, correct?

23 A Correct.

24 Q And that is a recommendation that the Commission not
25 approve expansion of IRM scope and/or spending, correct?

1 A Correct.

2 Q And you indicate starting at line 21, "In order to ensure
3 DTE meets its annual goals on critical infrastructure
4 replacement, DTE Gas is requesting an increase in the
5 annual amount included in the surcharge as the work
6 becomes more complex and market and inflation pressures
7 increase costs," correct?

8 A Correct.

9 Q And similarly, in your rebuttal on page 2 --

10 A I'm on page 2.

11 Q Starting at question and answer 5, you provide rebuttal
12 testimony to Attorney General witness Sebastian Coppola;
13 is that right?

14 A Correct.

15 Q And in this answer and, I think in the sense continuing
16 in your rebuttal, you are responding to his
17 recommendation that IRM expenditures be held at \$240
18 million per year, correct?

19 A Can you repeat your question, please?

20 Q Yes. So beginning at question and answer 5 on page 2 of
21 your rebuttal, you are opposing -- I understand now. Let
22 me rephrase the question.

23 Page 2, question and answer 5, you are
24 opposing Attorney General Witness Coppola's
25 recommendation that the Commission set spending levels

1 for the IRM of \$303 million for 2025, comprised of
2 240 million for the MRP and 48 million for the combined
3 MMO Programs, and 15 million for Pipeline Integrity, and
4 then allow those budgets or that spending level to
5 increase at a rate of inflation for subsequent years,
6 correct?

7 A So in question 5 on page 2, we are responding to what we
8 believe AG Witness Coppola's recommendations are, these
9 are not DTE's recommendations.

10 Q Agreed. Both the Attorney General and the MNSC parties
11 have proposed capping or fixing continued expansion of
12 IRM spending in some way, and in your rebuttal testimony,
13 you're opposing those recommendations, right?

14 A Correct.

15 Q Let's look at page 10 of your direct testimony.

16 A I'm on page 10.

17 Q So immediately below that Table 2 we were looking at, in
18 question and answer 20, you describe what you call three
19 primary drivers of cost increases in the GRP Program
20 relative to those U-20940 levels, correct?

21 A Correct. Correct. Sorry if you cannot hear me again.

22 Q I did. Sorry, I was thinking about the next question.

23 And you list those as, (1) Increasing contractor and
24 material costs; (2) Municipal permit requirement for
25 various aspects of the work; and (3) A change in the

1 scale and scope of projects identified by a Probabilistic
2 Risk Assessment, correct?

3 A Correct.

4 Q Take a look at the MNSC folder, proposed Exhibit MEC-86,
5 which is Discovery Response MNSCDG-5.17.

6 A We have it open.

7 Q In this question we asked you for a breakdown of the
8 incremental increase in cost associated with each of
9 these three primary drivers that you testified about,
10 right?

11 A Correct.

12 Q And you indicated that the Company is unable to provide
13 such a breakdown; is that right?

14 A We do state that the Company has not performed a detailed
15 analysis for the primary cost drivers.

16 MR. BZDOK: Your Honor, I want to move to
17 admit proposed Exhibit MEC-86.

18 JUDGE THOITS: Are there any objections
19 to the admission of this exhibit? (No response.)

20 Hearing none, Exhibit MEC-86 is admitted.

21 MR. BZDOK: Thank you.

22 Q (By Mr. Bzdok): You also in this response refer us for
23 more details to question and answers 21, 22, and 23,
24 correct, of your direct?

25 A Correct.

1 Q Let's take a look at those questions and answers.
2 Question 21 and answer 21, which starts on page 10 and
3 leads to page 11, addresses the first driver, the
4 contractor costs, correct?

5 A Correct.

6 Q In this answer, you refer to a variety of information.
7 The first set of information is information from
8 something called PowerAdvocate, with a capital P, a
9 capital A, and one word, PowerAdvocate, correct?

10 A Correct.

11 Q And this is a third-party provider of industry market and
12 cost intelligence, correct?

13 A They do perform that for us, yes.

14 Q O.K. And you indicate in your testimony that
15 PowerAdvocate estimates that market prices have increased
16 25 percent from 2020 levels for gas distribution
17 construction work, correct?

18 A Correct.

19 Q Take a look in that folder at your exhibit, sorry, at the
20 MNSC folder, the Janness folder, proposed Exhibit MEC-87,
21 which is Discovery Response MNSCDG-5.18a. Do you have
22 that available?

23 A Yes.

24 Q In this question we asked you to produce the
25 PowerAdvocate information you relied on in question and

1 answer 21, correct?

2 A Correct.

3 Q You did not produce that information in response to this
4 request, correct?

5 A Correct.

6 Q Then take a look at proposed Exhibit MEC-97, which is
7 Discovery Response MNSCDG-10.4.

8 A Yes.

9 Q Do you have that one available?

10 A Yes.

11 MR. BZDOK: Your Honor, may I share
12 screen just so I can point to some things with my cursor?

13 JUDGE THOITS: Yes.

14 MR. BZDOK: Thank you.

15 Q (By Mr. Bzdok): Mr. Janness, can you also -- I know you
16 have it in front you, but can you also see the version of
17 proposed MEC-97 that's on my screen?

18 A Yes.

19 Q O.K. And here you're presenting certain information that
20 was derived from whatever PowerAdvocate gave you; is that
21 right?

22 A Correct.

23 Q So the request was, again, to produce the pricing from
24 PowerAdvocate, right?

25 A Correct.

1 Q And there's a graph here that presents certain
2 information as having been given to DTE Gas from
3 PowerAdvocate; is that right?

4 A Correct.

5 Q And that graph, just looking at my cursor, begins in the
6 first quarter of 2020 and runs through the first quarter
7 of 2023; is that right?

8 A Correct.

9 Q And it includes historical information up to the first
10 quarter of 2022; is that right?

11 A Correct.

12 Q And then it provides three different forecasts starting
13 around the first quarter of 2022 and running to the first
14 quarter of 2023; is that right?

15 A Correct.

16 Q Understanding the relationship between the 100 over here
17 and the numbers over here, I interpret that this means
18 that in the high case forecast from PowerAdvocate, there
19 is a 25.85-percent estimate in increase in pricing; is
20 that right?

21 A That is correct.

22 Q But in the median case forecast, there's an 18.31-percent
23 increase in pricing from PowerAdvocate; is that right?

24 A Correct.

25 Q And in the low case forecast from PowerAdvocate, there is

1 a 10.78-percent increase in forecast pricing from
2 PowerAdvocate; is that right?

3 A Correct.

4 Q In your testimony, question and answer 21, you never
5 indicate that the PowerAdvocate 25-percent figure is the
6 high case out of three estimates from PowerAdvocate, do
7 you?

8 A We do not, no.

9 Q You never disclose in your testimony the existence of a
10 number of cases of estimate from PowerAdvocate, do you?

11 A No.

12 MR. BZDOK: Your Honor, I'm going move to
13 admit proposed Exhibits MEC-87 and MEC-97, the two
14 discovery responses we've just been looking at.

15 JUDGE THOITS: Are there any objections
16 to the admission of these two exhibits? (No response.)

17 Hearing none, Exhibit MEC-87 and 97 are
18 admitted.

19 MR. BZDOK: Thank you.

20 Q (By Mr. Bzdok): Continuing on in your answer 21, so
21 we're on page 11 of your direct testimony now.

22 A I'm there.

23 Q You make a statement starting at line 9, "The DTE Gas
24 Renewal Program is experiencing construction contractor
25 cost increases of approximately 10 percent in Southeast

1 Michigan and approximately 15 percent in Greater
2 Michigan, resulting in total increases as shown in Table
3 3 below," correct?

4 A Correct.

5 Q And Table 3 has a label, Total incremental cost from
6 construction contractor pricing; is that right?

7 A Yes.

8 Q And it states a figure in 2024 of \$25 million; is that
9 right?

10 A Yes.

11 Q And an average figure 2025 through 2029 of \$35 million;
12 is that right?

13 A Correct.

14 Q In proposed Exhibit MEC-88, which is in that SharePoint
15 folder with your name on it, there is a Discovery
16 Response MNSCDG-5.18b. I will note for the moment that
17 this document does not include the confidential
18 attachment, we're not there yet, but 5.18b asks you to
19 produce the sources and documentation for the incremental
20 cost resulting from the construction contractor pricing,
21 correct?

22 A Correct.

23 Q And there is a reference in this response to the
24 provision of a confidential attachment NDA-U-21291
25 MNSCDG-5.18b Contractor Costs; is that right?

1 A That is correct.

2 MR. BZDOK: O.K. Your Honor, at this
3 point, it would be appropriate to move into the
4 confidential session. I expect it will be brief, in the
5 range of five or perhaps ten minutes at most.

6 JUDGE THOITS: All right. We will do
7 that after we go off the record briefly. We are off the
8 record.

9 (Brief Off-record discussion at 9:58 a.m.)

10 - - -

11 (Testimony continues on Page 682 of the Confidential
12 record.)

13 - - -

14

15

16

17

18

19

20

21

22

23

24

25

1 (Transcript continues following Page 687 of the
2 Confidential Record.)

3 - - -

4 MR. BZDOK: May I proceed?

5 JUDGE THOITS: Yes.

6 MR. BZDOK: Thank you. So I am going to
7 move, without describing further contents of it in the
8 public session, for the admission of proposed Exhibit
9 89C.

10 JUDGE THOITS: Are there any objections
11 to the admission of Exhibit MEC-89C? (No response.)

12 Hearing none, Exhibit -- I'm sorry.

13 MR. WATSON: Your Honor, I just wanted to
14 clarify, was that the confidential document and that will
15 be the confidential record?

16 MR. BZDOK: Yes. Admission into the
17 confidential record.

18 JUDGE THOITS: It will be admitted into
19 the confidential record, yes.

20 MR. WATSON: Thank you, your Honor. I
21 was just clarifying.

22 JUDGE THOITS: All right. Exhibit
23 MEC-89C is admitted into the confidential record.

24 MR. BZDOK: And while we're at it, I will
25 also move for the admission of MEC-88, which was the

Penn Reporting, LLC - lori.penn@yahoo.com

1 public exhibit attaching the confidential attachment.

2 JUDGE THOITS: Are there any objections
3 to the admission of this exhibit? (No response.)

4 Hearing none, Exhibit MEC-88 is admitted.

5 Q (By Mr. Bzdok): Let's open now proposed -- thank you.

6 Let's open now proposed Exhibit MEC-98, which is
7 Discovery Response MNSCDG-10.5a and b. Do you have that
8 available?

9 A Yes.

10 Q On the first page of this exhibit, sub-response (a), we
11 asked you, referring to that confidential attachment we
12 were looking at a moment ago in confidential session, we
13 asked to you reconcile or explain how the figures in that
14 attachment support the estimates in Table 3 of your
15 direct, correct?

16 A Correct.

17 Q And if the attachment does not support those estimates,
18 we asked you to provide the supports for the estimates in
19 Table 3, correct?

20 A Correct.

21 Q And you state in your answer, "The attachment", we were
22 looking at it a minute ago, "shows from a base spend at
23 2020 levels to the new 2024 spend, construction
24 contractor costs have had an incremental increase of only
25 \$9 million by 2024;" is that right?

1 A Correct.

2 Q And that 9 million was the difference between the one
3 number we talked about in confidential and the other
4 number we talked about in confidential; is that right?

5 A Yes.

6 Q And then you make the statement, "This was due to
7 rigorous contract negotiations that did not finalize
8 until after we filed testimony in this case proceeding,"
9 correct?

10 A Correct.

11 Q Now, you never revised your testimony in this case to
12 correct the inaccurate statements about a \$25 million
13 increase projected for 2024, correct?

14 MR. WATSON: Object to form.

15 (Inaudible.)

16 COURT REPORTER: I'm sorry. The only
17 thing we've established?

18 MR. WATSON: I don't think we have
19 established that any information was accurate. I think I
20 might have said number, I'm sorry.

21 JUDGE THOITS: Overruled.

22 MR. BZDOK: Lori, could you repeat the
23 question.

24 (The record was read aloud as follows:

25 "Q Now, you never revised your testimony in this
Penn Reporting, LLC - lori.penn@yahoo.com

1 case to correct the inaccurate statements about
2 a \$25 million increase projected for 2024,
3 correct?")

4 A I have not revised my testimony.

5 MR. BZDOK: Thank you. I'm going to move
6 to admit proposed Exhibit MEC-98.

7 JUDGE THOITS: Are there any objections
8 to the admission of this exhibit? (No response.)

9 Hearing none, Exhibit MEC-98 is admitted.

10 MR. BZDOK: Thank you.

11 Q (By Mr. Bzdok): Let's talk now about municipal permit
12 requirements, the second driver of your claim of
13 increased costs for the GRP. You address municipal
14 permit requirements in question and answer 22 of your
15 direct on pages 11 and 12; is that right?

16 A Correct.

17 Q You indicate in this testimony, just to paraphrase it to
18 save some time, that there are various requirements that
19 certain municipalities have adopted which have increased
20 the cost of the Main Renewal work; is that right?

21 A Correct.

22 Q And you give some examples in answer 22; is that right?

23 A Correct.

24 Q Take a look at proposed Exhibit MEC-90, which is
25 Discovery Response MNSCDG-5.19.

1 A Yes.

2 Q In this request we referenced your question and answer 22
3 there, and we asked you to produce all sources and
4 documentation for the incremental cost resulting from the
5 changes in municipal permit requirements that you
6 describe in your testimony; is that right?

7 A Correct.

8 Q And here you provide a descriptor that the added
9 requirements placed on DTE by municipalities primarily
10 affect the engineering and design, restoration, and
11 flowable fill of pipes; is that right?

12 A Correct.

13 Q And then you provide us, you say, "Answering further,
14 please see the attached Detroit City permit, by way of
15 example;" is that right?

16 A Correct.

17 Q And if you scroll down to the next 16 pages of that
18 response, that, on the representation I've not modified
19 anything, that is the DTE Gas, Gas Renewal Program, City
20 of Detroit, Public Right of Way Permit for 2023; is that
21 right?

22 A Correct.

23 Q Okay. And in that attachment at various, at certain
24 places, I'm looking at page 4 is the first one, you have
25 highlighted certain requirements of that permit; is that

1 right?

2 A That's correct.

3 Q You additionally highlight some requirements on page 6,
4 page 11 -- sorry -- page 12 -- page 6, page 12, as well
5 as a header on page 13, and that's the information you
6 highlight, right?

7 A Correct.

8 Q Take a look at proposed Exhibit MEC-99, which is
9 Discovery Response MNSCDG-10.6. Here we asked you,
10 referring to that response we were just looking at, if
11 you had any other information that was responsive to the
12 request for all sources and documentation regarding the
13 incremental cost resulting in the changes from municipal
14 permit requirements you described in answer 22, right?

15 A Correct.

16 Q And you indicated you had no other information to
17 provide, right? Did you respond? I'm not sure I heard
18 it.

19 A Correct. I apologize. Yes, I did respond.

20 MR. BZDOK: Your Honor, at this time I'm
21 going to move to admit proposed Exhibits MEC-90 and
22 MEC-99, the Discovery Responses MNSCDG-5.19 with
23 Attachment and MNSCDG-10.6.

24 JUDGE THOITS: Are there any objections
25 to the admission of these exhibits? (No response.)

1 Hearing none, Exhibit MEC-90 and MEC-99
2 are admitted.

3 MR. BZDOK: Thank you.

4 Q (By Mr. Bzdok): The third driver you claim to be
5 increasing costs for the GRP program in your answer 20
6 was the change in the scale and scope of projects as
7 identified by the Probabilistic Risk Assessment; is that
8 right?

9 A Correct.

10 Q And you offer some more information regarding that on
11 page 12 of your direct testimony in question and answer
12 23; is that right?

13 A Correct.

14 Q You describe a pilot project which was undertaken in 2023
15 on 40 miles of mains identified by the PRA; is that
16 right?

17 A Correct.

18 Q And you indicate there's an estimate that the costs for
19 those grids was 20 to 30 percent more than the GRP's 2022
20 average cost per mile of abandonment; is that right?

21 A That's correct.

22 Q And you then offer some description of reasons why that
23 is so, right?

24 A Correct.

25 Q Take a look at proposed Exhibit MEC-91, which is
 Penn Reporting, LLC - lori.penn@yahoo.com

1 Discovery Response MNSCDG-5.20.

2 A O.K.

3 Q Here we asked you to, referring to that answer 23, we
4 asked you to produce all sources and documentation for
5 the incremental cost resulting from implementation of the
6 new risk assessment, both for average cost per mile and
7 for total cost, correct?

8 A Correct.

9 Q You provided no sources and documentation, but rather
10 explained that the PRA changed the order in which work
11 was done resulting in more expensive work being done
12 sooner rather than later, right?

13 A Correct.

14 MR. BZDOK: Your Honor, at this time I'm
15 going to move to admit proposed Exhibit MEC-91.

16 JUDGE THOITS: Are there any objections
17 to the admission of this exhibit? (No response.)

18 Hearing none, Exhibit MEC-91 is admitted.

19 Q (By Mr. Bzdok): Take look at your direct testimony on
20 page 6, and I'm looking at question and answer 12.

21 A I'm there.

22 Q In question and answer 12 on line, starting at line 22,
23 you make statement, "The program is on pace" -- let me
24 back up.

25 On line 21, you state that, "GRP
Penn Reporting, LLC - lori.penn@yahoo.com

1 currently has a goal to replace 206 miles of legacy mains
2 and move out 14,790 inside meters annually," correct?

3 A Correct.

4 Q And then you state, "The program is on pace to conclude
5 in 2035 upon elimination of all legacy mains and the
6 moving outside of all feasibly possible inside meters,"
7 correct?

8 A Correct.

9 Q What happens to the IRM after that?

10 A I'm unfamiliar with what would happen to the IRM after
11 that.

12 Q O.K. Mr. Janness, were you present for Mr. Abona's
13 examination on Teams on Friday morning?

14 A I listened to part of it.

15 Q Did you listen to the part where he indicated that the
16 NPV revenue requirement model used to determine customer
17 contributions to new attachments and Community Expansion
18 Projects assumes that the IRM will remain at at least its
19 current spending levels for the next 20 years?

20 A I did not hear that portion of his cross-exam.

21 Q O.K. Thank you. Let's look, then, at your direct
22 testimony, pages 12 and 13.

23 A I'm there.

24 Q Question and answer 24 starting at the bottom of page 12,
25 starting at the bottom of page 12 and then moving on over

1 on to page 13, you describe a number of what you refer to
2 as capital efficiency initiatives deployed since case
3 U-20940 to gain efficiencies and reduce cost, correct?

4 A Correct.

5 Q And then you have eight numbered items on page 13, right?

6 A Correct.

7 Q And then you have a statement underneath all those items
8 saying, "Overall, our cost reduction efforts have
9 resulted in approximately \$17 million in savings over the
10 past two years," correct?

11 A Correct.

12 Q Take a look at proposed Discovery Response MNSCDG --
13 sorry -- Exhibit, proposed Exhibit MEC-92, which is
14 Discovery Response MNSCDG-5.21a and b. Are you there?

15 A Yes.

16 Q Here we asked you for a breakdown of the savings
17 estimated for each of those capital efficiency
18 initiatives you described in your answer 24, correct?

19 A Correct.

20 Q You indicated the Company had not performed the detailed
21 analysis; is that right?

22 A Correct.

23 Q And I interpret that as therefore you were unable to give
24 us a breakdown of the \$17 million?

25 A Correct.

1 Q Is that fair?

2 A Yes.

3 Q And in, on answer (b) on the next page, we asked you for
4 sources and documentation, and you referred us back to
5 21a; is that right?

6 A Correct.

7 Q And I interpreted that as you were not in a position to
8 provide us with sources or documentation; is that right?

9 A Correct.

10 MR. BZDOK: Your Honor, I'm going to move
11 at this time to admit proposed Exhibit MEC-92, Discovery
12 Response MNSCDG-5.21a and b.

13 JUDGE THOITS: All right. Are there any
14 objections to the admission of this exhibit? (No
15 response.)

16 Hearing none, Exhibit MEC-92 is admitted.

17 MR. BZDOK: Your Honor, may we go off the
18 record for a moment?

19 JUDGE THOITS: Yes. But I note that
20 we've been going at it about an hour and a half, so why
21 don't we take a ten-minute break or so, and we will
22 reconvene at 10, let's make it 10:40. We're off the
23 record.

24 (Recess from 10:27 a.m. until 10:40 a.m.)

25 JUDGE THOITS: All right. We're back on
Penn Reporting, LLC - lori.penn@yahoo.com

1 the record. Mr. Bzdok.

2 MR. BZDOK: Thank you, your Honor.

3 Q (By Mr. Bzdok): Mr. Janness, let's talk about Cathodic
4 Protection. This is, Cathodic Protection is the program
5 that DTE Gas is proposing to add to the IRM in this case;
6 is that right?

7 A Correct.

8 Q In your rebuttal testimony, you respond to, we'll take
9 Mr. Coppola first. You respond on page 5.

10 A I'm on page 5.

11 Q Thank you. You respond in question and answers 10 and
12 11, really 9, 10, and 11, to Attorney General Witness
13 Coppola's recommendation that Cathodic Protection not be
14 added to the IRM in this case, correct?

15 A I'm sorry, can you repeat your question?

16 Q Sure. I'm just orienting us now. In your rebuttal
17 testimony, question and answers 9 through 11, you respond
18 to Attorney General Witness Coppola's recommendation that
19 Cathodic Protection not be added to the IRM in this case,
20 correct?

21 A That is correct.

22 Q And then additionally on page 8 of your rebuttal,
23 question and answer 19, you respond to MNSC Witness
24 Napoleon's recommendation that there need to be more
25 stringent guidelines for what programs are eligible to be

1 included in the IRM, correct?

2 A Correct.

3 Q Let's look at a couple of discovery responses on this
4 topic, if we could, starting with proposed Exhibit
5 MEC-104, which was Discovery Response MNSCDG-5.14.

6 A We're there.

7 Q Here we asked you to produce internal documents related
8 to the decision to seek approval to include Cathodic
9 Protection expenditures in the IRM, and you answered that
10 there were no such documents, but you -- and then you go
11 on to explain the basis for the proposal to add Cathodic
12 Protection expenditures to the IRM, correct?

13 A Correct.

14 Q And then in proposed Exhibit MEC-93, which is
15 Discovery -- let's look at proposed 93, which is
16 Discovery Responses 5.22, 23, and 24. So on the first
17 page of that exhibit, proposed exhibit, which is Response
18 5.22, we asked you for evidence supporting the IRM
19 amounts for Cathodic Protection, correct?

20 A Correct.

21 Q And you referred us to your testimony question and answer
22 86, right?

23 A Correct.

24 Q And then we asked you in the next question to give us a
25 list of any and all disallowances of Cathodic Protection

1 expenditures in the last 10 years, and you indicated that
2 there have been no such disallowances; is that right?

3 A Correct.

4 Q And then in 5.24, we asked if DTE's ever requested to
5 recover Cathodic Protection expenditures through the IRM
6 before, and you indicated that DTE Gas has not done so,
7 correct?

8 A Correct.

9 Q And then lastly in Exhibit, proposed Exhibit MEC-101, 101
10 is a compilation of two discovery responses from two
11 different parties. The first question is MNSCDG-10.8 in
12 which we asked you to look at your response to 5.24,
13 which we just looked at in MEC-93, and asked what
14 necessitates the change now, the change, in other words,
15 to add Cathodic Protection to the IRM in this case, and
16 you indicated we should look at the answer to AGDG-4.51,
17 right?

18 A Correct.

19 Q Did you give me an affirmative on that?

20 A I apologize. Yes. Yes. I've been hearing that there's
21 been issues with me, with people not being able to hear
22 me, so if you are not able to here me, please let me
23 know, but I am responding.

24 Q I appreciate that comment, and I mostly am able to hear
25 you, and it's just occasionally, it's more on these kind

1 of routine, right, like --

2 A I think it's a technical issue in our room that we're
3 having.

4 Q O.K. But thank you.

5 So looking at the second page of proposed
6 MEC-101, which is AGDG-4.51, it's a similar question, why
7 is the change necessary now to include Cathodic
8 Protection in the IRM when in prior years the Company's
9 been able to recover the cost of Cathodic Protection in
10 routine capital expenditures as part of base rates? Here
11 in response to the Attorney General's request, which
12 you're also referencing in response to our request, you
13 reiterate some of your direct testimony; is that right?

14 A Correct.

15 Q In your -- in the second paragraph of your answer, you
16 state, "Including Cathodic Protection in the IRM ensures
17 spending on this strategic capital improvement is made a
18 priority while providing increased long-term certainty on
19 recovery of reasonable and prudent expenditures,"
20 correct?

21 A Correct.

22 Q If the Company has never had a disallowance of Cathodic
23 Protection in the last 10 years, how much more certainty
24 of recovery does the Company require?

25 A Can I ask you to please repeat that question?

1 Q Sure. If the Company has never had a disallowance of
2 Cathodic Protection expenditures in the last 10 years,
3 how much more certainty of recovery does the Company
4 require?

5 A I do not have that information.

6 Q O.K. Looking again at your rebuttal testimony to --
7 well, looking at this discovery response still, so I'm
8 still on 101, page 2, which was the AGDG-4.51, and I'm
9 referencing your statement, for this question I'm
10 referencing your statement that: Including Cathodic
11 Protection in the IRM ensures that spending on this
12 strategic capital improvement is made a priority. You
13 make a similar statement in your rebuttal to Ms. Napoleon
14 in answer 19 starting on line 8, carrying over to line 9
15 on page 8, "The IRM ensures that the spending on these
16 capital improvements is made a priority." Do you see
17 that?

18 A You said line 8 and line 9?

19 Q Line 8, yep, lines 8 and 9 on page 8.

20 A Yes.

21 Q And then you state, starting on line 11, "IRM investments
22 are required under federal and state safety standards and
23 are an integral part of the Company's overall effort to
24 ensure the safety and reliability of its system." Do you
25 see that?

1 A I do.

2 Q So my question is, would expenditures that are required
3 by federal or state safety standards and integral to
4 improve safety and reliability, would such expenditures
5 not a be a priority without the IRM?

6 A They would still be a priority.

7 MR. BZDOK: Your Honor, I'm going to move
8 to admit proposed Exhibits MEC-104, 93, and 101.

9 JUDGE THOITS: Are there any objections
10 to the admission of these exhibits? (No response.)

11 Hearing none, Exhibits MEC-104, 93, and
12 101 are admitted.

13 MR. BZDOK: Thank you. I believe that I
14 did admit 92 before the break. Does anyone have a
15 different record?

16 MR. WATSON: That's in my notes, correct,
17 Chris.

18 JUDGE THOITS: No, it's been admitted.

19 MR. BZDOK: Thank you. Just a moment to
20 review my notes, your Honor.

21 JUDGE THOITS: All right. Let's go off
22 the record.

23 (At 10:51 a.m., brief pause.)

24 JUDGE THOITS: All right. We're back on
25 the record. Mr. Bzdok.

1 Q (By Mr. Bzdok): Mr. Janness, I appreciate your time and
2 answers today, and I have no further questions for you at
3 this time.

4 A Thank you.

5 Q Thank you.

6 JUDGE THOITS: Are there any other
7 parties who have questions of this witness? (No
8 response.)

9 Hearing none. Mr. Watson, do you have
10 any questions of this witness?

11 MR. WATSON: Your Honor, just a few
12 moments, please, to confer.

13 JUDGE THOITS: Sure. We'll go off the
14 record.

15 (Recess from 10:53 a.m. until 10:58 a.m.)

16 JUDGE THOITS: We're back on the record.
17 Mr. Watson, you do not have any questions of this
18 witness, correct?

19 MR. WATSON: Correct, your Honor.

20 JUDGE THOITS: All right. Are there any
21 objections to this witness being excused? No response.)

22 Hearing none, Mr. Janness, thank you,
23 sir, for your time. You are excused.

24 THE WITNESS: Thank you.

25 (The witness was excused.)

1 JUDGE THOITS: Previously DTE proposed
2 the admission of various exhibit schedules sponsored by
3 Mr. Janness. Are there any objections to the admission
4 of those exhibit schedules? (No response.)

5 Hearing none, the following schedules to
6 Exhibit A-12 are admitted; Schedule B5.3, B5.5, B5.20,
7 B6, B6.1, B6.2, B6.3, B6.4, B6.5: And the following
8 schedules to Exhibit A-32 are admitted; Schedule V- as in
9 Victor 1, V2.

10 All right. I believe that is, that takes
11 care of the scheduled witnesses who the parties, certain
12 parties wished to cross-examine, so we're now to binding
13 in testimony. It's 11:00 clock, we might as well take
14 advantage of that time before the lunch break to bind in
15 testimony.

16 I'm going to move to the back of the list
17 and see if, if the Clean Energy Organizations are ready
18 and willing to bind in testimony and exhibits for their
19 witnesses?

20 MR. ABRAMS: Yes, your Honor, we're
21 ready.

22 JUDGE THOITS: All right. Please
23 proceed.

24 MR. ABRAMS: At this time, on behalf of
25 the Environmental Law & Policy Center, the Ecology

Penn Reporting, LLC - lori.penn@yahoo.com

1 Center, the Union of Concerned Scientists, and Vote
2 Solar, who I will refer to as the Clean Energy
3 Organizations, and by stipulations of the parties, I move
4 to bind in the Refiled Direct Testimony of Brad Cebulko,
5 consisting of a cover page, a table of contents, and 55
6 pages of questions and answers; and I move for the
7 admission of Exhibits CEO-1 through CEO-43. I also move
8 to bind in the Rebuttal Testimony of Brad Cebulko,
9 consisting of a cover page, a table of contents, and nine
10 pages of questions and answers.

11 JUDGE THOITS: All right. Are there any
12 objections to the admission of this testimony and these
13 exhibits? (No response.)

14 Hearing none, the Direct and Rebuttal
15 Testimony of Brad Cebulko is bound into the record, and
16 Exhibits CEO-one through CEO-43 are admitted.

17 (Testimony bound in.)

18 - - -
19
20
21
22
23
24
25

**STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION**

In the matter of the application of DTE GAS)	
COMPANY for authority to increase its)	
rates, amend its rate schedules and rules)	Docket No. U-21291
governing the distribution and supply of)	
natural gas, and for miscellaneous accounting)	
authority)	

REFILED DIRECT TESTIMONY OF

Bradley Cebulko

ON BEHALF OF

**THE ECOLOGY CENTER, THE ENVIRONMENTAL
LAW & POLICY CENTER, UNION OF CONCERNED SCIENTISTS, AND VOTE
SOLAR**

May **27**, 2024

Table of Contents

I.	Introduction and Summary	1
II.	The Company’s Business-As Usual Approach is Costly and Risky for Customers in a Rapidly Changing Energy Landscape	7
	<i>A. The Company’s Rate Case Application Does Not Account for Risk Posed by the State’s Emissions Reduction Goals and Emergent Building Electrification Will Further Erode Customer Demand</i>	<i>9</i>
	<i>B. DTE Does Not Have a Plan for Achieving Emissions Reduction Goals.....</i>	<i>21</i>
	<i>C. How DTE Can Better Use its Gas Delivery Plan for Emissions Reduction and Capital Investment Planning</i>	<i>25</i>
III.	DTE Should Not Abandon Demand Response Programs	30
	<i>A. DTE’s Initial Pilots Did Not Have Clear Objectives.</i>	<i>30</i>
	<i>B. DTE Did Not Identify Evaluation Criteria.....</i>	<i>34</i>
	<i>C. The Commission Should Require DTE to Develop New Demand Response Programs</i>	<i>40</i>
IV.	Using Granular Data and Mapping to Ensure Equitable Gas Service	43

1 **I. Introduction and Summary**

2 **Q: Please state your name and business address.**

3 A: My name is Bradley Cebulko. My business address is 24125 47th Ave SW, Vashon,
4 Washington, 98070.

5 **Q. By whom are you employed and in what capacity?**

6 A. I am the founder of CEB Energy Consulting. CEB Energy Consulting provides technical,
7 economic, and policy analysis to public interest organizations who participate in public
8 utility commission proceedings.

9 **Q. On whose behalf are you submitting this direct testimony?**

10 A. I am submitting testimony on behalf of The Ecology Center, The Environmental Law &
11 Policy Center, Union of Concerned Scientists, and Vote Solar, collectively referred to as
12 the Clean Energy Organizations or CEO.

13 **Q. Please summarize your qualifications, experience, and education.**

14 A. I founded CEB Energy Consulting in March 2024. Previously, I was a Senior Manager at
15 Strategen Consulting from 2021 to 2024. At Strategen, I led the gas transition practice, as
16 well as provided analysis on other utility regulatory issues including line extension
17 allowances, gas utility capital investment plans, alternative fuels, electric and gas long-
18 term planning, gas utility decarbonization plans, and new regulatory business models. Prior
19 to joining Strategen, I worked at the Washington Utilities and Transportation Commission
20 (“UTC”) for eight years. From 2013-2016, I was an analyst with the UTC Commission
21 Staff focused on electric and natural gas integrated resource planning (“IRP”), electric and
22 natural gas energy efficiency programs, and new program design and implementation.

1 From 2016-2021, I was an advisor to the Washington State Commissioners, where I led
 2 Commissioners' review of major filings and adjudications, natural gas general rate cases,
 3 purchase gas adjustments, rulemakings, and natural gas IRPs. From 2019 through 2020, I
 4 led the UTC's rulemakings to implement Washington state's Clean Energy Transformation
 5 Act.

6 **Q. Have you testified before the Michigan Public Service Commission previously?**

7 A. Yes. I testified on behalf of Michigan Environmental Council, NRDC, and Sierra Club in
 8 U-21148, Consumers Energy's 2021 gas rate case.

9 **Q: Have you testified or provided comments in similar state regulatory proceedings?**

10 A: Yes. I have testified and provided comments before several Public Utility Commissions
 11 including in Illinois, Minnesota, Colorado, Massachusetts, Oregon, Washington state, and
 12 Connecticut. My resume and summary of qualifications are attached as Ex. CEO-1 and
 13 provide additional detail.

14 **Q. Are you sponsoring any exhibits?**

15 A. Yes. I am sponsoring the following exhibits:

- 16 • Exhibit CEO-1: Resume of Bradley Cebulko
- 17 • Exhibit CEO-2: DTE Response to CEODG-2.4j, Figure 65 Data
- 18 • Exhibit CEO-3: DTE Response to CEODG-1.16
- 19 • Exhibit CEO-4: DTE Response to MNSCDG-2.1b, Annual Billed Sales Volumes
- 20 • Exhibit CEO-5: DTE Response to CEODG-1.27a, Historical Peak Day Demand
- 21 • Exhibit CEO-6: DTE Response to CEODG-1.24a, Five Year Forecast
- 22 • Exhibit CEO-7: Brattle, "The Future of Gas Series Utilities Series, Transitioning Gas
 23 Utilities to a Decarbonized Future." Part 1 of 3. August 21.
- 24 • Exhibit CEO-8: DTE Response to CEODG-2.1
- 25 • Exhibit CEO-9: DTE Response to CEODG-1.15a
- 26 • Exhibit CEO-10: DTE Response to ~~MNSCDG~~CEODG-2.1a, Annual Emissions from
 27 Customer Gas Consumption
- 28 • Exhibit CEO-11: Modification to DTE Response to ~~CEOMNSCDG~~CEODG-2.1a, Annual
 29 Emissions from Customer Gas Consumption

- Exhibit CEO-12: DTE Response to CEODG-1.30a
- Exhibit CEO-13: DTE Response to CEODG-1.30b
- Exhibit CEO-14: DTE Response to CEODG-1.30c
- Exhibit CEO-15: DTE Response to CEODG-1.30d
- Exhibit CEO-16: DTE Response to CEODG-2.6c
- Exhibit CEO-17: DTE Response to CEODG-2.6d
- Exhibit CEO-18: DTE Response to CEODG-2.7b, BWEC Hydrogen Blending Pilot
- Exhibit CEO-19: DTE Response to CEODG-2.7c
- Exhibit CEO-20: DTE response to CEODG-2.8a
- Exhibit CEO-21: DTE Response to CEODG-2.8b
- Exhibit CEO-22: DTE Response to CEODG-2.8c
- Exhibit CEO-23: DTE Response to CEODG-2.9a
- Exhibit CEO-24: B. Cebulko, *A Regulators Blueprint for 21st Century Gas Utility Planning* (December 2023)
- Exhibit CEO-25: R. Nelson, *Non-Pipeline Alternatives to Natural Gas Utility Infrastructure, An Examination of Existing Regulatory Approaches*
- Exhibit CEO-26: DTE Response to CEODG-1.3a
- Exhibit CEO-27: DTE Response to CEODG-1.8c
- Exhibit CEO-28: DTE Response to CEODG-3.7a
- Exhibit CEO-29: DTE Response to CEODG-3.7b
- Exhibit CEO-30: DTE Response to CEODG-3.7c
- Exhibit CEO-31: DTE Response to CEODG-3.7d
- Exhibit CEO-32: DTE Response to CEODG-3.7e
- Exhibit CEO-33: DTE Response to CEODG-3.7f
- Exhibit CEO-34: DTE Response to CEODG-3.8a
- Exhibit CEO-35: DTE Response to CEODG-3.8b
- Exhibit CEO-36: DTE Response to MNSCDG-2.6d, Gas DR Pilot Results Season 2 (“Gas Demand Response Winter 2022-23 Results” June 16, 2023) Gas DR Pilot Results Season 2
- Exhibit CEO-37: DTE Response to CEODG-3.12
- Exhibit CEO-38: DTE Response to CEODG-1.4a
- Exhibit CEO-39: DTE Response to CEODG-1.5a
- Exhibit CEO-40: DTE Response to CEODG-1.3c
- Exhibit CEO-41: DTE Response to MNSCDG-2.6d, Gas DR Pilot Results Season 1 (“Gas Demand Response Results – Year 1” May 11, 2022)
- ~~Exhibit CEO-42: DTE Response to MNSCDG-2.6d, Gas Demand Response Results Year 1~~
- Exhibit CEO-4~~23~~3: DTE Response to CEODG-4.1bi
- Exhibit CEO-4~~34~~3: DTE Response to CEODG-4.1di

Q: What is the purpose of your testimony?

1 A: The purpose of my testimony is threefold. First, I discuss the unreasonableness of DTE
2 Gas' business-as-usual rate case filing in which the Company fails to consider evolving
3 public policy and market trends. My primary concern is that the Company is not planning
4 to meet the state's emissions reduction goals nor is it accounting for emergent building
5 electrification as a long-term risk to investments the Company is making today. The
6 Company's approach is both costly and risky for customers. Second, I discuss DTE's
7 failure to develop and properly evaluate its demand response pilots and why the
8 Commission should require DTE to repropose new demand response programs. Finally, I
9 discuss the need for DTE Gas to incorporate the MiEJScreen mapping tool into its
10 programmatic and investment decision-making processes to ensure that environmental
11 justice communities experience equitable outcomes.

12 **Q. What are your recommendations to the Commission?**

13 A. In my testimony I make the following recommendations:

14 **Mitigating Cost and Risk in Capital Investment and Programmatic Decisions**

- 15 • I recommend the Commission order the Company to use its Gas Delivery Plan
16 to model specific emissions reductions pathways for meeting the state's
17 decarbonization goals, and report the potential costs, benefits, and risks of the
18 various resources and investments used in each pathway. The Company must
19 also consider electrification as an available decarbonization resource. As part
20 of its analysis, the Company should identify the customer rate impact of each
21 pathway.

- 1 • I recommend the Commission order the Company to develop an interim plan
2 that examines the decarbonization pathways either by July 2025 or with its next
3 general rate case, whichever comes first.
- 4 • I recommend that the Commission require DTE to work with stakeholders and
5 Commission Staff to develop a Nonpipeline Alternative (“NPA”) framework
6 for analyzing capital investment projects. I recommend that this framework
7 identify the types of projects that are eligible and threshold criteria using best
8 practices from across the industry. The Company should complete this
9 framework by July 2025 or prior to filing its next general rate case, whichever
10 comes first,
- 11 • I recommend the Commission require DTE to work with stakeholders and
12 Commission Staff to develop a framework for considering when pipeline repair
13 is a suitable alternative to pipeline replacement projects. The Commission
14 should require the Company to demonstrate that it conducted this analysis for
15 all capital projects that meet the identified pipeline repair criteria when it seeks
16 cost recovery of the eligible capital investment. The Company should complete
17 this framework by July 2025 or prior to filing its next general rate case,
18 whichever comes first.
- 19 • I recommend that going forward, the Commission require DTE Gas to
20 demonstrate the consideration of nonpipeline alternatives (“NPA”) and pipeline
21 repair as a condition of recovering additional investments in all pipeline
22 infrastructure. The Commission should hold DTE to this standard even while
23 the Company is developing its NPA and repair frameworks.

Demand Response Programs and Pilots Cost Recovery

- I recommend the Commission reject the Company's request to recover the \$2.6 million in deferred demand response costs as the Company did not identify clear objectives, identify reasonable evaluation criteria, nor develop and implement a robust set of pilots that tested the effectiveness of demand response.¹
- I recommend the Commission order DTE to work with Commission Staff and stakeholders to develop a more robust set of demand response programs. The Company and parties should establish clear objectives for each pilot, identify which costs and benefits will be evaluated, and undergo a thorough third-party evaluation. The Company and other stakeholders should consider the development of interruptible programs as part of this undertaking. The Company should complete this work by July 2025 or prior to filing its next general rate case, whichever comes first.

MiEJScreen and Equity

- I recommend that the Commission order DTE Gas to use the MiEJScreen tool to inform the impact of its capital investment decisions on low income and environmental justice communities in its next rate case. The Commission should require the Company to discuss how it used MiEJScreen to inform its investments in testimony.
- I recommend that the Commission order DTE gas to use the MiEJScreen tool to inform the design and implementation of its customer programs and policies, including the Company's energy efficiency and demand response programs,

¹ HJD-83, lines 18-20.

low-income energy efficiency and heating assistance programs, arrearage management programs, and residential disconnection policy in its next rate case. The Commission should require the Company to discuss how it used MiEJScreen to inform its investments in testimony.

- I recommend the Company integrate the six additional metrics discussed below as part of its use of the MiEJScreen tool. I identify the specific metrics beginning on page 49 of my testimony.

II. The Company's Business-As Usual Approach is Costly and Risky for Customers in a Rapidly Changing Energy Landscape

Q: Will you please describe the policy and economic landscape in which the Company is filing this rate case?

A: Yes. Society is undergoing a fundamental energy transition in which we are shifting away from fossil fuels and towards renewable forms of energy. The shift is primarily being driven by two factors: changing policy and changing economics. Various levels of governments are enacting policies that restrict greenhouse gas emissions and incentivize renewable forms of energy. In 2020, Michigan set a goal to achieve economy-wide carbon neutrality by 2050 and achieve net negative emissions thereafter.² The state set interim targets to reduce GHG emissions by 28% by 2025 and 52% by 2030.³ On an even more local level for DTE, the city of Ann Arbor is evaluating a plan to replace gas distribution infrastructure with lower emission technologies like highly efficient electric appliances.⁴

² BV-49, lines 7 – 10.

³ *Id.*

⁴ BV-49, 7 – 10.

1 Concurrently, the cost to transition to less carbon-intensive energy has plummeted
2 in recent decades, most notably in the power generation sector. As I will explain later in
3 my testimony, we are seeing the emergence of highly efficient electric appliances for
4 space and water heating. In some jurisdictions, all-electric new residential homes are
5 already less expensive than new residential homes that use gas.⁵

6 **Q: Does DTE's rate case reflect this shifting political and economic reality?**

7 DTE's rate case does not reflect the changing landscape much less propose
8 actions that will direct the Company down a path towards meeting the state's emissions
9 reduction goals. In fact, the Company does not have a plan to achieve the state's
10 emissions reduction goals. Moreover, the Company continues to invest in its delivery
11 system as if it does not need to meet the state's emissions reduction targets or with due
12 consideration for the coming energy transition. This is costly and risky for customers.
13 The Company is making capital investments today in new pipes that will be in rates for
14 the next 40 to 65 years. Whether and to what extent the Company's proposed investments
15 are necessary must be more carefully examined.

16 To respond to the changing environment, the Company must take a different
17 approach, and that means looking for opportunities to reduce its capital investment
18 spending. The Company must show the Commission how its spending, particularly its
19 capital expenditures, are reasonable considering the state's emissions reduction goals and
20 the larger energy transition. For example, I would expect when considering how to
21 remedy a segment of leaky pipe, the Company's decision-making process would involve

⁵ Tan, L. et al, "The Economics of Electrifying Buildings: Residential New Construction. Rocky Mountain Institute. 2022. Available at: <https://rmi.org/insight/the-economics-of-electrifying-buildings-residential-new-construction/>

1 consideration of alternatives to replacements that are cheaper for customers and which
2 better align with the state’s emissions reductions goals. Unfortunately, the Company does
3 not make that showing in this case.

4 **A. *The Company’s Rate Case Application Does Not Account for Risk Posed by the***
5 ***State’s Emissions Reduction Goals and Emergent Building Electrification Will***
6 ***Further Erode Customer Demand***

7 **Q: Why does the Company say it is filing this rate case?**

8 A: The Company is filing this rate case because it is forecasting a revenue shortfall of \$266
9 million for the projected 2025 test year.⁶ The forecasted shortfall includes \$106 million
10 associated with an Infrastructure Recovery Mechanism (“IRM”) surcharge, which is
11 currently included in customers’ bill. The IRM is set to expire at the end of 2024 and the
12 Company is seeking to renew the program for the next five years.

13 **Q: Does the Company provide a forecast of capital investments?**

14 A: Yes. The Company identifies its 10-year capital plan in its Gas Delivery Plan (“GDP”).⁷
15 The Company plans to spend an incremental \$764 million per year for the next 10 years
16 for a total of \$8,407,600,000 by 2033.⁸ As can be seen in Figure 1, the Company’s 10-year
17 capital expenditure plan shows that the Company continues to increase the pace of capital
18 expenditure investments.

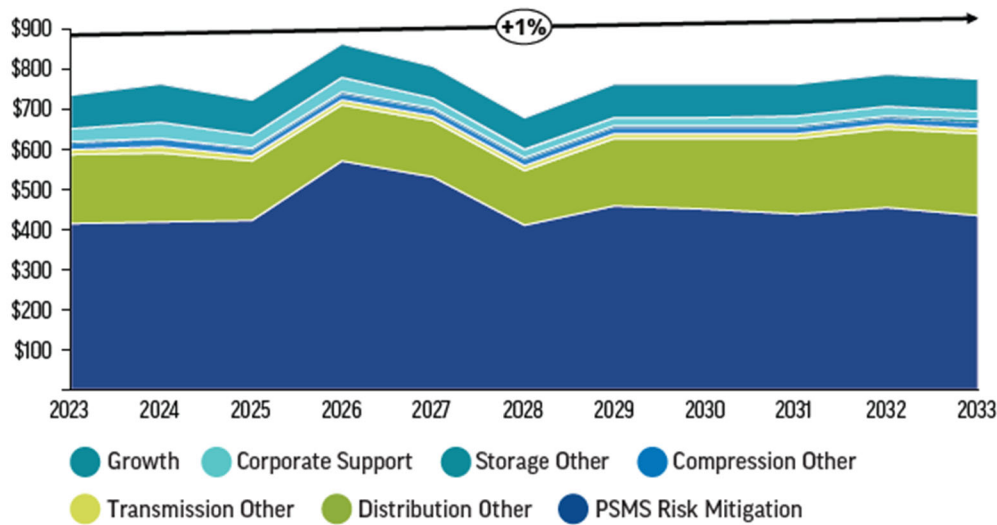
19 *Figure 1: DTE Gas 10-Year Capital Plan (\$M) Figure 65*⁹
20

⁶ RMT-8, lines 1 – 11.

⁷ Case No. U-21291, Exhibit A-12, Schedule B5.6, Page 68.

⁸ CEO-2, DTE Response to CEODG-2.4j Figure 65 Data.

⁹ Case No. U-21291, Exhibit A-12, Schedule B5.6, Page 68, Figure 65.



Q: What is your concern with the Company's pace and scope of its capital investment plan?

A: The Company's capital investment plan is risky for three reasons. **First**, the Company's own projections, which do not account for any building electrification,¹⁰ forecasts declining customer demand.¹¹ All else equal, when capital investments increase but demand decreases, customers rates will increase. **Second**, I am concerned that by not considering the impact of building electrification on its future demand, customer rates will increase more rapidly than anticipated. **Third**, the Company does not have a plan for meeting the state's emissions reduction targets. The Company's case demonstrates that it believes that it can continue to expand the gas delivery system indefinitely without making any efforts towards meeting the state's emissions reduction goals.

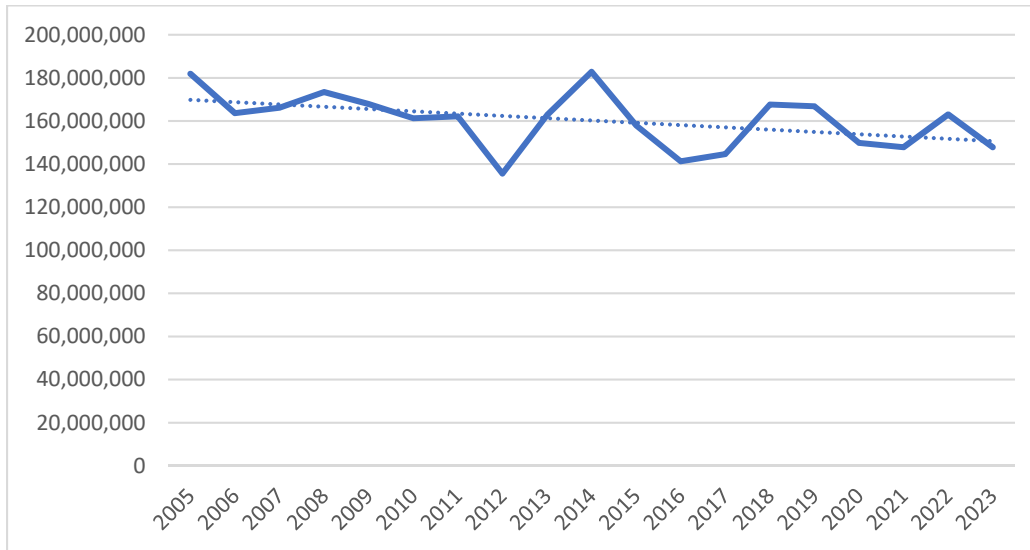
Q: Let's start with your first concern. Has customer demand increased or decreased in the past 20 years?

¹⁰ CEO-3, DTE Response to CEODG-1.16.

¹¹ See Figure 2 below.

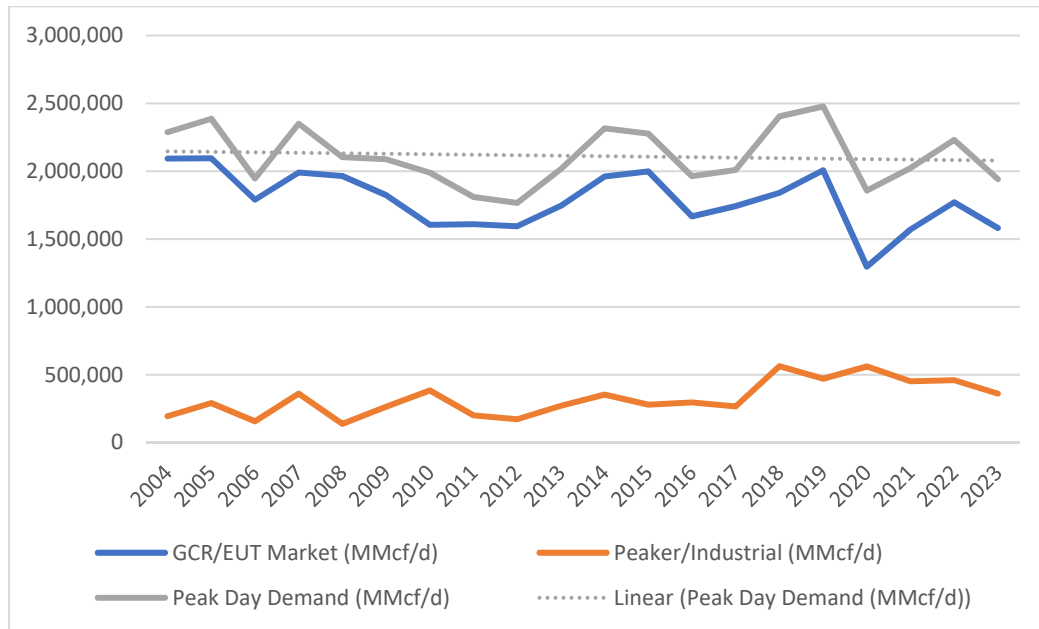
A: As shown in Figure 2 and 3 below, both the Company's annual sales and peak demand have declined over the past 20 years.

Figure 2: DTE Aggregate Gas Sales (MCF)¹²



¹² CEO-4, DTE Response to MNSCDG-2.1b, Annual Billed Sales Volumes.

Figure 3: DTE's Actual Peak Demand 2004 – 2023 (MMcf/d)¹³

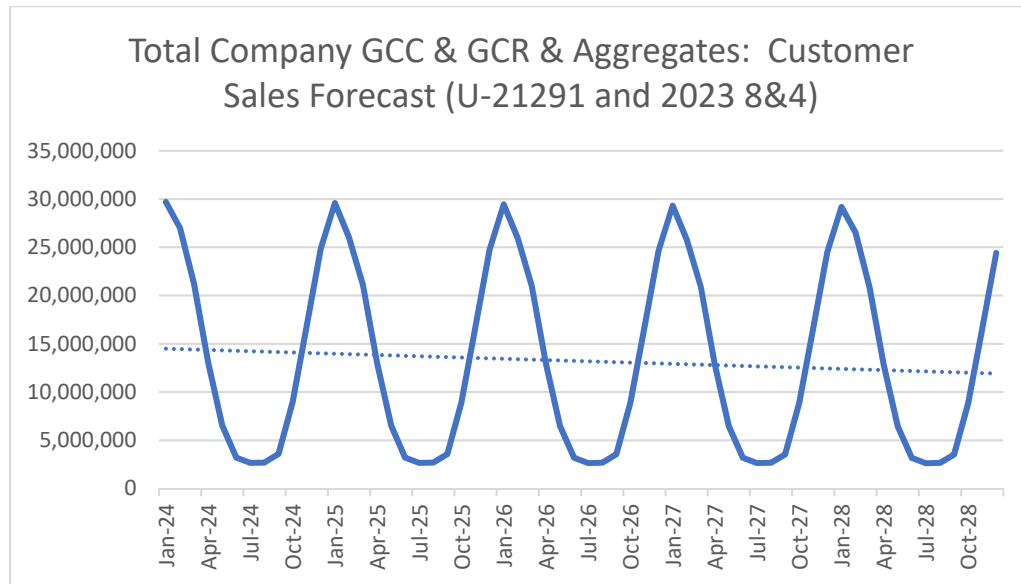


Q: Does the Company forecast increasing demand?

A: No. As shown in Figure 4, the Company is forecasting annual demand decreases through at least 2028. Although the Company is expecting to continue to add new customers to the system, use-per-customer (“UPC”) is expected to continue to decrease. The net impact is a decrease in annual and peak demand.

¹³ CEO-5, DTE Response to CEODG-1.27a, Historical Peak Day Demand.

Figure 4: Total Company (GCC & GCR) Customer Sales Forecast¹⁴



Q: Why is it relevant that the Company is forecasting declining demand?

A: The Company is planning on investing hundreds of millions of dollars into its gas delivery system over the next 10 years. Concurrently, the Company is forecasting declining demand. All else equal, when the Company increases its investments in its delivery system, but demand declines, customer rates must increase. This is because a portion of the fixed costs of the gas delivery system is recovered through the variable charge. As fixed costs are spread over fewer and fewer therms, the cost per therm goes up. Ultimately, low-income customers bear a disproportionate burden of the increasing rates.

Q: Why are low-income customers disproportionately impacted by increasing rates?

A: By definition, low-income customers have less disposable income and therefore the impact of increasing gas bills is more acutely felt and experienced. Moreover, low-income customers are less capable of taking actions to reduce their energy bills. Low-income

¹⁴ CEO-6, DTE Response to CEODG-1.24a, Five Year Forecast.

1 customers have less access to capital to invest in weatherization or energy efficiency
2 measures and are more likely to be renters¹⁵ and therefore have less ability to, or control
3 over decisions to, invest in weatherization or energy efficient appliances. Moreover,
4 middle- and high-income customers, because they have more access to capital, are more
5 likely to be able to afford high efficiency gas, or electric appliances. As middle and high-
6 income customers reduce their reliance on gas, the costs of operating the gas system will
7 be disproportionately borne by those least likely to electrify: low-income customers.

8 **Q: Let's turn to your second concern. Is there a risk that demand will further erode in**
9 **the future?**

10 A: Yes, I expect gas demand will further erode primarily due to cost-effective building
11 electrification and decarbonization policies. To start, there have been substantial
12 improvements in heat pump technology and costs, particularly for cold climate heat pumps.
13 In 2021, the US Department of Energy ("DOE") launched a Residential Cold Climate Heat
14 Pump Challenge to develop more efficient cold climate heat pumps. In November 2022,
15 Trane, a heat pump manufacturer, announced that its newest prototype exceeded DOE
16 targets by performing at temperatures as low as -23 degrees Fahrenheit.¹⁶ A 2022 study

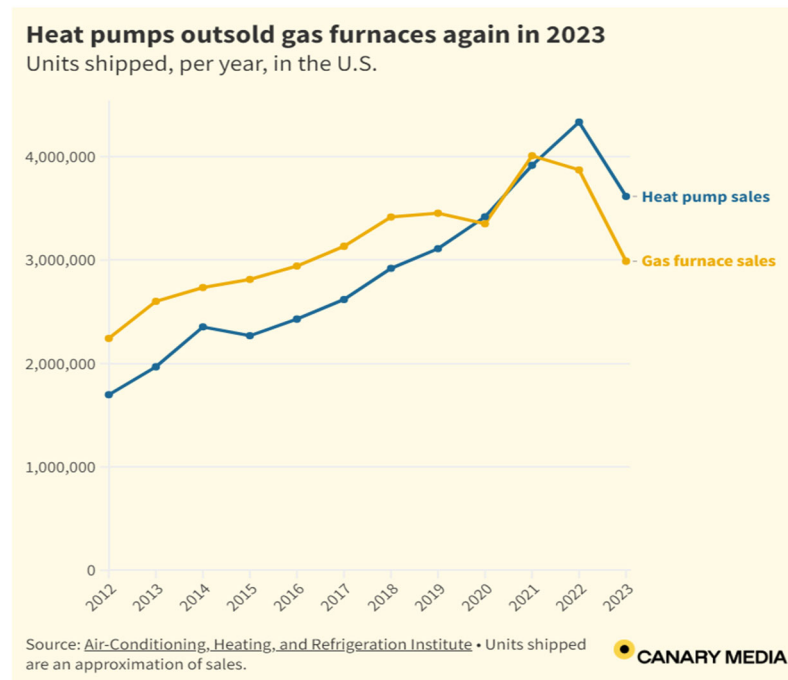
¹⁵ United States Census Bureau, "Low-Income Renter Spent Larger Share of Income on Rent in 2021." Available at: <https://www.census.gov/library/stories/2023/03/low-income-renters-spent-larger-share-of-income-on-rent.html#:~:text=Renters%20Household%20Incomes%20Lower%20Than%20Homeowners&text=Renter%20Occupied%20households%20made%20up,were%20in%20renter%20Occupied%20units>.

¹⁶ *Trane Passes Heat Pump Challenge*, Cooling Post (Nov. 4, 2022). Available at: <https://www.coolingpost.com/world-news/trane-passes-heat-pump-challenge/>.

found that all electric, single-family new construction is cheaper to build and operate than a home with gas appliances in all nine cities studied.¹⁷

Customers are taking notice. As shown in Figure 5, electric heat pumps have now outsold gas furnaces two years in a row. These data do not account for the impact of the Inflation Reduction Act, which should help further accelerate the adoption of electric appliances through the program’s generous appliance rebates and tax incentives.¹⁸

Figure 5: Sales of Heat Pumps and Gas Furnaces from 2012 – 2023¹⁹



¹⁷ Tan, L. et al, “The Economics of Electrifying Buildings: Residential New Construction. Rocky Mountain Institute. 2022. Available at: <https://rmi.org/insight/the-economics-of-electrifying-buildings-residential-new-construction/>

¹⁸ Beginning in 2023, state programs offer low- and moderate-income households’ rebates for heat pumps at the point-of-sale, cutting costs of purchase and installation up to \$8,000. If home electrical upgrades are needed to integrate new heat pumps, rebates of up to \$4,000 are available to households. See <https://www.whitehouse.gov/cleanenergy/>.

¹⁹ Takemura, Alison. “Heat pumps outsold gas furnaces again last year – and the gas is growing” Canary Media. February 13, 2024. Available at :<https://www.canarymedia.com/articles/heat-pumps/heat-pumps-outsold-gas-furnaces-again-last-year-and-the-gap-is-growing>.

1 **Q: Now let's turn to your third concern, that the Company does not have a plan for**
2 **achieving the state's emissions reduction goals. Please explain why you expect**
3 **decarbonization policy to lead to a decline in demand for natural gas?**

4 A: Leading industry studies and state climate plans consistently identify building
5 electrification as a critical component of a decarbonization pathway. In Michigan, the MI
6 Healthy Climate Plan states that decarbonizing buildings will require evaluation and
7 adoption of innovative home heating alternatives, including electrification.²⁰ The Plan
8 further identifies a key strategy for meeting building decarbonization to include updates to
9 building codes.

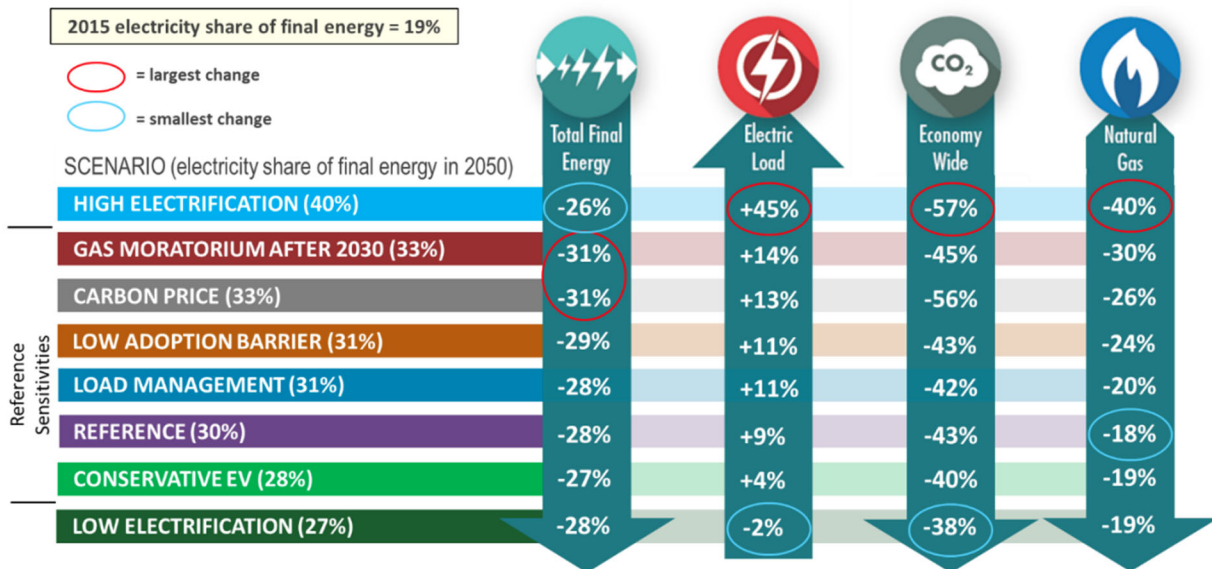
10 **Q: Is Michigan's finding that building electrification will be a critical component of a**
11 **decarbonization pathway consistent with findings from other states?**

12 A: Yes. The MI Healthy Climate Plan is consistent with other state decarbonization studies
13 and investigations. In Illinois, Ameren hired the Electric Power Research Institute
14 ("EPRI") to study the impact of electrification on its system. As shown in Figure 6, the
15 EPRI study found that in every scenario of the future it examined, efficient electrification
16 would result in gas throughput declines from 18% to 40% from 2015 to 2050.²¹ In
17 particular, the study identified residential gas throughput in Ameren Illinois's service
18 territory declining between 38% and 56% from 2015 to 2050.²²

²⁰ MI Healthy Climate Plan at 41. <https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Offices/OCE/MI-Healthy-Climate-Plan.pdf?rev=d13f4adc2b1d45909bd708cafccbffa>

²¹ Illinois Commerce Commission, Docket 23-0067, Ameren Illinois Company 2023 Gas Rate Case. PIO Exhibit 3.1REV. Available at: <https://www.icc.illinois.gov/docket/P2023-0067/documents/340150>

²² *Id.* at 11.

Figure 6: EPRI Electrification Scenarios for Ameren Illinois²³

In Massachusetts, the Massachusetts Department of Public Utilities (“DPU”) issued its finding from its Investigation into the role of Gas Local Distribution Companies for meeting the Commonwealth’s 2050 climate goals.²⁴ In its Order, the DPU found that building electrification is necessary to achieve state policy goals, that gas utilities have a role to play in facilitating building electrification, and that the state needs to modify its line extension policy. In Connecticut, the Connecticut Department of Energy & Environmental Protection (“DEEP”) stated that electrification must be the dominant form of energy for building heat, writing that to “achieve the long-term vision of a zero-carbon economy, widespread electrification of building thermal loads and the transportation sector is required. By 2050 electricity must become the dominant form of

²³ *Id.*

²⁴ Ma. Dep’t of Public Utilities, Docket 20-80 (Dec. 6, 2023), available at: <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18297602> (last visited Apr. 17, 2024).

1 energy consumed in Connecticut, and the cornerstone of the state’s carbon-free economy
2 will be decarbonization of the electric power sector.”²⁵

3 **Q: Throughout this testimony you have discussed the risk that building electrification**
4 **will lead to a decline in customer demand. Are you suggesting that building**
5 **electrification will lead to full electrification of the building sector?**

6 A: Not necessarily, but more to the point, I think focusing on the end state – to what extent
7 electrification will diminish gas demand – is misplaced. Even modest levels of building
8 electrification would lead to a decline in customer demand and therefore substantial rate
9 increases for remaining gas customers, which could lead to a cycle of further
10 incentivizing additional electrification.

11 In 2021, Brattle published its “Future of Gas” series that identified the risks and
12 opportunities of the energy transition for gas utilities. Brattle discussed its concern for a
13 “death spiral” that results from gas utilities seeking to recover increasing capital
14 expenditures from a shrinking customer base.²⁶ Brattle forecasted that “at the current
15 pace, the number of homes with electric space heating could surpass homes with gas
16 space heating by 2032.”²⁷ The Brattle report also found that “infrastructure is at risk of
17 being stranded” and gas “utilities need to minimize stranded asset risk.”²⁸ The report then

²⁵ Connecticut Department of Energy and Environment. Comprehensive Energy Strategy (2018). Page 10. Available at: <https://portal.ct.gov/-/media/DEEP/energy/CES/2018ComprehensiveEnergyStrategypdf.pdf>

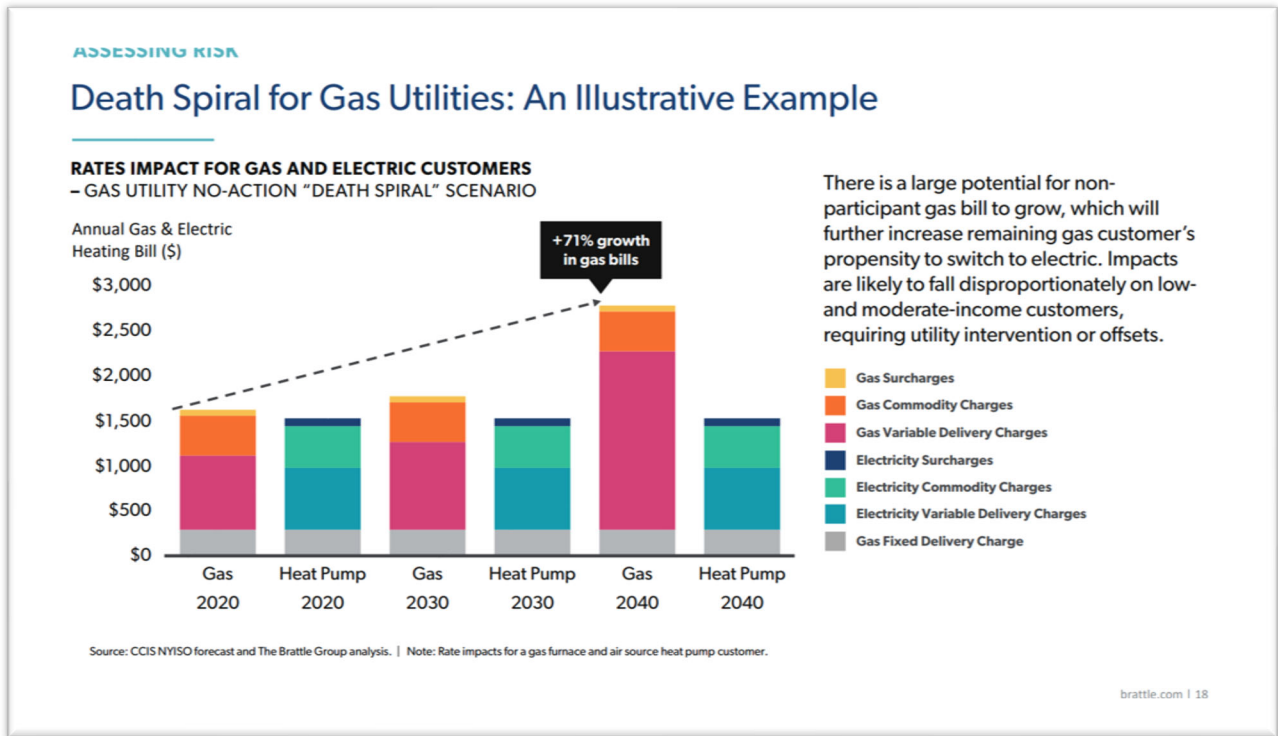
²⁶ CEO-7, Brattle, “The Future of Gas Series Utilities Series, Transitioning Gas Utilities to a Decarbonized Future.” Part 1 of 3. August 21. Available at: https://www.brattle.com/wp-content/uploads/2022/01/The-Future-of-Gas-Utilities-Series__Part-1.pdf.

²⁷ *Id.*

²⁸ *Id.*

suggested that commissions and utilities should be examining alternative depreciation schedules to ensure full recovery of gas investments.²⁹

Figure 7: Brattle The Future of Gas Utilities Series



The risk to DTE Gas and its customers, particularly low-income customers, is very real, and the Company should be assessing that risk in its decision making. Either increasing building electrification or emissions reduction requirements would have a substantial impact on the utility's current business model. The utility should be adjusting its business decisions to reflect the present opportunities and risks.

Q: Is DTE accounting for the risk of building electrification in its load forecast or capital investment decisions?

²⁹ *Id.*

1 A: No. The Company states that it does not include the impacts of building electrification on
2 its demand forecast as there is too much uncertainty related to the adoption of
3 electrification technologies to accurately forecast.³⁰ Moreover, the Company has not
4 conducted a study or analysis of the impacts of building electrification in its service
5 territory.³¹

6 **Q: Is the Company's position reasonable?**

7 A: No, the Company's refusal to assess the potential impact of building electrification on its
8 business is unreasonable and exposes its customers to too much risk. Although the
9 Company recognizes building electrification may have an impact on its gas system, the
10 Company argues that it is "premature to speculate" on what those impacts may be.³² The
11 Company continues that it is unwilling to consider building electrification in its demand
12 forecast, writing, "[a]s stated previously, there is too much uncertainty related to the
13 adoption of electrification technologies to accurately forecast. To date, the Company has
14 not seen any impact of electrification and therefore does not include it in current
15 forecasts."³³ The Company's position that it cannot assess the potential impact of building
16 electrification due to uncertainty is not a neutral position – rather, it is an assumption that
17 there will be no impact of building electrification. It is a failure to plan for the future and
18 justifying that failure by arguing that planning is too difficult.

19 The Company is making decisions today about capital investments that customers
20 will be paying for decades to come. The Company cannot wait for certainty about

³⁰ CEO-3, DTE Response to CEODG-1.16.

³¹ CEO-8, DTE Response to CEODG-2.1.

³² CEO-9, DTE Response to CEODG-1.15a.

³³ CEO-3, DTE Response to CEODG-1.16.

1 building electrification to assess its potential impact as it is impossible to achieve
2 certainty. It is necessary for any business, including a utility, to assess its uncertain
3 planning environment and make decisions without complete knowledge of the future. No
4 business can predict the future but every business, especially utilities with a captive
5 customer base, must properly plan for the future using the best information available to it
6 now.

7 In fact, the Company has developed processes for addressing uncertainty in other
8 area of the business. For example, the Company mitigates the impact of commodity price
9 volatility during the winter season by purchasing the bulk of its winter gas supply during
10 the summer and making use of financial hedging.³⁴ Moreover, the Company has a
11 planning process, the DTE Gas Delivery Plan, it could use to assess the potential impacts
12 of building electrification on its system and to customer rates. Because the Company did
13 not consider likely impacts of building electrification in its analysis, the load forecast and
14 capital investment plan are likely inflated.

15 ***B. DTE Does Not Have a Plan for Achieving Emissions Reduction Goals***

16 **Q: What are Michigan's emissions reductions goals?**

17 A: The State has a goal to achieve economy-wide carbon neutrality by no later than 2050,
18 with interim targets to reduce greenhouse gas emissions by 28% by 2025 and 52% by
19 2040.³⁵

20 **Q: Does DTE have emissions reduction goals?**

³⁴ Exhibit A-12, Schedule B5.6. DTE Gas Delivery Plan, p. 9 and 32.

³⁵ BV-49, lines 7- 10.

1 A: Yes. The Company issued a press release in 2020 stating its commitment to reduce
2 greenhouse gas emissions from its own operations and its suppliers to “net zero by 2050,”
3 as well as reduce greenhouse gas emissions from the combustion of gas at customer end-
4 use by 35% by 2050 (from 2005).³⁶ However, despite this press release and the
5 Company’s claim that “[d]ecarbonization and the reduction of greenhouse gas emissions
6 is an increasing priority within the energy industry in totality and gaining momentum in
7 the gas industry,” the Company has no plans for actually achieving these goals.³⁷

8 **Q: What are DTE’s current level of emissions as compared to its baseline 2005**
9 **emissions?**

10 A: DTE Gas reports that its gas consumption emissions were 7,969,415 metric tons of CO₂e
11 in 2023.³⁸ This is a 21% reduction from the Company’s 2005 emissions of 10,081,350
12 metric tons of CO₂e.³⁹ Based on the Company’s data, the decrease in emissions is
13 entirely explained by the decline in demand for natural gas. In fact, the Company is
14 already more than halfway to its goal without taking *any* proactive action. DTE Gas’s
15 demand has declined by an average of 1.3% from 2005 to 2023. If demand were to
16 continue to decline by 1.3% per year, the Company would achieve its goal to reduce
17 emissions 35% by 2038 without taking any action at all.⁴⁰

18 Moreover, as CEO witness Saad Siddique further explains, despite having a “net-
19 zero by 2050” goal for upstream and operational emissions, the Company does not have

³⁶ HJD-36, lines, 3 – 7.

³⁷ *Id.*

³⁸ CEO-10, DTE Response to MNSCDG-2.1a, Annual Emissions from Customer Gas ConsumptionCEODG-2.1a.

³⁹ *Id.*

⁴⁰ CEO-11, Modification to DTE Response to MNSCCEODG-2.1a.

1 baseline emissions for either sector. The Company’s “net zero by 2050” goal, at this time,
2 is meaningless and incalculable.

3 **Q: You state that DTE may achieve its 35% emissions reduction goal for end-use**
4 **combustion by 2038 without taking any action. Do you believe that the Company**
5 **should set a more ambitious target?**

6 A: Yes. If DTE believes that “[c]limate change is one of the defining public policy issues of
7 our time and it demands a bold response,”⁴¹ as the Company testifies, then the Company
8 should commit itself to a bold target and develop a public plan for achieving that target. At a
9 minimum, the Company should commit itself to reduce end-use combustion emissions to net-
10 zero by 2050, which is aligned with the state’s emissions reduction goals.

11 **Q: Why do you say that DTE does not have a plan for emissions reductions?**

12 A: Through discovery I asked the Company for reports, documents or other analysis that
13 demonstrates the Company’s plans for meeting its commitment to reduce greenhouse gas
14 emissions from its upstream suppliers, own operations, and customer end use. The
15 Company responded in each case that it has not identified pathways to achieve the DTE
16 Gas emission reduction goals and that the Company’s plans remain indeterminate due to
17 the uncertainty, cost, and feasibility of technology deployment.⁴² It seems the Company
18 does not know how it will achieve its goal in part because the Company has not
19 conducted basic analysis into key inputs and assumptions. For example, although the

⁴¹ HJD-36, lines 11 – 12.

⁴² Ex. CEO-12, DTE Responses to CEODG-1.30a; Ex. CEO-13, DTE Responses to CEODG-1.30b; Ex. CEO-14, DTE Responses to CEODG-1.30c; Ex. CEO-15, DTE Responses to CEODG-1.30d

Company writes that it intends to use advanced technologies such as RNG, hydrogen, and gas heat pumps to reduce customer use emissions by 35% by 2040, the Company has not:

- performed a pricing analysis for the future price of RNG,⁴³
- forecasted the percentage of the Company's emissions reductions that can be achieved through the use of RNG,⁴⁴
- performed a pricing analysis on the cost of green hydrogen,⁴⁵
- forecasted what percentage of the Company's emissions reductions can be achieved through the use of clean hydrogen,⁴⁶
- forecasted annual gas heat pump deployment,⁴⁷
- performed a pricing analysis of gas heat pumps,⁴⁸
- forecasted the percentage of the Company's emissions reduction that can be achieved through the use of gas heat pumps, and⁴⁹
- established interim targets for reducing customer end-use emissions 35% by 2040.⁵⁰

DTE's lack of a plan is problematic. The Company intends to continue its business-as-usual pace of capital investments without considering the impact of achieving state emissions reduction goals, its own corporate goals, or how those investments will impact customer rates. The Company has not developed critical information for its own decision-

⁴³ CEO-16, DTE Response to CEODG-2.6c.

⁴⁴ CEO-17, DTE Response to CEODG-2.6d.

⁴⁵ CEO-18, DTE Response to CEODG-2.7b, BWEC Hydrogen Blending Pilot.

⁴⁶ CEO-19, DTE Response to CEODG-2.7c.

⁴⁷ CEO-20, DTE Response to CEODG-2.8a.

⁴⁸ CEO-21, DTE Response to CEODG-2.8b.

⁴⁹ CEO-22, DTE Response to CEODG-2.8c.

⁵⁰ CEO-23, DTE Response to CEODG-2.9a.

1 making or for policymakers to understand how the Company can cost-effectively reduce
2 its emissions and the future costs and risks it is imposing on customers from its
3 investments today. The Company’s Gas Delivery Plan is an ideal place for the Company
4 to consider potential pathways and future energy scenarios.

5 ***C. How DTE Can Better Use its Gas Delivery Plan for Emissions Reduction and***
6 ***Capital Investment Planning***

7 **Q: What is the DTE Gas Delivery Plan?**

8 A: The DTE Gas Delivery Plan (“GDP”) is the Company’s 10-year demand and supply plan.⁵¹
9 DTE writes that the purpose of the GDP is to “allow the Company to manage the top
10 industry risks while meeting its objectives of providing safe, reliable, affordable, and
11 environmentally responsible natural gas service.”⁵² In its plan, DTE identifies the top
12 industry risks as gas supply and deliverability, transmission pipeline failures, distribution
13 gas leaks, system overpressure, storage well unintended gas release, cyber/physical
14 security, and excavation damage.⁵³

15 While I agree that each of those risks are important, the Company notably left out
16 risks associated with two of its four objectives: affordability and environmentally
17 responsible natural gas service. The Company does not use its GDP to explore how
18 variables both within and outside its control could impact customer affordability and meet
19 its emissions goals. Gas and electric utilities across the country use demand- and supply
20 plans like the GDP to assess the optimal mix of resources and investments in various

⁵¹ Exhibit A-12, Schedule B5.6, DTE Gas Delivery Plan

⁵² *Id.* at 6.

⁵³ *Id.* at 5.

1 futures using scenario and sensitivity analysis. Through its GDP, DTE should be exploring
2 the potential impact of electrification on its demand through scenario and sensitivity
3 analysis. No person or utility can predict the future. A scenario is a set of assumptions
4 about variables within or outside the control of the utility about the future. A sensitivity is
5 a modification of a single variable of a specific scenario to test the impact of that variable
6 on the outcome of the future. Scenario and sensitivity analysis is important for helping the
7 Company and policymakers understand the costs, emissions, and risks of various uncertain
8 futures. For example, the Company could conduct analysis on the impacts to customer rates
9 of various prices of alternative fuels, impacts of different levels of building electrification,
10 as well as different levels of capital investment spending.⁵⁴

11 **Q: Can you provide an example of a gas utility assessing the impact of electrification**
12 **and decarbonization pathways in a demand- and supply-plan?**

13 A: Yes. Consumers Energy annually releases its own Natural Gas Delivery Plan. In its most
14 recent Delivery plan, Consumers Energy explored the relative costs and benefits of various
15 decarbonization pathways, as well as the potential pipeline composition in 2050 by
16 scenario.⁵⁵ While I am not endorsing the specific inputs nor outcomes of Consumers
17 Energy's Natural Gas Delivery Plan, it is worth noting that Consumers Energy is using its
18 Plan to better understand how it can manage customer costs and risks in an uncertain future.

19 **Q: What is your recommendation as it relates to using the Company's Gas Delivery**
20 **Plan for assessing costs and risks to customers?**

⁵⁴ Ex. CEO-24, B. Cebulko, *A Regulators Blueprint for 21st Century Gas Utility Planning* (December 2023).

⁵⁵ <https://www.consumersenergy.com/-/media/CE/Documents/company/What%20We%20Do/consumers-energy-natural-gas-delivery-plan.pdf>

1 A: I recommend the Commission order the Company to use its Gas Delivery Plan to model
2 specific emissions reductions pathways for meeting the state's decarbonization goals, and
3 report the potential costs, benefits, and risks of the various resources and investments used
4 in each pathway. The Company must consider electrification as an available
5 decarbonization resource. As part of its analysis, the Company should identify the customer
6 rate impact of each pathway. I recommend the Commission order the Company to develop
7 an interim plan by July 2025 that examines the decarbonization pathways or with its next
8 general rate case, whichever comes first.

9 **Q: Where else, besides the Gas Delivery Plan, should DTE account for the risks of**
10 **electrification?**

11 A: The Company should also account for the risks of the energy transition when making any
12 capital investment decision, both investments that appear in the Gas Delivery Plan and
13 those that emerge outside of the Gas Delivery Plan. As any business facing an uncertain
14 future, the gas utility should account for risks outside its control when making business
15 decisions. The Company should be examining alternatives when making capital
16 investments, particularly for pipeline replacements and capacity expansions. The two most
17 common types of alternatives are pipeline repairs and non-pipeline alternatives.

18 **Q: What are pipeline repairs?**

19 A: Cutting out and replacing a segment of pipe is expensive. Pipeline repair is the process by
20 the gas utility repairs rather than replaces a segment of pipe. There are a variety of methods
21 for repairing a natural gas pipeline. For example, one repair method is to wrap the leaking

1 segment of pipe with a “sleeve.”⁵⁶ Repairing, rather than replacing the segment of pipe,
2 can be quite cost-effective. A 2023 study conducted by Gas Safety USA, submitted to the
3 Public Service Commission of the District of Columbia on behalf of the District of
4 Columbia Government, found that pipeline repair can cost between one tenth and one
5 hundredth of the cost of pipeline replacement.⁵⁷ Repairs can safely extend the serviceable
6 lives of the existing pipe without making an additional investment in new pipe that can
7 have a depreciable life of 40 to 65 years.

8 **Q: What are nonpipeline alternatives?**

9 A: NPAs in the gas sector are the equivalent of the electric sector’s “non-wires alternatives”
10 and refer to activities or investments that delay, reduce, or avoid the need to build or
11 upgrade traditional gas system infrastructure such as pipelines, storage, and peaking
12 resources.⁵⁸ An NPA can consist of a single demand- or supply-side resource, but more
13 often it is a portfolio of resources. The specific costs and benefits of NPA opportunities
14 depend on the nature of the utility’s pipeline system, capacity needs, types of customers,
15 and policy goals. Typical NPA resources include demand response, energy efficiency,
16 electrification of heat, behavioral programs, and on-system gas supply, such as compressed
17 or liquified natural gas. NPAs can help achieve several policy goals including cost
18 reductions, risk reductions, and emissions reduction.

⁵⁶ <https://pgjonline.com/news/2020/12-december/appropriate-methods-for-repairing-pipelines>

⁵⁷ Ackley, B. et al, “Strategic Electrification in Washington, D.C.: neighborhood Case Studies of Transition from Gas to Electric-Based Building Heating. For the Washington, D.C., Department of Energy and Environment.” December 14, 2022. Available at: <https://edocket.dcpssc.org/apis/api/Filing/download?attachId=186471&guidFileName=a9254ec8-d08f-46ed-af0e-31b28d707139.pdf>

⁵⁸ Ex. CEO-25; Nelson, R. et al, “Part 1 | Non-Pipeline Alternatives to Natural Gas Utility Infrastructure, An Examination of Existing Regulatory Approaches” A Strategen Report prepared for the Lawrence Berkeley National Laboratory.

1 **Q: Are other states requiring gas utilities to examine nonpipeline alternatives to**
2 **traditional capacity investments?**

3 A: Yes. Most recently, the Massachusetts Department of Public Utilities completed its Future
4 of Gas investigation and identified NPA analysis as a requirement for all capital
5 investments going forward. The DPU found that “[g]oing forward, [local distribution
6 companies] will have the burden to demonstrate the consideration of NPAs as a condition
7 of recovering additional investment in pipeline and distribution mains.”⁵⁹ Several other
8 states have required NPA analysis for certain capital projects. For example, in Colorado,
9 gas utilities are required to conduct NPA analysis for all capacity expansion and new
10 business projects over \$3 million.⁶⁰ Rhode Island set a cost threshold at \$0.5 million.⁶¹ New
11 York did not set a specific threshold, rather it created separate small and large project
12 thresholds for each gas distribution company (typically greater or less than \$2 million).⁶²
13 In Oregon, Avista agreed through a rate case settlement to conduct NPA analysis on all
14 capital investment projects over \$1 million.⁶³

15 **Q: What is your recommendation as it relates to alternatives analysis, namely pipeline**
16 **repair and nonpipeline alternatives?**

17 A: I recommend that the Commission require DTE to work with stakeholders and Commission
18 Staff to develop an NPA framework for analyzing capital investment projects going

⁵⁹ DPU 20-80.

⁶⁰ Ex. CEO-25.

⁶¹ *Id.*

⁶² *Id.*

⁶³ Oregon Public Utilities Commission Docket No. UG 461, Order No. 23-384. October 26, 2023. Available at: <https://apps.puc.state.or.us/orders/2023ords/23-384.pdf>

1 forward. I recommend that this framework identify the types of projects that are eligible
2 and threshold criteria using best practices from across the industry.⁶⁴ The Commission
3 should require the Company to demonstrate that it conducted this analysis for all capital
4 projects that meet the identified NPA criteria when it seeks cost recovery of that capital
5 investment. The Company should complete this framework by July 2025 or prior to filing
6 its next general rate case, whichever comes first.

7 I also recommend the Commission require DTE to work with stakeholders and
8 Commission Staff to develop a framework for considering when pipeline repair is a suitable
9 alternative to pipeline replacement projects. The Commission should require the Company
10 to demonstrate that it conducted this analysis for all capital projects that met the identified
11 pipeline repair criteria when it seeks cost recovery of capital investments that meet the
12 criteria. The Company should complete this framework by July 2025 or prior to filing its
13 next general rate case, whichever comes first.

14 **III. DTE Should Not Abandon Demand Response Programs**

15 ***A. DTE's Initial Pilots Did Not Have Clear Objectives.***

16 **Q: Will you please explain the Commission's 2019 Order directing the Company to**
17 **develop demand response programs?**

18 **A:** In 2019, following an extreme cold weather event that contributed to an energy emergency,
19 Governor Whitmer directed the Michigan Public Service Commission to conduct a
20 Statewide Energy Assessment (SEA) with a goal to ensure safe, reliable energy for

⁶⁴ Ex. CEO-25.

1 Michigan and to be prepared to mitigate impacts during potential future events.⁶⁵ The
2 purpose of the assessment was to 1) evaluate whether the design of electric, natural gas,
3 and propane delivery systems are adequate to account for changing conditions and extreme
4 weather events, and 2) provide recommendations to mitigate risk.⁶⁶ In its Statewide Energy
5 Assessment Report, the Commission identified the importance of demand response during
6 energy emergencies and instructed gas utilities to develop demand response programs. The
7 Commission wrote:

8 Given the pivotal role that DR can play during energy emergencies, the
9 development or expansion of natural gas DR programs should be analyzed. The
10 Commission recommends the utilities work with Staff and stakeholders to review
11 the potential for natural gas DR programs and develop recommendations to
12 encourage the development or expansion of natural gas DR programs.⁶⁷

13 **Q: Is the Company proposing any demand response programs in this case?**

14 A: No. DTE is not proposing to maintain any demand response programs going forward. In
15 2022, the Company developed three demand response pilots, which ended in 2023. The
16 Company determined that the programs were not successful and do not wish to continue
17 with the programs.

18 **Q: Please summarize the Company's recently completed demand response pilots.**

19 A: The Company conducted three demand response pilots over a two-year period. The
20 Company had two residential gas pilots, and one commercial pilot.⁶⁸ The residential

⁶⁵ Michigan Public Service Commission, "Michigan Statewide Energy Assessment, Final Report," September 11, 2019.

⁶⁶ *Id.* at i.

⁶⁷ *Id.* at 120.

⁶⁸ HJD-79, lines 7 – 8.

1 demand response pilots were referred to as the Smart Savers and Energy Action Days
2 pilots.

3 **Q: Please describe the residential demand response pilots.**

4 A: The Smart Savers pilot was available to gas-only and dual-fuel customers who already had
5 a Wi-Fi enabled smart thermostat. Customers who enrolled in the pilot received a \$50 up-
6 front gift card upon enrollment and then another \$50 season ending gift card if the customer
7 remain enrolled.⁶⁹ The customer did not receive a financial incentive or penalty for their
8 actual participation in an event.⁷⁰

9 The second program was the Energy Action Days program. The Company
10 automatically enrolled customers in two regions, one dual-fuel and one gas-only, for
11 participation in the program. Customers had to opt out of a program they did not voluntarily
12 choose to enter into. The pilot participants received resources that encouraged energy
13 efficient behavior and peak demand savings the day before an event. Participants did not
14 receive a monetary incentive or penalty for participation/non-participation.

15 **Q: Please describe the commercial demand response pilot.**

16 A: For this program, the Company installed telemetry equipment on participating customers
17 premises at no cost to the participant. Participants were asked to reduce their load during
18 events, which were to last no longer than eight hours. The Company testifies that “due to
19 delays on procuring and installing equipment” it only signed up 2 participating customers,

⁶⁹ HJD-79, lines 9 – 11.

⁷⁰ CEO-26, DTE Response to CEODG-1.3a.

1 both high schools.⁷¹ The Company’s testimony is not clear as to why procuring and
2 installing the telemetry data was delayed. Participating customers did not have a source of
3 backup heat⁷² and were not provided a monetary incentive for participation.

4 **Q: What were the programmatic objectives of the Company’s demand response pilots?**

5 A: The Company failed to set clear objectives for its demand response pilots, which as I will
6 explain later, is a significant driver as to why the Company concluded the programs were
7 not successful. In the Company’s testimony, the stated purpose of the pilots was to
8 “determine the effectiveness of gas demand response as a requirement of the Commission
9 in its State Energy Assessment report” and “assist in understanding the opportunity that
10 may exist within the gas demand response space and to determine whether future programs,
11 if any, should be offered.” The Company does not identify or explain what “effectiveness
12 of gas demand response as a requirement of the Commission” means. Nor did the Company
13 explain what understanding it was seeking from the pilots. Through discovery, the
14 Company provided an October 16, 2020, Gas Demand Response Pilots presentation, which
15 identified a goal to “identify opportunities to reduce need for future investment.”⁷³ Thus,
16 it is not surprising that the Company determined that the programs were not successful,
17 writing, “At the conclusion of the second year of the demand response pilot, DTE Gas
18 reviewed the results and determined the Demand Response program was not effective and
19 determined not to request to extend the pilot or make the program permanent.”⁷⁴

⁷¹ HJD-83, lines 6 – 8.

⁷² Ex. CEO-27, DTE Response to CEODG-1.8c.

⁷³ Gas Demand Response Pilots, An overview of potential gas demand response pilots for residential and C&I Customers. October 16, 2020. Slide 2.

⁷⁴ RMT-28, lines 20-23.

B. DTE Did Not Identify Evaluation Criteria

Q: Did the Company conduct cost-benefit analyses for each of the pilots?

A: No, the Company did not conduct a cost-benefit analysis on any of the pilots either before starting the pilots nor after the conclusion of the pilots.⁷⁵

Q: Did the Company identify the specific quantitative and qualitative benefits it would consider in its evaluation of the demand response pilots?

A: The Company did not identify any quantitative and qualitative benefits it would include in its evaluation of the success of the pilots. Through discovery, I asked the Company to identify the specific quantifiable and qualitative benefits that the Company evaluated. The Company response did not include a list of benefits; rather it responded with a list of “goals” for the program, such as to “[u]nderstand the capability of customers to reduce gas consumption following the notification of an event.”⁷⁶ Pilot goals are not the same as benefits of a pilot.

Q: What are common benefits that are considered in a demand response cost-benefits analysis?

A: Common quantifiable benefits included in a cost-benefit analysis are:

- Avoided transmission pipeline capacity,
- Avoided distribution capacity,
- Avoided gas purchases, and

⁷⁵ Ex. CEO-28, DTE Response to CEODG-3.7a; Ex. CEO-29, DTE Response to CEODG-3.7b; Ex. CEO-30, DTE Response to CEODG-3.7c; Ex. CEO-31, DTE Response to CEODG-3.7d; Ex. CEO-32, DTE Response to CEODG-3.7e; Ex. CEO-33, DTE Response to CEODG-3.7f

⁷⁶ Ex. CEO-34, DTE Response to CEODG-3.8a.

- Avoided emissions.

Q: Did the Company track the cost per pilot?

A: No, the Company did not track the costs of the individual pilot programs; rather it tracked the costs of the three programs in the aggregate. That is, the Company does not know the costs of any individual pilot.⁷⁷ Understanding the individual pilot program costs is necessary for determining if a pilot was successful.

Q: Is it concerning to you that the Company did not conduct a cost-benefit analysis?

A: Yes, it is concerning. In my more than 10 years working on utility pilots and programs, I have never seen a utility dismiss a program, much less a pilot, without conducting a cost-benefit analysis. As economic regulators, one of the most fundamental analyses relied upon by public utilities commissions is a quantitative assessment of a program's costs and benefits. A Commission may not rely entirely on quantitative analysis – I believe there is a role for qualitative analysis as well – but quantitative analysis is always the foundation of an evaluation. I do not understand how a Company could dismiss the efficacy of a program without undergoing this most basic of evaluations.

Q: How did the Company evaluate the success of the pilots?

A: The Company's testimony is not clear. The Company neither provided a detailed discussion in its testimony nor did it include an evaluation of the pilots with its testimony. In my experience, it is routine for utilities to conduct evaluations – typically third-party evaluations, of pilot programs. The objectives of the pilots were never clear, so it is not

⁷⁷ Ex. CEO-35, DTE Response to CEODG-3.8b.

1 surprising the Company did not have clear criteria for evaluating the performance of the
2 pilots.

3 Through discovery the Company provided two presentations titled “Gas Demand
4 Response Results – Year 1” and “Gas Demand Response Winter 2022-23 Results.”⁷⁸ While
5 the two presentations provided some observations of the programs, and the second
6 presentation included a slide titled “Key Learnings and Next Steps” it would not be
7 appropriate to call either of these presentations an evaluation. Typically, an evaluation
8 would include an assessment of the costs and benefits of the programs, identify areas of
9 success or problems with the pilots, identify the sufficiency of the data, and suggest options
10 for improvement. The presentations, on the other hand, use vague generalized statements
11 that lacked insight or critical analysis. For example, one presentation included a slide titled
12 “Key Learnings and Next Steps” which stated the following:

- 13 • *“There is only so much large customers are willing to do to reduce gas consumption*
14 *due to the comfort of customers and employees and the sensitivity around equipment*
15 *and process specifications” and*
- 16 • *“Recruitment and installation of large customers is difficult.”*⁷⁹

17 I would expect a proper evaluation to examine why recruitment and enrollment of large
18 customers was difficult. In testimony, the Company writes that one (of the two total) large
19 customers admitted to never reading the telemetry data.⁸⁰ I would expect an evaluator to
20 have reached out to the only two customers who took part in the pilot and ask why the

⁷⁸ Ex. CEO-36, DTE Response to MNSCDG-2.6d, “Gas Demand Response Winter 2022-23 Results” June 16, 2023.

⁷⁹ *Id.* at slide 22.

⁸⁰ HJD-83.

1 program was not successful, why they did not read their telemetry reports, and gauge
2 whether the program could be modified to be successful.

3 Finally, I think it is worth noting that the Company is dismissing a very large group
4 of customers, nonresidential customers, based on the experience of two high schools when
5 the Company had issues procuring necessary telemetry data. The Company's dismissal
6 based on such a small subset of customers is premature and I would have expected an
7 evaluator to have noticed that issue as well. Moreover, the Company had at least three other
8 commercial customers who wanted to participate in the program but were unable to
9 participate because DTE did not procure and install the telemetry equipment. When I asked
10 why the Company was "delayed" in procuring and installing the equipment, the Company
11 responded that the employees responsible for researching and designing a solution had
12 "competing priorities maintaining existing operational needs."⁸¹ My interpretation of the
13 Company's response is that it did not allocate sufficient resources and expertise to the
14 commitments it made to conduct demand response pilots.

15 **Q: You mentioned that the Company did not offer a monetary or financial incentive to**
16 **respond to a specific event for any of the three pilots. Did the Company perform an**
17 **analysis that examined the impact of offering customers a monetary incentive?**

18 **A:** No. The Company responded to a discovery request that it did not perform an analysis on
19 whether offering a monetary incentive is necessary to induce customers to participate.⁸²

20 Through discovery, the Company stated that it did not conduct any analysis on whether a

⁸¹ Ex. CEO-37, DTE Response to CEODG-3.12.

⁸² Ex. CEO-26, DTE Response to CEODG-1.3a; Ex. CEO-38, DTE Response to CEODG-1.4a; Ex. CEO-39, DTE Response to CEODG-1.5a

1 monetary incentive is necessary to induce customer participation.⁸³ The Company also
2 responded that behavioral programs do not include a financial incentive,⁸⁴ however, that
3 doesn't explain why the Company did not test if the other programs – particularly the
4 nonresidential program – would perform better with a financial incentive. I do not know if
5 offering a financial incentive would have changed the results of any of the pilots. But
6 testing various programmatic designs is the very purpose of a pilot program. The Company
7 had a terrific opportunity to explore a variety of approaches with the Commission's
8 approval through the relative safety of pilots, and the Company chose not to explore using
9 a financial incentive for active participation, one of the most common tools in demand
10 response programs. Indeed, in the Company's own Year 1 results, the Company noted that
11 one challenge is "lack of incentive for customer."⁸⁵ The Company recognizes the issue but
12 is ignoring it.

13 **Q: Let's turn to the commercial pilot. Was there a problem with the design and**
14 **implementation of the commercial program?**

15 A: Yes, there were several issues. First, the Company aimed to have 10 to 20 small and large
16 commercial customers participate in the nonresidential pilot.⁸⁶ In the end, the Company
17 only enlisted two customers, both high schools.⁸⁷ However, as mentioned previously, the
18 Company did not assign sufficient resources to the demand response pilots and therefore

⁸³ Ex. CEO-26, DTE Response to CEODG-1.3a.

⁸⁴ Ex. CEO-40, DTE Response to CEODG-1.3c.

⁸⁵ Ex. CEO-41, DTE Response to MNSDG-2.6d "Gas Demand Response Results – Year 1" May 11, 2022.

⁸⁶ ~~Id. DTE Response to MNSDG 2.6d "Gas Demand Response Results – Year 1" May 11, 2022, at~~ Slide 19.

⁸⁷ HJD-83, lines 7 – 9.

1 did not install telemetry data for three other customers who wished to participate in the
2 program.⁸⁸

3 Second, the Company only called two events during the winter of 2023 for two
4 customers both of whom are high schools.⁸⁹ I would not agree that two events for two
5 similarly situated customers is a robust data set for which it is reasonable to draw
6 conclusions about a customer class as large and diverse and the commercial customer class.

7 Finally, neither participating received a financial incentive for active participation,
8 nor did they have backup heat to rely on during the event.⁹⁰ It is not surprising to me that
9 the two high schools chose not to cut off heat to their schools during a peaking event much
10 less because it did not receive any financial remuneration for the action.

11 **Q: Now let's turn back to the residential Smart Saver pilot. Is it clear that the results of**
12 **the residential Smart Savers pilot were a failure, as the Company testifies?**

13 A: No. In fact, the limited data the Company evaluated in their presentation shows that the
14 Smart Savers pilot successfully reduced customer usage during the events.⁹¹ The Company
15 called only 5 events during the two-year pilot.⁹² The pilot grew from year one to year two.
16 The Company's slides show that customers decreased their use by 42%, 29%, 50%, 36%,
17 and 36% during the events.⁹³ That appears to be quite a successful response. At the end of
18 the event, the Company experienced "snapback." Snapback is a well-known phenomenon
19 whereby after the event, customer demand quickly rises. In one case for DTE, the snapback

⁸⁸ Ex. CEO-378, DTE Response to CEODG-3.12.

⁸⁹ HJD-83, lines 7 – 9.

⁹⁰ Ex. CEO-27, DTE Response to CEODG-1.8c.

⁹¹ Ex. CEO-412, DTE Response to MNSDG-2.6d, "Gas Demand Response Results – Year 1" May 11, 2022.

⁹² Ex. CEO-367, DTE Response to MNSDG-2.6d, "Gas Demand Response Winter 2022-23 Results" June 16, 2023.

⁹³ ~~Id., Ex. CEO-412, DTE Response to MNSDG-2.6d "Gas Demand Response Results – Year 1" May 11, 2022, DTE Response to MNSDG-2.6d "Gas Demand Response Winter 2022-23 Results" June 16, 2023.~~

1 was sufficiently large that cumulative energy use actually increased. However, the
2 Company does not evaluate the magnitude of this problem or if the snapback can be
3 managed. If the snapback does not occur concurrent with the system peak, it may not
4 actually be a problem for the utility and the benefits may still exceed the costs to the
5 Company. The Company did not evaluate this issue because it did not evaluate the costs
6 and benefits of the program. Nor did the Company demonstrate that it evaluated industry-
7 known opportunities for mitigating snapback. For example, the Company could stagger
8 customer reintegration or control the pace of a customer's increase in demand. DTE is not
9 the first utility to experience snapback and its lack of evaluation is concerning. Given that
10 the purpose of a pilot is to provide a relatively safe place for a utility to experiment, it
11 would have been reasonable for DTE to explore options for managing snapback through
12 its pilots.

13 *C. The Commission Should Require DTE to Develop New Demand Response*
14 *Programs*

15 **Q: The Company is choosing not to move forward with any demand response**
16 **programs. Has the Commission's fundamental concern, that gas demand response is**
17 **necessary during extreme events, been alleviated?**

18 A: To the best of my knowledge, there continues to be a risk posed by extreme weather events
19 and emergency situations. In its testimony the Company stated that it entered into a
20 Memorandum of Understanding with Consumers Energy in April 2021 to provide each
21 other mutual assistance in case of an emergency.⁹⁴ The Commission instructed the gas

⁹⁴ KMF-76, lines 14 – 16.

1 utilities to develop demand response programs in lieu of broad emergency appeals (a
2 behavioral program). The Company is proposing to walk away from the idea of creating
3 demand response programs and is not proposing any program in its place.

4 **Q: Are there other demand response type programs for large customers common place**
5 **in the industry?**

6 A: Yes. Many gas utilities across the country offer certain large, non-transport customers an
7 interruptible tariff. An interruptible tariff is a schedule open to specific sizes of customers
8 who, in exchange for a lower rate, agree to be curtailed during certain types of events. The
9 most common type of event is a near-peak event when the system is maximized but some
10 schedules also allow gas utilities to curtail these customers during gas price spike events.
11 The benefit of an interruptible tariff to the utility and the rest of its customers is that the
12 utility does not need to plan to meet interruptible customers' demand during peak periods
13 thus lowering the design day costs for customers.

14 **Q: The Commission primarily focused on the role demand response can play during an**
15 **energy emergency. Are there other potential benefits of demand response**
16 **programs?**

17 A: Yes, there are several potential benefits of a demand response program. The SEA Report
18 rightfully identified the benefits of gas demand response availability during energy
19 emergencies and as an alternative to broad emergency appeals. The report also briefly
20 mentioned several other demand response benefits, including avoided energy costs,
21 reduced market price volatility, improved electric and gas system reliability, deferred or

1 avoided capital investments, and air emissions reductions.⁹⁵ That is a comprehensive list
2 of potential demand response benefits. However, the benefits experienced by the utility
3 and its customers from a demand response program are determined by the structure of the
4 program. For example, a customer-wide demand response program may seek to maximize
5 price risk mitigation and avoided transmission capacity, while a targeted demand response
6 program focused on a specific neighborhood may seek to avoid the need for a specific
7 distribution system investment.

8 **Q: Earlier you mentioned the need to conduct alternatives analysis, including**
9 **nonpipeline alternatives. Can demand response be a component NPA portfolio of**
10 **resources?**

11 A: Yes, demand response can be part of a portfolio of resources used to avoid a traditional
12 pipeline investment. I would expect that demand response would feature most prominently
13 in NPAs that are avoiding an expansion to gas utility delivery system to meet forecasted
14 peak demand.

15 **Q: What are your demand response recommendations?**

16 A: First, I recommend the Commission reject the Company's request to recover the \$2.6
17 million in deferred demand response costs.⁹⁶ The Company did not put forth a reasonable
18 effort towards developing and evaluating demand response programs. The program lacked
19 clear objectives, was limited in scope, and did not undergo a basic evaluation of success.

⁹⁵ Michigan Public Service Commission, "Michigan Statewide Energy Assessment, Final Report," September 11, 2019, page 22.

⁹⁶ HJD-83, lines 18-20.

1 Second, I recommend the Commission order DTE to go back and work with
2 Commission Staff and stakeholders to develop a more robust set of demand response
3 programs that test multiple programs. The Company and parties should establish clear
4 objectives for each pilot, identify which costs and benefits will be evaluated, and undergo
5 a thorough third-party evaluation. The Company and parties should consider the
6 development of interruptible programs as part of this undertaking. Demand response is a
7 potentially important resource for mitigating peak demand and a properly designed demand
8 response program is essential to the program's success. Based on my review of DTE's
9 demand response pilot, I do not believe the Company allocated the necessary resources to
10 designing and implementing this program. I recommend the Commission require DTE to
11 commit the necessary resources to develop a robust demand response program. The
12 Company should complete this work by July 2025 or prior to filing its next general rate
13 case, whichever comes first.

14 **IV. Using Granular Data and Mapping to Ensure Equitable Gas Service**

15 **Q: What is the MI Healthy Climate Plan?**

16 **A:** In September 2020, Governor Whitmer signed Executive Directive 2020-10 ("ED 2020-
17 10") establishing an economy-wide goal of carbon neutrality by 2050 and to maintain net
18 negative greenhouse gas emissions thereafter.⁹⁷ ED 2020-10 charged the Department of
19 Environment, Great Lakes, and Energy ("EGLE") to develop and issue a MI Healthy
20 Climate Plan ("Plan") to serve as the action plan for the state to reduce greenhouse gas

⁹⁷ Office of Governor Gretchen Whitmer, Executive Directive 2020 – 10, September 23, 2020. Available at:
<https://www.michigan.gov/whitmer/news/state-orders-and-directives/2020/09/23/executive-directive-2020-10>

1 emissions and transition toward economy-wide carbon neutrality. EGLE issued the MI
2 Healthy Climate Plan in April 2022.⁹⁸ The Plan recognized that environmental justice
3 communities, most often communities of color and/or low-income have experienced
4 disproportionate negative impacts of society’s energy decisions.⁹⁹

5 **Q: Is there any other relevant legislation that requires the minimization of harm and**
6 **prioritization of benefits in certain communities?**

7 A: Yes. In 2023, the Michigan legislature passed SB 502, which authorizes the Commission to
8 consider both climate and equity in its decision-making.¹⁰⁰ Specifically, the bill states the
9 Commission shall prioritize certain goals including:

- 10 • “Equitable access to energy efficiency, weatherization, home electrification programs
11 and services, and clean energy technologies,” and
- 12 • “Minimization of harm and prioritization of benefits in communities consisting
13 predominately of minorities or households below the poverty line where factors,
14 including socioeconomic stressors, disproportionate cost and environmental burdens,
15 vulnerability to environmental degradation, and lack of accessibility in public
16 participation, may act cumulatively to affect public health and the environment and
17 contribute to persistent disparities.”

⁹⁸ Department of Environment, Great Lakes, and Energy, “MI Healthy Climate Plan.” April 2022. Available at: <https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-healthy-climate-plan>.

⁹⁹ *Id.* at 16.

¹⁰⁰ SB 502 (2023). Available at: <https://www.legislature.mi.gov/documents/2023-2024/billintroduced/Senate/htm/2023-SIB-0502.htm>

1 **Q: What specifically does the MI Healthy Climate Plan say about environmental justice**
2 **communities?**

3 A: The Plan states that “[e]nvironmental justice considerations are a key component of
4 equitable climate action and will continue to be a priority for the state as it works to
5 eliminate racial disparities impacting the health and wellbeing of Michiganders.”¹⁰¹ The
6 Plan continues that “many disadvantaged communities live and work in subpar buildings,
7 face higher energy burden, and are subject to health-related impacts from natural gas
8 appliances, all while lacking access to the investments in energy efficiency and onsite
9 renewable energy seen in other communities.”¹⁰²

10 The Plan continues that to ensure that the state’s response to climate change does
11 not reinforce challenges that historically disadvantaged communities, the state must
12 proactively and intentionally plan for equity and environmental justice.

13 **Q: Are there tools to help the DTE identify historically disadvantaged communities?**

14 A: Yes. EGLE’s Office of the Environmental Justice Public Advocate, in cooperation with the
15 Interagency Environmental Justice Response Team Data and Research Workgroup,
16 developed an interactive mapping tool called MiEJScreen.¹⁰³ According to the Department,
17 MiEJScreen is “an interactive mapping tool that identifies Michigan communities that may
18 be disproportionately impacted by environmental hazards.”¹⁰⁴ Users can identify the

¹⁰¹ Department of Environment, Great Lakes, and Energy, “MI Healthy Climate Plan.” April 2022. Page 16.
Available at: <https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-healthy-climate-plan>.

¹⁰² *Id.* at 17.

¹⁰³ <https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Maps-Data/MiEJScreen/MiEJScreen-Factsheet.pdf?rev=626af950b12349e499657e243b93af31>

¹⁰⁴ *Id.*

1 environmental, health, and socioeconomic conditions within a specific community or
2 region.

3 **Q: How can an interactive mapping tool be useful to DTE Gas?**

4 A: A mapping tool can provide granular, geographic-specific information regarding aspects
5 of the system and customer experience. For example, a mapping tool can be used to identify
6 geographic areas where there are: high concentrations of poverty, high concentrations of
7 people of color, higher levels of pollution, and parts of the system which may be older than
8 other areas. DTE has an obligation to serve all its customers and part of that obligation
9 requires it to serve all customers equitably. By identifying geographic areas that may be
10 under-served in terms of investment and/or programs, the Company can better target capital
11 investments or programming directly to these areas, thereby meeting its obligation to
12 provide service equitably.

13 **Q: Why is it important to identify areas with high concentrations of poverty and/or high**
14 **concentrations of people of color?**

15 A: To effectively reach communities with high concentrations of poverty and/or people of
16 color, DTE may have to engage with its customers in these areas in a different way than it
17 engages with its other customers. By identifying geographic areas with high concentrations
18 of poverty and/or people of color, DTE can better understand how to be more culturally
19 responsive to the challenges faced by these customers.

20 **Q: What indicators does the MiEJScreen tool measure?**

1 A: The tool measures 26 statewide indicators across four categories: Environmental exposure,
 2 environmental effects, sensitive populations, and socioeconomic factors.¹⁰⁵ In addition to
 3 individual indicator scores, the tool identifies a final composite score across the four
 4 categories to identify relative environmental risk factors in communities. A low composite
 5 score indicates that community, as a whole, has fewer environmental risk factors in the
 6 community as compared to other communities. A high composite score indicates that
 7 community experiences relatively more environmental risk. For example, the more
 8 affluent Grosse Pointe Farms census tract has a composite score of 12,¹⁰⁶ while a nearby
 9 census tract just south of Coleman A. Young International Airport has a composite score
 10 of 100.¹⁰⁷ The two census tracts are separated by about 6 miles.

11 **Q: Does DTE Gas use MiEJScreen or a similar mapping tool to inform its**
 12 **programmatic and capital planning decision making?**

13 A: No, the Company does not.¹⁰⁸ However, I recommend that the Commission order the
 14 Company to immediately start using the tool to plan, develop, and implement its programs
 15 and capital investment decisions.

16 **Q: Please explain how the Company should use MiEJScreen to inform its**
 17 **programmatic and capital planning decision making.**

18 A: The MiHealthy Climate Plan states that to ensure that Michigan's response to climate
 19 change does not reinforce challenges faced by historically disadvantaged communities, the

¹⁰⁵ <https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Maps-Data/MiEJScreen/MiEJScreen-Factsheet.pdf?rev=626af950b12349e499657e243b93af31>

¹⁰⁶ Census tract 26163550600

¹⁰⁷ Census tract 26163505500.

¹⁰⁸ Ex. CEO-423, DTE Response to CEODG-4.1bi; and Ex. CEO-434, DTE Response to CEODG-4.1di.

1 state must proactively and intentionally plan for equity and environmental justice. The
2 Michigan Public Service Commission, as a state agency, and DTE Gas, as a state-regulated
3 monopoly, must take responsibility for proactively and intentionally ensuring that
4 environmental justice communities are not disproportionately impacted for energy
5 decisions.

6 I recommend that the Commission order DTE Gas to use MiEJScreen to inform its
7 capital investment decisions going forward. When the Company is considering locations
8 for significant capital investments, for example the need for a route of a new distribution
9 main or transmission pipe, the Company would use the MiEJScreen to assess the potential
10 impact to environmental justice communities, as well as the impact of alternatives
11 proposals to meet the Company's need. The Company would then be responsible for
12 demonstrating that the preferred solution, either the original capital investment proposal or
13 an alternative, does not disproportionately negatively impact environmental justice
14 communities.

15 I also recommend that the Commission order DTE gas to use MiEJScreen to inform
16 the design and implementation of its customer programs and policies going forward.
17 Customer programs and policies include the Company's energy efficiency and demand
18 response programs, low-income energy efficiency and heating assistance programs,
19 arrearage management programs, and residential disconnection policy.

20 **Q: How can an interactive mapping tool help DTE inform the design and implementation**
21 **of its customer program, policies, and investments?**

22 A: The mapping tool can help to provide information on a program's effectiveness by
23 geography. For example, there may be certain geographic areas where energy efficiency

uptake is very low. By identifying those geographic areas, DTE can better understand where to target its spending on improving energy efficiency uptake.

Q: Is there precedent for the Commission ordering DTE to use the MiEJScreen tool to inform its decision making?

A: Yes. The Commission approved a rate increase for DTE Electric in December 2023. As part of its approval of DTE Electric's plan to harden Detroit's electric grid, the Commission directed the Company to provide a longer-term plan with benchmarks for performance and with an analysis of equity impacts, using MiEJScreen.¹⁰⁹

Q: Are there specific indicators and metrics the Company should be using in its program and capital investments decision making?

A: Yes. The MiEJScreen tool includes several socioeconomic indicators including low-income populations, Black, Indigenous, People of Color Populations, and Housing Burden.¹¹⁰ There are several indicators that are relevant to gas utilities that are not being measured in the state's tool. I recommend that the Company measure several other indicators at the most granular level, census block. I recommend the Company begin tracking:

- The average energy burden of residential customers measured at the census block. This indicator is calculated by dividing the average annual residential bill by the average

¹⁰⁹ Michigan Public Service Commission Press Release "MPSC approves \$368M rate increase for DTE Electric Co. to fund utility's reliability upgrades." December 1, 2023. Available at: <https://www.michigan.gov/mpsc/commission/news-releases/2023/12/01/mpsc-approves-368m-rate-increase-for-dte>.

¹¹⁰ The MiEJScreen socioeconomic indicators are Low Income Population, Black, Indigenous, People of Color Population, Education Attainment, Linguistic Isolation, Population Under Age 5, Population Over Age 64, Unemployment, and Housing Burden.

1 area median income by census block. Previous work by the CEO have demonstrated
2 that nearly 30 percent of DTE's residential customers are energy burdened and that
3 energy cost burdens are distributed unevenly across DTE's territory.¹¹¹ Calculating
4 energy burden at the census block group level will provide better insight as to where
5 high energy burdened customers are located, and allow the Company to better target
6 those areas for energy assistance.

- 7 • The percentage of residential customers disconnected per census block. This indicator
8 is calculated as the number of disconnected premises in a census block divided by the
9 total number of gas premises in the same census block.
- 10 • The percentage of low-income residential customers that participated in one or more
11 energy assistance programs in a year, measured at the census block level. This indicator
12 is calculated as the number of low-income households who participated in one or more
13 energy assistance programs in a year divided by the total number of low-income
14 households in the same census block. If the Company does not know the number of
15 low-income households in a census block, the utility should develop a stakeholder-
16 reviewed reasonable estimate.
- 17 • The percentage of low-income residential customers that participated in a payment plan
18 in a year, measured at the census block level. This indicator is calculated as the number
19 of low-income households who participated in a payment plan in a year divided by the
20 total number of low-income households in the same census block. If the Company does

¹¹¹ Docket No. U-21193, Direct Testimony of Boris Lukanov on Behalf of Environmental Law & Policy Center, The Ecology Center, Union of Concerned Scientists and Vote Solar. p. 3. Available at: <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000789BIAAI>

not know the number of low-income households in a census block, the utility should develop a stakeholder-reviewed reasonable estimate.

- The percentage of residential customers enrolled in Shutoff Protection Plan¹¹² in a year, measured at the census block level. This indicator is calculated as the number of households in a census block enrolled in the Shutoff Protection Plan divided by the total number of households in that same census block.
- The percentage of low-income residential customers that participated in the Company's energy efficiency program in a year, measured at the census block level. This indicator is calculated as the number of low-income households who participated in an energy efficiency program divided by the total number of low-income households in the same census block. If the Company does not know the number of low-income households in a census block, the utility should develop a stakeholder-reviewed reasonable estimate.

Q: Why do you recommend calculating these indicators?

A: Calculating and then analyzing these indicators at the census block level can help the utility, Commission, stakeholders, and policymakers identify where there may be discrepancies in the system and can help inform planning and investment decisions to better serve low-income communities and communities with high populations of Black, Indigenous and People of Color.

¹¹² DTE Shutoff Protection Plan. Available at: <https://www.dteenergy.com/us/en/business/billing-and-payments/energy-assistance/shutoff-protection-plan.html>

1 **Q: The MiEJScreen tool measures indicators at the census tract level. You recommend**
2 **measuring the additional indicators at the census block level. What is the value of**
3 **the more granular measurement to DTE and the Commission?**

4 A: The census block is the smallest geographic area for which census data is available.
5 Evaluating the Company's service at the census block groups level allows the Company
6 to be more precise when it considers program and investment level decisions. However, I
7 understand the need to balance using the best information with minimizing administrative
8 burden. To start, I recommend the Company use the existing MiEJScreen tool as it
9 develops its own internal processes for using this type of mapping tool for planning,
10 developing, and implementing programs and investments. At a later date, the Company
11 may need to either work with the state to update the MiEJScreen tool to go to the census
12 block level or develop its own mapping tool like Xcel Energy did in Minnesota. In the
13 meantime, the census block level information can still be used as available additional
14 information considered with the MiEJScreen tool that is available for refining Company
15 decision making.

16 **Q: Are you aware of any other states that use a similar mapping tool?**

17 A: Yes, I am aware of at least three other states: Minnesota,¹¹³ Washington state,¹¹⁴ and
18 California.¹¹⁵ Nationally, the U.S. Center for Disease Control maintains a national

¹¹³ Minnesota Department of Health, Minnesota Public Heat Data Access. Available at:
https://data.web.health.state.mn.us/equity_metadata

¹¹⁴ Washington State Department of Health, Washington Environmental Health Disparities Map. Available at:
<https://doh.wa.gov/data-and-statistical-reports/washington-tracking-network-wtn/washington-environmental-health-disparities-map>

¹¹⁵ California Office of Environmental Health Hazard Assessment. Available at:
<https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30>

1 Environmental Justice Index which measures 36 social vulnerability, environmental, and
2 health indicators for measuring cumulative environmental burden in communities. The
3 CDC's tool allows users to explore the indicators by census tract across the state of
4 Michigan.

5 In Minnesota, Xcel Energy, a dual-fuel utility like DTE, created its own interactive
6 map of its electric and gas service territories. Xcel Energy's gas division tracks many of
7 the same indicators I recommend DTE track and combined that data with demographic
8 data from the US Census Bureau.

9 **Q: How does the Minnesota Public Utilities Commission and Xcel use the interactive**
10 **mapping tool?**

11 **A:** The mapping tool is starting to be used by the Minnesota Public Utilities Commission, Xcel
12 Energy, and stakeholders to design and implement programs. First, Xcel Energy's mapping
13 shows that energy assistance uptake in certain geographic areas is relatively low and is
14 using this information to direct energy assistance to those areas. Furthermore, in Xcel
15 Energy's last rate case, interested parties used the mapping tool to posit that electric
16 reliability is lower for communities of color and electric disconnections are higher, even
17 when controlling for income. As a result, Xcel Energy evaluated that hypothesis and
18 published results in March 2024, which confirmed there were some disparities in reliability
19 and disconnections in certain areas with high concentrations of communities of color. The
20 MPUC and stakeholders are now in the process of determining whether and how to address
21 these disparities.

22 Second, after extensive work with the Company's Equity Stakeholder Advisory
23 Group, Xcel Energy recently unveiled a two-year pilot that would provide automatic bill

1 credits for customers in certain low-income areas.¹¹⁶ The Company and the stakeholder`
2 group utilized the mapping tool to identify the census block groups with the highest energy
3 burdens and proposed to provide an automatic bill credit to all households in high-energy
4 burdened census block groups. If approved, the automatic credit will bring the median
5 energy burden in all census block groups in Xcel Energy’s service territory down to 4%;
6 the bill credit will go to approximately 23,000 households in 77 census block groups. The
7 automatic credit occurs without active enrollment from the household, eliminating the need
8 for customers with high energy burdens to apply for energy assistance.

9 **Q: Please summarize your conclusions.**

10 **A:** My testimony discusses three separate issues, but there is a common thread that ties the
11 three together. DTE Gas is not reasonably responding to shifting policy and economic
12 trends.

13 As the Company acknowledges, there is a global energy transition occurring.¹¹⁷
14 Despite recognizing that “decarbonization and the reduction of greenhouse gas emissions
15 is an increasing priority within the energy industry in totality and gaining momentum in
16 the gas industry”¹¹⁸ the Company is not taking any meaningful action to meet the state’s
17 emissions reduction targets. Nor is the Company incorporating the risk of the shifting
18 policy and economics into its load forecasts and capital investment decisions. The
19 Company’s business-as-usual approach is both costly and risky for customers and the
20 Commission should order the Company to change its approach to mitigate future costs and
21 risks for customers.

¹¹⁶ <https://m.startribune.com/xcel-energy-bill-credit-low-income-census-area-minnesota/600360958/>

¹¹⁷ HJD-36, lines 23 – 25.

¹¹⁸ HJD-36, 23 – 24.

1 The Company's recalcitrance to effectively respond to changing conditions is
2 highlighted by the Company's lackadaisical approach to its demand response pilots.
3 Despite the Commission identifying demand response as an important resource during
4 emergency situations, the Company did not put sufficient effort into developing nor
5 evaluating the pilots before proposing to abandon a valuable demand-side resource.

6 Finally, I conclude that the Company needs to incorporate more granular data and
7 mapping tools to ensure equitable outcomes for its customers. In recent years, the state has
8 passed legislation requiring the Commission to ensure equitable access to utility programs,
9 minimize harms, and prioritize benefits to certain communities. The Commission can best
10 achieve its state mandate by requiring the Company to use an interactive mapping tool and
11 additional indicators to inform its program, policy, and capital investment proposals for
12 Commission approval.

13 **Q: Does this conclude your testimony?**

14 **A: Yes.**

**STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION**

In the matter of the application of DTE GAS) COMPANY for authority to increase its) rates, amend its rate schedules and rules) governing the distribution and supply of) natural gas, and for miscellaneous accounting) authority)	Docket No. U-21291

REBUTTAL TESTIMONY OF

Bradley Cebulko

ON BEHALF OF

**THE ECOLOGY CENTER, THE ENVIRONMENTAL
LAW & POLICY CENTER, UNION OF CONCERNED SCIENTISTS,
AND VOTE SOLAR**

May 29, 2024

Table of Contents

I. Introduction and Summary 1

II. The IRM is Costly and Risky for Customers in a Rapidly Changing Energy Landscape 2

III. Using Granular Data and Mapping to Ensure Equitable Gas Service 6

IV. Conclusion 9

1 **I. Introduction and Summary**

2 **Q: Please state your name and business address.**

3 A: My name is Bradley Cebulko. My business address is 24125 47th Ave SW, Vashon,
4 Washington, 98070.

5 **Q. On whose behalf are you submitting this rebuttal testimony?**

6 A. I am submitting testimony on behalf of The Ecology Center, The Environmental Law &
7 Policy Center, Union of Concerned Scientists, and Vote Solar, collectively referred to as
8 the Clean Energy Organizations or CEO.

9 **Q. Are you the same Bradley Cebulko who filed direct testimony on May 7, 2024, in this**
10 **proceeding.**

11 A. Yes.

12 **Q. Please summarize your direct testimony.**

13 A: In my direct testimony, I demonstrated that DTE Gas Company (“DTE” or “the Company”)
14 is not reasonably responding to shifting policy and economic trends and made a series of
15 recommendations to the Commission for better aligning DTE’s policies and programs with
16 the public interest. First, I discussed the Company’s recognition of the global energy
17 transition currently underway¹ and that “decarbonization and the reduction of greenhouse
18 gas emissions is an increasing priority within the energy industry in totality and gaining
19 momentum in the gas industry.”² I noted that despite this recognition, the Company is
20 not taking any meaningful action to meet the state’s emissions reduction targets nor is the

¹ Decker Direct, p. 36, lines 23-25.

² *Id.*

1 Company incorporating the risk of the shifting policy and economics into its load forecasts
2 and capital investment decisions. Second, I discussed DTE’s failure to adequately develop
3 and administer demand response pilots and why the Commission should require DTE to
4 propose new demand response programs. Finally, I discussed the need for the Company to
5 incorporate more granular data and mapping tools to ensure equitable outcomes for its
6 customers.

7 **Q: What is the purpose of your rebuttal testimony?**

8 A: First, I respond to MEC-NRDC-SC Witness Alice Napoleon’s critiques of the Company’s
9 IRM program. I explain how authorization of a “blank check” rider like the IRM conflicts
10 with long-term trends in gas consumption in Michigan related to the State’s emission
11 reduction goals and electrification. Second, I respond to the Frontline Organization (FLO)
12 witnesses who highlight structural issues in DTE’s territory which lead to inequitable
13 outcomes. I suggest that the Commission adopt the recommendations made in my direct
14 testimony to address FLO’s big picture concerns.

15 **II. THE IRM IS COSTLY AND RISKY FOR CUSTOMERS IN A RAPIDLY**
16 **CHANGING ENERGY LANDSCAPE**

17 **Q. In your direct testimony, you argued that DTE should incorporate the risk of shifting**
18 **policy and economics into its capital investments, programs and policies. Did another**
19 **witness identify a specific regulatory investment mechanism that highlights the risks?**

20 A: Yes. MEC-NRDC-SC Witness Alice Napoleon testified that the design and structure of the
21 Infrastructure Recovery Mechanism (IRM) is problematic.³ Amongst other findings,

³ Napoleon Direct, p. 5, lines 11-17.

1 Witness Napoleon finds that the IRM fails to provide adequate incentives for the utility to
2 minimize costs, the IRM process lacks meaningful review and opportunity for contestation,
3 and DTE does not consider or pursue non-pipeline alternatives, which could reduce
4 investments and impacts on rates.⁴

5 **Q. How does Witness Napoleon’s examination of the IRM relate to your testimony on**
6 **the need to account for shifting political and economic realities of the energy**
7 **transition?**

8 A: I did not address the IRM directly in my direct testimony, instead I performed a holistic
9 assessment of the Company’s capital investments, policies, and programs in light of the
10 energy transition. I concluded that the Company cannot continue to plan its delivery system
11 investment strategy as if there isn’t any risk to the utility and its customers and that the
12 Commission must make modifications to the Company’s planning and capital investment
13 strategy.⁵

14 Witness Napoleon identifies a specific regulatory mechanism, the IRM, that
15 exemplifies my concern. The IRM is one of the primary regulatory tools the Company uses
16 for recovering capital investments. The Company’s IRM budget grew from \$93 million in
17 2016 to \$336 million in 2023, and, as Witness Napoleon testifies, the Company could not
18 stay on budget. The Company overspent in every year from 2016 through 2023 by as much
19 as \$50 million in one year.⁶ Going forward, the Company is seeking to spend on average
20 \$333 million annually in the IRM from 2024 through 2029.⁷

⁴ MEC-NRDC-SC-4, lines 4-14.

⁵ Cebulko Direct p. 13, lines 4-10.

⁶ Napoleon Direct, p. 9, lines 1-6.

⁷ Napoleon Direct, p. 11, lines 5-12.

1 Witness Napoleon rightfully identifies the structure of the IRM as problematic and
2 risky for customers. To start, the IRM is recovered using a tariff rider based on forecasted
3 projection of costs, and any overspending by the Company is recovered in the next IRM
4 filing. Thus, the Company does not have an incentive to reduce annual costs as it would
5 cause a decrease in the following budget.

6 Witness Napoleon also spotlighted several other problems with the IRM. For
7 example, the IRM does not have clear, specific parameters for projects to qualify for the
8 IRM, the structure of the IRM incentivizes the Company to continue to increase annual
9 budgets, and there is not a meaningful review process for prudence.⁸ Finally, as I also
10 discussed in my direct testimony, the Company does not evaluate whether there are cheaper
11 alternatives to pipeline replacement such as through a nonpipeline alternatives analysis.⁹
12 Witness Napoleon rightfully identifies that the Company appears to be focused on using
13 the IRM to deliver “premium shareholder returns”¹⁰ at the short- and long-term expense of
14 customers.

15 **Q: What is your main takeaway after reading Witness Napoleon’s analysis of the IRM?**

16 **A:** My takeaway is that the structure of the IRM is exacerbating near-term and long-term costs
17 and risks for customers and the Commission should discontinue the use of the IRM. My
18 direct testimony highlighted the risk of the Company’s capital investment plan and
19 identified the need for incorporating alternatives analysis to minimize costs and risks to
20 customers. Witness Napoleon’s testimony demonstrates that one of the principal pathways
21 for mitigating costs and risks to customers is to reconsider the use of the IRM as a cost

⁸ Napoleon Direct, p. 15-18.

⁹ Napoleon Direct, p. 19, line 5-15. Cebulko Direct, p. 29, line 17 through p. 30, line 13.

¹⁰ Ex. MEC-21, DTE 2023 Year-end Earnings Conference Call (February 8, 2024), p. 4.

1 recovery mechanism. Gas pipeline and other delivery system assets have multi-decade
2 lives. The investments the Company makes today will be paid for by customers for the next
3 40 to 65 years. Yet the Company is making these investments without any consideration
4 of the fundamental energy transition that it acknowledges is occurring.

5 **Q: What are Witness Napoleon's IRM recommendations?**

6 A: Witness Napoleon recommends the Commission initiate an open collaborative proceeding
7 to consider and revise the purpose, requirements, process, and structure of the IRM, and
8 the Commission should not approve an increase in IRM spending in this rate case.

9 **Q: Do you agree with Witness Napoleon's recommendations?**

10 A: Witness Napoleon's recommendations are reasonable. However, I think the Commission
11 has sufficient evidence in this case to discontinue the IRM as a tool for cost recovery.

12 **Q: Why is it in the public interest for the Commission to discontinue the use of the IRM**
13 **in this proceeding?**

14 A: My direct testimony demonstrated that the Company and the Commission need to take a
15 closer look at how we invest in the gas system going forward. What was once reasonable
16 and prudent is no longer reasonable and prudent in light of declining demand due to shifting
17 economic and policy conditions, namely electrification and the need to meet the State's
18 emission reduction goals. The Company's IRM delivers certainty of recovery and pre-
19 approval of investments—moving the Company further away from the careful planning
20 necessary to contain costs and properly maintain the system in light of the transformative
21 change on the horizon.

1 **Q: Would discontinuing the IRM mean the Company could not recover prudently**
2 **incurred costs or jeopardize customer safety?**

3 A: No. The IRM, as a tariff rider, allows the Company to recover costs for the program
4 concurrent with its spending. Allowing cost recovery through a tariff rider is a departure
5 from traditional regulation where a utility must demonstrate that an investment is used-
6 and-useful in a rate case before it is authorized to recover its investment from customers.
7 Discontinuing the IRM would simply treat IRM projects the same as all other capital
8 investments the Company makes. Nor would requiring the Company to seek recovery of
9 IRM investments in a rate case jeopardize customer safety. The Company would still have
10 an obligation to maintain a safe and reliable system, and it would seek to recover prudently
11 incurred costs during a rate case.

12 **III. USING GRANULAR DATA AND MAPPING TO ENSURE EQUITABLE GAS**
13 **SERVICE**

14 **Q: Did any parties raise new ideas on your third issue, the need for DTE to incorporate**
15 **more granular data and mapping tools to ensure equitable outcomes for its**
16 **customers?**

17 A: Yes. While I focused on short-term steps the Company can take to better track and measure
18 inequitable outcomes using the MiEJScreen Tool, several witnesses testified on behalf of
19 Soulardarity, Urban Core Collective, and We Want Green Too, collectively referred to as
20 the Frontline Organization (FLO), regarding the big picture structural issues faced by
21 DTE's customers which are exacerbated by inequitable gas service. FLO Witness Jackson
22 Koeppel testified regarding the inequitable distribution of burdens in the existing energy

1 burden and advocated for a just energy transition, which includes coordinated planning.¹¹
2 FLO Witness Justin Schott testified regarding significant energy burdens in DTE's
3 territory,¹² which the Company does not account for in this case, as well as, DTE's issues
4 regarding uptake of its assistance programs¹³ and its high rates of shutoffs¹⁴ compared to
5 peer-Michigan utilities.

6 **Q: Do you see parallels between Witnesses Koeppel's and Schott's recommendations and**
7 **your recommendation for the Company to use the MiEJScreen tool?**

8 A: Yes. Witnesses Koeppel and Schott identify a set of structural issues in DTE's territory
9 leading to inequitable outcomes for the Company's customers. In my testimony, I proposed
10 a set of small-scale steps the Company could take, using the MIEJScreen tool to begin to
11 track and measure its progress on equity issues like: energy burdens, disconnections,
12 energy efficiency participation, and shut-offs. My direct testimony can provide the
13 Commission and the Company with a roadmap for beginning to address these issues.

14 To overcome the Company's structural equity issues, DTE will need granular data
15 and a mapping tool to identify environmental justice communities overlayed with its own
16 delivery system. This mapping analysis works in conjunction with a more holistic
17 coordinated delivery system planning that forecasts customer demand and optimizes for
18 the least cost, least risk set of resources and investments for meeting customer demand
19 while complying with all applicable regulations and policies, like the state's emissions
20 reduction targets. A mapping tool like MiEJScreen will help DTE Gas to better understand

¹¹ Koeppel Direct, p. 17, line 15 through p. 18, line 6.

¹² Schott Direct, p. 23, lines 1 through p. 24, lines 3-10.

¹³ Schott Direct, p. 16, lines 12-14.

¹⁴ Schott Direct, p. 44, line 5 through–p. 45, line 4.

1 its customers, and in particular, to better understand where there are geographic areas of
2 customers with low incomes, high energy burdens, and high shutoff rates, and tailor its
3 programs and policies to more effectively reach those customers.

4 **Q: Witness Koeppel testifies that integrated gas and electric planning is necessary to**
5 **ensure a just and equitable transition. Do you agree with Witness Koeppel’s findings?**

6 A: Yes, and a mapping tool like MiEJScreen is complementary to integrated or coordinated
7 gas and electric planning. Witness Koeppel testifies that by coordinating infrastructure and
8 business planning between gas and electric systems, DTE could develop innovative
9 approaches to rate structures and technology transformation.¹⁵ Witness Koeppel also
10 testifies that the lack of coordinated or integrated gas and electric planning exacerbates
11 equity concerns for frontline communities.¹⁶

12 I agree with Witness Koeppel that uncoordinated parallel investments in the gas
13 and electric systems will likely lead to an overbuilt gas system, which would lead to
14 skyrocketing gas rates. Low-income households who are unable to take advantage of
15 beneficial electrification, and therefore remain on the gas system, would be
16 disproportionately impacted. Through coordinated or integrated gas and electric planning,
17 DTE can forecast the impact of the energy transition to both their electric and gas demand
18 over the planning horizon, and then optimize for the least cost, least risk set of resources
19 and investments necessary for meeting customers’ near- and long-term needs while
20 complying with all applicable regulations and policies, such as the state’s emissions
21 reduction targets. Then, using a mapping tool like MiEJScreen, the Company can optimize

¹⁵ Koeppel Direct, p. 38, lines 6-18.

¹⁶ Koeppel Direct, p. 36, line 15 through p. 38, line 3.

1 for opportunities to incentivize whole-home improvements to income-constrained
2 households. Witness Koepfel specifically identified an opportunity for DTE Energy, where
3 it provides both gas and electric service, to conduct analysis overlapping socioeconomic
4 indicators with its infrastructure.¹⁷ To target disproportionately impacted communities and
5 low-income households, the Company would need to use a mapping tool like MiEJScreen.

6 **IV. Conclusion**

7 **Q: Does this conclude your written Rebuttal Testimony?**

8 **A:** Yes.

¹⁷ Koepfel Direct, p. 38, line 6 through p. 39, line 16.

1 MR. ABRAMS: Thank you, your Honor. At
2 this time, on behalf of the Clean Energy Organizations
3 and by stipulation of the parties, I move to bind in the
4 Refiled Direct Testimony of Saad Siddique, consisting of
5 a cover page, a table of contents, and eight pages of
6 questions and answers; and I also move for the admission
7 of CEO-44 and CEO-45.

8 JUDGE THOITS: Are there any objections
9 to the admission of this testimony and these exhibits?
10 (No response.)

11 Hearing none, the Direct Refiled
12 Testimony of Saad Siddique is bound in the record, and
13 Exhibits CEO-44 and 45 are admitted. My apologies if I
14 mispronounced that witness's name.

15 (Testimony bound in.)

16 - - -
17
18
19
20
21
22
23
24
25

**STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION**

In the matter of the application of DTE GAS	)	
COMPANY for authority to increase its	)	
rates, amend its rate schedules and rules	)	Docket No. U-21291
governing the distribution and supply of	)	
natural gas, and for miscellaneous accounting	)	
authority	)	

REFILED DIRECT TESTIMONY OF

Saad Siddique

ON BEHALF OF

**THE ECOLOGY CENTER, THE ENVIRONMENTAL
LAW & POLICY CENTER, UNION OF CONCERNED SCIENTISTS, AND VOTE
SOLAR**

May 27, 2024

Table of Contents

I. Introduction and Summary	1
II. The Company's Responsibly Sourced Gas (RSG) Proposal is Insufficient to Meet its Decarbonization Goals.....	3

I. Introduction and Summary

Q: Please state your name and business address.

A: My name is Saad Siddique (he/him/his). My business address is 35 E. Wacker Dr., Ste. 1600, Chicago, Illinois 60601

Q: By whom are you employed and in what capacity?

A: I am employed by Environmental Law & Policy Center (ELPC) as an economist & energy analyst.

Q: On whose behalf are you submitting this direct testimony?

A: I am submitting testimony on behalf of The Ecology Center, The Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar, collectively referred to as the Clean Energy Organizations or CEO.

Q: Please summarize your qualifications, experience, and education.

A: I have been employed at ELPC since November 2023. As an economist & energy analyst, I provide research, engineering and economic analyses, and data analysis in utility rate cases, grid and resource planning proceedings, and energy policy issues at ELPC. Previously, I was a Senior Energy Systems Analyst at GTI Energy from 2022-2023, where I led a long-term strategy planning and modeling project for natural gas, hydrogen, and carbon capture, utilization and sequestration) infrastructures in the lower 48 states of the US to reach economy-wide net-zero CO2 goals by 2050. I also led a project that conducted a meta-analysis of multiple decarbonization studies that modeled and analyzed ‘technological, economic, and policy pathways to economy-wide net-zero emissions by 2050 for the US. Prior to joining GTI Energy, I worked as a Sustainability Analyst at Stanford University from 2021-2022. From 2020-2021, I was an Energy Products

1 Consultant for OPEX Digital Consulting LLC., where I created an energy industry
2 dashboard that provided data across energy value chains. I hold a Master of Science in
3 Energy and Earth Resources from The University of Texas at Austin (2020), where I wrote
4 a thesis on investment and strategic decision-making for gas pipeline infrastructure projects
5 under uncertainty and under risks of cost-and-time overruns. In 2018, I received a
6 certification in Economics, Financial Accounting and Business Analytics from Harvard
7 Business School Online. I graduated with a Bachelor of Engineering in Mechanical
8 Engineering (2015) from Visvesvaraya Technological University in India. My resume is
9 attached as Ex. CEO-4~~4~~5.

10 **Q: Have you testified before the Michigan Public Service Commission previously?**

11 A: No, I have not.

12 **Q: Have you testified or provided comments in similar state regulatory proceedings?**

13 A: No, I have not.

14 **Q: Are you sponsoring any exhibits?**

15 A: Yes. I am sponsoring the following exhibits:

- 16 • Exhibit CEO-4~~4~~5: Resume of Saad Siddique
- 17 • Exhibit CEO-4~~5~~6: DTE Gas Company's Response to the Ecology Center,
18 the Environmental Law & Policy Center, Union of Concerned Scientists,
19 and Vote Solar's First Discovery Request; CEODG 1.31a

20 **Q: What is the purpose of your testimony?**

21 A: The purpose of my testimony is to explain that DTE's proposal to purchase Responsibly
22 Sourced Gas ("RSG") will have limited impact because upstream emissions represent a
23 far smaller share of the Company's total emissions than emissions associated with DTE's

customers' consumption. The Company should focus on reducing emissions by reducing customer usage of gas, rather than purchasing Responsibly Sourced Gas.

Q: Please summarize your testimony.

A: The Company's RSG proposal would reduce DTE's total emissions 0.047% - 0.095% for its test year through the purchase of RSG, with a much greater proportion of emissions attributable to end-use. About 90% of total GHG emissions take place at customer end-use. The Company fails to demonstrate how the inclusion of RSG in its portfolio will have a cost-effective impact on its long-term emissions reduction goals.

Before DTE purchased RSG, the Company should have prepared a plan to achieve its upstream, mid-stream, and downstream decarbonization goals. At the upstream level, it should determine the role of RSG in achieving those goals. Then, the Company needs to develop an RSG purchase strategy based on a cost-benefit analysis. The Company should develop and provide a detailed analysis regarding its plan, including research findings on RSG certificates, its RSG suppliers/producers and their baseline emissions.

The Company pays a premium when it purchases Responsibly Sourced Gas, and the Commission should not approve recovery of the Company's RSG premium costs until the Company justifies that it did a proper cost-benefit analysis.

II. The Company's Responsibly Sourced Gas (RSG) Proposal is Insufficient to Meet its Decarbonization Goals

Q: What are Michigan's and DTE Gas' emission reduction goals?

A: The State and Company both have substantial emission reduction goals. As CEO Witness Cebulko discusses in his testimony, the state has a goal to achieve economy-wide net-

zero carbon emissions by 2050, and interim targets to reduce GHG emissions by 28% by 2025 and 52% by 2040.¹ DTE issued a press release on June 24, 2020 announcing the Company's commitment to reduce greenhouse gas emissions from the Company's own operations and its suppliers' operations to net zero by 2050. Additionally, it set a goal to reduce its customers' end use greenhouse gas emissions 35% by 2050 (from 2005).²

Q: Where do major emissions of the Company come from?

A: While I cannot calculate the Company's actual total emissions for the test year, I used EPA's GHG equivalencies calculator to do a best estimate.³ For the Company's test year (Oct 1, 2024 – Sep 30, 2025), it projects a demand of 159,076,731 mcf (or Dth)^{4,5}. Further, based on the EPA calculator, I estimate the total GHG emissions to be around 8,416,750 metric tons of CO₂e.⁶ We do not know what the upstream emissions are because the Company does not have a baseline estimate for supplier emissions. However, a study conducted by MiQ found that the average upstream emissions are around 1%-2.5%.⁷ In 2022, DTE Gas reported its annual operations-level midstream GHG emissions of 633,600 metric tons of CO₂e,⁸ which is approximately 8% of total projected emissions. This highlights that about 90% of DTE's emissions come from combustion of natural gas at customer end-use. The Company needs to focus on reducing emissions from customer end-use which is responsible for majority of the emissions.

¹ BV-49, lines 7-10

² HJD-36, lines 3-7

³ [Greenhouse Gas Equivalencies Calculator | US EPA](#)

⁴ Ex. CEO-6, CEODG-1.24a Five Year Forecast

⁵ GHC-11, lines 14-15

⁶ [Greenhouse Gas Equivalencies Calculator | US EPA](#)

⁷ <https://miq.org/wp-content/uploads/2023/06/MiQ-Highwood-Index.pdf>

⁸ Ex. CEO-456, CEODG-1.31a DTE Gas GHG Emissions Summary

Q: How does DTE Gas propose to use Responsibly Sourced Gas (RSG) to meet its decarbonization goal?

A: DTE Witness Decker testifies that the Company intends to purchase RSG to reduce methane intensity of its supply portfolio. DTE's goal to reduce methane emissions at the point of production is in addition to its goals to reach net-zero emissions in its own operations.⁹

Q: Please explain how RSG plays a role in carbon reduction?

A: Responsibly Sourced Gas or Certified Gas is natural gas that's upstream methane emissions have been evaluated based on criteria established mainly by Equitable Origin, MiQ, and Project Canary.¹⁰ Each certificate has a unique identifier, provides intensity of methane emissions from production at facility or platform level, and provides evidence of where and when the gas was produced.¹¹ The assessment at facility level is performed by third party evaluators.¹² MiQ and Equitable Origin verify and certify the gas based on its performance on emissions management and ESG criteria. In essence, certified gas enables tracking of emissions from natural gas production and gives buyers information on emissions attached to the gas they choose to purchase. It is a market-based product designed to create demand for lower emissions-intensity natural gas from buyers and downstream users.¹³

⁹ HJD-38, lines 8-16

¹⁰ <https://www.bloomenergy.com/blog/what-certified-responsibly-sourced-gas-does-for-the-environment-and-the-industry/>

¹¹ <https://www.miqregistry.org/>

¹² <https://www.erm.com/contentassets/88be880d269247c789a51e20522eeb4a/comparison-of-natural-gas-certification-programs.pdf>

¹³ <https://www.bloomenergy.com/blog/what-certified-responsibly-sourced-gas-does-for-the-environment-and-the-industry/>

1 **Q: What is the Company's RSG Proposal?**

2 A: The Company issued non-binding requests for information (RFIs)¹⁴ in 2022 and 2023
3 soliciting offers for RSG for purchase during the respective summers in April thru
4 October. DTE Witness Decker states that DTE's primary goal was to glean information
5 on where the industry is in supplying RSG.¹⁵ In 2022, the Company purchased 1,134,200
6 Dth of RSG paying a premium of \$36,808. In 2023, the Company purchased 1,990,200
7 Dth of RSG paying a premium of \$29,853.¹⁶ The Company did not issue an RFI for the
8 projected test period of October 1, 2024 – September 30, 2025. Based on the information
9 gleaned during the RFI process, the Company has forecasted a purchase of 4,000,000 Dth
10 of RSG gas for the test period, which is 2.5% of their total projected purchase of natural
11 gas. The company estimates paying a premium price of \$0.045 per Dth based on current
12 market conditions in 2024. DTE projects paying a total premium of \$180,000, which it
13 includes in its projected test year in Exhibit A-22, Schedule L3, Responsibly Sourced Gas
14 Schedule.¹⁷ The Company does not intend to implement a prescriptive RSG purchase
15 strategy in the projected test period.¹⁸

16 **Q: What are your concerns regarding DTE Gas' plans for RSG?**

17 A: The Company's projected CO₂e emission reduction estimation through RSG is an
18 extremely small proportion of total emissions (upstream, midstream, operations and end-
19 use combustion emissions). RSG only accounts for methane emissions avoided at
20 production-level, and DTE doesn't say what percentage of its emissions come at the

¹⁴ HJD-44, lines 11-18

¹⁵ HJD-44, line 21

¹⁶ HJD-41, lines 8-11

¹⁷ HJD-49, lines 1-6

¹⁸ HJD-48 line 15-18

1 production level. However, MiQ conducted a very large study in 2023 using flyovers and
2 drones and in total about 400,000 measurements were taken across the United States.
3 That study, along with calculations from existing government data from EPA, concluded
4 that the average emissions from upstream gas are around 1.0% in the US, and 2.5%-3%
5 worldwide.¹⁹ While this number could vary by region and by producer, it provides the
6 best information we have.

7 The Company estimates its test year RSG purchase of 4,000,000 Dth would prevent
8 approximately 4,000 to 8,000 metric tons CO₂e from being released to the atmosphere,
9 depending on the methane intensity of the RSG purchased.²⁰ Thus, emissions reduced from
10 RSG purchased in the test year will be a minimal 0.047% - 0.095%. The Company's focus
11 on reducing methane leakage at the wellhead and gathering lines is misplaced. The vast
12 majority of the Company's emissions occur with end use combustion, and the Company
13 never justifies the premium it pays for RSG.

14 **Q: What's your conclusion regarding DTE's proposed RSG spending?**

15 A: The Company needs a carbon reduction plan which analyzes the premium it pays for RSG
16 as part of a long-term strategy to reduce all of its carbon emissions. Additionally, the plan
17 should include a cost benefit analysis that analyzes RSG as a cost-effective method for
18 reducing upstream emissions.

19 **Q: Does this conclude your testimony?**

20 A: Yes.

¹⁹ <https://www.csis.org/analysis/growing-market-certified-natural-gas>

²⁰ HJD-49, lines 2-8

1 MR. ABRAMS: Thank you, your Honor. On
2 behalf of the Clean Energy Organizations, we rest our
3 case.

4 JUDGE THOITS: All right. Thank you. Is
5 Michigan Power Limited Partnership ready and interested
6 to bind in with respect to their witness?

7 MS. HESTON: Yes, I am, your Honor.
8 Thank you.

9 JUDGE THOITS: Please proceed.

10 MS. HESTON: Thank you, your Honor. At
11 this time, your Honor, I move to admit into the record
12 the prefiled Direct Testimony of Brian C. Collins
13 submitted on behalf of the Michigan Power Limited
14 Partnership. Mr. Collins' prefiled direct testimony
15 consists of a cover page, 20 pages of questions and
16 answers, and a three-page appendix. I also move to bind
17 into the record the Revised Rebuttal Testimony of Brian
18 C. Collins submitted on behalf of Michigan Power Limited
19 Partnership. Mr. Collins' revised rebuttal testimony
20 consists of a cover page, six pages of questions and
21 answers, and three pages of an appendix. I also move to
22 admit into evidence Mr. Collins' exhibits, there are 10
23 exhibits in total. Those exhibits are marked as MPL-1
24 through MPL-6, and then he has four revised exhibits that
25 are marked as Revised Exhibit MPL-7, Revised Exhibit

1 MPL-8, Revised Exhibit MPL-9, and Revised Exhibit MPL-10.

2 JUDGE THOITS: Are there any objections
3 to the admission of this testimony or these exhibits?

4 (No response.)

5 Hearing none, the Direct Testimony of
6 Brian Collins is bound into the record, and Exhibits
7 MLP-1 through MLP-6 and Revised Exhibits MLP-7 through
8 MLP-10 are admitted.

9 MS. HESTON: Just for clarification, your
10 Honor, those exhibits are marked with the three-letter
11 prefix MPL.

12 JUDGE THOITS: Oh, I apologize. All
13 right, MPL. Thank you.

14 MS. HESTON: Thank you, your Honor.

15 COURT REPORTER: I'm sorry, there was
16 rebuttal, also, or just direct?

17 MS. HESTON: There was revised rebuttal
18 as well.

19 JUDGE THOITS: Yes. Again, my fault.
20 Yes, the Revised Rebuttal Testimony of Mr. Collins is
21 bound into the record. I guess I need a break.

22 (Testimony bound in.)

23 - - -

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

**In the matter of the application of
DTE GAS COMPANY for authority
to increase its rates, amend its
rate schedules and rules
governing the distribution and
supply of natural gas, and for
miscellaneous accounting
authority**

Case No. U-21291

Direct Testimony and Exhibits of

Brian C. Collins

On behalf of

Michigan Power LP

May 7, 2024



STATE OF MICHIGAN

Case No. U-21291

Direct Testimony of Brian C. Collins

1 Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

2 A Brian C. Collins. My business address is 16690 Swingley Ridge Road, Suite 140,
3 Chesterfield, MO 63017.

4 Q WHAT IS YOUR OCCUPATION?

5 A I am a consultant in the field of public utility regulation and a Managing Principal with
6 the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory
7 consultants.

8 Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

9 A This information is included in Appendix A to my testimony.

10 Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

11 A I am testifying on behalf of the Michigan Power LP a large gas-fired cogeneration
12 business that purchases substantial gas delivery service from DTE Gas Company

1 (“DTE”) on Rate XXL (Double Extra Large Transportation) and served at the
2 transmission level.

3 **Q WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?**

4 A My testimony is directed toward DTE’s natural gas cost of service study and the
5 allocation of any allowed gas distribution rate increase. I have examined the testimony
6 and exhibits presented by DTE in this (and previous) proceedings with respect to cost
7 of service and revenue allocation, and I will comment on the propriety of these
8 proposals and make certain comments and recommendations.

9 **Q DOES YOUR TESTIMONY ADDRESS THE NECESSITY OF A RATE INCREASE**
10 **FOR DTE?**

11 A No. In order to make my presentation consistent with the revenue levels requested by
12 DTE, I have used its numbers at the \$265.5 million revenue increase level under its
13 proposed rates. Use of these numbers should not be interpreted as an endorsement
14 of them for purposes of determining the total dollar amount of any rate increase
15 authorized for DTE.

16 **Summary of Conclusions and Recommendations**

17 **Q PLEASE BRIEFLY SUMMARIZE YOUR CONCLUSIONS AND**
18 **RECOMMENDATIONS IN THIS PROCEEDING.**

19 A The summary of my conclusions and recommendations is listed below:

- 20 1. DTE is proposing a 14.7% increase to Rate XXL customers while stating that this
21 rate is designed to retain these extremely large customers with competitive
22 alternatives.
- 23 2. DTE erroneously allocates a category of cost identified as distribution-other to Rate
24 XXL based on total class usage while only 4.5% of Rate XXL throughput is at

the distribution level. Correcting the allocation of distribution-other in the DTE study to only low-pressure distribution usage results in a corrected rate increase to Rate XXLT of 8.2% based on DTE's requested revenue increase.

3. DTE's cost of service study uses a weighted peak demand and throughput allocation method termed the average and peak ("A&P") method to allocate fixed demand-related delivery system costs. The A&P method (which can more accurately be called the throughput and peak method) is at odds with system design and cost causation. It is important to note that, if the system was designed to meet average throughput, it would be impossible for DTE to deliver enough gas to meet customer demands on the coldest days in the winter.

4. I recommend that a peak day demand allocation method be used in place of DTE's proposed demand and throughput. Design day peak demand by class best reflects the actual design of the system and is basically the same as the straight fixed variable method ("SFV") endorsed by the Federal Energy Regulatory Commission. Use of this method would make DTE's large transportation rates much more competitive.

5. The DTE method uses the annual system load factor to determine the percentage of fixed delivery system investment allocated on system throughput. As load factor increases, which is a measure of system efficiency, the percentage of plant allocated on system throughput increases. Large manufacturing customers use gas consistently throughout the year and increase system load factor. Therefore, the DTE method is unreasonable because it allocates even more costs to these customers as the load factor (system efficiency) increases.

6. As a reasonable alternative solution, the "75/25" method is a far superior, stable and more equitable form of cost allocation than DTE's current A&P method. The Commission has adopted this method for electric utilities in Michigan for many years. The 75/25 method allocates 75% of fixed costs on a demand basis and 25% of fixed costs on an average energy basis. Increases in system load factor do not increase the average throughput weighting, thereby removing the bias against the system efficiency increase.

7. Correcting DTE's cost of service to a peak day method shows that Rate XXLT should be significantly decreased. Limiting the throughput allocation to no more than 25% consistent with the electric cost allocation shows that Rate XXLT should be modestly decreased.

8. The Rate XXLT rate class is not adequately homogeneous with respect to the cost of service characteristics. To the extent low-pressure distribution customer(s) are allowed on the rate, those customer(s) should pay an additional charge to recover the cost associated with the low pressure distribution required for service. Certainly customers served at transmission should not pay for distribution service.

9. The alternative cost of service study shown in DTE Exhibit A-24 is problematic and should not be used for revenue distribution in this proceeding. The alternative study is a significant departure from past practice, produces harsh impacts to certain classes and to customers served by transmission service such as Michigan Power,

1 is not reflective of current rate structures and would take significant time and
2 resources to investigate and correct.

3 **Cost of Service and Rate Design Principles**

4 **Q COULD YOU PLEASE EXPLAIN THE RATEMAKING PROCESS AND THE DESIGN**
5 **OF RATES?**

6 **A** Yes. The ratemaking process has three steps. First, we must determine the utility's
7 total revenue requirement and whether an increase or decrease in revenues is
8 necessary. Second, we must determine how any increase in the utility's authorized
9 revenues should be distributed among the major customer classes. A determination of
10 how many dollars of revenue should be produced by each class is essential for
11 obtaining the appropriate level of rates. Finally, individual tariffs must be designed to
12 produce the required amount of revenues for each class of service and to reflect the
13 cost of serving customers within that class.

14 The guiding principle at each step should be cost of service. In the first step –
15 determining revenue requirements – it is universally agreed that the utility is entitled to
16 an increase only to the extent that its actual cost of service has increased. If current
17 rate levels exceed the utility's revenue requirement, a rate reduction is required. In
18 short, overall rate revenues should equal actual cost of service. The same principle
19 should apply in the next two steps. Each major customer class should produce
20 revenues equal to the cost of serving that particular class, no more and no less. This
21 may require a rate increase for some classes and a rate decrease for other classes.
22 The standard tool for making this determination is a class cost of service study which
23 shows the rates of return for each class of service. Rate levels should be modified so
24 that each major class of service provides approximately the same rate of return.
25 Finally, in designing individual tariffs, the goal should also be to relate the rate design

of each class to the cost of service so that each customer's rate tracks, to the extent practicable, the utility's cost of providing service to that customer.

Q WHY IS IT IMPORTANT TO ADHERE TO BASIC COST OF SERVICE PRINCIPLES IN THE RATEMAKING PROCESS?

A The basic reasons for using cost of service as the primary factor in the ratemaking process are equity and stability.

Q HOW IS THE EQUITY PRINCIPLE ACHIEVED BY BASING RATES ON COSTS?

A When rates are based on cost, each customer (to the extent practicable) pays what it costs the utility to serve that customer, no more and no less. If rates are not based on cost of service, then some customers contribute disproportionately to the utility's revenues by subsidizing service provided to other customers. This is inherently inequitable.

Q PLEASE DISCUSS THE STABILITY CONSIDERATION.

A When rates are closely tied to costs, the earnings impact on the utility associated with changes in customer usage patterns will be minimized as a result of rates being designed in the first instance to track changes in the level of costs. Thus, cost-based rates provide an important enhancement to a utility's earnings stability, reducing its need to file for future rate increases.

From the perspective of the customer, cost-based rates provide a more reliable means of determining future levels of costs and also provide more accurate price signals. If rates are based on factors other than costs, it becomes much more difficult for customers to translate expected utility-wide cost changes (i.e., expected increases

1 in overall revenue requirements) into changes in the rates charged to particular
2 customer classes (and to customers within the class). Again, from the customer's
3 perspective, this situation reduces the attractiveness of expansion, as well as of
4 continued operations, because of the lessened ability to plan.

5 **Q WHEN YOU SAY "COST," TO WHAT TYPE OF COST ARE YOU REFERRING?**

6 A I am referring to the utility's "embedded" or actual accounting costs of rendering service;
7 that is, those costs which are used by the Commission in establishing the utility's overall
8 revenue requirement.

9 **Q WOULD YOU PLEASE COMMENT ON THE BASIC PURPOSE OF A COST OF**
10 **SERVICE STUDY?**

11 A After determining the overall cost of service or revenue requirement, a cost of service
12 study is used to allocate the cost of service among customer classes. A cost of service
13 study shows how each major customer class contributes to the total system cost. For
14 example, when a class produces the same rate of return as the total system, it is
15 returning to the utility revenues just sufficient to cover the costs incurred in serving it
16 (including a reasonable return on investment). If a class produces a below-average
17 rate of return, then the revenues are insufficient to cover all relevant costs. On the
18 other hand, if a major class produces an above-average rate of return, it is paying
19 revenues beyond sufficient to cover the cost attributable to it. In addition, it is
20 subsidizing part of the cost attributable to other classes which produce a below-average
21 rate of return. The class cost of service study is important because it demonstrates the
22 various class revenue requirements, as well as the rates of return under current and
23 proposed rates.

1 **Q WOULD YOU PLEASE COMMENT ON THE PROPER FUNDAMENTALS OF A**
2 **COST OF SERVICE STUDY?**

3 A Yes. Cost of service is a basic and fundamental ingredient to proper ratemaking. In
4 all class cost of service studies, certain fundamental concepts must be recognized. Of
5 primary importance among these concepts is the functionalization, classification, and
6 allocation of costs. Functionalization is the determination and arrangement of costs
7 according to major functions, such as transmission, distribution and storage.
8 Classification involves identifying the nature of these costs as to whether they vary with
9 the quantity of gas consumed, the demand placed upon the system or the number of
10 customers being served.

11 Fixed costs are those costs which tend to remain constant over the short run
12 irrespective of changes in gas deliveries and are generally considered to be
13 demand-related. Fixed costs include those costs which are a function of the size of the
14 investment in utility facilities and those costs necessary to keep the facilities "on-line."
15 Variable costs, on the other hand, are basically those costs which tend to vary with
16 throughput and are generally considered to be commodity-related. Customer-related
17 costs are those which are closely related to the number of customers served, rather
18 than the quantity of gas consumed or the demands placed upon the system. A correct
19 application of these concepts is essential to the proper development of a cost of service
20 study, as well as appropriate rate design within the customer class.

21 With respect to allocation, fixed cost should be allocated on a peak demand
22 factor, variable cost should be allocated on a throughput factor and customer-related
23 cost should be allocated on a per customer allocation factor.

DTE's Gas Cost of Service Study

Q HAVE YOU REVIEWED THE GAS COST OF SERVICE STUDIES PERFORMED BY DTE IN THIS PROCEEDING?

A Yes. DTE witness T.J. Krynski submitted a projected test year ending September 30, 2025 gas cost of service study. I will focus on this projected test year study used for revenue allocation of any increase that might be granted in this case and rate design.

Q DO YOU AGREE WITH THE ALLOCATION METHODS UTILIZED BY DTE IN ITS TEST YEAR GAS COST OF SERVICE STUDY?

A While I agree with some of the allocations used by DTE, significant over-allocations to the transportation class continue. The Commission should take this opportunity to stop the over-allocation of cost to the Rate XXLT double-extra large transportation customers. Failing to correct this inequity will result in DTE's rates becoming even less competitive. Specifically, I take issue with the allocation of distribution-other to the Rate XXLT class based on total class usage. I also take issue with the use of the A&P method to allocate fixed costs of the gas delivery system. Elimination of the A&P method would make rates more reflective of cost and would make Michigan more attractive to energy-intensive industries through more competitive gas transportation rates. DTE states that Rate XXLT was designed to retain its very largest customers. Decker Direct, p. 12. A more cost causative allocation method could basically eliminate this customer retention problem and make DTE's rates much more competitive. DTE should be held accountable for proposing a methodology that makes its rates uncompetitive. The allocation of fixed cost on the basis of throughput in the A&P method is directly harmful to energy-intensive industries and in conflict with the goal of making Michigan more attractive to energy-intensive customers with competitive rates.

1 DTE has taken some steps to incorporate cost-causative principles that more
2 appropriately reflect the lower cost of serving energy-intensive industrial customers.
3 However, the A&P method continues to over-allocate significant costs to
4 energy-intensive (high load factor) customers, making industrial rates in Michigan less
5 competitive and less attractive compared to rates not based on throughput allocations.

6 **Q HOW DOES DTE DETERMINE WHAT PORTION OF FIXED COSTS SHOULD BE**
7 **ALLOCATED ON THE PEAK BASIS AND WHAT PORTION ON TOTAL ANNUAL**
8 **THROUGHPUT (AVERAGE) BASIS?**

9 A DTE uses its average system load factor based on projected annual system throughput
10 and a system design peak day requirement. The calculated average system load factor
11 represents the amount that is allocated on total annual throughput (average) and one
12 minus the average system load factor is used to determine the amount to allocate on
13 the peak basis, as shown on DTE Exhibit A-16, Schedule F1.2, p. 3 of 22.

14 **Q WHAT IS THE DTE SYSTEM LOAD FACTOR?**

15 A It is a measure of the efficiency of DTE's system. The load factor used in the A&P
16 formula in this case is 35.8%. The load factor relates the average use of the system to
17 the peak requirements of the system.

18 **Q WHAT ARE THE IMPLICATIONS OF THIS RELATIONSHIP?**

19 A The system must be designed to deliver gas to the load that occurs on the coldest
20 winter day, also known as the design peak day demand. The average throughput is
21 881,773 Mcf and the design peak day demand is 2,465,544 Mcf. A system designed
22 to serve 881,773 Mcf is clearly inadequate to serve the winter peak day demand of

2,465,544 Mcf. Allocating fixed delivery system cost on average annual throughput over-allocates cost to high load factor customers and under-allocates cost to low load factor customers that require the system deliverability to meet the peak load during the coldest period. Ironically, the over-allocation to high load factor customers increases as system load factor (efficiency) increases.

Q DO CUSTOMERS BENEFIT FROM A MORE EFFICIENT SYSTEM?

A Yes. More throughput without an increase in demand makes the system more efficient and reduces overall costs to all ratepayers. This is because if the system load factor improved (increased throughput without an increase in peak demand), the system would be more efficient and fixed cost per unit would decrease. However, the A&P formula unfairly increases the allocation on throughput and punishes the higher load factor classes that are responsible for increasing the efficiency of the system by increasing their costs. Thereby, the use of A&P penalizes customers that exhibit efficient gas consumption (higher load factors). Under-utilization of the system should not be encouraged since it results in higher per unit prices, but this is what DTE's current rate structure has the effect of doing. Based on DTE data, the residential load factor is approximately 23% while the Rate XXLT load factor is 86% as shown on Exhibit MPL-1 (BCC-1).

Q IS THE A&P APPROACH APPROPRIATE TO ALLOCATE FIXED RELATED DELIVERY SYSTEM COSTS?

A No. In this case and the previous cases, DTE has made it clear that it designs its gas delivery system to meet peak demand. In a previous case, DTE witness J.A. Aud's testimony regarding system design stated:

1 “The design peak day reflects a consumption level consistent with the
2 design of the utility’s system.”

3 (Aud, Direct p. 21, U-18999)

4 There is no indication that load factor is significant for system planning of the DTE
5 system.

6 In addition, the A&P is in direct conflict with efficiency improvement on the
7 system. The system must be sized to meet the peak day demand for DTE to satisfy its
8 gas service obligation throughout the year. As such, average annual throughput is
9 unrelated to cost causation with respect to demand related delivery system costs.

10 There is no logical reason to design and construct the system to meet peak demand
11 and then allocate those costs on average annual throughput.

12 **Q WHAT APPROACH SHOULD DTE USE TO ALLOCATE ITS FIXED RELATED**
13 **DELIVERY SYSTEM COSTS?**

14 A The peak day demand method is far superior to the A&P approach for allocating based
15 on actual cost causation. The peak day demand is the main driver in the planning
16 activities for system design and hence, the cost of constructing and operating a system
17 that can reliably serve 2,465,544 Mcf on the coldest winter days. A system designed
18 to serve the average daily throughput of 881,773 Mcf could serve only 35.8% of the
19 load during the cold winter peak period.

20 **Q IS THE ALLOCATION OF FIXED DELIVERY COSTS BASED ON PEAK DAY**
21 **DEMAND DISCUSSED IN THE NATIONAL ASSOCIATION OF REGULATORY**
22 **COMMISSIONERS (“NARUC”) MANUAL?**

23 A Yes. NARUC recognizes that distribution mains should be allocated to customer
24 classes based on: (1) design peak day demands for the demand component; and

(2) the number of customers for the customer component. In that regard, the NARUC

Gas Distribution Rate Design Manual states the following:

Demand or capacity costs vary with the size of plant and equipment. They are related to maximum system requirements which the system is designed to serve during short intervals and **do not directly vary** with the number of customers **or their annual usage**. Included in these costs are: the capital costs associated with production, transmission and storage plant and their related expenses; the demand cost of gas; and most of the capital costs and expenses associated with that part of the distribution plant not allocated to customer costs, such as the costs associated with distribution mains in excess of the minimum size.

(NARUC Manual, Gas Distribution Rate Design, June 1989, pp. 23-24; emphasis added)

Q ARE YOU AWARE OF ANY OTHER AUTHORITATIVE AGENCY'S POSITION ON THE CLASSIFICATION AND ALLOCATION OF GAS DISTRIBUTION MAIN COSTS?

A Yes. In Order 636, the Federal Energy Regulatory Commission ("FERC") endorsed the SFV cost methodology, which allocates fixed pipeline cost 100% on a demand basis. In this regard, FERC states:

The Commission believes that requiring SFV comports with and promotes Congress' goal of a national gas market as discussed above and goes hand-in-hand with the equity principle.

Moreover, the Commission's adoption of SFV should maximize pipeline throughput over time by allowing gas to compete with alternative fuels on a timely basis as the prices of alternate fuels change. The Commission believes it is beyond doubt that it is in the national interest to promote the use of clean and abundant natural gas over alternate fuels such as foreign oil. SFV is the best method for doing that. (FERC Order 636, Final Rate Issued April 8, 1992, pp. 127-129 (footnote omitted))

The FERC SFV allocation method appropriately treats fixed pipeline costs as demand-related costs. Similarly, distribution main costs not classified as customer-related on

1 DTE's system should be treated as demand-related costs to achieve the goals and
2 benefits outlined by FERC and in accordance with NARUC guidance. The peak day
3 demand method allows this to be done.

4 **Q HOW DOES PANHANDLE PIPELINE ALLOCATE FIXED COSTS?**

5 A Panhandle's rate filing before FERC, Docket No. RP19-1523-000, included Panhandle
6 witness Lawrence J. Biediger's testimony wherein he states:

7 **"Q. What rate design underlies the rates included in the current**
8 **filing?**

9 A. Panhandle continues to use the Straight Fixed Variable ("SFV")
10 cost classification, cost allocation and rate design methodology, as
11 previously approved in its last rate case and its Order No. 636
12 restructuring proceeding in Docket Nos. RP92-166-000, and RS92-22-
13 000, respectively."

14 (Panhandle witness Biediger Direct Testimony, pp 5-6)

15 Panhandle witness Bradly J. Sherbenou states the following:

16 **"Q. How does Panhandle use the SFV methodology in its filing?**

17 A. Panhandle uses the SFV methodology for cost classification,
18 cost allocation and rate design. Under this method, all of the storage
19 and transmission fixed costs including return on equity are included in
20 the reservation component of transportation rates. Variable costs are
21 included in the commodity component of transportation rates."

22 (Panhandle witness Sherbenou Direct Testimony, p 9)

23 It therefore appears that the competitive pipeline to which DTE is worried about losing
24 customers uses a demand-based cost allocation methodology.

25 **Q HAVE YOU PERFORMED A STUDY USING THE PEAK DAY TO ALLOCATE FIXED**
26 **COSTS TO CLASSES?**

27 A Yes. I have used DTE's model to perform a peak day demand cost of service study
28 and also corrected the allocation of distribution-other to the Rate XXLT class. The
29 results are shown in Exhibit MPL-2 (BCC-2). Peak day demand data by class as

provided by DTE is used to allocate fixed delivery costs in place of the A&P method. The results of this study indicate that transportation customers are providing revenues significantly in excess of their cost of service. It is important to note that this design peak day demand study supports a sizeable revenue decrease of 45.0% to the Rate XXLT class, at proposed rate levels. The design peak day demand study is most reflective of system design and cost causation. Use of the design peak day demand study would also make DTE's Rate XXLT much more competitive which is consistent with the purpose of the rate.

Q WHAT CORRECTION IS REQUIRED IN THE ALLOCATION OF DISTRIBUTION-OTHER TO THE RATE XXLT CLASS?

A Rate XXLT was established to recognize the lower cost to serve a limited number of extremely large customers with competitive alternatives to purchasing transportation service from DTE. The rate was established as a transmission or high pressure service rate. Apparently, a small amount of lower pressure-distribution service has been added to the rate. Exhibit MPL-3 (BCC-3) is a discovery response that shows the annual usage and peak day demand by service level for the Rate XXLT class. Only 4.5% of usage occurs at the low-pressure distribution service level.

Q WHAT COSTS ARE INCLUDED IN DTE'S DISTRIBUTION-OTHER?

A Distribution-other includes:

- Land and Land Rights (FERC Account No. 374);
- Structures and Improvements (FERC Account No. 375);
- Compressor Station Equipment (FERC Account No. 377); and
- Measuring and Regulating Station Equipment (FERC Account Nos. 378, 379).

1 Similar equipment is already included in DTE's transmission plant accounts (FERC
2 Accounts 365, 366, 368 and 369). These costs are allocated to Rate XXLT at the
3 transmission level.

4 **Q SHOULD THE COSTS INCLUDED IN DTE'S DISTRIBUTION-OTHER BE**
5 **ALLOCATED TO THE RATE XXLT CLASS BASED ON TOTAL CLASS**
6 **THROUGHPUT AND TOTAL CLASS DEMAND?**

7 A No. Only 4.5% of Rate XXLT usage occurs at the distribution level. It is not appropriate
8 to allocate distribution costs to Rate XXLT class customers based on total class usage.

9 **Q HAVE YOU PERFORMED AN ALTERNATIVE COST OF SERVICE STUDY?**

10 A Yes. Although I believe the design peak day demand study is the most reflective of
11 cost causation, I have performed a "75/25" study as an alternative method to correct
12 the unfairness of the A&P study, which penalizes customers that increase system
13 efficiency by operating at higher load factors. The results are shown in Exhibit MPL-4
14 (BCC-4). The 75/25 study adds stability and certainty to the cost allocation method
15 and is consistent with most electric cost of service studies approved by the MPSC,
16 although is not as cost based as the design peak day demand approach. It would be,
17 in that sense, a step in the right direction without requiring as dramatic a shift in costs
18 among classes in the short-term.

19 In place of using a system load factor to determine the throughput weighting in
20 the allocation methodology, I have used the "75/25" formula. I have also corrected the
21 distribution-other allocation to the Rate XXLT class. The Commission has recognized
22 the merits of the 75/25 weighting for decades. This formula fixes the average or
23 throughput weighting in the allocation factor at 25%. On that basis, increases in system

1 load factor will not cause increases to the throughput weighting in the allocation formula
2 to the detriment of efficient high load factor customers. Absent these unique Rate XXLT
3 customers, the DTE system load factor would be reduced to 29.6% as shown on Exhibit
4 MPL-1 (BCC-1) which is very close to the 25% in the 75/25 approach.

5 **Q IF A PEAK DAY DEMAND STUDY PRODUCES MORE COST-BASED RESULTS,**
6 **WHY DID YOU PERFORM A 75/25 STUDY?**

7 A The Commission has previously expressed a preference for some form of average
8 throughput weighting to the allocation of fixed delivery cost, so I have provided an
9 alternative that is not purely demand based. Use of the 75/25 methodology is
10 preferable to the A&P methodology because it significantly reduces the negative
11 incentives on system efficiency. To my knowledge, there is no showing that system
12 load factor under the A&P methodology is the appropriate weighting mechanism and it
13 is detrimental to improvements in system efficiency by allocating more cost to high load
14 factor customers that benefit other users of the DTE system, as discussed above. In
15 addition, the load factor changes and causes illogical and unwarranted changes to the
16 A&P cost allocation. In this case, the load factor is 35.8%. In the previous case, DTE
17 Used 32.5%. The MPSC Staff, based on different sales projections, used a different
18 percentage. These variations impact the cost study with no logical basis or support.
19 The 75/25 method corrects that unsupported and erroneous change in cost allocation
20 to classes.

1 **Q HAVE YOU CORRECTED THE DTE COST OF SERVICE STUDY TO LIMIT THE**
2 **ALLOCATION OF DISTRIBUTION-OTHER TO ONLY THE USAGE AT**
3 **LOW-PRESSURE DISTRIBUTION?**

4 A Yes. Exhibit MPL-5 (BCC-5) corrects only the allocation of distribution-other. The
5 resulting rate increase to Rate XXLT is shown as 8.2%, based on DTE's approach and
6 requested increase.

7 **Distribution of Revenue Increase**

8 **Q HAVE YOU CALCULATED HOW THE INCREASE WOULD BE ALLOCATED TO**
9 **CLASSES BASED ON THE 75/25 COST OF SERVICE STUDY?**

10 A Yes. The revenue allocation shown in Exhibit MPL-4 (BCC-4) is based on DTE's test
11 year cost study, using the 75/25 allocation method of demand related costs and also
12 corrects the allocation of distribution-other cost to Rate XXLT. Based on the
13 75/25 allocation method, Rate XXLT be decreased by 5.8% to be reflective of cost.

14 **Q WHAT IS YOUR RECOMMENDATION CONCERNING THE ALLOCATION OF**
15 **REVENUES TO THE CUSTOMER CLASSES IN THIS CASE?**

16 A I recommend that any increase to Rate XXLT transportation customers be limited to a
17 maximum of those set forth in the corrected 75/25 study as a first step in moving to a
18 competitive rate for our State's largest employers. I continue to recommend the peak
19 day method as a long-term solution to the competitive issue associated with DTE's gas
20 transportation rates, but if the Commission is not willing to take that step immediately,
21 then the 75/25 allocation is an intermediate step that substantially addresses the anti-
22 competitive and inefficiency biases inherent in DTE's A&P methodology. DTE's
23 proposed 14.7% to Rate XXLT customers should be rejected. As previously stated,

1 DTE's corrected approach would increase Rate XXLT by 8.2% at the full requested
2 rate increase. However, a rate decrease of 5.8% is warranted based on the 75/25 cost
3 of service study.

4 **Q PLEASE DISCUSS THE RATE XXLT RATE DESIGN.**

5 A First, it is important to recognize that although Rate ST, Rate LT, Rate XLT, and Rate
6 XXLT each are treated separately in the cost of service study, they are all contained in
7 one transportation rate which uses breakeven points based on usage to provide target
8 rate levels.

9 Exhibit MPL-6 (BCC-6) shows the usage characteristics of the various rate
10 classes. Rate XXLT is unique in that seven customers account for 26.3% of total DTE
11 sales (throughput) and operate at a highly efficient 85.9% load factor.

12 As explained by Mr. Decker regarding the purpose of Rate XXLT:

13 "The XXLT transportation rate schedule provides a gas transportation
14 rate that is designed to retain the very largest EUT customers that would
15 otherwise bypass DTE Gas's system and take service from interstate
16 transmission pipelines, which are not regulated by the Commission.
17 Their size, energy consumption, and location near interstate pipelines
18 afford these customers the opportunity and means to make an
19 investment to bypass DTE Gas's system."

20 (Decker Direct, p. 12-13)

21 Adding unwarranted charges in excess of the cost to serve these customers is
22 at odds with the purpose of the XXLT rate schedule and should not be allowed by the
23 Commission. The rate should actually be decreased, and certainly no increase is
24 warranted.

1 **Q PLEASE COMMENT ON AN ENHANCEMENT TO THE RATE XXLTL RATE DESIGN.**

2 A Rate XXLTL is homogeneous with respect to size and competitive alternatives, but not
3 with respect to service levels. Since certain volumes require low-pressure distribution
4 equipment to provide service, those volumes should incur an additional charge for that
5 service not used by other Rate XXLTL customers. This low-pressure distribution service
6 cost is particularly unfair to those customers served at the transmission level, such as
7 Michigan Power.

8 The revenue requirement allocated to Rate XXLTL for distribution-other as
9 corrected for low-pressure distribution usage is \$249,000. That amount divided by the
10 low-pressure distribution usage of 3,806,336 Mcf amounts to \$0.0654 per Mcf. That
11 amount should be an additional charge for low-pressure distribution service volumes
12 and \$249,000 should be removed from the Rate XXLTL revenue requirements for the
13 Rate XXLTL throughput charge.

14 **Q HAVE YOU REVIEWED THE ALTERNATE COST OF SERVICE STUDY FILED BY**
15 **DTE?**

16 A Yes. DTE filed an alternate cost of service study in Exhibit A-24. To my knowledge
17 DTE has not endorsed or used this study for revenue distribution or rate design in this
18 case.

19 **Q SHOULD THE ALTERNATE STUDY BE USED FOR REVENUE DISTRIBUTION OR**
20 **RATE DESIGN IN THIS CASE?**

21 A No. The alternate study is presented but not explained by DTE. The alternate study is
22 a significant departure from past practice and produces an extremely harsh impact on

1 rates for customers such as those on Rate XXLT. The pressure levels are not
2 contained as requirements for certain rates within the DTE approved tariff.

3 For a customer such as Michigan Power LP which is served and metered at the
4 transmission service level, the alternative study produces completely erroneous
5 results.

6 A review and correction to this alternative study would take significant time and
7 resources which are beyond the limits of this procedural schedule. We urge the
8 Commission to reject this study for use in this proceeding.

9 **Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

10 **A** Yes, it does.

Qualifications of Brian C. Collins

1 **Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A Brian C. Collins. My business address is 16690 Swingley Ridge Road, Suite 140,
3 Chesterfield, MO 63017.

4 **Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?**

5 A I am a consultant in the field of public utility regulation and a Managing Principal with
6 the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory
7 consultants.

8 **Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK**
9 **EXPERIENCE.**

10 A I graduated from Southern Illinois University Carbondale with a Bachelor of Science
11 degree in Electrical Engineering. I also graduated from the University of Illinois at
12 Springfield with a Master of Business Administration degree. Prior to joining BAI, I was
13 employed by the Illinois Commerce Commission and City Water Light & Power
14 ("CWLP") in Springfield, Illinois.

15 My responsibilities at the Illinois Commerce Commission included the review of
16 the prudence of utilities' fuel costs in fuel adjustment reconciliation cases before the
17 Commission as well as the review of utilities' requests for certificates of public
18 convenience and necessity for new electric transmission lines. My responsibilities at
19 CWLP included generation and transmission system planning. While at CWLP, I
20 completed several thermal and voltage studies in support of CWLP's operating and
21 planning decisions. I also performed duties for CWLP's Operations Department,
22 including calculating CWLP's monthly cost of production. I also determined CWLP's

1 allocation of wholesale purchased power costs to retail and wholesale customers for
2 use in the monthly fuel adjustment.

3 In June 2001, I joined BAI as a Consultant. Since that time, I have participated
4 in the analysis of various utility rate and other matters in several states and before the
5 Federal Energy Regulatory Commission ("FERC"). I have filed or presented testimony
6 before the Arkansas Public Service Commission, the California Public Utilities
7 Commission, the Colorado Public Utilities Commission, the Delaware Public Service
8 Commission, the Public Service Commission of the District of Columbia, the Florida
9 Public Service Commission, the Georgia Public Service Commission, the Guam Public
10 Utilities Commission, the Idaho Public Utilities Commission, the Illinois Commerce
11 Commission, the Indiana Utility Regulatory Commission, the Kentucky Public Service
12 Commission, the Public Utilities Board of Manitoba, the Minnesota Public Utilities
13 Commission, the Mississippi Public Service Commission, the Missouri Public Service
14 Commission, the Montana Public Service Commission, the North Carolina Utilities
15 Commission, the North Dakota Public Service Commission, the Public Utilities
16 Commission of Ohio, the Oklahoma Corporation Commission, the Oregon Public Utility
17 Commission, the Rhode Island Public Utilities Commission, the Public Service
18 Commission of Utah, the Virginia State Corporation Commission, the Washington
19 Utilities and Transportation Commission, the Public Service Commission of Wisconsin,
20 and the Wyoming Public Service Commission. I have also assisted in the analysis of
21 transmission line routes proposed in certificate of convenience and necessity
22 proceedings before the Public Utility Commission of Texas.

23 In 2009, I completed the University of Wisconsin – Madison High Voltage Direct
24 Current ("HVDC") Transmission Course for Planners that was sponsored by the
25 Midwest Independent Transmission System Operator, Inc. ("MISO").

1 BAI was formed in April 1995. BAI and its predecessor firm have participated
2 in more than 1,000 regulatory proceedings in forty states and Canada.

3 BAI provides consulting services in the economic, technical, accounting, and
4 financial aspects of public utility rates and in the acquisition of utility and energy
5 services through RFPs and negotiations, in both regulated and unregulated markets.
6 Our clients include large industrial and institutional customers, some utilities and, on
7 occasion, state regulatory agencies. We also prepare special studies and reports,
8 forecasts, surveys and siting studies, and present seminars on utility-related issues.

9 In general, we are engaged in energy and regulatory consulting, economic
10 analysis and contract negotiation. In addition to our main office in St. Louis, the firm
11 also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix,
12 Arizona.

493752

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

**In the matter of the application of
DTE GAS COMPANY for authority
to increase its rates, amend its
rate schedules and rules
governing the distribution and
supply of natural gas, and for
miscellaneous accounting
authority**

Case No. U-21291

Revised Rebuttal Testimony and Exhibits of

Brian C. Collins

On behalf of

Michigan Power LP

June 5, 2024



STATE OF MICHIGAN

Case No. U-21291

Rebuttal Testimony of Brian C. Collins

1 Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

2 A Brian C. Collins. My business address is 16690 Swingley Ridge Road, Suite 140,
3 Chesterfield, MO 63017.

4 Q ARE YOU THE SAME BRIAN COLLINS WHO PREVIOUSLY FILED DIRECT IN THIS
5 PROCEEDING ON BEHALF OF MICHIGAN POWER LP?

6 A Yes, I am.

7 Q WHAT IS THE SUBJECT MATTER OF YOUR REBUTTAL TESTIMONY?

8 A My testimony will respond to the direct testimonies of Commission Staff witnesses
9 Kevin S. Krause, Nicholas M. Revere and Madison S. Todd on cost of service, revenue
10 allocation and rate design and to discuss the Alternate 2 or Hi-Low pressure cost of
11 service study and associated rate proposals.

1 **Overview**

2 **Q PLEASE PROVIDE AN OVERVIEW OF STAFF'S RATE INCREASE**
3 **RECOMMENDATIONS.**

4 A Staff's filing has reduced DTE's overall \$265.5 million requested increase to
5 \$175.7 million. On the basis of the \$175.7 million level, Staff's proposed increase to
6 Rate XXLT is shown as \$9.9 million or 31.5%, as shown on Revised Exhibit S-6,
7 Schedule F2. This is in a sharp contrast to the DTE proposed increase to Rate XXLT
8 of \$4.6 million or 14.7% based on the overall \$265.5 million revenue increase. Staff is
9 proposing to drastically increase the revenue requirement burdon of the seven
10 customers in the Rate XXLT class.

11 **Q IS STAFF'S PROPOSAL REASONABLE IN THIS CASE?**

12 A No. Staff's proposal is based on its so-called alternative (or Hi-Lo) cost of service study.
13 Staff states that this study is to "inform rate design" but in actuality Staff is proposing to
14 change the revenue responsibility of the largest transportation class and changes the
15 results of the A&P study for the revenue responsibility of the largest transportation
16 customers from the previously approved A&P study methodology.

17 **Staff's Proposal**

18 **Q DOES STAFF'S A&P COST OF SERVICE OVER-ALLOCATE COST TO RATE XXLT**
19 **CUSTOMERS?**

20 A Yes. As I explained in my direct testimony, use of the A&P method erroneously
21 allocates excess costs to high usage high load factor customers based on annual
22 throughput and simply does not make sense. Customers that increase throughput and
23 load factor are beneficial to DTE's gas system and do not increase the capacity cost of

1 facilities that are already in place to provide service. The A&P method is not reflective
2 of cost causation. A system designed for average usage would be incapable of
3 providing service to customers on colder than average days, which indicates the lack
4 of intellectual and functional validity of the A&P method.

5 Despite this over-allocation to high usage high load factor customers, an
6 examination of Staff's cost of service model includes a revenue distribution to classes
7 based on previously approved methodology by DTE and Staff. Revised Exhibit MPL-
8 7 (BCC-7) is a cost based revenue distribution to classes, based on the Staff A&P
9 study. The increase to Rate XXLT is shown as \$1,522 million or 4.86%.

10 **Q IS THE \$1,522 MILLION INCREASE THE FINAL INCREASE TO RATE XXLT**
11 **PROPOSED BY STAFF?**

12 A No. Staff adds significantly more cost to Rate XXLT based on the Alternative 2 (Hi-Lo)
13 study which is claimed to only "inform rate design." Informing the XXLT rate design
14 resulted in changing the rate increase from \$1,522 million or 4.86% to \$9.879 million
15 or 31.54% as shown on Staff witness Todd's Revised Exhibit S-6.0, Schedule F-2. Staff
16 adds a \$6.357 million rate design adjustment to the Rate XXLT revenue requirement
17 based on the Alternative 2 (Hi-Lo) study.

18 **Q IS THE STAFF'S ADDITIONAL INCREASE TO RATE XXLT REASONABLE?**

19 A No. Staff's additional increase to Rate XXLT should be rejected for a number of
20 reasons including the following.

- 21 1. The alternative study has not been approved for establishing class revenue
22 requirements and it should not be approved in this case.
- 23 2. The alternative study has been provided with very minimal testimony by DTE or
24 Staff and has not been adequately vetted for use. Issues concerning the validity of

1 loads needed for allocation factors were previously identified. No testimony
2 concerning the correction of this issue has been presented in this case.

3 3. The alternative study is not in accord with approved or proposed rates.
4 Transportation rates are based on usage, not service or pressure levels. To be fair
5 to customers, rates should reflect cost of service. If cost of service is done by
6 service level or pressure, rates should be based on pressure. They are not.

7 4. Staff's proposal is particularly egregious for transmission level (transmission
8 metered) customers on Rate XXLT. These customers (three (3) out of seven (7)
9 or 44% of class) will be blatantly overcharged by Staff's proposal. Staff argues that
10 this 10 month rate case schedule does not provide enough time to establish
11 corrected rates. Staff used that same argument in the previous DTE rate case.

12 5. It would be extremely unfair to use the time constraint argument again while
13 overcharging the three transmission customers for distribution equipment, they do
14 not use.

15 6. Rate XXLT was established to prevent bypass and has been successful in that
16 regard. More study and better analysis is required prior to imposing an extra
17 \$6.357 million on seven (7) customers, at least three (3) of which should obviously
18 not receive the increase. An average of an approximately \$1 million inappropriate
19 increase annually should not be allowed due to time constraints. A better approach
20 is to do the rate design correctly prior to any unwarranted and unfair increase to
21 customers.

22 **Q PLEASE EXPLAIN THE STAFF'S PROPOSAL WITH RESPECT TO THE RATE**
23 **XXLT.**

24 **A** Staff employs the Alternative 2 (Hi-Lo) study to add Hi and Lo pressure distribution
25 main cost to Rate XXLT because four (4) of the seven (7) customers use a portion of
26 those costs. However, three (3) of the seven (7) customers are served from the
27 transmission system and do not use the distribution system. Normally, high pressure
28 customers of this size only use a radial line which is a limited amount of discrete
29 distribution, and do not use the integrated system. Gross allocations based on usage
30 generally over-allocate cost to these large customers. The data to study the discrete
31 use of the system is usually confidential and should be done by Staff or DTE. This
32 proposal by Staff is inadequate and certainly incorrect for the customers served at the

1 transmission level. This approach was endorsed by the NARUC subcommittee on gas
2 as far back as November 1, 1985. As the preferred cost based approach to prevent
3 bypass.

4 **Recommendation**

5 **Q WHAT DO YOU RECOMMEND?**

6 A I recommend that Staff's proposal be rejected for this case. Much more analysis is
7 required and Staff again proposing a short-cut, harmful approach due to time
8 constraints should not be allowed. Staff used the same time constraint argument in the
9 last case in 2021. In that case, U-20940, Rate XXLT was increased by \$6.3 million or
10 26.1% while the average overall increase was 3.6% and the overall transportation class
11 increase was 14.1%, based on Attachment A to the final order. That excessive above
12 average increase was based on an interim solution due to time constraints. Years have
13 gone by and we urge the Commission to not allow the time constraint argument again.
14 Customers on Rate XXLT would be harmed by an excessive increase under Staff's
15 proposal.

16 If despite this serious shortcoming, the Commission adopts Staff's approach,
17 then only the customers using the distribution system should pay the increased costs
18 associated with the distribution allocation to Rate XXLT as proposed by Staff.
19 Transmission level customers should at most pay the rate shown in the A&P study
20 provided in Revised Exhibit MPL-8 (BCC-8). The additional \$6.357 million imposed by
21 Staff amounts to an additional 10.12 cents/Mcf based on the distribution volume of
22 62,813,535 Mcf provided by DTE. This approach would coincide with the Staff's
23 recommendation, but not overcharge the transmission customers on Rate XXLT.

1 Overcharging each of the transmission customers by approximately \$1 million per year
2 is simply wrong and should not be allowed.

3 **Q DOES REVISED EXHIBIT MPL-8 (BCC-8) ADEQUATELY PROVIDE A COST**
4 **BASED TRANSMISSION LEVEL RATE USING STAFF REVENUE REQUIREMENTS**
5 **AND THE A&P STUDY?**

6 A No, two enhancements are required. First, Staff used the rate adjustments developed
7 by DTE for establishing break-even usage levels. Updating the break-even usage
8 analysis decreases the Rate XXLT rate increase to approximately zero. Second,
9 distribution other remains in the XXLT class and for only transmission customers,
10 distribution other should be removed.

11 The correct Rate XXLT for transmission level service is shown on Revised
12 Exhibit MPL-9 (BCC-9) and a rate decrease is required. The associated rate design is
13 provided on Revised Exhibit MPL-10 (BCC-10). Distribution level customers should
14 either be excluded from the rate or pay a distribution cost surcharge of 16.73 cents per
15 Mcf.

16 **Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

17 A Yes, it does.

Qualifications of Brian C. Collins

1 **Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A Brian C. Collins. My business address is 16690 Swingley Ridge Road, Suite 140,
3 Chesterfield, MO 63017.

4 **Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?**

5 A I am a consultant in the field of public utility regulation and a Managing Principal with
6 the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory
7 consultants.

8 **Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK**
9 **EXPERIENCE.**

10 A I graduated from Southern Illinois University Carbondale with a Bachelor of Science
11 degree in Electrical Engineering. I also graduated from the University of Illinois at
12 Springfield with a Master of Business Administration degree. Prior to joining BAI, I was
13 employed by the Illinois Commerce Commission and City Water Light & Power
14 ("CWLP") in Springfield, Illinois.

15 My responsibilities at the Illinois Commerce Commission included the review of
16 the prudence of utilities' fuel costs in fuel adjustment reconciliation cases before the
17 Commission as well as the review of utilities' requests for certificates of public
18 convenience and necessity for new electric transmission lines. My responsibilities at
19 CWLP included generation and transmission system planning. While at CWLP, I
20 completed several thermal and voltage studies in support of CWLP's operating and
21 planning decisions. I also performed duties for CWLP's Operations Department,
22 including calculating CWLP's monthly cost of production. I also determined CWLP's

1 allocation of wholesale purchased power costs to retail and wholesale customers for
2 use in the monthly fuel adjustment.

3 In June 2001, I joined BAI as a Consultant. Since that time, I have participated
4 in the analysis of various utility rate and other matters in several states and before the
5 Federal Energy Regulatory Commission ("FERC"). I have filed or presented testimony
6 before the Arkansas Public Service Commission, the California Public Utilities
7 Commission, the Colorado Public Utilities Commission, the Delaware Public Service
8 Commission, the Public Service Commission of the District of Columbia, the Florida
9 Public Service Commission, the Georgia Public Service Commission, the Guam Public
10 Utilities Commission, the Idaho Public Utilities Commission, the Illinois Commerce
11 Commission, the Indiana Utility Regulatory Commission, the Kentucky Public Service
12 Commission, the Public Utilities Board of Manitoba, the Minnesota Public Utilities
13 Commission, the Mississippi Public Service Commission, the Missouri Public Service
14 Commission, the Montana Public Service Commission, the North Carolina Utilities
15 Commission, the North Dakota Public Service Commission, the Public Utilities
16 Commission of Ohio, the Oklahoma Corporation Commission, the Oregon Public Utility
17 Commission, the Rhode Island Public Utilities Commission, the Public Service
18 Commission of Utah, the Virginia State Corporation Commission, the Washington
19 Utilities and Transportation Commission, the Public Service Commission of Wisconsin,
20 and the Wyoming Public Service Commission. I have also assisted in the analysis of
21 transmission line routes proposed in certificate of convenience and necessity
22 proceedings before the Public Utility Commission of Texas.

23 In 2009, I completed the University of Wisconsin – Madison High Voltage Direct
24 Current ("HVDC") Transmission Course for Planners that was sponsored by the
25 Midwest Independent Transmission System Operator, Inc. ("MISO").

1 BAI was formed in April 1995. BAI and its predecessor firm have participated
2 in more than 1,000 regulatory proceedings in forty states and Canada.

3 BAI provides consulting services in the economic, technical, accounting, and
4 financial aspects of public utility rates and in the acquisition of utility and energy
5 services through RFPs and negotiations, in both regulated and unregulated markets.
6 Our clients include large industrial and institutional customers, some utilities and, on
7 occasion, state regulatory agencies. We also prepare special studies and reports,
8 forecasts, surveys and siting studies, and present seminars on utility-related issues.

9 In general, we are engaged in energy and regulatory consulting, economic
10 analysis and contract negotiation. In addition to our main office in St. Louis, the firm
11 also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix,
12 Arizona.

493752

1 JUDGE THOITS: All right. Is the
2 Michigan Environmental Council ready and interested in
3 binding in the testimony and exhibits of their witnesses?

4 MR. BZDOK: Yes, your Honor. And I will
5 make two offers; the first offer will be of two witnesses
6 on behalf of MEC, NRDC, and Sierra Club, and the second
7 offer will be on behalf of two witnesses on behalf of the
8 Citizens Utility Board of Michigan, if that's
9 permissible?

10 JUDGE THOITS: Yes. Please proceed.

11 MR. BZDOK: On behalf of the Michigan
12 Environmental Council, Natural Resources Defense Council,
13 and Sierra Club, I would move at this time to bind into
14 the record the Direct Testimony of Dr. Asa S. Hopkins,
15 which consists of a cover page, a table of contents, 64
16 pages of questions and answers; and I would move to admit
17 into evidence proposed Exhibits MEC-1 through MEC-16.

18 I would also move on behalf of those
19 parties to bind into the record the Direct Testimony of
20 Alice Napoleon, consisting of a cover page, a table of
21 contents, 42 pages of questions and answers; and move to
22 admit into evidence proposed Exhibits MEC-17 through 30.

23 JUDGE THOITS: All right. Are there any
24 objections to the admission of this testimony or these
25 exhibits? (No response.)

1 Hearing none, the Direct Testimony of Asa
2 Hopkins is bound into the record, and Exhibits MEC-1
3 through MEC-16 are admitted; and the Direct Testimony of
4 Alice Napoleon is bound into the record, and Exhibits
5 MEC-17 through MEC-30 are admitted.

6 (Testimony bound in.)

7 - - -

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE
GAS COMPANY** for authority to increase
its rates, amend its rate schedules and rules
governing the distribution and supply of
natural gas, and for miscellaneous
accounting authority.

Case No. U-21291

DIRECT TESTIMONY OF DR. ASA S. HOPKINS
ON BEHALF OF
MICHIGAN ENVIRONMENTAL COUNCIL, NATURAL RESOURCES
DEFENSE COUNCIL, AND SIERRA CLUB

May 7, 2024

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291****TABLE OF CONTENTS**

I.	INTRODUCTION AND QUALIFICATIONS.....	1
II.	SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS.....	4
III.	INTRODUCTION TO THE ENERGY TRANSITION	6
IV.	LOAD FORECAST	20
V.	INDIVIDUAL CUSTOMER ATTACHMENTS.....	31
VI.	COMMUNITY EXPANSION	38
VII.	THE FUTURE OF HEAT.....	57

**DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

1 **I. INTRODUCTION AND QUALIFICATIONS**

2 **Q1 Please state your name, business address, and position.**

3 **A1** My name is Asa S. Hopkins. My business address is 485 Massachusetts Ave., Suite
4 3, Cambridge, Massachusetts 02139. I am a Vice President at Synapse Energy
5 Economics, Inc. Among other work, I lead Synapse’s consulting regarding the
6 future of gas utilities, and I also work extensively in the related area of building
7 decarbonization technology and policy.

8 **Q2 Please describe Synapse Energy Economics.**

9 **A2** Synapse Energy Economics is a research and consulting firm specializing in energy
10 industry regulation, planning, and analysis. Synapse works for a variety of clients,
11 with an emphasis on consumer advocates, state policymakers, regulatory
12 commissions, and environmental advocates.

13 **Q3 Please describe your professional experience before beginning your current**
14 **position at Synapse Energy Economics.**

15 **A3** Before joining Synapse Energy Economics in 2017, I was the Director of Energy
16 Policy and Planning at the Vermont Public Service Department from 2011 to 2016.
17 In that role, I was the director of regulated utility planning for the state’s public
18 advocate office, and the director of the state energy office. I served on the Board of
19 Directors of the National Association of State Energy Officials. Prior to my work
20 in Vermont, I was an AAAS Science and Technology Policy Fellow at the U.S.
21 Department of Energy (“DOE”), where I worked in the Office of the
22 Undersecretary for Science to develop the first DOE Quadrennial Technology

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 Review. Prior to my time at the U.S. DOE, I was a postdoctoral fellow at Lawrence
2 Berkeley National Laboratory, working on appliance energy efficiency standards.
3 I earned my PhD and Master's degrees in physics from the California Institute of
4 Technology and my Bachelor of Science degree in physics from Haverford College.
5 My resume is included as Exhibit MEC-1.

6 **Q4 Have you previously provided evidence before the Michigan Public Service**
7 **Commission ("the Commission")?**

8 **A4** No.

9 **Q5 Have you previously provided testimony in other jurisdictions on topics**
10 **similar to those you are testifying to in this case?**

11 **A5** Yes. I have testified on gas utility issues, as relates to capital decision-making, rates,
12 and business risk in Connecticut, Quebec, Ontario, Maryland, Washington, DC,
13 Wisconsin, and New York. When I testified before the Régie de l'Energie in
14 Quebec I was recognized as an expert in "energy transition in the gas industry, and
15 business risk." The Ontario Energy Board qualified me as an expert on "the future
16 of electric and gas utility regulatory and business models and associated business
17 risk in the context of deep building decarbonization objectives."

18 **Q6 On whose behalf are you providing evidence in this case?**

19 **A6** I am testifying on behalf of Michigan Environmental Council, Natural Resources
20 Defense Council, and Sierra Club.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 **Q7 What is the purpose of your testimony?**

2 **A7** The purpose of my testimony is to introduce the energy transition and evaluate
3 several components of DTE Gas Company's ("DTE", "DTE Gas", or "the
4 Company") rate proposal within that frame, notably the Company's underlying
5 load forecast and its assumptions and accounting for new customer attachments and
6 community expansions. I also address the need for a "future of heat" regulatory
7 proceeding.

8 **Q8 How is your testimony organized?**

9 **A8** My testimony begins with a summary of my conclusions and recommendations.
10 Section III introduces the energy transition and puts this case in that context.
11 Section IV addresses DTE's load forecast. Section V addresses individual customer
12 attachments; Section VI addresses community expansions. Section VII concludes
13 my testimony with a discussion of a future of heat regulatory proceeding.

14 **Q9 Are you sponsoring any exhibits?**

15 **A9** Yes, I am sponsoring the following exhibits:

16	Exhibit MEC-1:	Resume of Asa Hopkins
17	Exhibit MEC-2:	ICF RNG Report
18	Exhibit MEC-3:	LETI. <i>Hydrogen: A decarbonisation route for heat in</i>
19		<i>buildings?</i>
20	Exhibit MEC-4:	Liebreich Hydrogen Ladder
21	Exhibit MEC-5:	Net Zero America Data
22	Exhibit MEC-6:	Brattle Future of Gas
23	Exhibit MEC-7:	Comparison of Customer Economics
24	Exhibit MEC-8:	DPU Order 20-80

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 Exhibit MEC-9: MNSCDG-6.1a
 2 Exhibit MEC-10: MNSCDG-2.10c
 3 Exhibit MEC-11: MNSCDG-5.11gi
 4 Exhibit MEC-12: MNSCDG-1.8h
 5 Exhibit MEC-13: MNSCDG-1.8fi
 6 Exhibit MEC-14: MNSCDG-1.8b
 7 Exhibit MEC-15: MNSCDG-1.9, -4.4bi, and -4.4ai
 8 Exhibit MEC-16: MNSCDG-4.6f Attachment, DTE Low Carbon Energy
 9 Infrastructure Enhancement and Development Grant
 10 Proposal

11 **II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS**

12 **Q10 Please summarize your primary conclusions.**

13 **A10** I find that:

- 14 • Michigan has committed to achieve net-zero emissions by 2050. The
 15 resulting energy transition will lead to substantial decreases in the volume
 16 of gas transported through DTE's distribution system, which will result in
 17 changes to DTE's rates and competitive position.
- 18 • The energy transition is relevant for decision-making about planning and
 19 investment in the Company's capital system, how the Company accounts
 20 for system expansions to serve new customers, how the Company makes
 21 decisions about repair or replacement of its assets and considers their future
 22 usefulness, and how the Company depreciates its assets.
- 23 • DTE has not adjusted its load forecast and customer count forecast
 24 methodology or its analysis of customer attachments and community
 25 expansion to account for the energy transition.
- 26 • DTE's gas demand forecast does not fully reflect potential future changes
 27 in gas demand and therefore is likely to be too high. This is mainly because
 28 DTE's load forecasting methodology heavily relies on historical trends and

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 does not recognize any climate policy impacts that are likely to arise over
2 the next decade.

3 • It is not reasonable for DTE to assume that new customers will use a
4 constant amount of gas over 20 years when calculating those customers'
5 expected contributions in aid of construction.

6 • DTE consistently overestimates the number of customers that will connect
7 to community expansion projects. This results in under-collection of
8 contributions in aid of construction relative to expectations, and it shifts
9 costs for community expansion projects to non-participating customers.

10 • Based on historical rates of customer attachments, the Mesick-Buckley
11 expansion will have a deficit of about \$838,000 and the Peach Ridge
12 expansion will have a deficit of about \$912,000. DTE's past overestimates
13 likely have an aggregate under-recovery of between \$6 million and \$11
14 million. It is not just and reasonable to ask DTE's non-participating
15 customers to pay these costs.

16 • To correct these deficits, the monthly customer charges in expansion areas
17 would need to rise substantially. At these higher customer charge levels,
18 electric heat pump equipment would have lower operating costs than gas.

19 • DTE's aggregate overrun for the construction cost of 15 recent community
20 expansion costs is about \$9.75 million, or about 16 to 17 percent.

21 **Q11 Please summarize your primary recommendations.**

22 **A11** I recommend that the Commission:

23 • Require DTE to develop a policy-consistent load forecast and evaluate the
24 need for and prudence of its investments in light of that forecast;

25 • Require DTE to amend its tariffs to use a 10-year period for calculating the
26 revenue deficiency;

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

- 1 • Order DTE to use customer adoption rates based on historical experience
- 2 when calculating new attachment surcharges, and shift to using a 10-year
- 3 period of stable consumption when setting the surcharge;
- 4 • In the event that DTE cannot or will not adjust the customer charges for
- 5 Mesick-Buckley and Peach Ridge to align with the corrected levels,
- 6 disallow \$838,000 from the revenue requirement for Mesick-Buckley and
- 7 \$912,000 for Peach Ridge;
- 8 • Order that cost overruns for expansion projects will face a rebuttable
- 9 presumption of imprudence and disallowance; and
- 10 • Initiate a “Future of Heat” proceeding that would bring all essential utilities
- 11 and stakeholders together to address the energy transition in building and
- 12 industrial heat.

13 **III. INTRODUCTION TO THE ENERGY TRANSITION**

14 **Q12 Could you please describe what you mean by the term “energy transition”?**

15 **A12** By “energy transition” I mean the transition away from fossil fuel energy sources
 16 and toward renewable and zero-carbon energy sources as part of an economy-wide
 17 transition to reduce greenhouse gas (GHG) emissions by 80 percent or more by
 18 2050. This transition is the instantiation of many state- and nation-level
 19 commitments to achieve net-zero emissions, including Michigan’s, which I discuss
 20 in further detail below.

21 **Q13 What are the primary pathways seen for the energy transition in the building**
 22 **and industrial sectors?**

23 **A13** Today, the building and industrial sectors consume electricity for a wide range of
 24 end uses and directly combust fuels for space, water, and process heating (as well

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 as cooking, laundry, and other incidental uses). Electricity decarbonization is a
2 relatively straightforward process and already underway, spurred by falling costs
3 of renewable generation technologies such as solar and wind, and accompanied by
4 advances and falling costs in battery and other energy storage technology.
5 Decarbonization of heating, on the other hand, requires either substitution of fossil
6 fuels with limited and/or expensive supplies of lower-carbon combustion fuels, or
7 electrification (such as with highly efficient heat pump technologies).
8 Electrification reduces emissions by taking advantage of the known pathways to
9 decarbonized electricity to supply these end uses.

10 **Q14 Why does electrification rise to the top of the options for building sector**
11 **decarbonization, rather than low-carbon fuels?**

12 **A14** Low-carbon fuels such as renewable natural gas (RNG), hydrogen, and synthetic
13 methane face a set of challenges that impede their ability to provide a
14 decarbonization solution at scale while competing with electrification. These
15 challenges are: (1) limited supply of biological feedstocks; (2) non-zero net GHG
16 emissions; and (3) high cost. Each fuel option faces a different blend of these
17 challenges.

18 RNG is generated from biological wastes (such as from landfills, food, forestry, or
19 animal wastes). There is a limited quantity of such wastes, sources are not
20 connected to the gas system, and that quantity is substantially lower than the total
21 amount of fossil gas that needs to be displaced or replaced. For example, a recent
22 ICF study conducted for the Commission states that “ICF’s estimates for renewable
23 natural gas deployment in Michigan for the Achievable and Feasible scenarios

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 amount to 8.5% and 22.0% of the average annual natural gas consumption in
2 relevant sectors for the last five years for which there are data available.”¹ In
3 addition, RNG made from these biological sources generally has net-positive GHG
4 emissions; the only common exception is RNG from animal wastes. Animal wastes
5 are a limited subset of feedstocks for RNG.

6 Green hydrogen (made from splitting water) could be created at a larger scale,
7 provided sufficient electric power is available. Here the primary supply-side
8 challenge is that hydrogen is competing with other uses for electric power that can
9 more efficiently provide many of the same energy services. Producing hydrogen
10 from electricity and then combusting that hydrogen to provide heat is much less
11 efficient than using electricity directly through heat pumps; multiple times more
12 electricity is required via the hydrogen pathway.² In addition, hydrogen has severe
13 limits when using existing distribution system infrastructure. Hydrogen embrittles
14 steel, so it either has to use a blend level below 7 percent (on an energy or emissions
15 basis, and therefore with only a small impact on emissions) or requires full-system
16 conversion to hydrogen-safe materials (which may also need to be resized to deliver
17 sufficient energy using a lower-density gas). This retrofitting would include all
18 equipment in customer homes. Hydrogen may be suitable for a small number of

¹ ICF. September 23, 2022. *Michigan Renewable Natural Gas Study: Final Report*. Prepared for the Michigan Public Service Commission. Accessed at <https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/RenewableNaturalGas/MI-RNG-Study-Final-Report-9-23-22.pdf>. Attached as Exhibit MEC-2.

² LETI. *Hydrogen: A decarbonisation route for heat in buildings?*. Attached as Exhibit MEC-3.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 hard-to-electrify end uses where it has fewer competitors,³ but that is not sufficient
2 scale to change the implications for gas utilities.

3 Synthetic methane, produced by combining green hydrogen with carbon captured
4 from non-fossil sources, is even more costly and uncertain because it requires
5 access to a pure source of non-fossil carbon in addition to overcoming almost all of
6 the challenges of hydrogen.⁴

7 **Q15 Why is the energy transition relevant for this case?**

8 **A15** Gas distribution utilities such as DTE Gas get their revenue by transporting fossil
9 fuel gas to customers over an extensive pipeline network, and by recovering the
10 cost of that transmission and distribution network over many years through delivery
11 charges added to the cost of the gas commodity. Under the principles of utility
12 regulation used in Michigan and across the country, utilities can recover and earn a
13 return on prudent investment in their systems from their customers through rates if
14 the assets are used and useful. The energy transition will require substantial
15 reductions in the amount of gas delivered. For example, the Net Zero America
16 study, conducted by researchers at Princeton University, identified that pipeline gas
17 use in Michigan would fall by a factor of two or more by 2050 in all scenarios that
18 achieve net-zero emissions; in high electrification cases Michigan pipeline gas use

³ Liebreich, M. *Clean Hydrogen Ladder, Version 5.0*. Attached as Exhibit MEC-4.

⁴ Synthetic methane does have the advantage relative to hydrogen that it can be used in existing equipment and transported using existing pipelines.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 falls by more than a factor of seven.⁵ Reductions like these will require changes in
 2 the Company's rates. This will change the competitive position of the Company's
 3 service compared with alternatives. In addition, some of the Company's assets may
 4 no longer be needed to provide service (that is, no longer used and useful) and
 5 would therefore need to be removed from the rate base. If these assets are not fully
 6 depreciated, this could create stranded costs borne by either utility investors or the
 7 Company's remaining customers. The energy transition is therefore relevant for
 8 decision-making about planning and investment in the Company's capital system,
 9 system expansions to serve new customers, decisions about repair or replacement
 10 of its assets and considers their future usefulness, and asset depreciation.

11 **Q16 Is it generally accepted that there is a transition happening in the energy**
 12 **sector?**

13 **A16** Yes. The federal government has made formal international commitments to reduce
 14 nationwide GHG emissions by more than half from 2001 levels by 2030, and to put
 15 the country on a path to net-zero emissions by 2050. Numerous states have
 16 established targets through laws and executive orders. At both the federal and state
 17 levels, policymakers are taking actions to make those commitments a reality
 18 through regulations, incentives, codes and standards, and other policies and
 19 programs. U.S. GHG emissions fell by more than 15 percent from their peak in

⁵ See Exhibit MEC-5 (from <https://netzeroamerica.princeton.edu/?explorer=pathway&state=michigan&table=e-negative&limit=200>).

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 2007 to 2021 and are below 1990 levels, a substantial impact resulting from climate
2 policies.⁶ Many states have seen emissions fall further.

3 **Q17 Have policymakers studied the energy transition at the state and federal levels**
4 **and implemented policies that will directly affect the economics of gas**
5 **distribution utilities?**

6 **A17** Yes. Numerous states have conducted pathway analyses and energy plans that
7 examine the energy transition. Notable comprehensive analyses include the New
8 York Climate Scoping Plan, Massachusetts 2050 Roadmap and Clean Energy and
9 Climate Plans (for 2025, 2030, and 2050), the Colorado GHG Pollution Reduction
10 Roadmap, and the California Climate Change Scoping Plan. All of these state-level
11 analyses identify electrification as a primary approach to decarbonizing the electric
12 sector and project substantial reductions in pipeline gas use, and each of these states
13 has initiated or enhanced policies and programs to encourage building
14 electrification through incentives and utility obligations. These states have also all
15 implemented regulatory processes to examine and reform how gas utilities conduct
16 their business. New York has established a gas planning proceeding; Massachusetts
17 regulators have completed Case No. 20-80 and laid out reformed approaches to gas
18 utility planning; Colorado policymakers have established a requirement for Clean
19 Heat Plans that will reduce emissions from customers of the natural gas system;

⁶ U.S. Environmental Protection Agency (EPA). Accessed December 13, 2023. “Climate Change Indicators: U.S. Greenhouse Gas Emissions.” Available at: <https://www.epa.gov/climate-indicators/climate-change-indicators-us-greenhouse-gas-emissions>.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 and California policymakers have studied non-pipeline alternatives and initiated a
2 Long Term Gas Planning Rulemaking.

3 **Q18 What about in Michigan?**

4 **A18** Governor Whitmer has issued several executive orders that lay out a pathway to
5 deep decarbonization. Through Executive Order 2019-12, Michigan joined the
6 United States Climate Alliance, committing Michigan to reduce GHG emissions 26
7 to 28 percent below 2005 levels by 2025. In Executive Order 2020-10, Governor
8 Whitmer directed the state to achieve economy-wide climate neutrality by 2050,
9 and net-negative GHG emissions thereafter. The Governor further directed the
10 creation of the Michigan Healthy Climate Plan, which was issued in April 2022.
11 The Healthy Climate Plan includes a roadmap to 52 percent GHG reductions from
12 2005 baselines by 2030, including a 17 percent reduction in emissions related to
13 heating Michigan buildings. The plan elaborates further with respect to natural gas:
14 “To complement immediate policy actions, the Plan recommends the state
15 undertake a pathway analysis to assess options to achieve carbon neutrality from
16 natural gas production, transmission, distribution, compression, storage, and end
17 uses in a least-cost manner. This analysis should consider a full range of options
18 for decarbonizing natural gas end uses, including energy efficiency, electrification,
19 fuel switching to renewable natural gas and hydrogen, and other potential
20 opportunities.”⁷

⁷ Michigan Healthy Climate Plan, p. 43. <https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Offices/OCE/MI-Healthy-Climate-Plan.pdf>.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 Michigan legislators have taken concrete action to change the policy landscape in
2 line with the Healthy Climate Plan. The enacted Senate Bill 273 of 2023 explicitly
3 allows electric utilities to offer efficiency electrification measures, encourages gas
4 utilities to achieve most of their required energy waste reduction through building
5 shell improvements that reduce heating demand (rather than through gas-burning
6 equipment), and allows gas utilities to receive credit for waste reduction through
7 electrification measures.

8 **Q19 Could you please summarize the state of energy transition planning and**
9 **strategies at the federal level?**

10 **A19** Federal climate planning occurs within the context of the United Nations
11 Framework Convention on Climate Change and the Paris Agreement reached under
12 the auspices of that multinational process. Under the Paris Agreement, countries
13 pledge to take actions to meet nationally determined contributions (NDC) toward
14 the worldwide emissions reductions required to keep temperatures at or below 2
15 degrees above pre-industrial levels. In 2016, as part of its initial NDC, the U.S.
16 government presented the *United States Mid-Century Strategy for Deep*
17 *Decarbonization*, a report that shows pathways and considerations for the United
18 States to reduce GHG emissions by 80 percent or more below 2005 levels by 2050.⁸
19 The report lays out two primary strategies for a low-carbon buildings sector: energy

⁸ United States Executive Office of the President. 2016. "United States Midcentury Strategy for Deep Decarbonization." Washington, DC, p. 5. Available at: https://unfccc.int/files/focus/long-term_strategies/application/pdf/mid_century_strategy_report-final_red.pdf.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 efficiency and electrification of end uses. In the residential and commercial sector,
2 the plan involves a transition to electric space heating, hot water heating appliances,
3 and high-efficiency heat pumps.

4 In 2021, the United States re-joined the Paris Agreement and set more ambitious
5 reductions goals in its revised NDC: achieving net-zero emissions no later than
6 2050 and an interim goal of reducing net GHG emissions by 50–52 percent of 2005
7 levels by 2030. The government presented an updated *Long-Term Strategy* in 2021
8 in line with these updated goals and studied multiple pathways to achieve them.⁹

9 All viable pathways emphasize decarbonizing electricity and electrifying end uses.
10 For the building sector, the efficient use of electricity for heating, hot water,
11 cooking, and other end uses is the primary driver for emissions reductions, moving
12 away from natural gas and other fossil fuels. Specifically, the pathways assume that
13 heat pumps and other electric heaters and electric cooking account for more than
14 60 percent of all sales by 2030 and almost 100 percent by 2050.¹⁰

15 The federal government will support rapid evolution in the energy sector and clean
16 technology deployment through investment and incentives. The Long-Term
17 Strategy identifies that the primary goals for the next decade are to increase
18 efficiency measures and sales of electric appliances. In the longer term, the federal
19 government has stated that all buildings need to be decarbonized through end-use

⁹ United States Executive Office of the President. 2021. "The Long-Term Strategy of the United States," Washington, DC. Available at: https://unfccc.int/sites/default/files/resource/US_accessibleLTS2021.pdf.

¹⁰ *Id.* at 32.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC

CASE NO. U-21291

1 electrification and significant implementation of energy efficiency measures to
 2 lower overall demand and reduce energy waste. In the industrial sector, low- and
 3 medium-temperature heat processes are priority candidates for industrial
 4 electrification in the near term through increased use of industrial heat pumps,
 5 electric boilers, or electromagnetic heating processes. Energy demand overall is
 6 expected to decrease as efficiency improves, and the share of electricity in final
 7 energy demand will grow as end uses are electrified: from about 50 percent in 2020
 8 to 90 percent or more by 2050 because the onsite combustion of gas, oil, and other
 9 fuels will decrease substantially.¹¹

10 **Q20 What policy and programmatic actions has the federal government taken that**
 11 **reflect the pathways and priorities identified in the Long-Term Strategy?**

12 **A20** The *Inflation Reduction Act* and *Infrastructure Investment and Jobs Act* (also
 13 known as the *Bipartisan Infrastructure Law*) together allocate tens of billions of
 14 dollars for energy efficiency implementation and deployment of low- and no-GHG
 15 emission technologies.¹² These laws are expected to drive large-scale adoption of
 16 technologies that will support electrification. The *Inflation Reduction Act* provides
 17 up to \$2,000 of federal tax credits for air-source heat pumps and a 30 percent tax

¹¹ *Id.* at 45.

¹² See Nadel, Steven. 2023. *How Utility Energy Efficiency Programs Can Use New Federal Funding*, American Council for an Energy-Efficient Economy (ACEEE). Available at: https://www.aceee.org/sites/default/files/pdfs/home_energy_upgrade_incentives_2-1-23_1.pdf; ACEEE. 2023. *Home Energy Upgrade Incentives*. Available at: https://www.aceee.org/sites/default/files/pdfs/how_utility_energy_efficiency_programs_can_use_new_federal_funding_-_encrypt_1.pdf.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC

CASE NO. U-21291

1 credit for geothermal heat pumps.¹³ The *Inflation Reduction Act's* Home
 2 Electrification Rebates Program provides substantial amounts of rebates, up to
 3 \$8,000 for heat pumps and up to \$1,750 for heat pump water heaters, to low- and
 4 moderate-income customers.¹⁴ One study estimated that electric space heating
 5 would exceed the number of homes with gas space heating by 2032, even before
 6 factoring in the impact of the *Inflation Reduction Act*.¹⁵ As these incentives make
 7 heat pumps more widely accessible, adoption rates will continue to accelerate.

8 The federal government has taken other substantial actions to accelerate
 9 electrification in the buildings sector and to shape and expand the market for heat
 10 pumps. President Biden invoked the *Defense Production Act* to speed up domestic
 11 production of heat pumps.¹⁶ Under this program, the DOE will award up to \$250
 12 million to entities capable of establishing or expanding manufacturing capacity.
 13 Administrators for the Energy Star program, jointly run by the U.S. Environmental
 14 Protection Agency (EPA) and DOE, have proposed to update its programs for

¹³ Rewiring America. "25C Residential Energy Efficiency Tax Credit and 25D Residential Clean Energy Tax Credit." Available at: <https://www.rewiringamerica.org/ira-fact-sheets>.

¹⁴ Nadel, Steven. 2023. *How Utility Energy Efficiency Programs Can Use New Federal Funding*. ACEEE. Available at: https://www.aceee.org/sites/default/files/pdfs/home_energy_upgrade_incentives_2-1-23_1.pdf.

¹⁵ Mifsud, Ana Sophia and Rachel Golden. 2022. *Millions of US Homes Are Installing Heat Pumps. Will It Be Enough?* RMI. Available at: <https://rmi.org/millions-of-us-homes-are-installing-heat-pumps-will-it-beenough/> (citing EIA Residential Energy Consumption Survey).

¹⁶ U.S. Department of Energy. Last Accessed January 2, 2024. "Enhanced Use of Defense Production Act." Available at: <https://www.energy.gov/mesc/enhanced-use-defense-production-act-1950>.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 heating systems to advance this policy direction. Specifically, the Energy Star
2 program administrators have proposed to sunset Energy Star certification for
3 furnaces and for cooling-only air conditioners, effective at the end of 2024 (with no
4 new products certified as of December 30, 2023).¹⁷ The program’s proposal states
5 that “With the passage of the *Inflation Reduction Act*, EPA sees an unprecedented
6 opportunity for the ENERGY STAR program to support the national transition to
7 the most energy efficient equipment available. The Agency recognizes an important
8 responsibility to guide consumers to the choices that support the efficient
9 electrification of residential space conditioning. As such, EPA is proposing to phase
10 out the labeling and promotion of residential gas furnaces and [central air
11 conditioners].”¹⁸ The Energy Star statement also indicates that a similar approach
12 would be taken for oil and gas boilers and dryers. As of this writing, Energy Star
13 program administrators have not yet formally decided to make these program
14 changes.

15 **Q21 Do industry consultants see a changing world for gas utilities?**

16 **A21** Yes. For example, The Brattle Group developed an introductory set of materials as
17 part of its marketing to gas utilities, called the “Future of Gas Utilities Series,”

¹⁷ U.S. EPA (Climate Protection Partnerships Division) - ENERGY STAR. 2023. *HVAC Sunset Letter*. Available at:
<https://www.energystar.gov/sites/default/files/asset/document/HVAC%20Sunset%20Letter.pdf>.

¹⁸ *Ibid.*

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC

CASE NO. U-21291

1 presented as a series of webinars in the summer and fall of 2021. The first of these
 2 webinars lays out the context for risk assessment, and its materials¹⁹ state that:

- 3 • "...cost declines related to innovation, as well as federal, state, and
 4 municipal support policy, will increase electrification"²⁰
- 5 • "Utilities will need to consider how to recover their costs from a shrinking
 6 customer base, which could lead to higher rates and create a vicious
 7 cycle."²¹
- 8 • "Waiting Passively Is Not a Sustainable Option for Utilities or Customers.
 9 If gas utilities defer building a long-term strategy, they risk not having a
 10 voice in the policy, planning, and regulation process. Gas demand reduction
 11 and bill increases for remaining customers will come with or without utility
 12 involvement. However, the needed change is likely to be delayed or
 13 inefficient without utility involvement.... The transition process will play
 14 out over many years, but the planning must start now."²²
- 15 • "The transition is already underway: at the current rate, the number of
 16 homes with electric space heating could exceed the number of homes with
 17 gas space heating by 2032."²³
- 18 • "As states pursue degasification policies and homes convert to electric
 19 heating, utilities risk losing customers and load. Nationally, electric heating
 20 is outpacing gas heating adoption. Technology mandates and policy further

¹⁹ The Brattle Group. August 2021. *The Future of Gas Utilities Series. Transitioning Gas Utilities to a Decarbonized Future Part 1 of 3*. Accessed at https://www.brattle.com/wp-content/uploads/2022/01/The-Future-of-Gas-Utilities-Series_Part-1.pdf and attached as Exhibit MEC-6.

²⁰ *Id.*, p. 2.

²¹ *Id.*, p. 2.

²² *Id.*, p. 4.

²³ *Id.*, p. 9.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC

CASE NO. U-21291

1 accelerate the problem. Utilities will likely continue investing in their
2 existing system for safety and reliability but need to recover those costs
3 from a shrinking customer base. This puts remaining customers at risk, a
4 “death spiral” trend pushing more customers to electrification. Up to \$150–
5 180 billion of gas distribution assets could be under-recovered as a result of
6 the transition. This spiral will increase customer costs and increase energy
7 burdens, especially for low-income and vulnerable populations.”²⁴

8 **Q22** What do you see as the major implications of the energy transition for gas
9 utilities?

10 **A22** Utility commissions are increasingly recognizing that business-as-usual approaches
11 to managing the gas system cannot continue. The major implications of the energy
12 transition for gas utilities are:

- 13 • The future of gas consumption and gas utility asset utilization will not look
14 like the past or present. Energy delivered by the gas system will fall
15 substantially, and the building sector share of gas consumption will fall.
- 16 • To the extent that biomethane, hydrogen, or synthetic methane are used,
17 they will be expensive enough that customers who can afford to electrify
18 will do so instead of using those fuels via the gas system.
- 19 • Business-as-usual approaches to leak-prone pipe replacement are not
20 justified. Capital investments should not be made until they are shown to be
21 superior to alternatives that incorporate repair, efficiency, electrification,
22 and retirement, accounting for the limited lifetime of pipe replacements.
- 23 • The recovery of invested capital over a smaller volume of sales will mean
24 higher gas distribution rates and increased competition from electricity. The

²⁴ *Id.*, p. 11.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 extent of these gas rate increases can be reduced by changes to the utility's
2 approach to capital investment, repairs, retirement, and depreciation.

- 3 • Utilities have a responsibility to undertake prudent planning and investment
4 actions to adapt to the energy transition, taking into account the timeframe
5 of that transition and how it relates to the lifetime of gas assets. Failure to
6 make prudent capital decisions increases stranded-asset risk, which may be
7 borne by customers and/or investors.

8 **Q23 What is the important take-away regarding the energy transition for this case?**

9 **A23** The future will not be like the present or past. Given long lives of utility assets,
10 practices relating to those assets will need to change during their lifetime, even if
11 near-term changes in sales are small. Gas infrastructure investment practices that
12 assume continuity with the past are no longer reasonable or justified.

13 **Q24 Has DTE adopted these lessons?**

14 **A24** No, it has not. As discussed in the remainder of my testimony, DTE has not adjusted
15 its load forecast and customer count forecast methodology or its analysis of
16 customer attachments and community expansion to account for the energy
17 transition. The failure to do so is unreasonable and imprudent, and DTE should bear
18 the costs and risks of its decisions in this regard.

19 **IV. LOAD FORECAST**

20 **Q25 How does DTE develop load forecasts for its gas customers?**

21 **A25** DTE develops its load forecasts primarily based on the projected number of
22 customers and average gas usage per customer (GHC-11, GHC-16). I will explain

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 in detail how DTE develops projections of customer counts and average gas usage
2 per customer below.

3 **Projections of customer counts**

4 DTE projects total customer counts based on DTE's projections of customer
5 attachments (from new properties) and customer non-attachments (from the
6 existing properties that are currently receiving gas services from DTE). Witness
7 Chapel provides the projected average number of customers through 2028 in
8 Exhibit A-15, Schedule E3. This projection shows a steady increase in customers
9 over the next five years at annual growth rates of 0.7 percent for residential heating
10 customers and 0.3 percent for commercial heating customers.

11 According to Witness Chapel, "[p]rojected attachments are provided by the
12 Company's Marketing Department and is their assessment of how many new
13 customers the Company expects to attach through marketing efforts in expanding
14 areas."²⁵ DTE also states that "DTE uses historical attachment data and current
15 market trends that identifies the cost differential between propane and natural gas
16 to forecast attachments."²⁶ DTE develops its forecast of customer counts for two
17 sub-groups: "Routine" growth (i.e., new construction customers) and "Proactive"

²⁵ Direct Testimony of George H. Chapel, GHC-6: 7-10.

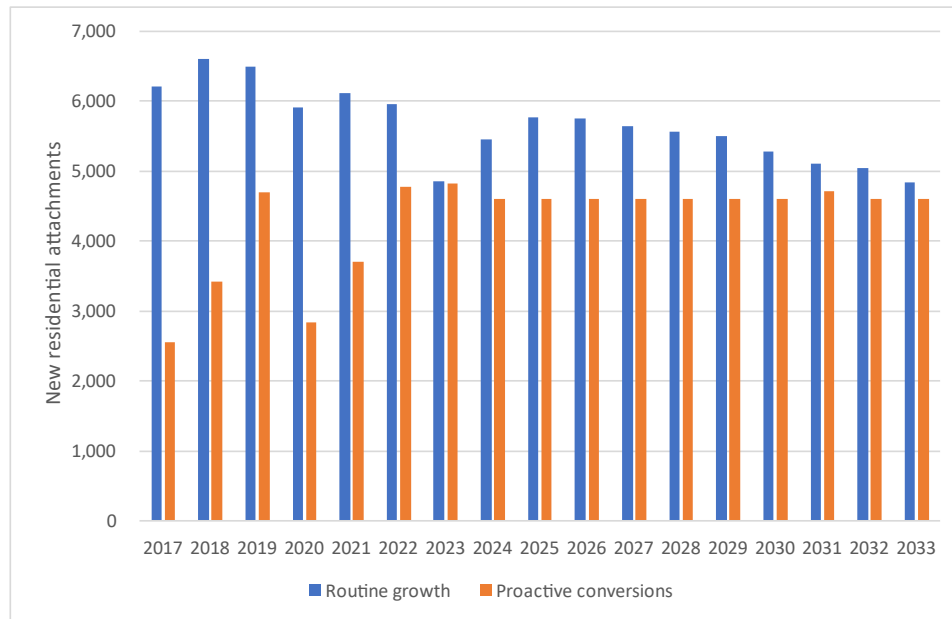
²⁶ DTE's response to MNSCDG-2.7b.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC

CASE NO. U-21291

1 conversions (i.e., line extensions and on-main conversions).²⁷ DTE’s forecasts for
2 these two types of customers are shown in Figure 1 below.

3 *Figure 1. DTE’s estimates of historical and forecasted residential customer*
4 *attachments*



5

6 Source: DTE Excel file *U-21291 MNSCDG-2.7a -Jun 2023 New Markets Attachments - 2023 Rate Case*, “Forecast Summary
7 2023” tab.

8 DTE provided its analysis of residential customer attachments in response to
9 MNSCDG-6.1a. This analysis shows that, for the Routine category, DTE relies on
10 Global Insight’s forecast for new residential housing starts for the entire state to
11 estimate the number of new houses with gas service within DTE’s territory,
12 assuming a factor of 78 percent for “Michigan State Nat Gas Penetration” and a
13 factor of approximately 32 percent for “DTE Gas Service Territory Customer

²⁷ DTE’s response to MNSCDG-9.1c.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC

CASE NO. U-21291

1 Share” through 2033.²⁸ The share of DTE gas service customers in the state is based
 2 on the data for 2013 (per the “Assumptions - New Way” tab). In addition, the 78
 3 percent factor for the share of gas heating customers out of all heating customers in
 4 the state is based primarily on a *Detroit News* article from October 26, 2012.²⁹ DTE
 5 states that it uses these historical data as a baseline and adjusts the data “if the
 6 previous year’s actual results produced a +/- 10% difference to the respective
 7 forecast.”³⁰ DTE’s analysis indicates that it did not make any adjustments to the
 8 historical data mentioned above, which implies that the difference between actual
 9 results and forecasts were within the +/- 10% range.³¹

10 For Proactive conversions, DTE develops separate forecasts as shown in Figure 1
 11 above. DTE develops these forecasts based on “historical attachment data and
 12 current market trends that identifies[sic] the cost differential between propane and
 13 natural gas.”³²

14 DTE employs a different approach for non-attachment customers. DTE forecasts
 15 non-attachment customers based on the changes in customer counts in recent
 16 historical years (1 to 3 years) in seven different demand regions.³³ In one place,

²⁸ An Excel file “U-21291 MNSCDG-2.7a -Jun 2023 New Markets Attachments - 2023 Rate Case,” the “Forecast Summary 2023” tab and the “Assumptions - New Way” tab.

²⁹ Ex MEC-9, DTE’s response to MNSCDG-6.1a.

³⁰ DTE’s response to MNSCDG-9.1a.

³¹ An Excel file “U-21291 MNSCDG-2.7a -Jun 2023 New Markets Attachments - 2023 Rate Case,” the “Forecast Summary 2023” tab.

³² DTE’s response to MNSCDG-2.7b. Also see DTE’s response to MNSCDG-10.11b.

³³ Chapel Direct, GHC-5 to 6; DTE’s response to MNSCDG-2.8b.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 Witness Chapel mentions “a recent three-year historical average growth/loss rate
2 calculated for each of DTE Gas’s seven demand regions”³⁴ for estimating customer
3 counts and in another place he mentions “the 12-month historical look-back of net
4 non-attachment customer change to the growth/loss rate.”³⁵ While Witness Chapel
5 is not clear exactly how DTE used these two methods (e.g., which methods it used
6 for each region), what is clear is that DTE is using recent historical data to project
7 growth in non-attachment customers and assumes no impacts from future policy
8 changes.

9 **Projections of usage per customer**

10 On average, DTE’s sales per customer have declined about 30 percent over the 26-
11 year period from 1997 to 2022.³⁶ DTE projects continuing declines in gas usage per
12 customer. Witness Chapel explains that DTE forecasts changes in overall gas usage
13 per customer based on various factors including changes in the volumetric energy
14 content of the gas DTE provides (the “heating value”), demographic changes in
15 DTE’s customer base, DTE’s Energy Waste Reduction (EWR) program, and
16 customer behavior in response to weather.³⁷ Among these factors, it appears that
17 the EWR program has the largest impact. Witness Chapel states that DTE

³⁴ Chapel Direct, GHC-5: 24-25; GHC-6: 1.

³⁵ Chapel Direct, GHC-6: 6-7.

³⁶ U.S. Energy Information Administration. Natural Gas Annual Respondent Query System. See <https://www.eia.gov/naturalgas/ngqs/#?report=RPC&year1=1997&year2=2022&company=Name&items=1010CT,1010VL,101TVL,1110CT,1110VL>.

³⁷ GHC-11, line 5 to 10.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 “projected annual demand reductions due to EWR to be 1.05% for 2023, dropping
2 down to 1.00% in 2024 and beyond” for residential customers.³⁸ This annual
3 savings rate closely corresponds to the per-customer usage reductions that I observe
4 from Exhibit A-15, Schedule E2, page 1 and 2, which shows projected gas volumes
5 and average number of customers.

6 **Q26 Does that forecast reflect what we know about the future demand for gas?**

7 **A26** No. DTE’s gas demand forecast does not fully reflect potential future changes in
8 gas demand and therefore is likely to be too high. This is mainly because DTE’s
9 load forecasting methodology heavily relies on historical trends and does not
10 recognize any climate policy impacts that are likely to arise over the next decade
11 (except small impacts from the continuation of the existing EWR programs). For
12 example, as shown in Figure 1 above, DTE is forecasting almost the same number
13 of Proactive conversions (i.e., line extensions and on-main conversions) per year
14 for the next decade through 2033. Recall that DTE also assumes that the share of
15 gas for space heating in new construction relative to other fuels and electricity stays
16 the same (78 percent) over the next decade. DTE’s load forecasting approach is
17 inadequate for forecasting future gas demand because the future demand for gas
18 will not be like the present or past, as I discussed earlier in this testimony.

³⁸ Chapel Direct, GHC-16: 18-19.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC

CASE NO. U-21291

1 **Q27** Are there any other aspects of DTE’s load forecasting methodology that are
 2 not appropriate for forecasting future gas consumption or customers?

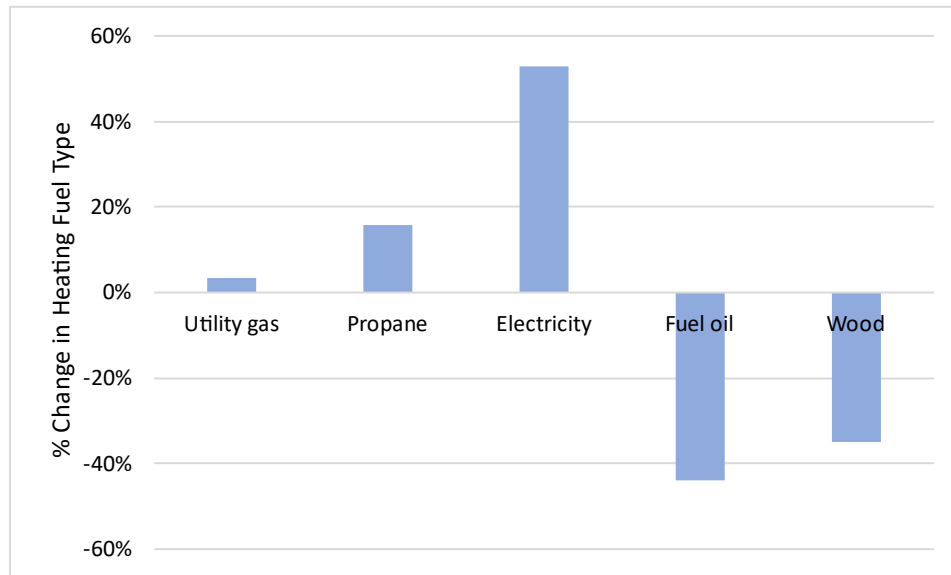
3 **A27** Yes. DTE develops forecasts of Proactive conversions based on “historical
 4 attachment data and current market trends that identifies[sic] the cost differential
 5 between propane and natural gas.”³⁹ This approach is inadequate to fully capture
 6 the current market trend, because adoption of electric heating has been increasing
 7 considerably over the past several years. According to the U.S. Census Bureau’s
 8 American Community Survey, the number of Michigan households with electric
 9 space heating increased by 53 percent in 2022 relative to 2013, while the increase
 10 in utility gas heating households was only about 3 percent and the increase in
 11 propane was about 16 percent during the same period, as shown in Figure 2.⁴⁰ On
 12 the other hand, the number of households with wood space heating or fuel oil space
 13 heating declined substantially (falling by 35 percent to 45 percent, respectively).
 14 This clearly shows that DTE’s approach that evaluates the choice as being only
 15 between utility gas and propane misses the biggest trend in the space heating
 16 market: toward electrification.

³⁹ DTE’s response to MNSCDG-2.7b.

⁴⁰ U.S. Census Bureau’s American Community Survey 1-Year estimate for 2013.
<https://data.census.gov/table/ACSDP1Y2013.DP04?g=040XX00US26>; U.S. Census
 Bureau’s American Community Survey 1-Year estimate for 2022.
<https://data.census.gov/table/ACSDP1Y2022.DP04?g=040XX00US26>.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 *Figure 2. Changes in Michigan heating fuel type, 2022 relative to 2013*



2

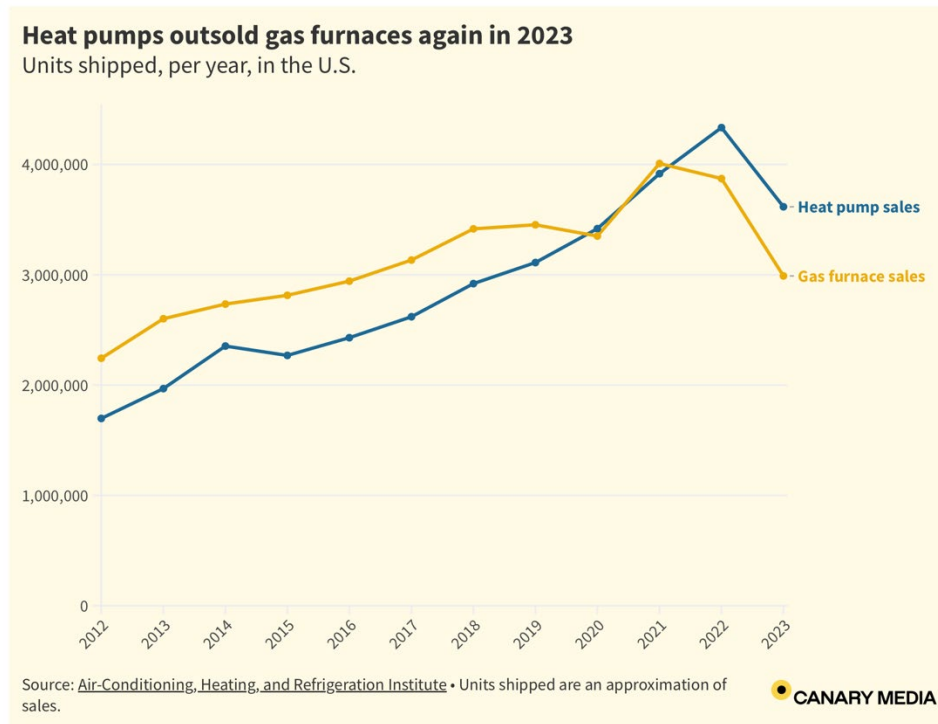
3 Source: U.S. Census Bureau. American Community Survey 1-Year estimates for 2013 and 2022.

4 Heat pump and gas furnace sales at the national level show a similar trend. As
5 shown in Figure 3, the relative gap in equipment sales has been narrowing over the
6 past decade between heat pumps and gas furnaces; heat pump sales surpassed gas
7 furnace sales in 2022 and 2023.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC

CASE NO. U-21291

1 *Figure 3. National trend in heat pump and gas furnace sales*



2
3 Source: Takemura, A. 2024. "Heat pumps outsold gas furnaces again last year — and the gap is growing."
4 *Canary Media*. February 13. Available at: [https://www.canarymedia.com/articles/heat-pumps/heat-pumps-](https://www.canarymedia.com/articles/heat-pumps/heat-pumps-outsold-gas-furnaces-again-last-year-and-the-gap-is-growing)
5 [outsold-gas-furnaces-again-last-year-and-the-gap-is-growing](https://www.canarymedia.com/articles/heat-pumps/heat-pumps-outsold-gas-furnaces-again-last-year-and-the-gap-is-growing).

6 Lastly, this recent historical trend in heat pump and gas heating adoption rates is
7 not consistent with the way DTE is forecasting the number of gas customers for
8 new construction (or routine growth), where it is assuming a fixed share of 78
9 percent gas customers among all residential new construction projects.

10 **Q28 Does DTE take state policy encouraging electrification into account in its load**
11 **forecasting?**

12 **A28** In MNSCDG-2.8d, Witness Chapel states that "DTE Gas Company does not
13 incorporate the impacts of the state's climate and clean energy laws into its
14 customer count forecast. DTE Gas Company does not take a position about the
15 impact of Senate Bill 273 on gas customer counts or attachments for its customer

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 count forecast.” Witness Chapel further states that “DTE Gas Company did not
 2 incorporate in its sales forecasts the impacts of the state’s climate and clean energy
 3 laws, including Senate Bill 273.”⁴¹ DTE’s Gas Delivery Plan includes a projection
 4 of future bills through 2033.⁴² When asked if DTE takes account of electrification
 5 when making this projection, Witness Fedele stated that “[c]urrently, given the
 6 current legislation and costs, we don’t believe electrification will have a significant
 7 impact on natural gas consumption in the next ten years. If it becomes significant
 8 in the future, our current methodology would be adapted to include the impact.”⁴³
 9 This assessment is inconsistent with both state decarbonization policies that require
 10 emissions reduction within the next 10 years and already existing trends towards
 11 residential electrification.

Q29 What are the implications of a load forecast that is too high?

13 **A29** A load forecast with high gas consumption is likely to lead to overbuilding of gas
 14 pipeline systems. Such a forecast would also prevent DTE from considering
 15 retirements of gas pipelines in some segments of its service territory where a
 16 majority of customers may leave the system (e.g., switch to electric heating) to
 17 choose cleaner heating options that are supported by state and federal policies.
 18 Overbuilding of gas pipeline systems driven by DTE’s flawed load forecast could
 19 result in overly expensive gas system costs and overly high gas bills for consumers.

⁴¹ Ex MEC-10, discovery response MNSCDG-2.10c.

⁴² Exhibit A-12 Schedule B5.6, p. 9, Figure 5.

⁴³ Ex MEC-11, discovery response MNSCDG-5.11gi.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 **Q30** **What should DTE do to improve its load forecast?**

2 **A30** As I mentioned above, I expect to see significant policy and programmatic actions
3 at the state and federal levels that influence gas consumption in Michigan. DTE
4 should develop a load forecast that accounts for such policy and programmatic
5 actions and changing market conditions. More specifically, I recommend that the
6 Commission require DTE to develop a forecast of future sales that reflects policy
7 and market developments. For example, the Healthy Climate Plan lays out a
8 roadmap to 52 percent GHG reductions from 2005 baselines by 2030, including a
9 17 percent reduction in emissions related to heating Michigan buildings. The
10 Commission should require DTE to incorporate this 17 percent reduction in
11 emissions from space heating end uses when it develops a policy-consistent sales
12 forecast. For a business-as-usual case, I recommend that DTE develop its forecasts
13 of gas customer counts and gas usage based on updated market conditions,
14 including the latest data on the share of heat pump and gas furnace sales and
15 installations. DTE should also examine the impacts of the declining share of gas
16 customers, driven by various policies, on its forecast of gas demand. The
17 Commission should also order DTE to make all underlying data, models, and
18 assumptions for its forecast publicly available so that stakeholders and Commission
19 staff can review the Company's methods.

20 Further, DTE should be required to evaluate all capital expenditures and supply
21 contracts against both its business-as-usual forecast and a policy-consistent
22 forecast.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 **Q31** What are the implications of a change in load forecast for rate cases such as
2 this one?

3 **A31** DTE is proposing extensive investments in its system, justified in part by the
4 continued need to meet customer demands over the foreseeable future. DTE should
5 ensure that each of its investments remains a prudent use of ratepayer funds under
6 the corrected load forecast, and it should remove or change any investments that
7 are not needed in this case.

8 **V. INDIVIDUAL CUSTOMER ATTACHMENTS**

9 **Q32** Could you please summarize how DTE determines how customer
10 contributions in aid of construction are calculated?

11 **A32** DTE lays out its cost and revenue estimation and allocation approach in Section C8
12 of its Rate Book. As a high-level summary: DTE estimates the cost of constructing
13 and maintaining the assets required to serve the new customer(s). It then estimates
14 the incremental revenues associated with the new customers (not including the
15 commodity cost of fuel), assuming constant per-customer gas consumption, and
16 calculates the revenue deficiency. The revenue deficiency is the difference between
17 the 20-year present value of the costs and the 20-year present value of the revenues.
18 DTE requires that new customers pay for the revenue deficiency, either up front or
19 over time. Note that this payment does not cover the full capital cost of the
20 expansion: costs more than 20 years after installation are not reflected in the
21 calculation. DTE applies the same general approach to both individual and

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 community expansions, although community expansions have uncertainty
2 regarding which customers will connect.

3 **Q33 Over what time period does DTE conduct this calculation?**

4 **A33** Twenty years. That means that, if DTE's assumptions about the number of
5 customers and their consumption are correct, there are no incremental revenues
6 available from the new assets over 20 years to contribute to the cost of the rest of
7 the gas system. Only after 20 years do revenues from new customers contribute to
8 costs associated with the rest of the utility's system—the upstream portions of
9 which will have been serving these customers throughout those 20 years.

10 **Q34 What happens if the consumption or number of customers are lower than**
11 **expected over that 20-year period?**

12 **A34** In that case, new customers do not pay for the costs of the assets that serve them,
13 and DTE's other customers cover the difference, essentially subsidizing system
14 growth. Put differently, on a present value basis, customers served by the new assets
15 in this example do not contribute to other utility system costs for more than 20
16 years.

17 **Q35 What happens if the consumption or number of customers is so low that the**
18 **asset is retired before the new customers contribute enough to cover the**
19 **revenue deficiency?**

20 **A35** In that case, DTE's other ratepayers protect DTE from a stranded cost. If the new
21 assets were a standalone business, without subsidy from other customers, that
22 business would have gone bankrupt: its total revenues would not have covered its

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 total costs. Because of the nature of the regulated utility model, which shares system
2 costs, however, the utility's other customers protect the utility's investors from
3 experiencing that loss by paying higher bills.

4 **Q36 Is it likely that sales from new customer additions will fall over 20 years?**

5 **A36** Yes. On average, DTE's sales per customer have declined about 30 percent over
6 the 26-year period from 1997 to 2022. More competitive electric alternatives, based
7 on heat pump technology, have become more widely available and adopted within
8 the last decade, so electrification will join energy efficiency as a driver of future
9 declines. While each community expansion samples only a subset of DTE
10 customers, this general trend should apply to the subset. In addition, 20 years from
11 now is 2044, just six years shy of the 2050 deadline for Michigan to achieve its
12 goal of carbon neutrality (and the country's commitment to net-zero emissions). To
13 meet these emission objectives, Michigan's use of natural gas will need to decline
14 substantially—accelerating the declines seen over the last generation. One major
15 driver of this decline will be electrification of space- and water-heating equipment.
16 As buildings served by new mains and service lines electrify some or all of their
17 equipment, their gas use will decline. The market segment of customers who
18 electrify completely will also stop contributing their monthly customer charges to
19 the revenue required to pay for the new gas assets.

20 **Q37 Is it reasonable for DTE to set rates based on the assumption that gas use will**
21 **remain constant over 20 years for all new customer attachments?**

22 **A37** No, it is not reasonable. Ignoring these market and policy trends will result in
23 DTE's failure to meet the revenue deficiency, thereby pushing out for more than 20

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 years any customer contributions to the broader system's cost of service, beyond
2 the cost of the assets serving their own building.

3 **Q38 What do you recommend the Commission do to address this situation?**

4 **A38** I recommend that the Commission require DTE amend its tariffs and associated
5 calculations to set a final date of 2034 beyond which DTE will not provide any cost
6 support for new customer attachments. In conducting its revenue deficiency
7 calculations, DTE would consider the present value of the net cost of the new assets
8 only through 2034. DTE would also require customers to pay the net cost of the
9 connection either up front or over a period that ends in or before 2034. By reducing
10 the assumed payoff period for assets built for new customers, DTE can increase the
11 likelihood that new customers will in fact pay off the revenue deficiency before
12 decarbonizing, accelerate the timeframe in which new customers contribute to
13 shared utility system costs, and reduce the likelihood of stranded costs.

14 **Q39 Why is 2034 a reasonable date to end socialized support for new customer**
15 **connections?**

16 **A39** Ten years is a reasonable period from today because it gives time for the utility and
17 customers to gradually transition. This timeframe is comparable to the lifetime of
18 gas-consuming equipment (e.g., about half the life of a typical gas heating system;
19 comparable to the life of a water heater), so is an appropriate timeframe over which
20 to transition to a new approach. By gradually removing subsidies year by year, this
21 change should avoid market shocks while transitioning to a future in which existing
22 customers are not subsidizing new customers to construct potential future stranded
23 assets.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC

CASE NO. U-21291

1 **Q40 Have other jurisdictions revisited new customer contributions recently?**

2 **A40** Yes. I am aware of three regulatory commissions that have set a path to reduce or
3 eliminate utility contributions toward the cost of new customer additions. That is,
4 in these jurisdictions new customers will be directly responsible for more or all
5 costs of the assets built to serve them.

6 **Q41 What are the three jurisdictions you have in mind?**

7 **A41** I am thinking of Oregon, Ontario, and California.

8 **Q42 Please describe the Oregon example.**

9 **A42** There are two examples in Oregon, related to NW Natural and to Avista.

- 10 • NW Natural offers a “line extension allowance” (LEA) for new customers.
- 11 The amount of the LEA has been fixed at levels corresponding to the type
- 12 of gas equipment to be installed, so that customers who will use more gas
- 13 get a larger allowance. This reflects a similar economic argument as that
- 14 which underlies DTE’s calculation. In NW Natural’s 2022 rate case, the
- 15 Public Utility Commission of Oregon (PUC-O) considered evidence
- 16 regarding reductions to the LEA.⁴⁴ The PUC-O concluded that the current
- 17 level of the LEA was “problematic” for three reasons: it did not account for
- 18 GHG emission compliance-related costs caused by customer expansion;
- 19 that it was “too generous and saddl[ed] existing customers with increased
- 20 costs for a period of time that is unreasonably long,”⁴⁵ and that “the current
- 21 methodology, which assumes customers remain on the system for 30 years

⁴⁴ Public Utility Commission of Oregon (PUC-O). *Order No. 22-388*. In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision (UG435). October 24, 2022. Pp. 31-54. Available at <https://apps.puc.state.or.us/orders/2022ords/22-388.pdf>.

⁴⁵ *Id.*, p. 49.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC

CASE NO. U-21291

1 with a predictable throughput, is likely too optimistic of an assumption
 2 given the changes in the industry that are identified by the parties.”⁴⁶ The
 3 PUC-O decided to reduce the LEA in each subsequent year, and to leave
 4 open the option to revisit the level of the LEA in a later proceeding.

5 • Avista agreed, as part of a stipulation settling its rate case in 2023, to phase
 6 down its line extension allowance: \$2,500 in 2024, \$1,250 in 2025, \$750 in
 7 2026, and \$0 in 2027.⁴⁷

8 **Q43 Please describe the Ontario example.**

9 **A43** Enbridge Gas, North America’s largest gas distribution utility, uses a similar
 10 revenue-deficiency-based calculation to determine customer contributions as does
 11 DTE. In its order in Enbridge Gas’s recent rate case, the Ontario Energy Board
 12 (OEB) considered a wide range of arguments regarding the appropriate timeframe
 13 over which to conduct the economic analysis for contributions, considering energy
 14 transition risk.⁴⁸ The utility proposed to maintain the timeframe at 40 years, while
 15 other parties suggested values as low as zero years. The OEB ordered a reduction
 16 to zero years beginning January 1, 2025, in order to eliminate stranded cost risk.

⁴⁶ *Ibid.*

⁴⁷ PUC-O. *Order No. 23-384*. In the Matter of AVISTA CORPORATION, dba AVISTA UTILITIES, Request for a General Rate Revision (UG461). October 26, 2023. P. 9. Available at <https://apps.puc.state.or.us/orders/2023ords/23-384.pdf>.

⁴⁸ Ontario Energy Board (OEB). *Decision and Order. Enbridge Gas Inc. Application for 2024 Rates – Phase 1*. EB-2022-0200. December 21, 2023. Pp. 23-45. Available at <https://www.oeb.ca/applications/applications-oeb/current-major-applications/eb-2022-0200>.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC

CASE NO. U-21291

1 **Q44** Please describe the California example.

2 **A44** The California Public Utilities Commission (CPUC) eliminated all subsidies for
 3 gas line extension in September 2022, through a rulemaking process, effective July
 4 1, 2023. This rulemaking process was “designed to be inclusive of any alternatives
 5 that could lead to the reduction of greenhouse gas emissions associated with energy
 6 use in buildings [related]... to the State’s goals of reducing economy-wide GHG
 7 emissions 40% below 1990 levels by 2030 and achieving carbon neutrality by 2045
 8 or sooner.”⁴⁹ The CPUC eliminated line extension allowances, a 10-year refundable
 9 payment option, and a discount payment option.⁵⁰ In December 2023, the CPUC
 10 went further by eliminating *electric* line extension allowances for new construction
 11 buildings that use natural gas and/or propane.⁵¹ As a result of this order, there are
 12 no subsidies from California’s regulated utilities to new buildings that burn gas.

⁴⁹ California Public Utilities Commission (CPUC). Order Instituting Rulemaking (OIR) 19-01-011. P. 2.

⁵⁰ CPUC. September 20, 2022. *Phase III Decision Eliminating Gas Line Extension Allowances, Ten-Year Refundable Payment Option, and Fifty Percent Discount Payment Option under Gas Line Extension Rules*. Available at <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M496/K987/496987290.PDF>.

⁵¹ CPUC. December 14, 2023. “CPUC Eliminates Last Remaining Utility Subsidies for New Construction of Buildings Using Natural Gas.” Accessed at <https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-eliminates-last-remaining-utility-subsidies-for-new-construction-of-buildings-using-gas-2023>.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291****1 VI. COMMUNITY EXPANSION**

2 **Q45** Could you please summarize DTE's community expansion program?

3 **A45** DTE considers expanding its mains to serve new areas under the auspices of its
4 customer attachment program. For each potential expansion, DTE conducts a
5 calculation that balances the cost of the expansion with the increased revenue
6 (referred to as the "spread") that the expansion would bring in, both over a 20-year
7 period. To the extent that the revenue does not balance the costs over that 20-year
8 period (on a present value basis), DTE calculates the gap (or revenue deficiency).
9 DTE then uses the gap and the estimated number of new customers to calculate the
10 additional monthly charge that will be placed for 10 years on the bills of all
11 customers served by the expansion. This charge is set at the level where the present
12 value of this revenue exactly offsets the deficiency that would otherwise exist
13 between costs and revenues. DTE conducts the necessary calculations in a
14 spreadsheet titled "Discounted Cost of Service Model Capm," which produces a
15 New Customer Attachments Form.

16 **Q46** What are the key parameters and assumptions for the economic evaluation of
17 the gap between costs and revenues?

18 **A46** Most of the parameters for community expansion are shared with the parameters
19 for individual customer attachments (such as the weighted average cost of capital,
20 tax rates, and depreciation rates). When evaluating the costs and revenues for a
21 community expansion project, DTE assumes that:

- 22 • Per-customer consumption will be constant over 20 years (which is the same
23 as in the individual customer case); and

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

- 1 • Fixed fractions of the potential customer base will connect each year,
2 generally starting around 60 to 65 percent in the first year and rising by 5 to
3 10 percent per year through the next four years.

4 DTE's calculation tool allows for assumptions regarding growth, seasonal
5 customers, and the costs of components (i.e., mains, services, and meters).

6 **Q47 What is the Mesick-Buckley CAP?**

7 **A47** The Mesick-Buckley CAP is a project whereby DTE would build a main
8 connecting the City of Manton to the villages of Mesick and Buckley, and serving
9 new customers along the route. DTE estimates the overall project cost to be \$14
10 million. DTE applied for and was awarded a grant of \$7.3 million from the state's
11 Low Carbon Energy Infrastructure Enhancement and Development Grant program.
12 This reduces the net upfront cost to ratepayers to \$6.8 million.

13 **Q48 How many customers does DTE project the Mesick-Buckley CAP will serve?**

14 **A48** DTE projects that this project will serve 1,063 customers who are located adjacent
15 to the project today, and 192 additional customers sourced from "miscellaneous"
16 growth (e.g., new construction in the area) over the next 10 years.

17 **Q49 What is the present value of the difference between the cost of the Mesick-
18 Buckley CAP and the additional revenues that it would enable?**

19 **A49** DTE calculates a deficit of \$2.16 million (after including the impact of the \$7.3
20 million state grant).

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 **Q50** What would each of these new customers pay as an additional monthly
2 charge?

3 **A50** Each new residential customer would pay an additional \$27.76 per month, or
4 \$333.12 per year, for the first 10 years after the project is commissioned.
5 Commercial customers would pay an upfront cost of \$2,212 (regardless of building
6 size).⁵²

7 **Q51** Does DTE expect all 1,063 identified customers to connect to the gas system
8 within five years of the Mesick-Buckley project's completion?

9 **A51** Yes. In discovery, Witness Abona states "Due to the low cost and savings as
10 detailed in the EIED application, DTE expects all 1,063 identified customers to
11 choose to connect to the gas system within 5 years of the project's completion."⁵³

12 **Q52** Has DTE received commitments to connect from all the prospective new
13 customers it has identified for the Mesick-Buckley project?

14 **A52** No.

15 **Q53** How many customers in the area of the Mesick-Buckley project have actually
16 expressed interest in connecting to it?

17 **A53** DTE does not know. The Company claims that customers have expressed interest
18 but apparently kept no records.⁵⁴

⁵² Ex MEC-12, MNSCDG-1.8h.

⁵³ Ex MEC-13, discovery response MNSCDG-1.8fi.

⁵⁴ Ex MEC-14, discovery response MNSCDG-1.8b.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 **Q54 Who bears the risk of additional costs if DTE's estimate of the number of**
2 **customers that connect proves too high?**

3 **A54** Witness Abona states that "[i]f volumes/connections are not obtained, DTE
4 shareholders will bear the costs."⁵⁵ However, in response to a follow-up question
5 (MNSCDG-4.5a), Witness Abona clarifies that "Prior to the filing of the next
6 general rate case, to the extent sales volumes are not obtained as anticipated would
7 result in lower revenues than those approved by the Commission. These lower
8 revenues would result in lower net income the company earns in that given time
9 period." Witness Abona further clarifies in MNSCDG-4.4bi and MNSCDG-4.4ai
10 that in the next rate case, all assets that are serving customers would be included in
11 the rate base used to calculate rates, and increases or decreases in sales and costs
12 are reset.⁵⁶ As a result, the utility would face no risk of lower net income from
13 falling short of expected volumes or connections. This means that, after a short
14 initial period between when an expansion project is complete and the next rate case,
15 all risk of shortfalls in expansion revenues are borne by DTE's ratepayers.

16 **Q55 Is it possible for DTE to collect more revenue than expected from an**
17 **expansion, and thereby benefit other ratepayers?**

18 **A55** In theory, yes, although such an outcome is highly unlikely. To do so, the project
19 would have to exceed at least one of the following conditions while still meeting
20 the other two: connect all customers presently located in the area to be served, make

⁵⁵ Ex MEC-15, discovery responses MNSCDG-1.9, 4.4bi, and 4.4ai.

⁵⁶ *Id.*

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 connections as quickly as expected by DTE, and achieve the Company's
2 expectations for sales volumes per customer. Shortfalls in any of these areas would
3 need to be more than overcome by overperformance in another area for there to be
4 a net benefit to other ratepayers.

5 **Q56 Does the payment of contributions in aid of construction mitigate stranded**
6 **cost risk associated with future reductions in gas use as part of a pathway to**
7 **mitigate climate change?**

8 **A56** No. Contributions are based on assumptions about how the assets will be used over
9 the first 20 years of their operating life and do not affect how they are treated in the
10 longer term. The depreciation rates used to calculate the customer contributions are
11 based on the same asset lives as other DTE assets of the same types and materials,
12 so there are substantial undepreciated plant balances after 20 years. Given that
13 Michigan's goal is carbon neutrality in 26 years, expansion projects add to DTE's
14 potential stranded asset risk.

15 **Q57 Overall, is the risk and reward symmetrical for DTE ratepayers, between**
16 **under- and over-projections of customer connections and sales?**

17 **A57** No, it is not symmetric. Decarbonization that would lead to net costs being borne
18 by ratepayers is much more likely than unexpected high growth leading to net
19 benefits.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC

CASE NO. U-21291

1 **Q58 Does DTE track whether the volumes and connections are, in fact, obtained?**

2 **A58** In part. DTE does not track the volumes of gas sold to customers by expansion
3 project. DTE was able to provide data regarding the number of connections
4 achieved for each project.

5 **Q59 Could you please summarize the data that DTE provided on customer**
6 **connections for recent community expansion projects?**

7 **A59** Yes. Upon request, DTE provided responses for 15 projects with more than 300
8 anticipated customers.⁵⁷ The following table shows the projected number of
9 customers at the time of project approval and the actual number of customers
10 connected to date for each project.

Project	Projected Customers	Connected to Date	Shortfall
Ellsworth	371	201	170 / 46%
NW Torch Lake	692	446	246 / 36%
Elk Tip	319	191	128 / 40%
NE Torch Lake	927	464	463 / 50%
Epsilon/Pickerel Lake	391	334	57 / 15%
Cherry Homes/Northport	340	222	118 / 35%
Evanston	336	237	99 / 29%
Lake Skegemog	324	212	112 / 35%
Myers Lake - Peterson Farms	496	332	164 / 33%
Ferry Road	320	148	172 / 54%
Holton Duck Lake	373	231	142 / 38%
Higgins Lake	419	212	207 / 49%
Arthur St	307	257	50 / 16%
Blue Lake	432	245	187 / 43%
W County Line	348	193	155 / 45%

⁵⁷ Projected: MNSCDG-1.12f; Actuals: MNSCDG-4.6d.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 **Q60** What is the approximate amount by which DTE overestimated the number of
2 customer connections for these projects?

3 **A60** Across all projects, DTE appears to have overestimated customer connections by
4 about 50 percent. That is, for every 300 projected customers, DTE has connected
5 only about 200. On average, DTE appears to get about 80 percent as many
6 customers as expected in Year 1, and by Year 3 (for projects that have been in
7 operation that long), the ratio of actual to projected falls to about two-thirds.⁵⁸

8 **Q61** What does this shortfall in customers mean for DTE ratepayers?

9 **A61** It means that DTE ratepayers not served by these expansion projects are paying a
10 substantial net cost for these expansions, beyond what was projected when the
11 projects were approved.

12 **Q62** Based on DTE's experience with customer attachment rates over the last few
13 years, is it reasonable for DTE to assume that all 1,063 identified customers
14 will connect to the Mesick-Buckley project within five years?

15 **A62** No, this is not a reasonable assumption. None of the 15 similar-sized projects from
16 the last few years have approached 100 percent participation. In fact, none of these
17 projects are approaching the level of full subscription over five years. Figure 4
18 shows the Mesick-Buckley customer connection projection by year (in orange dots)
19 compared with the same projections for the 15 other large projects (light grey dotted
20 lines; average shown in heavy dotted line) and with the actual customer uptake

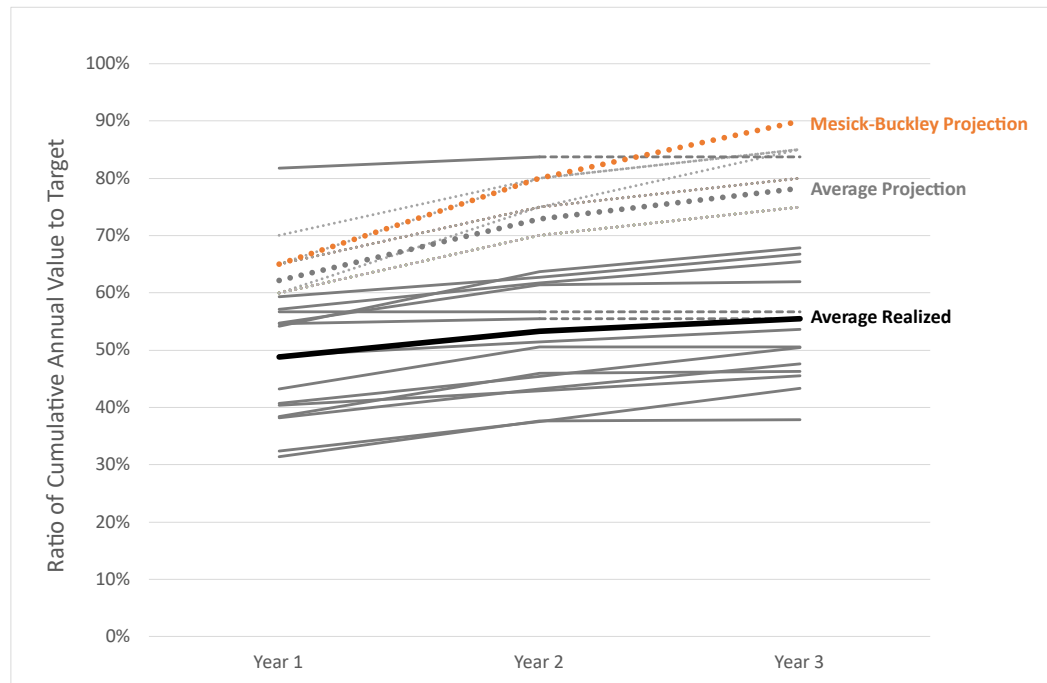
⁵⁸ Projected: U-21291 MNSCDG-4.6f New Customer Attachment Forms; Actuals: MNSCDG-4.6e.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC

CASE NO. U-21291

1 (dark grey solid lines; average shown in heavy black solid line). The Mesick-
 2 Buckley projection line is an outlier compared with other projections, and if
 3 participation were to follow this line it would be an even greater outlier compared
 4 with actual customer growth.

5 *Figure 4. Projected and actual customer connections for DTE expansion projects,*
 6 *shown as fractions of the total target population for each project*



7
 8 Sources: MNSCDG-4.6e, MNSCDG-4.6f Attachment, DTE Low Carbon Energy Infrastructure Enhancement
 9 and Development Grant Proposal (Exhibit MEC-16).

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 **Q63** The Mesick-Buckley project cost-revenue analysis assumes miscellaneous
2 customer growth. What is this?

3 **A63** Witness Abona states that “Miscellaneous growth is a mechanism that allows
4 additional new homes and businesses to be accounted for in the project calculations
5 for the first 10 years of the project.”⁵⁹

6 **Q64** How much miscellaneous growth does DTE project for the Mesick-Buckley
7 project?

8 **A64** DTE projects growth of 2 percent per year, or about 22 new customers per year.⁶⁰
9 As a result, by the end of the 20-year analysis window for the calculation of the
10 revenue gap, DTE projects the project will serve more than 1,500 customers.⁶¹

11 **Q65** How does the Mesick-Buckley project’s rate of assumed miscellaneous growth
12 compare with the equivalent rates for DTE’s 15 other projects with over 300
13 projected customers from the last few years?

14 **A65** None of the other projects include any assumed miscellaneous growth at all.

⁵⁹ MNSCDG-1.7m.

⁶⁰ Exhibit MEC-16. DTE Low Carbon Energy Infrastructure Enhancement and Development Grant Proposal, p. 47.

⁶¹ NDA U-21291 MNSCDG-1.7f Mesick-Buckley Capm 133a Effective 01012022.xls.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 **Q66** **Is it reasonable for DTE to assume that there will be 2 percent annual growth**
2 **on top of the 100 percent participation among existing buildings potentially**
3 **served by the Mesick-Buckley expansion?**

4 **A66** No, this is not a reasonable assumption. No other recent DTE system expansion
5 project with over 300 projected customers has come close to full subscription, much
6 less demonstrated further “miscellaneous” customer growth beyond the level
7 projected based on existing buildings.

8 **Q67** **If the Mesick-Buckley project is typical in its customer adoption rates, how**
9 **much will other DTE ratepayers be subsidizing the customers served by the**
10 **project?**

11 **A67** If two-thirds of the projected customers sign up, without any additional
12 miscellaneous growth, and DTE charges its projected amount for contributions in
13 aid of construction (i.e., \$27.76 per month for residential customers), DTE will face
14 a present-value shortfall of about \$838,000. Of this, a small (less than \$50,000) net
15 shortfall would result in the first three years and thus may be borne by DTE
16 investors (assuming DTE does not file another rate case within three years), while
17 about \$800,000 present value of costs would be borne by DTE’s ratepayers as a
18 whole after the assets are all included in rate base at the next rate case. This shortfall
19 calculation assumes that the remainder of DTE’s assumptions hold, including the
20 average use per customer and that use staying constant over 20 years.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 **Q68** **Could you please describe how you calculated the present value of the expected**
2 **shortfall to be about \$838,000?**

3 **A68** I used the New Customer Attachments file that DTE provided in MNSCDG-1.7f,
4 entitled *NDA U-21291 MNSCDG-1.7f Mesick-Buckley Capm 133a Effective*
5 *01012022.xls*. I modified the values on the “CAP Input” sheet to reduce the number
6 of new customers and service lines to two-thirds of the values that DTE used. I also
7 removed all miscellaneous growth. The shortfall is the value for the “Cum[ulative]
8 NPV” presented on the “Cost of Service” sheet.

9 **Q69** **Is it reasonable for DTE to shift \$800,000 of cost to customers who will not use**
10 **or benefit from the Mesick-Buckley project?**

11 **A69** No, it is not. DTE has used unreasonable assumptions regarding customer
12 connections to this project, and the resulting rates are therefore not just and
13 reasonable.

14 **Q70** **If DTE were to adjust the additional monthly customer charge for the Mesick-**
15 **Buckley customers to account for this average shortfall, what would the new**
16 **fixed charge be?**

17 **A70** The additional fixed connection charge would rise from \$27.76 per month to \$62.74
18 per month (or about \$753 per year). Commercial customers would pay \$5,000 up
19 front (rather than \$2,212). These fixed charges are reasonable charges because they
20 reflect reasonable expectations regarding customer connections to this project. I
21 calculated this value using the same file from MNSCDG-1.7f mentioned
22 previously, but this time I adjusted the customer surcharge to achieve a zero net-
23 present-value cost.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 **Q71** What if DTE also adjusted the timeframe for addressing the revenue
2 deficiency to 2034, as you recommend?

3 **A71** In this case, the additional fixed connection charge would rise from \$27.76 per
4 month to \$70.20 per month (or about \$842 per year). Commercial customers would
5 pay \$5,594 up front. These fixed charges are reasonable charges because they
6 reflect a reasonable assessment of the time before which newly connected
7 customers should contribute to the costs of the greater gas system from which they
8 benefit. I calculated this value using the same file from MNSCDG-1.7f mentioned
9 previously, but this time I adjusted the customer surcharge to achieve a zero net-
10 present-value cost, including only the costs and revenues over the first 10 years of
11 operation.

12 **Q72** How would the corrected connection charge affect the economics of
13 electrification with heat pumps compared to pipeline gas?

14 **A72** Assuming that electric heat pumps for space and water heating are about three times
15 as efficient as the fossil fuel equipment being replaced, an average Mesick-Buckley
16 residential customer in this case would save about \$439 per year in energy costs by
17 going all-electric rather than signing up for pipeline gas. Their annual cost for
18 electricity would go up about \$1,510 versus taking on a gas bill of around \$1,948.
19 In other words, electricity would offer about \$1125 in annual savings relative to
20 propane while gas would offer \$687. Exhibit MEC-7 shows this calculation.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 **Q73** Would the policy and market shift toward electrification that you detailed
2 earlier in this testimony make it more likely that Mesick-Buckley customers
3 would choose electricity over pipeline gas?

4 **A73** Yes. Federal and state incentives for heat pumps and heat pump water heaters will
5 make those technologies more accessible and affordable to households and
6 businesses. Even without correcting the Mesick-Buckley connection charge, the
7 high performance and reduced cost of these technologies may increase the fraction
8 of households that choose not to connect to the gas system.

9 **Q74** What is a typical useful life of gas mains and service lines?

10 **A74** These assets generally have engineering lives of more than 50 years.

11 **Q75** Would extending the cost-revenue calculation beyond 20 years enable the
12 Mesick-Buckley project to break even with the lower (\$27.76) connection
13 charge after a few more years, thereby obviating the need for a greater
14 connection charge?

15 **A75** I estimate that it would take about 50 years for the present value of the reasonably-
16 expected fixed level of sales and customer charges on the Mesick-Buckley
17 expansion to pay off the cost of building the expansion.

18 **Q76** Is it reasonable to think that the gas system 50 years from now will have the
19 same number of customers and same level of volumetric sales as it does today?

20 **A76** No, it is not. 50 years from now is 2074, far past 2050, which is the date at which
21 the United States and Michigan have committed to carbon neutrality and net-zero
22 or net-negative emissions. It is not reasonable to assume that Michigan can meet its

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 carbon neutrality plan while retaining all gas throughput and customers. A
2 declining trajectory is likely to occur in subsets of the DTE system, such as the
3 Mesick-Buckley expansion. I conclude that it is unlikely that the increased revenue
4 from the proposed connection charge in this project, along with the spread from
5 customers served by the project, will ever pay off the cost of the expansion. If
6 anything, I expect that customers taking action in line with the energy transition
7 will reduce the income from this project sooner than 20 years, thereby creating even
8 more of a net cost for DTE ratepayers not served by this project.

9 **Q77 What is the Peach Ridge expansion project?**

10 **A77** This is a \$4.9 million project to serve up to 493 homes in the Peach Ridge Area.
11 DTE states that “DTE Gas has received several inquiries from homeowners in the
12 Peach Ridge area located in the Kent City area. Due to the density of existing homes
13 and potential for additional growth through new homes and subdivisions, this area
14 was economically viable to expand our natural gas facilities to serve the area.”⁶²

15 **Q78 Have you conducted a similar analysis of this project to what you have done**
16 **for Mesick-Buckley?**

17 **A78** Yes, I have estimated that DTE will likely experience a revenue deficiency with a
18 present value of about \$912,000 if customer attachments for the Peach Ridge
19 project proceed according to DTE’s average experience of customer attachments to
20 expansion projects. Under DTE’s existing practice, this shortfall will be largely

⁶² Exhibit A-12, Schedule B5.5, p. 38 of 45.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 recovered from other DTE ratepayers who will see no benefit from the Peach Ridge
2 project.

3 **Q79 How did you calculate the \$912,000 shortfall?**

4 **A79** I used the same approach as previously described for Mesick-Buckley, but this time
5 using the file *NDA U-21291 MNSCDG-8.5 Peach Ridge Capm133a Effective*
6 *01012022.xls*, provided in MNSCDG-8.5.

7 **Q80 If DTE accounted for typical under-subscription when setting the customer**
8 **contributions in aid of construction, and limited subsidies to 2034, what impact**
9 **would that have on the monthly customer contribution?**

10 **A80** Making that correction would increase the contribution from about \$44 per month
11 to about \$125 per month.

12 **Q81 What impact would these changes in community expansion charges have on**
13 **the attractiveness of gas versus electricity in Peach Ridge?**

14 **A81** At DTE's proposed customer charge addition in Peach Ridge, gas customers would
15 save about \$95 per year relative to using efficient electric equipment. In contrast,
16 adjusting to a 10-year deficiency window (2024 to 2034) and accounting for under-
17 subscription would mean savings of \$869 per year from choosing electrification
18 instead of gas. See Exhibit MEC-7. DTE's overly optimistic assumptions about
19 customer signups in Peach Ridge are essential to justify the argument that gas is the
20 least-cost option. If more customers instead choose not to adopt gas, aligned with
21 all other recent expansions, all-electric homes will be less expensive to heat. Higher

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 resulting gas rates could drive customers to not sign up for gas, thus exacerbating
2 the revenue deficiency borne by all DTE customers.

3 **Q82 What conclusions do you draw with respect to the cost recovery gap for the 15**
4 **large existing expansion projects you evaluated?**

5 **A82** None of the 15 projects I examined have fully subscribed (although one has more
6 customers as of now than it was projected to have at this date). Assuming average
7 levels of customer attachments, the Mesick-Buckley project is about \$800,000
8 under-recovered (a bit more than 10 percent of the project's net cost after
9 accounting for the grant funds). The Peach Ridge project is about \$900,000 under-
10 recovered—a bit more than 20 percent of that project's cost. Based on this 10- to
11 20-percent under recovery range, I anticipate that the 15 other projects, which have
12 a combined budget of more than \$56 million, likely have an aggregate under-
13 recovery of more than \$6 million (present value) and perhaps as much as \$11
14 million, before accounting for cost overruns.

15 **Q83 What do you recommend to the Commission regarding the risk of expansion**
16 **project undersubscription?**

17 **A83** I recommend that the Commission order DTE to use customer adoption rates based
18 on historical experience when calculating new attachment surcharges, and order
19 DTE to gradually sunset subsidies for new attachments by 2034, aligned with my
20 recommendation for individual customers. This approach sets reasonable rates for
21 customer contributions that are fair to both new customers and DTE's existing
22 customers because they are based on real-world experience of customer

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 attachments, reasonable expectations of stable consumption levels, and a fair time
2 before new customers should contribute to the cost of the rest of the gas system.

3 These values would be \$70.20 per month for Mesick-Buckley (or \$5,594 up front)
4 and \$124.54 per month for Peach Ridge (or \$9,925 up front). If DTE is unable to
5 change the values for these projects (for example if customer attachment contracts
6 are already set and DTE is unwilling or unable to change the monthly charge), then
7 the Commission should reduce the allowed revenue requirement by \$838,000 for
8 Mesick-Buckley and \$912,000 for Peach Ridge.

9 An alternative, albeit more complex, approach, would be to establish a tracker that
10 shifts the risk of customer attachment decisions from DTE's existing customers to
11 DTE investors and the customers who will utilize the projects. Specifically, DTE
12 investors could bear the final risk for whether sufficient revenue is recovered from
13 each project to cover the cost of the expansion. By shifting risk to DTE's investors,
14 in line with Witness Abona's statement that "[i]f volumes/connections are not
15 obtained, DTE shareholders will bear the costs,"⁶³ DTE would have an incentive to
16 set appropriate rates for new customers. If DTE were overly optimistic about
17 revenue from customer connections, shareholders would bear the costs. DTE would
18 therefore be more likely to make reasonable assumptions. I would support such an
19 approach, although I think it would be simpler to require DTE to simply use better
20 assumptions from the start.

⁶³ MNSCDG-1.9.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 **Q84** **Who bears the risk of additional costs if the actual costs to construct a system**
2 **expansion project exceeds the projected cost?**

3 **A84** Witness Abona states that “[a]ny difference resulting from higher or lower costs
4 than those projected and included in this case are initially covered by DTE
5 shareholders and then any differences would be accounted for in DTE Gas’s next
6 general rate case.”⁶⁴ In this way, risk from overruns and underruns in project costs
7 are treated similarly to over- and under-estimates of new customer attachments in
8 a given expansion area: the Company takes a small amount of initial risk but shortly
9 after construction the actual costs are included in rate base and set for full recovery.

10 **Q85** **Does DTE do an accurate job of projecting expansion project costs?**

11 **A85** No. On average, DTE underestimates the cost to construct community expansion
12 projects by 16 to 17 percent—16 percent on a project-weighted basis and 17 percent
13 on a dollar-weighted basis. The following table shows projected project costs,
14 actual project costs, and overrun percentage for the 15 recent projects targeting over
15 300 new attachments. The standard deviation of the overrun is 33 percent. That
16 means that the scatter in the cost projection relative to the actual cost is about one-
17 third of the projected cost. The extreme cases are Epsilon/Pickerel Lake, where the
18 expansion cost 79 percent more than expected, and Cherry Homes/Northport,
19 which cost 24 percent less than expected.

⁶⁴ MNSCDG-8.4.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC

CASE NO. U-21291

Project	Projected Cost	Actual Cost	Over-run %
Ellsworth	2,082,368	1,614,173	-22%
NW Torch Lake	5,454,337	6,959,846	28%
Elk Tip	1,810,511	2,894,945	60%
NE Torch Lake	6,179,193	9,150,395	48%
Epsilon/Pickerel Lake	2,464,620	4,416,825	79%
Cherry Homes/Northport	5,582,000	4,255,178	-24%
Evanston	2,500,000	1,945,053	-22%
Lake Skegemog	2,334,000	1,787,139	-23%
Myers Lake - Peterson Farms	6,542,000	9,382,686	43%
Ferry Road	4,585,000	4,465,323	-3%
Holton Duck Lake	2,761,000	2,824,351	2%
Higgins Lake	2,354,000	2,672,417	14%
Arthur St	3,265,000	4,724,342	45%
Blue Lake	3,905,000	3,885,304	-1%
W County Line	4,731,000	5,322,606	13%
TOTAL	56,550,029	66,300,584	17%

1 **Q86** What is DTE's aggregate overrun for these 15 projects?

2 **A86** It is about \$9.75 million.

3 **Q87** If DTE accurately estimated the cost of expansion projects, would that tend to
4 increase or decrease stranded cost risk?

5 **A87** Better estimation would decrease stranded cost risk because it would allow the
6 Company to assign more accurate costs to the customers who are connecting. As it
7 stands, DTE tends to undercharge these customers both because it underestimates
8 the cost of construction and overestimates the number of customers. When DTE
9 under-collects from new customers (due to both of these effects), it puts more risk
10 on its investors and on other ratepayers.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 **Q88** What do you recommend to the Commission regarding the risk of expansion
2 project cost overruns?

3 **A88** I recommend that the Commission shift the risk of expansion project cost overruns
4 off DTE's existing customers, and onto DTE investors. If the actual cost of the
5 projects were known at the time when the contributions in aid of construction are
6 decided, these contributions would protect other non-benefitting ratepayers from
7 the cost overrun. There is no reason for non-benefitting ratepayers to pay extra
8 simply because the Company underestimated the cost, when they would otherwise
9 be held harmless. The Commission should make clear that cost overruns for
10 expansion projects will face a rebuttable presumption to be imprudent and
11 disallowed. As Company support for system expansion phases out over the period
12 through 2034, there will be reduced need for anyone other than the new customers
13 to take this risk.

14 **VII. THE FUTURE OF HEAT**

15 **Q89** Do you have other recommendations to the Commission regarding how it can
16 address issues you raise in your testimony?

17 **A89** Yes. My testimony, as well as that of my colleague Ms. Napoleon, is informed by
18 the fact that meeting state and federal GHG reduction goals will necessarily mean
19 that widespread electrification will change the way Michiganders heat their homes.
20 These changes will have long-lasting and deeply impactful implications for DTE,
21 Michigan's other gas utilities, and the state's electric system. I recommend that the
22 Commission conduct a "Future of Heat" proceeding that would bring all essential

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 utilities and stakeholders together to address this transformation in a manner that
2 will protect ratepayers.

3 **Q90 Why is a separate proceeding appropriate?**

4 **A90** A standalone proceeding is appropriate because the future of heat has implications
5 for both electric and gas systems, and a coordinated response on both systems is
6 necessary for the Commission to help the utilities chart a path forward that
7 maintains safe and reliable heating service to all customers throughout the energy
8 transition. Once there is a well-established joint framework, the Commission can
9 expect each utility to bring forward its specific investments and other choices in
10 company-specific dockets.

11 **Q91 Does the need for a Future of Heat docket mean that it is appropriate for DTE**
12 **to defer consideration of the energy transition in this proceeding?**

13 **A91** No. Recognizing the need for coordination among the state's utilities does not
14 obviate the need for DTE to behave prudently and draw upon the best available
15 information in its own planning and proposals in this or any other docket.

16 **Q92 What are the core components of a Future of Heat proceeding?**

17 **A92** One core objective for a Future of Heat proceeding should be to develop a shared
18 vision regarding the physical configuration of the future of heating for buildings
19 and industry in a state. In many cases, this requires a study that examines different
20 decarbonization pathways and quantifies the relative advantages and disadvantages
21 of each one. While each state likes to consider itself unique, in practice, such studies
22 conducted by independent analysts tend to follow a common structure and reach

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 similar conclusions: electrification using heat pump technology is the primary cost-
2 effective technology to decarbonize buildings; RNG and other low-carbon fuels are
3 limited, expensive, and generally play a limited role serving end uses that are hard
4 to electrify; and the use of hybrid heating systems can be effective in the near term
5 (noting that using the gas system to serve building heat only on the coldest days
6 creates challenges for the gas utility business model).

7 Once a common understanding is developed for the physical configuration of the
8 future heating ecosystem, the proceeding moves to evaluating regulatory policy and
9 utility business models. This phase considers:

- 10 • the allocation of costs and risk—over time and among customers and utility
11 investors, including detailed analysis of stranded assets, stranded costs, and
12 their mitigation and allocation;
- 13 • how to evaluate and implement non-pipeline alternatives and/or clustered
14 or targeted electrification in concert with gas and electric utility capital
15 planning;
- 16 • cost allocation for system expansion and new customer attachments;
- 17 • electric-gas utility interaction and coordination;
- 18 • utility business model innovation and shareholder incentives;
- 19 • protections and mitigations for low- and moderate-income customers and
20 communities from adverse customer impacts;
- 21 • workforce development and job impacts;
- 22 • environmental justice; and
- 23 • depreciation approaches for existing and future capital assets.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 The energy transition will not a be a “set it and forget it” process—the Commission
2 should plan to revisit these questions on a recurring basis to ensure the transition is
3 on track and to adapt to new technologies, regulatory innovations, and market
4 changes.

5 **Q93 Would Michigan be the first state to conduct a coordinated Future of Heat**
6 **proceeding?**

7 **A93**No, and in fact Michigan can benefit from the work done in other states to scope
8 such proceedings and learn about the issues likely to arise.

9 **Q94 What are some examples that Michigan could use?**

10 **A94**The processes in Massachusetts and Rhode Island are illuminating.

11 **Q95 Could you describe the Massachusetts process you reference?**

12 **A95**Of course. The Massachusetts Department of Public Utilities (DPU, its regulatory
13 commission) opened Case No. 20-80 in 2020, in part in response to a petition from
14 the state’s Attorney General, to investigate how the state’s net-zero emissions law
15 would impact the state’s gas utilities. The DPU required the state’s gas distribution
16 utilities to contract with a consultant team to conduct an independent study of
17 pathways to deep decarbonization and the resulting regulatory implications. The
18 consultant team conducted a series of stakeholder meetings to inform its analysis,
19 then presented its conclusions. The utilities then proposed regulatory steps
20 informed by the consultant work. The DPU issued Order 20-80 in late 2023,
21 drawing upon the full record in the proceeding. I have attached the DPU’s order as
22 Exhibit MEC-8. Order 20-80 established a new framework for the gas utility system

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 in Massachusetts, including: (1) an expectation of increased utility support for
2 electrification; (2) rejection of adding RNG to default gas supply portfolios; (3)
3 support for pilots of networked geothermal, targeted electrification, hybrid heating
4 systems, and renewable hydrogen, with the greatest emphasis on networked
5 geothermal and targeted electrification; (4) to dissuade gas customer expansion,
6 adjustment of the decoupling mechanism to eliminate the incentive for customer
7 growth and examine depreciation rates; and (5) placement of the burden on the gas
8 utilities to show that non-pipeline alternatives are non-viable or cost-prohibitive in
9 order to receive cost recovery for new investments. The DPU specifically
10 highlighted the need to reexamine how costs are allocated for expansion to serve
11 new customers, and it directed the gas utilities to review policies and tariffs to
12 determine whether current practices accurately reflect how capital investments will
13 be recovered (among other considerations). Finally, the DPU ordered that each gas
14 utility prepare and submit Climate Compliance Plans every five years, to be
15 developed in coordination with electric distribution companies.

16 **Q96 What process lessons do you draw from the Massachusetts example?**

17 **A96** The Massachusetts process had a number of promising features, but also some
18 shortcomings. On the positive side, the use of an independent consultant to conduct
19 analysis provided important shared facts for all parties in the proceeding. The scope
20 of the consultants' pathways and regulatory studies was appropriately broad and
21 covered important aspects of cost, risk, and equity. The stakeholder input process
22 also held great promise, and the recurring Climate Compliance Plan process will
23 provide an opportunity for revision and course correction. However, some

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC

CASE NO. U-21291

1 participants found the stakeholder process to be frustrating because the consultants
 2 were not required to incorporate any of the suggestions or concerns raised by
 3 stakeholders.⁶⁵ The consultants were selected and hired by the utilities, and that
 4 colored how their results were received. Further, one potential advantage of being
 5 hired by the utilities was lost: the consultants were not granted access to any non-
 6 public information about the gas system. By putting the gas utilities in the center of
 7 this process, the DPU also sidelined the important contributions that the electric
 8 utilities could have provided regarding impacts on and of their systems.⁶⁶ Based on
 9 this experience, I would recommend that Michigan not rely on its gas utilities to
 10 oversee or conduct the primary analysis in a Future of Heat proceeding.

11 **Q97 Could you describe the Rhode Island process you reference?**

12 **A97** The Rhode Island Public Utilities Commission (“RIPUC”) opened a Future of Gas
 13 proceeding on its own initiative in June 2022. The RIPUC began the process by
 14 consulting with stakeholders to establish the scope for a study to be conducted by

⁶⁵ Gandbhir, P. Dec. 8, 2022. *Building a Successful Future of Gas Proceeding*. Presentation to the Connecticut 2022 Comprehensive Energy Strategy Technical Session 7. On behalf of Conservation Law Foundation. See <https://portal.ct.gov/deep/energy/comprehensive-energy-plan/comprehensive-energy-strategy> and https://ctdeep.zoom.us/rec/play/aoHZ0bFjyoiimFGQIvLNedPni0JFEtH8asoPTHwy66J13xC27kKqgwBV3q2ZW1Adp69AKOKr4XhxbYGOA.75oC4K8rPVzfoFZ2?startTime=1670508004000&_x_zm_rtaid=uom_SMIKRpivO-62XizETg.1670871656268.fe90398f6d04d63e3a6591ca10f5a11a&_x_zm_rhtaid=953 beginning circa 4:33 timestamp.

⁶⁶ Massachusetts’s largest gas utilities, as in Michigan, are dual-fuel utilities and share a corporate parent with an electric utility. However, the electric utility service territories are largely disjoint from the gas territories and the electric utilities are run as relatively separate organizations.

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

1 an independent consultant, who would be contracted to the RIPUC. After
2 developing the scope, the RIPUC contracted with a consulting firm, which has
3 conducted a study. The consultant held a series of stakeholder working group
4 sessions to vet assumptions, develop scenarios, and receive feedback on methods
5 and results. The gas utility, Rhode Island Energy, participated in these stakeholder
6 meetings and provided information requested by the consultants. Rhode Island
7 Energy is also the state's dominant electric utility; but unfortunately, the electric
8 utility staff were less engaged. This was in part because the study was framed as
9 the future of gas, rather than the future of heat. I would recommend that electric
10 and gas utilities be equal stakeholders in a future of heat proceeding to avoid this
11 asymmetry. As of this writing, the RIPUC has not issued an order addressing the
12 results of the study.

13 **Q98 What process lessons do you draw from the Rhode Island example?**

14 **A98** The RIPUC learned from the Massachusetts example and improved upon the
15 process for scoping and conducting analysis. Specifically, the RIPUC consulted
16 extensively with stakeholders to set the scope for the study and contracted with the
17 consultant directly. This should result in more stakeholder trust of the final analysis.
18 By empowering the consultant through the imprimatur of the RIPUC, the
19 consultants were able to access important utility data and insights in an open way
20 that educated all stakeholders.

21 **Q99 Could you summarize your recommendations regarding the Future of Heat?**

22 **A99** I recommend that the Commission open a "future of heat" proceeding with the
23 following characteristics:

DIRECT TESTIMONY OF DR. A. HOPKINS ON BEHALF OF MEC-NRDC-SC**CASE NO. U-21291**

- 1 • Required engagement from all electric and gas utilities in the state;
- 2 • An open process for stakeholder participation;
- 3 • A participatory process to set the scope for the proceeding and required
- 4 analysis;
- 5 • Learnings from similar processes conducted in other places;
- 6 • Expert advice, analysis, and modeling conducted on behalf of the
- 7 Commission; and
- 8 • Explicit goals to develop both (1) a shared understanding of the range of
- 9 policy-consistent futures for building and industrial heat in Michigan,
- 10 including an expected pathway to use for planning, and (2) a set of
- 11 regulatory and policy tools to use in pursuing that pathway and adapting
- 12 utility finance and business models to it.

13 **Q100** **Does this conclude your testimony at this time?**

14 **A100** Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE
GAS COMPANY** for authority to increase
its rates, amend its rate schedules and rules
governing the distribution and supply of
natural gas, and for miscellaneous
accounting authority.

Case No. U-21291

DIRECT TESTIMONY OF ALICE NAPOLEON
ON BEHALF OF
MICHIGAN ENVIRONMENTAL COUNCIL, NATURAL RESOURCES
DEFENSE COUNCIL, AND SIERRA CLUB

May 7, 2024

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE OF TESTIMONY	1
II. FINDINGS AND RECOMMENDATIONS	4
III. THE DESIGN AND STRUCTURE OF THE IRM PROPOSAL IS PROBLEMATIC	6
A. Background and overview of current proposal	6
B. Concerns with the IRM.....	12
IV. DTE’S GAS DELIVERY PLAN INCLUDES QUESTIONABLE STRATEGIES FOR ACHIEVING EMISSIONS REDUCTIONS	23
A. Responsibly Sourced Gas	24
B. Carbon Offsets and Renewable Natural Gas	31
V. DTE FAILED TO PROVIDE ADEQUATE SUPPORT FOR ITS PROPOSAL TO DISCONTINUE ALL EXISTING DEMAND RESPONSE PROGRAMS.	37

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

TABLE OF TABLES

TABLE 1. IRM TOTAL COSTS 2016–2022 (\$M)	9
TABLE 2. PROPOSED IRM BUDGET, 2024–2029 (\$000)	11
TABLE 3. IRM PROPOSED PROJECT COSTS (\$000)	12
TABLE 4. IRM PROPOSED PROJECT TARGETS	12
TABLE 5. IRM PROJECT COST PER UNIT (\$/MILE OF MAIN OR \$/METER)	14

TABLE OF FIGURES

FIGURE 1. IRM EXPENDITURE, 2016–2023 (\$M)	9

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name and occupation.

A My name is Alice Napoleon. I am a Principal Associate at Synapse Energy Economics, Inc. (“Synapse Energy Economics”) located at 485 Massachusetts Avenue, Suite 3, Cambridge, MA 02139.

Q Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources, energy efficiency policies and programs, integrated resource planning, electricity market modeling and assessment, renewable resource technologies and policies, and climate change strategies. Synapse works for a wide range of clients, including state attorneys general, offices of consumer advocates, trade associations, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse’s staff includes over 35 professionals with extensive experience in the electricity and gas industries.

Q Please summarize your work experience and educational background.

A Since joining Synapse in 2005, I have provided economic and policy analysis of electric and gas systems and emissions regulations on behalf of a diverse set of clients throughout the United States and in Canada. I have co-authored several reports and comments on the

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

1 role of energy efficiency in New York State in meeting its Reforming the Energy Vision
2 (“REV”) objectives, as well as two white papers on natural gas regulatory reforms needed
3 if New York is to meet its decarbonization targets. I have also provided policy analysis
4 and technical support on issues related to the future of natural gas utilities in many other
5 states, including Hawaii, Maryland, Rhode Island, Colorado, Massachusetts, Nevada, and
6 California.

7 I have provided expert advice on demand-side management programs in numerous states
8 and Canadian provinces regarding a range of issues including incentive-setting
9 methodologies, cost-benefit analysis, avoided costs, load forecasting, and locational
10 demand-side management. I also co-authored a manual for regulators on designing
11 performance incentive mechanisms for utilities, which has been highly utilized by many
12 states.

13 Before joining Synapse, I worked at Resource Insight, Inc., where I supported
14 investigations of electric, gas, steam, and water resource issues, primarily in the context
15 of reviews by state utility regulatory commissions.

16 I hold a Master’s in Public Administration from the University of Massachusetts at
17 Amherst and a Bachelor’s in Economics from Rutgers University. My resume is attached
18 as Exhibit MEC-17.

19 **Q On whose behalf are you testifying in this case?**

20 **A** I am testifying on behalf of Michigan Environmental Council, Natural Resources Defense
21 Council, and Sierra Club.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

1 **Q** **Have you previously testified before the Michigan Public Service Commission (“the**
2 **Commission”)?**

3 **A** No.

4 **Q** **What is the purpose of your testimony?**

5 **A** The purpose of my testimony is to review and critique the proposals of DTE Gas Company
6 (DTE or the Company) regarding the Infrastructure Recovery Mechanism (IRM), the
7 strategies for reducing greenhouse gas (GHG) emissions reductions in its 2024–2033 Gas
8 Delivery Plan (GDP), and the termination of its demand response pilots.

9 **Q** **Are you sponsoring any exhibits in this proceeding?**

10 **A** Yes, I am sponsoring the following exhibits:

11 Exhibit MEC-17: Resume of Alice Napoleon

12 Exhibit MEC-18: MNSCDG-5.12 and Attachment

13 Exhibit MEC-19: MNSCDG-5.3a

14 Exhibit MEC-20: MNSCDG-5.2e and f

15 Exhibit MEC-21: DTE 2023 Year-End Earnings Conference Call (Feb. 8, 2024)

16 Exhibit MEC-22: MNSCDG-5.10a

17 Exhibit MEC-23: MNSCDG-3.16b

18 Exhibit MEC-24: MNSCDG-3.13

19 Exhibit MEC-25: MNSCDG-2.4f

20 Exhibit MEC-26: Case No. U-20839, DTE Gas Company’s CleanVision Natural Gas
21 Balance 2023 Annual Impact Report dated March 27, 2024 and DTE
22 Gas Company’s CleanVision Natural Gas Balance Annual Report
23 (2022) dated March 29, 2023

24 Exhibit MEC-27: MNSCDG-6.3b

25 Exhibit MEC-28: MNSCDG-2.6e

26 Exhibit MEC-29: ACEEE, “Winter Demand Response Using Baseboard Heaters”

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

Exhibit MEC-30: MNSCDG-5.5ai, bi, and ci

II. FINDINGS AND RECOMMENDATIONS

Q Please summarize your primary conclusions.

A My findings include the following:

- **IRM**

- As implemented, the IRM fails to provide adequate incentives for the utility to minimize costs.
- The dollars flowing through the IRM have risen dramatically.
- The IRM process lacks meaningful review and opportunity for contestation.
- The criteria for what types of projects qualify for the IRM are unclear.
- Over three-quarters of the proposed IRM expenditure is for replacing old pipes (which may or may not be leak-prone). DTE doesn't consider or pursue non-pipeline alternatives (NPA), which could reduce investments and impacts on rates.

- **Gas Delivery Plan**

- Responsibly Sourced Gas (RSG) does not represent a valid GHG-reduction measure. Given the speculative nature of the GHG reductions from RSG, if approved this pilot might incur costs with no associated benefits to DTE customers or to the state.
- The Carbon Offsets and Renewable Natural Gas program is neither a viable nor cost-effective approach to reducing GHG emissions. Further, the program could work at cross-purposes by giving program participants the

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

message that it is easy to offset their emissions and could lead to an increase in consumption by participants.

- Demand Response

- DTE's assessment of gas savings during peak hours does not support its recommendation to discontinue the Smart Savers pilot program.
- DTE did not conduct a benefit-cost analysis of its demand response pilots.
- Demand response is an option for DTE to seek alternatives to pipeline investments.

Q Please summarize your recommendations.

A Based on my findings, I offer the following recommendations:

- IRM

- Given the high likelihood of cost recovery for approved IRM programs, there should be more stringent guidelines for IRM program eligibility.
- The Commission should reconsider and revise the purpose, requirements, process, and structure of the IRM.
- At a minimum, the Commission should not approve expanding the scope or increasing the dollars in the IRM.

- Gas Delivery Plan

- Michigan utilities' decarbonization approach should be considered in a holistic way in which stakeholders (including gas and electric) consider the challenges and opportunities with different pathways for achieving policy goals, i.e., a future of heat proceeding.

- Demand Response

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

- DTE should continue offering the Smart Savers pilot program.

III. THE DESIGN AND STRUCTURE OF THE IRM PROPOSAL IS PROBLEMATIC

A. Background and overview of current proposal

Q What is the IRM?

A The IRM is a cost recovery mechanism that allows DTE to seek pre-approval of costs for select programs. DTE submits a five-year plan for capital expenditure and project activity to be recovered through customer surcharges. Total IRM costs are approved at the start of the five-year expenditure period; however, surcharges are calculated annually in a reconciliation filing. In testimony, Witness Janness states that the purpose of IRM programs is “to ensure the safety of DTE Gas’s customers and the public and to allow the Company to provide reliable utility service.”¹

Q How are IRM costs recovered from customers?

A IRM costs are recovered by charging customers a surcharge that is determined annually based on approved investment plans, minus any budget underruns from the previous year. The IRM surcharge is calculated each calendar year of the five-year investment period and is based on the predetermined cumulative incremental revenue requirement associated with the incremental capital investment. The Company files an annual reconciliation in the first quarter of the year for the capital invested in the prior year for the Commission to review. IRM investments incur pre-tax rate of return, while regular rate-based investments

¹ Direct Testimony of Eric D. Janness, p. EDJ-5.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

1 earn an after-tax rate of return. The current pre-tax rate of return on IRM investments is
2 8.78 percent.²

3 **Q Please describe the original IRM that the Commission approved for Mich Con, the**
4 **predecessor of DTE Gas.**

5 **A The Commission approved Mich Con’s IRM in 2013 in Case No. U-16999.³ The original**
6 IRM funded the 10-year Main Removal Program (MRP) (now called the Gas Renewal
7 Plan, or GRP) and Meter Move Out (MMO) programs that the Commission had already
8 approved in other dockets in 2011.⁴ The Commission also approved IRM spending on the
9 Pipeline Integrity (PI) program, based on a finding that the program was “required under
10 federal and state safety standards and is an integral part of the company’s overall effort to
11 improve the safety and reliability of its system.”⁵

12 The initial IRM was approved at spending levels of \$77.4 million per year, including \$46.9
13 million per year for the MRP, \$22.7 million per year for the MMO program, and \$7.8
14 million per year for the PI program.⁶

15 **Q Please describe the Company’s current IRM.**

16 **A The Commission approved DTE Gas’s current IRM in Case No. U-20940. The approved**
17 IRM allowed DTE to recover the predetermined incremental revenue requirement for

² Response to Discovery MNSCDG-7.1ai & MNSCDG-7.1aii, K. Vangilder, April 9, 2024.

³ Case No. U-16999, Order, April 16, 2013.

⁴ Case No. U-16999, Order, April 16, 2013, p. 2, citing Case No. U-16451, Orders dated September 13, 2011, and November 10, 2011, and Case No. U-16407, Order, September 13, 2011.

⁵ Case No. U-16999, Order, April 16, 2013, p. 22.

⁶ Case No. U-16999, Order, April 16, 2013, pp. 24-25.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

annual infrastructure capital expenditures in certain programs for each year from 2022 to 2026.⁷ The current, approved IRM includes four programs: MRP, MMO, Meter Assembly Check/Meter Move Out (MAC/MMO), and PI.

Q How does DTE decide eligibility for inclusion in the IRM?

A It is unclear how DTE determines which programs are appropriate for inclusion in the IRM. DTE claims that all of the programs currently included within the IRM are essential to ensure safety and reliability. However, there are many other programs that DTE determines to be essential for safety and reliability that are *not* included in the IRM.⁸

DTE states that cost recovery through the IRM “ensures spending included in rates for strategic capital improvements is spent for those purposes and provides greater long-term certainty on recovery of reasonable and prudent costs related to those improvements.”⁹

Q How have IRM budgets changed over time?

A As noted above, the initial IRM was approved for an annual budget of about \$77 million. In contrast, the 2022 annual budget is \$287 million, which is about 370 percent of the initial IRM annual budget. Much of the increase in IRM budgets occurred over the past seven years, during which time the annual budget for IRM programs has more than tripled, as shown in Table 1.

⁷ Direct Testimony of Rajan M. Telang, p. RMT-23.

⁸ Response to Discovery, MNSCDG-5.11d.

⁹ MNSCDG-5.4.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

Table 1. IRM Total Costs 2016–2022 (\$M)

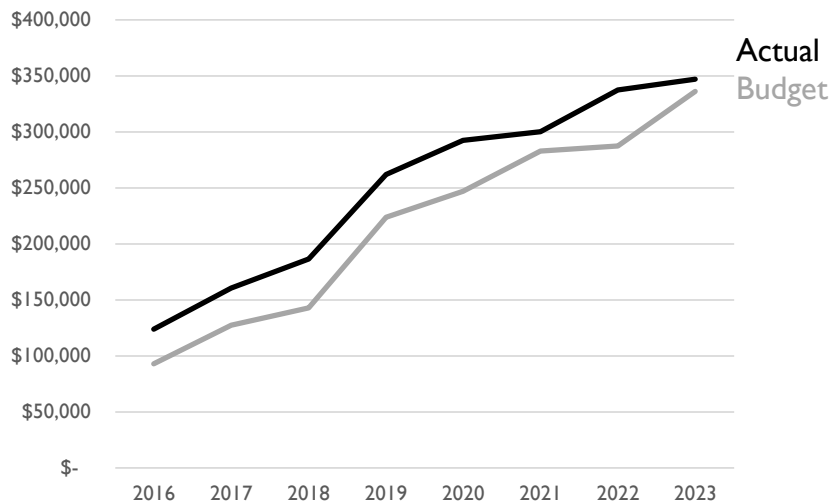
	2016	2017	2018	2019	2020	2021	2022	2023
Budget	\$93	\$128	\$143	\$224	\$247	\$283	\$287	\$336
Actual	\$124	\$161	\$187	\$262	\$292	\$300	\$338	\$347
Cost Variance	\$31	\$33	\$44	\$38	\$45	\$17	\$50	\$10

*As reported in Discovery Response MNSCDG-5.8 Exhibit A-12 B6.1; 2023 expenditure from U-21291 Exhibit A-12 Schedule B6.5 E.D. Janness. Values are rounded to the nearest million.

Q How have actual IRM expenditures compared to budget historically?

A DTE has overspent its IRM annual budget by as much as \$50 million per year. As shown in Figure 1, DTE spent more than its budget every year from 2016 to 2022.¹⁰

Figure 1. IRM Expenditure, 2016–2023 (\$M)



Source: 2016–2022 expenditure from Response to Discovery MNSCDG-5.8 B6.1, 2023 expenditure from U-21291 Exhibit A-12 Schedule B6.5 E.D. Janness.

¹⁰ Response to Discovery MNSCDG-5.8, Exhibit A-12 B6.1, E.D. Janness, March 15, 2024.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

1 **Q** **What happens to expenditures on IRM programs that exceed the authorized IRM**
2 **spending amounts?**

3 **A** They are included in rate base in the next rate case.¹¹

4 **Q** **Which programs are proposed for inclusion in the IRM in this rate case?**

5 **A** The Company is proposing to continue the IRM for the five-year period 2025–2029 with
6 two adjustments.¹² DTE is proposing to (1) include Cathodic Protection as part of the
7 IRM, and (2) consolidate the MRP and MMO programs into the GRP. The Company is
8 phasing out the MAC/MMO program because the Company is caught up on its MAC
9 backlog.¹³ If Cathodic Protection capital expenditures are not included in the final IRM
10 surcharge calculation in this rate case, those costs must be included in Routine Distribution
11 capital expenditures.¹⁴

12 If the Commission approves DTE’s proposal in the immediate rate case, the IRM will
13 include the following three programs:

- 14 1. GRP: MRP and MMO
- 15 2. Cathodic Protection Program
- 16 3. PI

¹¹ Janness Direct, p. EDJ-8.

¹² Telang Direct, p. RMT-24, lines 8-13.

¹³ Telang Direct, p. RMT-25 to 25.

¹⁴ Telang Direct, p. RMT-26.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

1 **Q Is the Company proposing other changes to the IRM?**

2 **A Yes.** DTE is proposing to increase the pre-tax rate of return from the current rate, 8.78
3 percent, to 9.31 percent in this docket.¹⁵

4 **Q What is the Company's budget forecast for the IRM proposals?**

5 **A DTE** is asking for increased funding for the IRM, which will result in higher IRM
6 surcharges.¹⁶ The Company's proposed budget is almost \$1.7 billion over seven years
7 (through 2029), with an annual spending of \$310–355 million.¹⁷ As proposed, DTE's
8 budgets for the IRM programs would increase to \$349.1 million in 2024 and \$354.2
9 million in 2025, followed by a modest decrease from the 2025 peak spending to \$344.5
10 million in 2026 and 2027, and \$311.4 million in 2028 and 2029.¹⁸

11 **Table 2. Proposed IRM Budget, 2024–2029 (\$000)**

	2024	2025	2026	2027	2028	2029
Total IRM	\$349,135	\$354,205	\$344,545	\$344,545	\$311,425	\$311,425

12 Source: Response to Discovery MNSCDG-5.12 attachment.

13 **Q How does this compare with previous IRM annual budgets?**

14 **A The** proposed annual program budgets exceed annual budgeted expenditures for each of
15 the past seven years, 2016 through 2022.

16 **Q Please describe the proposed budget for IRM programs.**

17 **A See** Table 3, below. The vast majority of IRM spending is in the GRP.

¹⁵ Response to Discovery MNSCDG-7.1ai & MNSCDG-7.1aii, K. Vangilder, April 9, 2024.

¹⁶ Janness Direct, p. EDJ-6.

¹⁷ Case No. U-21291, Exhibit A-12 part 2, Schedule B6.5, E.D. Janness.

¹⁸ Ex MEC-18, discovery response MNSCDG-5.12 and attachment; see also, Janness Direct, p. 9, Table 1.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

Table 3. IRM Proposed Project Costs (\$000)

Program		2025	2026	2027	2028	2029
GRP	MRP	\$274,000	\$274,000	\$274,000	\$274,000	\$274,000
	MMO	\$47,545	\$47,545	\$47,545	\$16,705	\$16,705
PI		\$23,060	\$13,400	\$13,400	\$11,120	\$11,120
Cathodic Protection		\$9,600	\$9,600	\$9,600	\$9,600	\$9,600
Total		\$354,205	\$344,545	\$344,545	\$311,425	\$311,425

*Data from Discovery Response MNSCDG-5.12 Exhibit A-12 B6.5 and Janness Direct Testimony.

Q What are DTE's proposed targets for the IRM programs?

A The Company proposes the following targets for the IRM programs.

Table 4. IRM Proposed Project Targets

Program		Units	2025	2026	2027	2028	2029
GRP	MRP	Miles of Main	206	206	206	206	206
	MMO	Number of Meters	18,500	18,500	18,500	6,500	6,500
PI		*none reported	-	-	-	-	-
Cathodic Protection		Corrosion Work Orders	1,695	1,695	1,695	1,695	1,695
		CP Engineering	12	12	12	12	12

*Data from Discovery Response MNSCDG-5.12 Exhibit A-12 B6.5 and Janness Direct Testimony (Cathodic Protection unit targets page EDJ-47). Unit targets are not reported for PI program.

B. Concerns with the IRM

Q Please summarize your concerns with the IRM.

A The IRM is a channel for DTE to make infrastructure investments in a way that is low risk to the utility, because spending on the IRM is pre-approved. The IRM poses several issues:

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

- 1 1. As implemented, the IRM fails to provide adequate incentives for the utility to
2 minimize costs.
- 3 2. Budget and actual spending on IRM programs has increased substantially since the
4 IRM was first approved, and DTE's IRM expenditures have consistently exceeded
5 budget.
- 6 3. The IRM process lacks meaningful external review and opportunity for
7 contestation.
- 8 4. The criteria for what types of projects qualify for the IRM are unclear, and the
9 utility has incentives to include routine projects in the IRM. The IRM includes
10 minimal guardrails.
- 11 5. Over three-quarters of the proposed IRM expenditure is for replacing old pipes
12 (which may or may not be leak-prone). DTE doesn't pursue alternatives to
13 conventional delivery system investments (NPAs), which could reduce investments
14 and impacts on rates. The IRM provides no oversight over decisions to replace old
15 pipes rather than evaluate and pursue NPAs.

16 **Q With respect to your first concern, how does the IRM provide a reduced incentive to**
17 **minimize costs?**

18 **A IRM surcharges are set based on the previous year's expenditure. This disincentivizes**
19 DTE from minimizing annual costs, because reducing annual costs could limit future IRM
20 budgets.

21 Additionally, DTE has not conducted a benefit-cost analysis to determine the cost-
22 effectiveness of the Gas Renewal Program, the Meter Move Out Program, or the Pipeline

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

Integrity program.¹⁹ To the extent there are alternatives to these programs, such as emissions monitoring and pipe repair, an assessment of the cost-effectiveness of these programs relative to the alternatives is a necessary step to understanding and minimizing costs. However, this step is not incorporated into the IRM process.

Q Please describe your second concern.

A As discussed earlier, DTE's IRM budget has increased dramatically over the past seven years. At the same time, DTE's IRM expenditures have consistently exceeded budget.

Q Do you have concerns with past IRM performance and associated expenditures?

A Yes. As shown in Table 1 above, DTE's IRM spending has consistently exceeded its budget. Furthermore, as shown in Table 5, below, DTE's actual cost per unit has been higher than projected most years from 2016 to 2022.

Table 5. IRM Project Cost per Unit (\$/mile of main or \$/meter)

		2016	2017	2018	2019	2020	2021	2022	Avg.
MRP	Planned	762,195	762,602	858,943	1,379,675	936,893	1,128,157	1,128,157	993,803
	Actual	926,991	925,149	911,522	1,090,960	1,106,683	1,121,831	1,185,158	1,038,328
	Difference	164,796	162,548	52,579	(288,715)	169,790	(6,326)	57,001	44,525
MMO	Planned	1,775	1,775	1,535	1,535	1,535	1,535	1,535	1,603
	Actual	3,459	1,737	1,759	1,979	2,254	1,664	2,108	2,137
	Difference	1,684	(38)	224	444	719	129	573	534
MAC/ MMO	Planned	-	-	-	2,538	2,538	2,063	2,630	1,954
	Actual	-	-	2,044	2,001	2,190	2,708	2,777	2,344
	Difference				(536)	(347)	645	147	(98)

*Values from Response to Discovery MNSCDG-5.8 Exhibit A-12 B6.1.

¹⁹ Ex MEC-30, Responses to Discovery MNSCDG-5.5ai, MNSCDG-5.5bi, and MNSCDG-5.5ci, E. D. Janness, March 15, 2024.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

1 **Q** **Does this indicate that DTE's IRM expenditures are not being adequately**
2 **scrutinized?**

3 **A** Not necessarily. There may be reasonable explanations for each exceedance. However,
4 the overall pattern gives rise to concerns that DTE's spending on investments not subject
5 to normal rate case review has been high and that there is a lack of oversight of its
6 spending.

7 **Q** **Please describe your third concern regarding the IRM process.**

8 **A** The IRM surcharge approval process lacks opportunity for external stakeholder review of
9 cost prudence and project completion. DTE is required to file an annual report
10 (reconciliation filing) of IRM expenditures, completed main/meter units, and adjusted
11 surcharges for Commission review.²⁰ However, there is no opportunity for stakeholders
12 to participate in review of the reconciliation filing such as through a hearing or other
13 processes.²¹ Further, there is little threat that the Commission will disallow IRM
14 expenditures.

15 **Q** **Has the Commission ever disallowed IRM expenditures based on the annual**
16 **reconciliation filing?**

17 **A** No.²²

²⁰ Janness Direct, p. EDJ-49.

²¹ Case No. U-16999 Order, March 20, 2013, p. 10.

²² Ex MEC-19, Response to Discovery, MNSCDG-5.3a, R. M. Telang, March 15, 2024.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

1 **Q** **Regarding your fourth concern, how does DTE determine what types of projects**
2 **qualify for the IRM?**

3 **A** DTE has provided no clear set of specific parameters for projects to qualify for the IRM.
4 DTE states that the projects included in the IRM are “strategic capital improvements”
5 essential for the safety and reliability of the system and are required “under federal or state
6 safety standards.”²³ Moreover, DTE’s description of investments that align with the
7 IRM’s purpose leaves substantial room for interpretation. DTE acknowledges that the
8 IRM is not intended to cover all safety and reliability investments.²⁴

9 **Q** **Why are vague criteria for qualifying projects for the IRM problematic?**

10 **A** DTE may be applying these parameters liberally to proposed investments that are part-
11 and-parcel of a gas utility’s business and do not reasonably warrant special treatment.
12 Qualifying projects for the IRM reduces the Company’s risk that the project could be
13 found imprudent in the future. Safety and reliability investments are supposed to be the
14 core duties of the utility and are required by law. Nothing is stopping DTE from applying
15 these parameters liberally to proposed investments.

16 **Q** **Do utilities have incentives to make capital investments without the special treatment**
17 **provided by the IRM?**

18 **A** Yes. Regulated utilities have an existing and powerful incentive to spend on capital
19 projects because they can earn a return for shareholders on capital expenditures. Even
20 without the reduced risk from IRM investments, DTE has an incentive to favor capital

²³ Ex MEC-20, Response to Discovery MNSCDG-5.2e, E.D. Janness, March 15, 2024.

²⁴ Ex MEC-20, MNSCDG-5.2f.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

1 expenditures over operating expenses (which typically do not earn a return) in order to
2 increase earnings and profit to investors. The IRM enhances and magnifies an incentive
3 that the utility already has.

4 In addition, I note that there may also be cost recovery advantages of passing investments
5 through the IRM. IRM investments incur a pre-tax rate of return, while the overall rate of
6 return on rate-based investments are after-tax. I have not analyzed the impacts of the
7 difference but note that the currently-approved pre-tax rate of return used to calculate the
8 IRM tariff rates is 8.78 percent,²⁵ while DTE Gas' currently approved overall required
9 rate of return (for investments recovered through base rates) is 5.41 after taxes.²⁶ For this
10 case, the Company proposes a pre-tax rate of return of 9.31 percent to calculate the IRM
11 revenue requirement, while the proposed overall after-tax rate of return for non-IRM
12 investments is 6.04 percent.²⁷

13 **Q How does DTE describe returns on the IRM to investors?**

14 **A** In materials to shareholders, DTE indicated that it is “[d]elivering premium shareholder
15 returns” through “[i]ncreased 5-year utility capital investment.”²⁸ To this end, DTE Gas
16 highlights the “[s]ignificant investment recovered through Infrastructure Recovery
17 Mechanism (IRM) to support main renewal.”²⁹

²⁵ MNSCDG-7.1ai.

²⁶ MNSCDG-7.1bi.

²⁷ MNSCDG-7.1aai and MNSCDG-7.1bii.

²⁸ Ex MEC-21, DTE 2023 Year-end Earnings Conference Call (February 8, 2024), p. 4.

²⁹ *Id.*, p. 6.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

1 **Q** **With respect to your fifth issue, what are your concerns with long-term IRM pipeline**
2 **replacement?**

3 **A** Over three-quarters of the proposed IRM expenditure is for replacing old pipes.³⁰

4 As discussed above, the utility has incentives (lower risk) to pursue IRM projects, as
5 compared to other projects that go through prudence review in rate cases. Investments are
6 approved without any meaningful review, as IRM projects are approved in normal course.
7 Including pipe replacement in the IRM effectively increases DTE's incentives to replace
8 pipes, even when that action might not be the most prudent course of action. As I
9 discussed, utilities already have strong incentives to make capital investments, due to the
10 return on investment over a long period of time. In contrast, utilities have far less incentive
11 to invest in NPAs that would avoid spending on pipeline replacements and allow for pipe
12 retirement, even if NPAs would save ratepayers money.

13 **Q** **Could the IRM be reoriented to support initiatives that are more consistent with**
14 **policy priorities?**

15 **A** Yes. DTE currently replaces 15 miles of high-risk legacy main annually, selected using a
16 risk-ranking at the segment level.³¹ The Company is proposing switching to a grid-level
17 risk-ranking that considers population density and building occupancy in addition to other
18 risk factors.³² Assessing pipe replacement at the grid-level would be a good opportunity

³⁰ Calculated using values from Response to Discovery MNSCDG-5.12 Exhibit A-12 B6.5.

³¹ Janness Direct, p. EDJ-21.

³² Janness Direct, p. EDJ-25.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

1 for DTE to consider the cost-effectiveness of implementing NPAs instead of replacing
2 pipe.

3 **Q Has DTE done analysis on whether it would be cheaper for ratepayers to remove**
4 **pipe from service without replacing it, rather than replace it?**

5 **A**No. DTE doesn't evaluate, let alone pursue, NPAs, which could minimize investments
6 and impacts on rates. DTE "has not conducted any studies or analysis of NPAs as a
7 potential source of emissions reductions"³³ and states that "[n]o specific guidelines have
8 been developed to consider NPAs at this time"³⁴ and "[t]here are currently no processes
9 for broader implementation of NPAs."³⁵ DTE has not identified assets or types of assets
10 on its gas system that may be most or least likely to remain used and useful in the event
11 of widespread electrification of gas end uses.³⁶ This is contrary to ratepayer interests;
12 NPAs such as electrification or demand response are more consistent with state and
13 federal policies to curb GHG emissions and can prevent stranded assets as gas demand
14 declines with decarbonization. (Stranded costs are discussed in the testimony of Dr.
15 Hopkins.) Notably, DTE is proposing to end its existing demand response programs.

16 **Q Do other jurisdictions require consideration of NPAs in gas utility planning or**
17 **investment decisions?**

18 **A**Yes. As mentioned in the testimony of Dr. Hopkins, several other states have implemented
19 regulatory processes to examine and reform how gas utilities conduct their business. Some

³³ MNSCDG-7.3b.

³⁴ MNSCDG-7.3ci.

³⁵ MNSCDG-7.3cii.

³⁶ Ex MEC-22, Discovery response MNSCDG-5.10a.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

of these states, such as New York and Massachusetts, have or are exploring requirements for utilities to consider NPAs.

Q Please describe developments related to NPA requirements in New York.

A The New York Public Service Commission instituted a gas planning proceeding (Case 20-G-0131) in 2020 to “establish planning and operational practices that best support customer needs and emissions objectives while minimizing infrastructure investments and ensuring the continuation of reliable, safe, and adequate service to existing customers.”³⁷ In 2022, the Commission issued a Gas Planning Order in this docket which, among other things, requires each gas utility to file comprehensive, long-term plans analyzing gas system supply and demand over a 20-year planning horizon.³⁸ In these long-term plans, utilities must explicitly consider energy efficiency and NPAs, including analysis of an “NPA-only” scenario. Furthermore, the Gas Planning Order required utilities to propose NPA screening and suitability criteria to inform consideration of potential NPAs; the Commission is currently reviewing proposed NPA screening and suitability criteria.

Some New York utilities have begun implementing NPAs. For example, Con Edison has developed a “Whole Building Electrification Service” NPA program. Con Edison initially identified for NPA consideration more than 45 segments of leak-prone mains that would

³⁷ State of New York Public Service Commission. Order Instituting Proceeding. March 19, 2020. Case 20-G-0131 - Proceeding on Motion of the Commission in Regard to Gas Planning Procedures. Page 4. Available at: <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={2BE6F1CE-5F37-4A1A-A2C0-C01740962B3C}>.

³⁸ State of New York Public Service Commission. Order Adopting Gas System Planning Process. May 12, 2022. Case 20-G-0131 and Case 12-G-0297. Available at: <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={130B05B5-00B4-44CE-BBDF-B206A4528EE1}>.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

otherwise be replaced over the next decade.³⁹ Under this program, customers currently connected to an identified pipeline segment could be incentivized to fully electrify, allowing the utility to avoid replacing the pipe and retire it instead. As another example, New York State Electric and Gas Corporation has issued a request for proposals for NPAs to defer or avoid a planned pipeline reinforcement project in the Lansing, New York area.⁴⁰ This NPA portfolio includes installing efficient heat pumps and other energy efficiency measures.

Q What is the current state of NPA consideration as a part of gas utility planning in Massachusetts?

AThe Massachusetts Department of Public Utilities (DPU) opened Case No. 20-80 to examine the role of gas utilities in achieving the state’s climate goals and to “to develop a regulatory and policy framework to guide the evolution of the gas distribution industry in the context of a clean energy transition.”⁴¹ In 2023, the DPU issued an Order on Regulatory Principles and Framework in that docket (“Order 20-80”). Order 20-80 requires gas distribution companies to prove that they adequately considered NPAs for any new gas system investments. In this case, NPAs are broadly defined to include electrification, networked geothermal, and targeted energy efficiency. Gas utilities must prove that replacement was the best alternative (and NPAs were found to be “non-viable

³⁹ Consolidated Edison Company of New York, Non-Pipeline Alternatives Implementation Plan, NY PSC Case No. 19-G-0066 (Nov. 17, 2022), p. 20; NY PSC Case No. 19-G-0066.

⁴⁰ NYSEG. 2022. “Lansing Non-Pipes Alternatives (NPA) Portfolio.” Available at: https://www.nyseg.com/documents/40132/5899449/22-5069+NYSEG+Lansing+Non-Pipes+Alternatives_12.30.22.pdf.

⁴¹ See Exhibit 8, Order on Regulatory Principles and Framework, DPU-20-80-B (December 6, 2023) (“Order 20-80”).

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

or cost prohibitive”) before they can receive full cost recovery for additional investment in natural gas infrastructure.⁴²

Q Beyond immediate affordability issues, are there other concerns with the increases in rates caused by IRM investments?

A Yes. Gas system assets, including those in the IRM, have very long physical engineering lifetimes. In light of the market and policy developments that will put downward pressure on gas sales, as discussed in Dr. Hopkins’s testimony, utilities will seek to recover the costs of gas system assets over fewer sales, pushing up gas prices. In turn, reductions in load and customer defection from the gas system would escalate costs for remaining customers. This process may cause some gas assets to become underutilized or no longer serve customers and become stranded.

This process is particularly concerning for disproportionately vulnerable or disadvantaged customers, who generally face greater challenges with switching off of gas to more affordable options. Existing affordability problems for these customers are likely to compound.

Q What do you recommend?

A Given the high likelihood of cost recovery for IRM-approved programs, there should be more stringent guidelines for IRM program eligibility. I recommend that the Commission not approve the proposed IRM. Instead, the Commission should initiate an open, collaborative proceeding to consider and revise the purpose, requirements, process, and structure of the IRM. Through the IRM or otherwise, any investment in pipeline

⁴² See Exhibit 8, Order 20-80 at 97-98.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

replacements should be evaluated against gas demand projections as well as NPAs. In addition, the Commission should not approve increases in IRM spending or expansion of its scope in this rate case.

IV. DTE’S GAS DELIVERY PLAN INCLUDES QUESTIONABLE STRATEGIES FOR ACHIEVING EMISSIONS REDUCTIONS

Q Does DTE have internal emissions reduction targets?

A Yes. The Company has committed to achieving net-zero emissions by 2050 for its internal gas utility operations and for all the natural gas DTE Gas purchases. It has also committed to a 35 percent reduction in emissions by 2040 from the natural gas used by its customers.⁴³

Q What strategies has DTE identified for achieving emissions reductions to meet its internal climate targets and state policies?

A The Company’s GDP (Exhibit A-12 Schedule B5.6) is a ten-year overview of DTE’s natural gas infrastructure investment plans and how the Company plans to meet the needs for natural gas supply and demand.⁴⁴ DTE’s GDP outlines several actions by which it will reduce emissions from its customers and utility operations. These include investments in RSG, renewable natural gas (RNG), carbon offsets, and other “advanced technologies” such as hydrogen, gas heat pumps, and carbon capture.⁴⁵

⁴³ Exhibit A-12 Schedule B5.6 p. 10.

⁴⁴ Testimony of K.M. Fedele, p. KMF-15, lines 1-5.

⁴⁵ MNSCDG-2.2a

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

1 **Q Do you have concerns with these strategies?**

2 **A Yes. As I will describe, these strategies are unlikely to provide actual emissions**
3 reductions, and any potential emissions reductions from them are small compared to
4 alternatives such as electrification. They also entrench reliance on the gas system and
5 continued fossil fuel emissions from its use.

6 **A. Responsibly Sourced Gas**

7 **Q What is RSG?**

8 According to the Company, RSG (also called “certified” or “differentiated” gas) is
9 “natural gas that has been verified by a third party to have met specified environmental
10 targets during production.”⁴⁶ These environmental targets typically are focused on
11 mitigating methane emissions, with an emphasis on measurement and monitoring.⁴⁷
12 Methane, a potent GHG, is a primary component of fossil gas, and methane leakage is a
13 significant source of GHG emissions throughout the gas supply chain.⁴⁸ RSG provides a
14 construct for compensating producers for actions that may reduce GHG emissions
15 associated with fossil gas production. RSG certification schemes allow producers to
16 voluntarily differentiate all or a portion of their gas supply (e.g., for some or all of their
17 wells), which purchasers (such as DTE) can then purchase for a premium. Some such
18 programs require the gas to meet criteria for methane intensity, i.e., the amount of methane

⁴⁶ Testimony of Henry J. Decker, p. HJD-35, lines 17-18.

⁴⁷ Sankalp Garg et al. “A critical review of natural gas emissions certification in the United States” 2023. Environ. Res. Lett 18 023002. Available at: <https://iopscience.iop.org/article/10.1088/1748-9326/acb4af>

⁴⁸ Alvarez et. al. 2018. “Assessment of methane emissions from the U.S. oil and gas supply chain.” Science. DOI: 10.1126/science.aar7204. Available at: <https://science.sciencemag.org/content/361/6398/186>.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

1 emissions released relative to the amount of gas produced, typically expressed as a
2 percent.

3 **Q Please describe the Company’s proposals in this rate case related to RSG.**

4 **A** The Company is proposing to procure up to 4,000,000 Dth of RSG in the projected test
5 year, with an expected premium of \$180,000, or \$0.045 per Dth.⁴⁹ The Company estimates
6 this would reduce approximately 4,000 to 8,000 metric tons of carbon dioxide equivalent
7 (“CO₂e”) emissions, “depending on the methane intensity of RSG purchased.”⁵⁰

8 **Q Has DTE committed to any particular certification standard for RSG purchases?**

9 **A** No. DTE has not committed to a specific certification standard or process, only stating
10 that “at a minimum, third party verification is a criterion that will be used when procuring
11 RSG.”⁵¹

12 **Q Has DTE purchased RSG previously?**

13 **A** Yes. DTE has made two RSG purchases, in 2022 and 2023 respectively. The Company
14 issued a Request for Information (RFI) to understand the market dynamics for RSG.⁵² In
15 2022, DTE purchased 1,134,200 Dth of RSG from two different suppliers at a total cost
16 of \$7,858,562, which includes the commodity cost of \$7,821,754 and premium cost of
17 \$36,808, based on premium prices of \$0.02 and \$0.04 per Dth.⁵³ DTE calculates that this

⁴⁹ Decker Direct, p. HJD-49, lines 1-6, Q125.

⁵⁰ Decker Direct, p. HJD-49, lines 6-8.

⁵¹ Decker Direct, p. HJD-41, Q98, lines 2-3.

⁵² Decker Direct, p. HJD-41, Q99, lines 8-9.

⁵³ Exhibit A-22, Schedule L3.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

premium would be approximately \$0.03 annually per customer.⁵⁴ In 2023, DTE purchased 1,990,200 Dth of RSG, with a commodity cost of \$4,388,391 and a premium cost of \$29,853, based on a premium price of \$0.015 per Dth.⁵⁵

Q How is the Company seeking to recover the costs of RSG purchases?

A DTE is seeking recovery for both the commodity cost and the RSG premiums for RSG purchased in 2022 and 2023 as part of DTE’s annual GCR reconciliation cases.⁵⁶

Also, DTE seeks Commission guidance on “the integration of RSG into the portfolio as the Company continues to develop a robust RSG procurement strategy.” Further, DTE indicates that it “believes that as the industry has evolved, premiums paid for RSG attributes are reasonable and prudent similar to other environmental costs, which are recoverable.”⁵⁷

Q Do you have concerns with this proposal?

A Yes. DTE is relying on RSG as a decarbonization strategy without any indication that it reduces emissions. In the GDP, DTE highlights that acquiring RSG is a part of its long-term approach to support decarbonization goals.⁵⁸

⁵⁴ MNSCDG-3.11a.

⁵⁵ Exhibit A-22, Schedule L3.

⁵⁶ Decker Direct, p. HJD-46, lines 15-19 Q118.

⁵⁷ Decker Direct, p. HJD-48.

⁵⁸ Exhibit A-12, Schedule B5.6, p. 34.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

1 **Q** **What are the issues with relying on RSG as a long-term decarbonization strategy?**

2 **A** There are many issues with relying on RSG as a long-term decarbonization strategy, which
3 are being increasingly raised in the literature.⁵⁹ These include the following:

4 1. RSG is not regulated, and private standards for RSG lack uniformity. Further, DTE
5 has not set specific requirements for emissions reductions from RSG.

6 2. Federal emissions standards have likely reduced the benefits of RSG.

7 3. The potential for emissions reductions from RSG is limited.

8 4. DTE has not justified the cost-effectiveness of RSG compared to other GHG
9 emissions reduction strategies.

10 5. Significant dependence on RSG may prolong dependence on the gas system.

11 **Q** **Please describe your first point regarding regulation and uniformity of standards for**
12 **RSG.**

13 **A** There are no regulations or official standards for RSG. As it currently stands, certification
14 standards are developed by private entities. These standards are inconsistent, lack
15 transparency, and do not provide assurance that RSG provides incremental benefits above
16 what is already occurring in the industry (that is, they do not address whether emission
17 reductions are *additional*, i.e., an incremental improvement compared to counterfactual
18 scenarios). DTE claims that RSG “is becoming a new industry standard for lower methane
19 gas requirements.”⁶⁰ However, in DTE’s review of certification standards, the Company

⁵⁹ Environmental Defense Fund. Certification of Natural Gas with Low Methane Emissions: Criteria for Credible Certification Programs. 2022. Available at: https://blogs.edf.org/energyexchange/wp-content/blogs.dir/38/files/2022/05/EDF_Certification_White-Paper.pdf.

⁶⁰ Decker Direct, p. HJD-47.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

1 stated that the RSG certification process currently lacks uniformity.⁶¹ Furthermore, DTE
2 acknowledges that there is no standard calculation of methane emissions intensity for
3 natural gas: “the method of calculating and reporting intensity is not consistent across the
4 natural gas industry.”⁶²

5 Without uniform standards, it is difficult to know whether the emissions reductions from
6 RSG are additional, i.e., if they would not occur without the certification. Furthermore,
7 standards do not require all suppliers to participate, or even individual suppliers to certify
8 all of their wells. An individual supplier can opt to, and has a financial incentive to, certify
9 its already low-emitting wells and not certify its high-emitting wells; thus, this supplier
10 could earn incremental revenues from RSG certification without making any changes to
11 its operations or investments in technology that would reduce emissions.⁶³ If suppliers
12 select only their currently low-emitting wells to include in RSG programs, RSG
13 certification will produce no reductions in emissions, just higher costs to DTE ratepayers.

14 **Q Given the lack of uniformity of standards, has DTE set a limit on the methane**
15 **intensity of RSG purchases?**

16 **A**No, DTE has not set a specific methane intensity level or limit for its RSG purchases.⁶⁴
17 Of the three RSG purchases the Company procured in 2022 and 2023, each supplier had
18 a different certification standard and methane intensity: MiQ Grade A, with a methane

⁶¹ Decker Direct, p. HJD-40, Q97, lines 2-4.

⁶² Decker Direct, p. HJD-42, Q102, lines 6-8.

⁶³ Letter to the Chair of the Federal Trade Commission from Senators Markey, Merkley, Whitehouse, Warren, Blumenthal, Sanders, and Booker. February 12, 2024. Available at: https://www.markey.senate.gov/imo/media/doc/certified_gas_letter_21224.pdf.

⁶⁴ Ex MEC-23, discovery response MNSCDG-3.16b.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

intensity of less than 0.01, Project Canary Trustwell Platinum, with a methane intensity of less than 0.063, and EO Trustwell Platinum, with a methane intensity of less than 0.05.⁶⁵ Since DTE has not committed to any specific methane intensity requirements for the program, there is no assurance that the program will produce any GHG emission reductions.

Q With respect to your second point, please describe how federal emissions standards relate to RSG.

A In late 2023, the U.S. Environmental Protection Agency released new regulations for the oil and gas industry. These regulations require reductions in fugitive emissions from wells and transmission and distribution systems.⁶⁶ To provide *additional* emissions reductions, RSG providers would have to reduce emissions beyond what is mandated by law. It is currently unclear whether individual RSG standards, such as those DTE has used previously, offer any environmental benefits beyond the new federal regulations. These regulations may reduce or eliminate the environmental benefits that DTE can claim from procuring RSG.

Q Regarding your third point, can purchase of RSG substantially reduce emissions?

A The potential for emissions reductions from RSG is very limited; by itself, it cannot meet federal or state GHG reduction targets. RSG will still release GHGs during combustion, and RSG will leak from the distribution system and from customer end-use equipment

⁶⁵ MNSCDG-3.14c.

⁶⁶ U.S. Environmental Protection Agency. 2023. "EPA's Final Rule for Oil and Natural Gas Operations Will Sharply Reduce Methane and Other Harmful Pollution." December 2. <https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-operations/epas-final-rule-oil-and-natural-gas>.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

1 just the same as traditional “uncertified” fossil gas. Furthermore, RSG will emit criteria
2 pollutants such as nitrogen oxides when burned, thus causing the same indoor and outdoor
3 air quality public health impacts problems when combusted as conventional fossil gas.

4 **Q Turning to your fourth point, has DTE compared the cost of emissions reductions**
5 **from RSG to other alternatives for reducing emissions?**

6 **A**No.⁶⁷ Considering that RSG may provide very little or no real reductions in emissions,
7 the cost per avoided ton of GHG is very high.

8 **Q With respect to your fifth point, do you have other concerns with RSG?**

9 **A**Yes. RSG sends a message to customers implying that natural gas is an environmentally
10 preferred solution. Customers may be more likely to continue to stay on the gas system if
11 they believe RSG is a viable decarbonization pathway, and as a result they may make
12 investments in gas-fired equipment that will last for decades.

13 **Q What do you conclude about the proposed RSG pilot?**

14 **A**I find that RSG does not represent a valid GHG reduction measure. Given the speculative
15 nature of the GHG reductions from RSG, if approved this pilot might incur costs with no
16 associated benefits to DTE customers or to the state.

17 **Q What do you recommend?**

18 **A**The Commission should reject the RSG pilot.

⁶⁷ Ex MEC-24, discovery response MNSCDG-3.13

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

B. Carbon Offsets and Renewable Natural Gas

Q Please describe the Company's voluntary carbon emissions offset program.

A According to the Company's filing, the Company's CleanVision Natural Gas Balance Program is a fee-based voluntary carbon emissions offset program that customers may opt into to reduce some or all of their emissions from gas usage through RNG attributes and carbon offsets. The product mix includes 5 percent RNG attributes and 95 percent carbon offsets.

The program was launched in January 2021 as a three-year pilot.⁶⁸ Currently there are 10,352 DTE Gas residential and small business customers enrolled in the program. DTE claims that the program resulted in 11,792 metric tons of CO₂e emissions negated using carbon offsets in 2022.⁶⁹ In 2022, the program also acquired 11,264 mcf of RNG; DTE claims that this negated 621 metric tons of CO₂e emissions.⁷⁰

Q What are carbon offsets?

A Offsets are credits produced by projects intended to reduce GHG emissions, increase carbon storage, or remove GHG from the atmosphere. Offsets are purchasable; one offset represents one metric ton of CO₂e emissions reduced. Offset programs are designed to allow purchasers to credit offsets against their emissions, with the intention of negating or reducing those emissions on net. However, as I describe further below, many offsets on the market today do not actually lead to GHG emissions

⁶⁸ MNSCDG-3.2a

⁶⁹ MNSCDG-2.4c, 2022 NGB Annual Report.

⁷⁰ MNSCDG-2.4c, 2022 NGB Annual Report.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

1 reductions.^{71,72} The purchase of an offset that is not associated with a real emission
2 reduction will not achieve the buyer's objective, which is to decrease net GHG emissions.

3 **Q What is renewable natural gas?**

4 **A** RNG is pipeline-quality gas derived from biomass or other renewable resources which
5 has been processed or upgraded to be fully interchangeable with conventional natural
6 gas.⁷³

7 **Q Is DTE providing RNG to participants in the program?**

8 **A** DTE does not appear to be providing physical RNG to all participants. The environmental
9 attributes of RNG (or hydrogen or other alternative fuel) can be purchased separately from
10 the physical gas. DTE purchases RNG environmental attributes that are bundled or
11 unbundled with physical gas. DTE retires the environmental attributes.⁷⁴ Of the four
12 sources of RNG procured for the Natural Gas Balance program, two include the physical
13 gas commodity while the other two sources are only the environmental attribute of the
14 RNG.⁷⁵ DTE states that "[w]hen DTE is purchasing just the environmental attribute, DTE
15 does not track the final end use of the specific molecule and therefore does not identify

⁷¹ Song, Lisa. 2019. "An Even More Inconvenient Truth - Why Carbon Credits For Forest Preservation May Be Worse Than Nothing." *ProPublica*. May 22. Available at: <https://features.propublica.org/brazil-carbon-offsets/inconvenient-truth-carbon-credits-dont-work-deforestation-redd-acre-cambodia/>

⁷² Haya, Barbara. 2019. *Policy Brief: The California Air Resources Board's U.S. Forest offset protocol underestimates leakage*. Center for Environmental Public Policy, Univ. of Calif. Berkeley. May 7. Available at: https://gspp.berkeley.edu/assets/uploads/research/pdf/Policy_Brief-US_Forest_Projects-Leakage-Haya_4.pdf.

⁷³ Michigan Public Acts of 2021, Act No.87, <https://www.legislature.mi.gov/documents/2021-2022/publicact/htm/2021-PA-0087.htm>.

⁷⁴ MNSCDG-3.8di.

⁷⁵ MNSCDG-3.8c.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

the end use of the RNG.”⁷⁶ RNG environmental attributes on their own do not represent gas that is physically delivered to customers purchasing the attributes; this means that these customers are not actually reducing their own emissions on-site.

It is important to note that the GHG emissions associated with RNG vary considerably based on the feedstock and process used to make it. Many RNG sources should not be considered zero-emissions or even low emissions, compared with fossil gas. DTE indicates that its sources of RNG are either from animal manure or landfill gas feedstocks.⁷⁷ While RNG from animal manure is likely to reduce GHG emissions, RNG from landfill gas will likely result in GHG emissions that are lower than fossil gas but still positive.⁷⁸

Q Do you have concerns with carbon offsets as a decarbonization strategy?

A Yes. While the CleanVision Natural Gas Balance (NGB) program costs are not considered in this proceeding, the inclusion of this program in DTE’s long-term decarbonization strategies in its GDP is concerning. Carbon offset programs and projects have been widely discredited upon evaluation. In light of the concerns I raise herein, it is critical that the Commission investigate whether the NGB provides net benefits to any ratepayers,

⁷⁶ MNSCDG-3.8dvi.

⁷⁷ MNSCDG-3.8c.

⁷⁸ According to ICF’s September 2022 study on RNG, the carbon intensity associated with extraction and processing of fossil gas is 8.27, while RNG from landfill gas is higher, 10.91. How RNG is transported will impact the overall carbon intensity. If RNG is blended with fossil gas in the distribution system, RNG leakage will occur at the same rates as fossil gas. (ICF. September 23, 2022. *Michigan Renewable Natural Gas Study: Final Report*. Prepared for the Michigan Public Service Commission. Accessed at <https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/RenewableNaturalGas/MI-RNG-Study-Final-Report-9-23-22.pdf>).

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

whether they participate or not. While I have not conducted a thorough investigation of NGB benefits and costs, it appears that their main benefit is for DTE's marketing purposes i.e., to broadcast the likely false claim that the Company is reducing emissions from its gas portfolio through this program.

Q Please explain.

A To ensure credibility and environmental integrity, carbon offsets should meet five criteria:

1. Permanent: Emissions reductions or removals should not be reversible, meaning that a reduction in emissions now will not be followed by an equivalent increase in emissions later.
2. Additional: The offset project should represent new emissions reductions. Offsets are additional if they enable carbon reduction to occur that would not otherwise occur without the offset funding.
3. Verifiable: Emissions reductions from offsets should be monitored and regularly verified by an independent third party.
4. Enforceable: To avoid double-counting, the ownership of an offset should be enforceable to ensure that only one credit can be claimed for the offset.
5. Real: Offsets should represent one ton of carbon emissions reduced as the result of the offset project without carbon displacement occurring, which occurs when the offset results in the same emissions occurring elsewhere rather than actually

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

reducing overall emissions. This criterion involves ensuring that the quantity of emissions reductions are not inflated and that accurate accounting takes place.⁷⁹

DTE uses the American Carbon Registry for its carbon offsets in the NGB program.⁸⁰ Verified carbon offset registries, including DTE's chosen registry, lack transparency regarding the actual impacts of their carbon offset projects. For example, a satellite analysis released in December 2022 detected no real climate benefit from 10 years of forest carbon offsets administered by the American Carbon Registry and the Climate Action Reserve in California.⁸¹ Another analysis of the global Joint Implementation offset program in 2015 found that roughly 75 percent of offset credits issued were unlikely to represent additional emissions reductions.⁸²

Q Has DTE analyzed the costs of these decarbonization strategies to customers?

A No. DTE "has not done an evaluation of the costs to customers" for any of the initiatives to reduce customer emissions, including the voluntary carbon offset program and RNG.⁸³

⁷⁹ World Resources Institute. 2010, The Bottom Line on Offsets. Available at: <https://www.wri.org/research/bottom-line-offsets>.

⁸⁰ MNSCDG-3.5b.

⁸¹ Coffield, Shane and James Randerson. 2022. "Satellites detect no real climate benefit from 10 years of forest carbon offsets in California." *The Conversation*. December 1. Available at: <https://theconversation.com/satellites-detect-no-real-climate-benefit-from-10-years-of-forest-carbonoffsets-in-california-193943>; Coffield, S.R., Vo, C.D., Wang, J.A, Badgley, G. Goulden, M.L., Cullenward, D., Anderegg, W.R.L, & Randerson, J.T. 2022. "Using remote sensing to quantify the additional climate benefits of California forest carbon offset projects." *Global Change Biology* (Vol. 28, Issue 22). Available at: <https://onlinelibrary.wiley.com/doi/10.1111/gcb.16380>.

⁸² Kollmuss, A., L. Schneider, V. Zhezherin. 2015. *Has Joint Implementation reduced GHG emissions? Lessons learned for the design of carbon market mechanisms*. Stockholm Environment Institute, Working Paper 2015-07. Available at: <https://mediamanager.sei.org/documents/Publications/Climate/SEI-WP-2015-07-JI-lessons-for-carbon-mechs.pdf>.

⁸³ Ex MEC-25, MNSCDG-2.4f.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

This program is likely not a least-cost way to achieve GHG emission reductions. DTE found that the NGB program offers customers emission reductions at approximately \$37 per mt, for “Level 4” customers balancing 100 percent of their gas usage.⁸⁴ However this value only reflects the customer program fee and does not reflect DTE’s program administration costs. While not included in base rates, the total expenses for the NGB program in 2022 and 2023 were over twice the revenues, with a program net loss of over \$1 million each year.⁸⁵ This is not a cost-effective model for significant long-term emissions reductions.

Q Do you have other concerns with this strategy?

Yes. As with RSG, pursuing a customer-facing carbon offset program could work against the state’s efforts to reduce GHG emissions. Participants in particular, and customers in general, receive the message that it is easy to offset their emissions, or they delay switching off of gas. Such misinformation can have negative consequences: participants may increase their gas consumption, resulting in even higher GHG emissions. According to research, carbon offsets might be perceived as a moral license to behave in environmentally harmful ways.⁸⁶ Assuming this is true of consumption that leads to GHG

⁸⁴ Ex MEC-24, MNSCDG-3.13.

⁸⁵ Ex MEC-26, Case No. U-20839, DTE Gas Company’s CleanVision Natural Gas Balance 2023 Annual Impact Report dated March 27, 2024 and DTE Gas Company’s CleanVision Natural Gas Balance Annual Report (2022) dated March 29, 2023.

⁸⁶ Warburg, Johan, Britta Frommeyer, Julia Koch, Sven-Olaf Gerdt, and Gerhard Schewe. “Voluntary carbon off setting and consumer choices for environmentally critical products—An experimental study.” Business Strategy and the Environment. Volume 30, Issue 7. p. 3009-3024.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

emissions, the availability of offsets may lead to an increase in gas consumption by NGB participants.

Q What are your recommendations?

A As discussed in Dr. Hopkins's testimony, Michigan utilities' decarbonization approach should be considered in a holistic setting in which stakeholders (including gas and electric utilities) consider the challenges and opportunities of different pathways for achieving climate policy goals while reducing the risk of stranded assets, i.e., in a future of heat proceeding. Until then, and until there has been a full assessment of the net benefits of the NGB, the Commission should not approve the NGB or any similar programs, in this docket or in any other docket. If DTE wishes to pursue the NGB program, it should be funded by shareholders exclusively.

V. DTE FAILED TO PROVIDE ADEQUATE SUPPORT FOR ITS PROPOSAL TO DISCONTINUE ALL EXISTING DEMAND RESPONSE PROGRAMS

Q Please summarize briefly DTE's demand response pilot program.

A Pursuant to the settlement in Case U-20642 and the Commission's recommendation on demand response in the Statewide Energy Assessment report in the same case, DTE implemented two residential gas demand response pilot programs and one commercial demand response pilot program. Details of these pilots are as follows:

- The Smart Savers Gas pilot: this pilot targeted residential customers who already had a Wi-Fi enabled smart thermostat installed. In the program, DTE remotely adjusted the set point of participants' thermostats by up to 4 degrees to achieve peak load reduction. Program participants received a \$50 up-front gift card upon

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

1 enrollment and another \$50 gift card if they remained enrolled at the end of the
2 pilot program. The program enrolled approximately 6,140 devices during the
3 2022–2023 winter period.

- 4 • The Energy Action Days pilot: through this behavior-based demand response
5 program, DTE provided customers a variety of educational resources to encourage
6 customers to save gas usage during winter peak periods. DTE did not provide any
7 financial incentives to customers. The pilot targeted two DTE regions (Southeast
8 Michigan and Northeast Michigan) and used an opt-out approach where all
9 customers were automatically enrolled in the pilot.

- 10 • The Small and Large Commercial pilot: this pilot targeted large customers (e.g.,
11 customers who are under rate GS-1, GS-2, or the S-rate). This program did not
12 provide any financial incentives to participants, but instead installed telemetry
13 equipment at the participants' premises at no cost in order to measure peak load
14 gas usage during peak load events. DTE asked the participants to voluntarily
15 reduce gas usage during the peak load events.⁸⁷

16 DTE implemented these pilots for two years from 2022 to 2023. Per the settlement, DTE
17 would defer up to \$4 million for the cost of the programs as a regulatory asset. To date,
18 DTE has incurred approximately \$2.5 million on the demand response pilot programs.⁸⁸

⁸⁷ Decker Direct, pp. HJD-79 to HJD-80.

⁸⁸ Exhibit A-26. Schedule P1.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

1 **Q What is DTE’s proposal regarding its demand response pilots?**

2 **A DTE witnesses conclude that DTE’s demand response program was not effective and**
3 mentions DTE does not request an extension of the program. More specifically, Witness
4 Telang mentions as follows: “At the conclusion of the second year of the demand response
5 pilot, DTE Gas reviewed the results and determined the demand response program was
6 not effective and determined not to request to extend the pilot or make the program
7 permanent. DTE Gas believes that this pilot fulfilled the purpose set forth by the
8 Commission and the costs were incurred reasonably and prudently.”⁸⁹ In addition,
9 Witness Decker states as follows:

10 “the Company conducted multiple pilots, gathered and analyzed results and
11 ultimately made the decisions not to continue with any gas [demand response]
12 pilots or programs at this time. The Company was able to gather valuable
13 information with total costs of the pilots being less than the total amount allowed
14 for in the deferral. The total cost was reasonable and prudent because it achieved
15 the goal of obtaining information at the request of the Commission. At the
16 conclusion of the pilots, it was clear that [demand response] programs were not
17 effective and DTE Gas determined that it would not be reasonable or prudent to
18 propose additional [demand response] programs and therefore further costs were
19 not incurred.”⁹⁰

20 **Q Did any of DTE witnesses define the “effectiveness” of the demand response pilot**
21 **program?**

22 **A DTE witnesses do not clearly define what effectiveness means with respect to the demand**
23 response pilot programs. However, it appears that effectiveness refers to gas savings
24 during the peak gas events based on Witness Decker’s discussion of the three demand

⁸⁹ Telang Direct, p. RMT-28: 20-23.

⁹⁰ Decker Direct, p. HJD-84: 6-14.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

1 response pilot programs in his direct testimony.⁹¹ Also, DTE's response to data request
2 MMSCDG-2.6f clearly makes a connection between gas consumption reductions during
3 events and effectiveness, as follows: "Overall, based on the results of the three pilots, the
4 Company did not observe gas reductions across the various events which would lead the
5 Company to determine the pilots were effective, thus driving our determination not to
6 request extension of the pilot or to make the program permanent."

7 **Q Do you have any concerns about DTE witnesses' conclusions about the demand**
8 **response pilot programs?**

9 **A** Yes. I have two concerns about DTE witnesses' conclusions about the demand response
10 pilot programs. First of all, I found that DTE's own assessment of gas savings during peak
11 hours does not support its recommendation to discontinue the Smart Savers pilot program.
12 In fact, this pilot program led to a 36 percent to 72 percent reduction in gas use during the
13 past five gas events, as shown in Table 5 below (see the "% Reduction" column).⁹² While
14 it is notable that the overall gas consumption for the participants during one of the five
15 peak day events (January 28) increased slightly, that event was an outlier caused by
16 snapback effects.⁹³ For all other days, the pilot saved considerable amounts of gas during
17 the peak events, as shown in Table 6 under "Cumulative Event Usage (therms)." The
18 results of the Smart Savers Program illustrate its effectiveness as a peak load reduction
19 program.

⁹¹ Decker Direct, p. HJD-80 to HJD-83.

⁹² Ex MEC-27, produced by DTE gas in response to MNSCDG-6.3b.

⁹³ One of the files DTE provided in response to MNSCDG-2.6, titled "U-21291 MNSCDG-2.6d Gas DR Pilot Results Season 2," slide 7 through 9, clearly shows snapback effects that occurred right after the peak gas reduction periods.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

Table 6. Performance of the Smart Savers Pilot Program

Date	Event Time	Devices Targeted	Gas Reduction (therms)	Gas Reduction per Device (therms)	Cumulative Event Usage (therms)	Event Avg. Temp	Opt-Out (%)	% Reduction
1/20/2022	5pm-7pm	1,309	509	0.386	(349)	18°	11.2	72%
1/28/2022	6am-8am	1,278	387	0.295	66	13°	10.6	41%
1/30/2023	5pm-7pm	6,138	1,850	0.301	(241)	21°	13.0	50%
1/31/2023	6am-8am	6,138	2,184	0.356	(1,354)	5°	16.4	36%
2/3/2023	6am-8am	6,058	2,120	0.350	(1,983)	8°	15.3	36%

Source: Ex MEC-27, DTE's response to MNSCDG-6.3b.

Second, DTE did not assess the cost-effectiveness of any of the demand response pilot programs. In response to MNSCDG-2.6e, DTE states that "The Company did not evaluate any avoided commodity or gas infrastructure costs" for the demand response pilot programs.⁹⁴

Q Are there any demand response pilots that DTE should continue offering?

A Yes. DTE should continue offering the Smart Savers pilot program. DTE's evaluation showed that its pilot reduced large amounts of gas usage during gas demand events. Demand response is an opportunity for DTE to seek alternatives to pipeline investments.

Q Do you have any recommendations regarding the evaluation of the Smart Savers pilot program?

A Yes. DTE's evaluation shows a small increase in gas consumption among the participants in one out of five peak day events. To increase the success rate, DTE should explore and evaluate ways to reduce snapback effects. One approach DTE could explore is pre-heating

⁹⁴ Ex MEC-28, discovery response MNSCDG-2.6e.

**DIRECT TESTIMONY OF A. NAPOLEON ON BEHALF OF MEC-NRDC-SC
CASE NO. U-21291**

participants' buildings by remotely increasing thermostat temperatures slightly prior to peak gas events.⁹⁵

Second, I recommend that the Commission require DTE to evaluate the cost-effectiveness of demand response as an alternative to conventional gas pipeline investments, as discussed in Section III. Witness Telang's direct testimony notes, "DTE pursued these pilots to determine the effectiveness of gas demand response as a requirement of the Commission in its State Energy Assessment report and the settlement agreement in Case U-20642."⁹⁶ The Commission's order in U-20642 recommends that the gas utilities work with Staff and stakeholders to evaluate the potential for natural gas demand response programs. It is the industry-standard practice to evaluate cost-effectiveness of any demand-side resources including demand response when they are promoted or examined as a ratepayer-funded program, as DTE did when it evaluated the cost-effectiveness of its Energy Waste Reduction program.⁹⁷

Q Does this complete your direct testimony?

A Yes, it does.

⁹⁵ See, Ex MEC-29, ACEEE. "Winter Demand Response Using Baseboard Heaters: Achieving Substantial Demand Reduction Without Sacrificing Comfort." 2016. Available at: https://www.aceee.org/files/proceedings/2016/data/papers/1_88.pdf.

⁹⁶ Telang Direct, p. RMT-28: 9-11.

⁹⁷ DTE. 2020. 2020 Annual Report – Energy Waste Reduction. Available at: <https://newlook.dteenergy.com/wps/wcm/connect/24f9b27e-6ffd-4a2f-905e-5360dc331f28/2020EWRAnnualReport.pdf?MOD=AJPERES>.

1 MR. BZDOK: Thank you, your Honor. At
2 this time, on behalf of the Citizens Utility Board of
3 Michigan, I would move to bind into the record the Direct
4 Testimony of Ram Veerapaneni, which consists of a cover
5 page, a table of contents, nine pages of questions and
6 answers; and I would move to admit into evidence proposed
7 Exhibits CUB-1 through CUB-3.

8 I would also move to bind in the record
9 the Direct Testimony of Matthew Bandyk, which consists of
10 a cover page, a table of contents, and 17 pages of
11 questions and answers; and I would move for the admission
12 of the exhibits Mr. Bandyk sponsors, which are CUB-4
13 through CUB-9.

14 JUDGE THOITS: Are there any objections
15 to the admission of this testimony or these exhibits?
16 (No response.)

17 Hearing none, the Direct Testimony of Ram
18 Veerapaneni is bound in the record, and Exhibits CUB-1
19 through CUB-3 are admitted; and the Direct Testimony of
20 Matt Bandyk is bound into the record, and Exhibits CUB-4
21 through CUB-9 are admitted.

22 (Testimony bound in.)

23 - - -
24
25

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE
GAS COMPANY** for authority to
increase its rates, amend its rate schedules
and rules governing the distribution and
supply of natural gas, and for
miscellaneous accounting authority.

Case No. U-21291

DIRECT TESTIMONY OF RAM VEERAPANENI

ON BEHALF OF

CITIZENS UTILITY BOARD OF MICHIGAN

May 7, 2024

DIRECT TESTIMONY OF R. VEERAPANENI OBO CUB
CASE NO. U-21291

TABLE OF CONTENTS

I. INTRODUCTION 1

II. SUMMARY 4

III. CAPITAL EXPENDITURES - ADJUSTMENTS 7

IV. CONCLUSIONS.....9

**DIRECT TESTIMONY OF R. VEERAPANENI OBO CUB
CASE NO. U-21291**

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Ram Veerapaneni. My business address is 115 West Allegan Street, Suite 710, Lansing MI 48933.

Q. By whom are you employed and what is your position?

A. I am a gas industry consultant and an employee of 5 Lakes Energy.

Q. Please briefly describe your educational background?

A. I have a Master of Science degree in Mechanical Engineering from Wayne State University, Detroit, Michigan. I have a bachelor's degree in mechanical engineering from Andhra University, Vishakhapatnam, India. I completed 20 credits towards a Master of Business Administration degree at Wayne State University.

Q. Please summarize your employment and professional experience.

A. I retired as a Principal Engineer at the DTE Gas Company after working for 23 years in various positions. I worked for the Michigan Public Service Commission (MPSC) for 22 years. I have been working for 5 Lakes energy as a Senior Consultant since September 2019. Details of that experience are shown in Exhibit CUB-1.

Q. Please give us examples of utility cases you have provided testimony and/or participated in settlement negotiations, representing the MPSC Staff.

A. The following are a list of utility cases I have previously provided testimony for:

U-3665 Revision of Michigan Gas Safety Code

U-4717 Consumers Power Company Rate Case

DIRECT TESTIMONY OF R. VEERAPANENI OBO CUB
CASE NO. U-21291

1	U-5304	Michigan Consolidated Gas Company to revise its Purchased Gas
2		Adjustment Clause, Rule 30
3	U-5365	Michigan Consolidated Gas Company Rate Case
4	U-5732	Consumers Power Company Rate Case
5	U-5748	Michigan Gas Utilities Company for approval of a 60-day emergency gas
6		service agreement with Michigan Consolidated Gas Company
7	U-5759	Consumers Power Company for authority to amend its Purchased Gas
8		Adjustment Clause
9	U- 5955	Michigan Consolidated Gas Company Rate Case
10	U-6486	Great Lakes Steel / Michigan Consolidated Gas Company
11	U- 6839	Great Lakes Steel / Michigan Consolidated Gas Company
12	U-8409	Rate charges for gas service by Michigan Consolidated Gas Company
13	U-8565	Michigan Consolidated Gas Company GCR Plan
14	U-8565R	Michigan Consolidated Gas Company GCR Reconciliation
15	U-8635	Special Contract- Michigan Consolidated Gas Company (combined with U-
16		8812, U-8854)
17	U-8779	Michigan Gas Processors Company for authority to construct and operate the
18		Oceana/Mason Pipeline
19	U-8847	Michigan Consolidated Gas Company/Panhandle Eastern Pipeline Company
20	U-8870	Michigan Consolidated Gas Company GCR Plan
21	U-8870R	Michigan Consolidated Gas Company GCR Reconciliation
22	U-8954	Northern States Power Company GCR Plan
23	U-8955	Wisconsin Public Service Corporation GCR Plan
24	U-9175	Peninsular Gas Company GCR Plan
25	U-9257	Consumers Power Company, Rule Expansion
26	U-9263	Consumers Power Company, Rule-Building Meter

**DIRECT TESTIMONY OF R. VEERAPANENI OBO CUB
CASE NO. U-21291**

1 U- 9298 Wisconsin Public Service Corporation GCR Plan
2 U- 9323 Michigan Gas Company Rate Case
3 U-9475 Michigan Consolidated Gas Company Rate Case
4 U-9650 Michigan Consolidated Gas Company- GCR Plan

5 **Q. What cases have you filed testimony as a gas industry consultant?**

6 **A.** I have been an expert witness in the following cases in Michigan: Case No. U-21490
7 (Consumers Energy Company Gas Rate Case); Case No. U-21226 (Northern States Power
8 Company Gas Rate Case); Case No. U-20650 (Consumers Energy Company Gas Rate
9 Case); Case No. U-20642 (DTE Gas Company Rate Case); and Case No. U-20479 (SEMCO
10 Energy Gas Company Rate Case).

11 **Q. What is the purpose of your direct testimony in this proceeding?**

12 **A.** The purpose of my testimony is to make recommendations to the Commission on behalf of
13 the Citizens Utility Board of Michigan (CUB).

14 I am addressing the following topics in this case:

- 15 1. Capital Expenditures:
- 16 a) Distribution Plant
- 17 b) Transmission Plant
- 18 c) Storage Plant
- 19 d) General Plant
- 20 e) Large Capital Projects

**DIRECT TESTIMONY OF R. VEERAPANENI OBO CUB
CASE NO. U-21291**

1 **Q. Do you agree with all other aspects of the Company's proposals?**

2 **A.** No. The absence of discussion on other matters in my testimony does not indicate agreement
3 with the other items contained in the rate case filing.

4 **Q. Are you sponsoring any exhibits?**

5 **A.** Yes. I am sponsoring the following exhibits:

6 Exhibit CUB-1: Resume of Ram Veerapaneni

7 Exhibit CUB-2: Capital Expenditures

8 Exhibit CUB-3: Capital Expenditures-Adjustments

9 **II. SUMMARY**

10 **Q. Please provide a summary of your findings.**

11 **A.** DTE Gas Company (DTE) filed for a rate increase of \$266 million based on a test year
12 ending September 30, 2025. I reviewed the testimony, exhibits, and discovery responses
13 and concluded that the capital expenses related to the categories described in Exhibit CUB-
14 2 should be \$713,811,000. It results in a reduction of \$5,868,000. The proposed reductions
15 are shown in column (d) of Exhibit CUB-3.

16 **Q. Please describe the history of DTE's previous rate case filings including requested rate
17 increases, timings of rate filings, and Commission Orders authorizing rate relief.**

18 **A.** On June 9, 2009, DTE (Known as Michigan Consolidated Gas Company at that time) filed
19 an application (U-15985) to increase rates by \$192.6 million using a projected test year for
20 the 12- month period ending June 3, 2010. On June 3, 2010, the Michigan Public Service
21 Commission (MPSC) issued an order to increase rates by \$118.6 million. On April 20, 2012,
22 DTE, in case number U-16999, filed for rate increase of \$76.7 million based on projected

**DIRECT TESTIMONY OF R. VEERAPANENI OBO CUB
CASE NO. U-21291**

test year ending on October 31, 2013. On December 20, 2012, the MPSC issued an order approving a rate increase of \$ 19.9 million. On December 18, 2015, DTE filed for rate increase of \$182.9 million in case number U-17999. On December 9, 2016, the MPSC issued an order authorizing annual rate increase of \$ 122.3 million.

On November 22, 2017, DTE filed for \$85.1 million rate increase in Case Number U-18999, based on test year ending on September 30, 2019. On December 20, 2018, the MPSC issued an order granting authority to increase rates in the amount of \$8.974 million. On November 25, 2019, DTE filed for rate increase of \$203.8 million in case Number U-20642 using test year ending on September 30, 2022. On August 20, 2020, the MPSC issued an order granting authority to increase rates in the amount of \$110 million by approving the settlement agreement in the case. On February 12, 2021, in case number U-20940, DTE filed for \$195 million rate increase using a projected test year ending December 31, 2022. On December 9, 2021, the MPSC issued an order for a rate increase of \$ 84.2 million.

The table below shows the rate increase history.

Filing Date	Case No.	Rate Incr Req	Test Year	Order Date	Rate Increase
12/31/2010	U-15985	\$192,600,000	12/31/2010	6/03/2010	\$ 118,600,000
4/20/2012	U-16999	\$ 76,700,000	10/31/2013	12/20/2012	\$ 19,900,000
12/18/2015	U-17999	\$182,900,000	10/31/2017	12/09/2016	\$ 122,300,000
11/22/2017	U-18999	\$ 85,100,000	9/30/2019	12/20/2018	\$ 8,974,000
11/25/2019	U-20642	\$203,800,000	9/30/2022	8/20/2020	\$ 110,000,000
2/12/2021	U-20940	\$195,000,000	12/31/2022	12/09/2021	\$ 84,173,000

**DIRECT TESTIMONY OF R. VEERAPANENI OBO CUB
CASE NO. U-21291**

1 In recent history, DTE has shown that it is preparing to file the next rate case during the
2 time the current rate case is undergoing the hearing process before the MPSC. Recent
3 history has shown that approximately one year after receiving the final order, DTE has been
4 filing its next rate case. The utility customers who pay the bills on time every time they
5 receive a bill from DTE do not have the same luxury and opportunity to get increases in
6 funds. The company has the unique ability to project increases year after year and get ready
7 to pass on projected future costs to loyal ratepayers. The customers do not have the same
8 opportunity or ability to receive increases in earnings to pay for higher utility bills. It is my
9 understanding that the rate setting process is to provide a reasonable opportunity to the
10 utility to earn a fair rate of return but not a guarantee. Filing rate increase applications before
11 the projected test year is complete, negates the use of complicated future forecasts of capital
12 expenses by cutting and pasting testimony and exhibits used in the previous rate case. The
13 captive customers of DTE will benefit more if the company executives and employees are
14 concentrating on providing safe, efficient, and reliable utility service rather than preparing
15 testimony and exhibits for the next rate case by updating testimony and exhibits used in the
16 previous rate case. The detrimental effects related to regulatory lag claimed by Utility
17 witnesses are minimized by its annual filings. The utility shareholders should be given an
18 opportunity to earn a fair rate of return on their investment considering the effects of
19 regulatory lag in a regulated industry. I believe the use of an average of 2022 and 2023
20 historical data as a proxy for the test year is appropriate for this rate case.

21 Therefore, I urge the Commission to use recent historical data to set rates in this case, instead
22 of using future projected test year data the company prepares waiting for the final order in

**DIRECT TESTIMONY OF R. VEERAPANENI OBO CUB
CASE NO. U-21291**

the current rate case. I support the use of historical 2022 and 2023 average data as proxy for the test year ending on September 30, 2025, for capital expenditures.

III. CAPITAL EXPENDITURES -ADJUSTMENTS

Q. What are your recommendations for capital expenditures related to distribution plant, transmission plant, storage plant, general plant, large capital projects, and infrastructure recovery mechanism (IRM)?

A. DTE witness Fedele describes in her testimony and exhibits the company's capital expenditures in Routine, Large Capital Projects, and IRM. Routine capital investments contain Distribution Plant, Transmission Plant, Storage Plant and General Plant. Company witness E. M. Abona describes Highest cost Top 25 Capital projects in his testimony. Ms. Fedele's exhibit A-12, B5 supports the historical amounts for 2022 and 2023 for these categories. Exhibit CUB-2 shows 2022 and 2023 actual amounts and averages for the two years for the above-described categories. I used the 2023 actual amounts provided in discovery response AGDG-5.125-01, A-2 Schedule B5. Exhibit CUB-3 shows DTE's projected test year amounts and the average amounts for 2022 and 2023. Column (d) of Exhibit CUB-3 shows the adjustments I am proposing to the capital expenditures supported by DTE Witnesses.

Q. Please describe routine capital projects?

A. Routine Distribution Plant includes assets from city gate stations to customer meter. These expenditures include unplanned main renewals, public improvement projects, service abandonments, service alterations, Service renewals, System Reliability, Communications & Control-Meters, Advance Metering Infrastructure (AMI), Revenue Protection and New Market Attachments.

**DIRECT TESTIMONY OF R. VEERAPANENI OBO CUB
CASE NO. U-21291**

1 Routine Transmission Plant expenditures include approximately 1,959 miles of high-
2 pressure pipelines and facilities that typically operate between 150 and 1,800 psig. These
3 systems are located upstream and include the city gate stations.

4 Routine Storage Plant expenditures reflect expenditures at four storage fields totaling 139.2
5 Bcf capacity. DTE Gas owns 47 compressor units totaling 179,325 horsepower.
6 Compression expenditures include installation, replacement, or upgrade of engines,
7 compressors and associated equipment, gas-liquid separation, and gas dehydration
8 equipment. Storage fields work includes field header piping, well laterals, new wells, well
9 and well-paid upgrades, well abandonment and well stimulations.

10 Routine General Plant Expenditures include physical structures and improvements;
11 transportation vehicles and equipment; tools such as leak detection equipment, pipe locating
12 equipment, measurement equipment fusing machines, tapping/stopping equipment,
13 laboratory equipment. Communication and control equipment includes SCADA
14 (Supervisory Control and Data Acquisition) system, communications network, compressor
15 station process control system, city gate station devices and field devices used to monitor
16 flow rates, pressure, and gas quality.

17 Capital expenditures and adjustments related to Routine Distribution Plant, Transmission
18 Plant, Storage Plant and General Plant are shown on lines 1, 2, 3, and 4 of Exhibits CUB-2
19 and CUB-3. The last column of both exhibits show the source exhibits of the DTE witnesses.

20 **Q. Please describe large capital projects.**

21 **A.** These projects have capital expenditures that are not considered routine and are not part of
22 IRM programs. These expenditures are required to ensure the safety and reliability of DTE

**DIRECT TESTIMONY OF R. VEERAPANENI OBO CUB
CASE NO. U-21291**

1 gas systems. I am supporting the two-year average of \$70,121,000 as an estimate for the
2 test year. Line 5 of my exhibits show the actual amounts for 2023 and 2024 with company
3 exhibit references in the last column.

4 **IV. CONCLUSIONS**

5 **Q. What are your final conclusions and recommendations?**

6 A. The proposed rate increase is significant and is extremely burdensome for residential rate
7 payers considering current economic conditions. I urge the Commission to consider the
8 current economic disruptions experienced by ratepayers in considering the significant rate
9 increase proposed by DTE. We are in April of 2024, and I expect that DTE would be
10 preparing testimony and exhibits for the next rate case filing with projections of future
11 projects containing larger capital and O & M expenses. The cycle never ends if the MPSC
12 approves even a small portion of the requested increase. DTE has the responsibility to
13 provide safe and reliable utility service because they have long-term franchises to provide
14 gas service. No other gas utility can provide service in competition because DTE is the only
15 one who has mains and services connected to the customers' piping. I urge the Commission
16 to consider the franchise limitations and loyal customers' inability to look for other sources
17 of gas. I request that the Commission use average historical data for 2022 and 2023 and the
18 adjustments shown in Exhibit CUB-3 for capital expenses as a proxy for the test year ending
19 on September 30, 2025.

20 **Q. Does this conclude your testimony?**

21 A. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE
GAS COMPANY** for authority to increase
its rates, amend its rate schedules and rules
governing the distribution and supply of
natural gas, and for miscellaneous
accounting authority.

Case No. U-21291

DIRECT TESTIMONY OF MATT BANDYK

ON BEHALF OF

CITIZENS UTILITY BOARD OF MICHIGAN

May 7, 2024

**DIRECT TESTIMONY OF M. BANDKY ON BEHALF OF CUB
CASE NO. U-21291**

TABLE OF CONTENTS

I. INTRODUCTION	1
II. A “JUST AND REASONABLE” RETURN	2
III. METHODS.....	9
IV. RECOMMENDATIONS	17

**DIRECT TESTIMONY OF M. BANDYK ON BEHALF OF CUB
CASE NO. U-21291**

1 **I. INTRODUCTION**

2 **Q Please state for the record your name, position, and business address.**

3 **A My name is Matthew Bandyk. I am a consultant at 5 Lakes Energy, LLC, a Michigan**
4 limited liability corporation, located at Suite 218, 220 MAC Avenue, East Lansing,
5 Michigan, 48823.

6 **Q Please summarize your experience in the field of utility regulation.**

7 **A I have over 13 years of experience in the field of utility regulation as a journalist and/or**
8 financial analyst. My experience is summarized in my resume, as provided as Exhibit
9 CUB-4.

10 **Q On whose behalf are you testifying in this case?**

11 **A I am testifying on behalf of Citizens Utility Board of Michigan (CUB).**

12 **Q Have you previously testified before the Michigan Public Service Commission (“the**
13 **Commission”)?**

14 **A Yes, I have previously testified on behalf of Michigan Environmental Council, Natural**
15 Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan in
16 Consumers Energy Gas Case filed in 2023 (Case No. U-21490), on behalf of Michigan
17 Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens
18 Utility Board of Michigan in Consumers Energy Company’s Electric Rate Case filed in
19 2023 (Case No. U-21389); and on behalf of Citizens Utility Board of Michigan in the
20 proceeding regarding Consumer Energy Company’s application for approval to implement
21 a power supply cost recovery plan in 2022 (Case No. U-21048).

**DIRECT TESTIMONY OF M. BANDYK ON BEHALF OF CUB
CASE NO. U-21291**

1 **Q** **Are you sponsoring any exhibits in this proceeding?**

2 **A** Yes, I am sponsoring the following exhibits:

3 Exhibit CUB-4: Resume of Matt Bandyk

4 Exhibit CUB-5: Huntoon, Steve. “Nice Work If You Can Get It.” Fortnightly
5 Magazine, August 2016, last accessed August 29, 2023

6 Exhibit CUB-6: Dunkle Werner, Karl and Jarvis, Stephen. “Rate of Return
7 Regulation Revisited.” Energy Institute at Haas, August 2023

8 Exhibit CUB-7: CAPM Analysis

9 Exhibit CUB-8: Equity Risk Premium Estimates

10 Exhibit CUB-9: Cost of Capital

11 **II. A “JUST AND REASONABLE” RETURN**

12 **Q** **Please explain the concept of cost of capital and its significance.**

13 **A** The cost of capital is the return demanded by investors on the capital they supply to the
14 Company. It is the weighted average of the costs of the various classes of capital supplied
15 by investors — in this case, debt and equity. The cost of debt and cost of equity are each
16 weighted by the respective amounts of debt and equity in the Company’s total capital
17 structure, so the ratio of equity to debt is another important component of the cost of capital.
18 The cost of debt can be relatively easily observed through the interest rates lenders demand
19 on debt issued by the Company. The cost of equity, however, is the product of market
20 expectations that can only be estimated by looking at a number of factors.

21 Estimating the cost of equity for a regulated utility must be done carefully so as to arrive
22 at a return that is “just and reasonable,” a principle elaborated on in the landmark U.S.

**DIRECT TESTIMONY OF M. BANDYK ON BEHALF OF CUB
CASE NO. U-21291**

1 Supreme Court cases that set the legal standards governing public utility regulation,
2 *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*
3 and *Federal Power Commission v. Hope Natural Gas Co.*

4 For example, in *Hope*, the Court said that the “just and reasonable” standard implies that:

5 *...the return to the equity owner should be commensurate with returns on*
6 *investments in other enterprises having corresponding risks. That return,*
7 *moreover, should be sufficient to assure confidence in the financial integrity*
8 *of the enterprise, so as to maintain its credit and to attract capital.*

9 But the Court was also clear that the determination of what return is “sufficient” in that
10 regard must also involve a consideration of the interests of the company’s customers.
11 Indeed, just as a return for a utility that is set below the amount “commensurate with returns
12 on investments in other enterprises having corresponding risks” causes the utility to lose
13 wealth relative to what it should earn with a more appropriate return, a return that is set
14 above this amount will cause the utility’s customers to be overcharged and lose wealth
15 relative to what they would be charged with a lower and more appropriate return. In this
16 latter case, that wealth is instead transferred from customers to the utility holding
17 company’s shareholders.

18 **Q What does it mean for a cost of capital to be “just and reasonable” under the**
19 **standard used in *Bluefield* and *Hope*?**

20 **A** In *Hope*, the Supreme Court held that for a public utility commission’s determination of
21 “just and reasonable” rates, it is the result reached, not the method employed, which is
22 controlling, and that result should be a rate that people would reasonably consider to be
23 commensurate with the risk of the investment. In practice, the financial academic
24 community has interpreted “just and reasonable” returns to be those that are arrived at

**DIRECT TESTIMONY OF M. BANDYK ON BEHALF OF CUB
CASE NO. U-21291**

1 through methods that are widely accepted in the financial community to estimate investor
2 perceptions of risk. I will rely on these methods in my testimony to estimate the Company's
3 ROE.

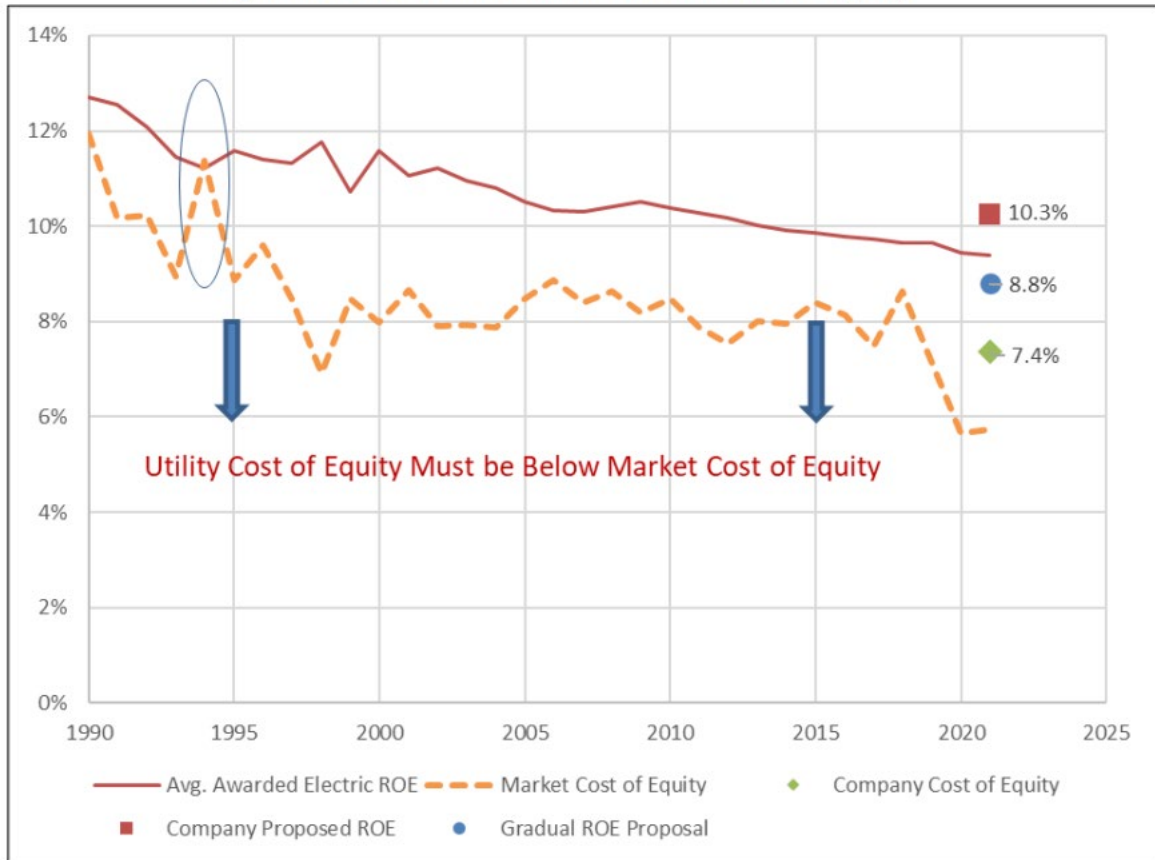
4 **Q How have public regulatory commissions historically fared at estimating “just and**
5 **reasonable” returns on equity for utilities?**

6 **A** There is strong evidence from multiple observers that public regulatory commissions on
7 average have tended to set electric utility ROEs above what objective observers in the
8 financial community would arrive at using the widely-accepted methods for estimating
9 ROE. I will describe this ROE that regulatory commissions have tended to miss as a
10 “market-based ROE” since it is estimated using methods that gauge how the market rates
11 the risk of a utility investment. The failure by commissions to match a market-based ROE
12 has resulted in a transfer of wealth from ratepayers to shareholders.

13 As I described above, arriving at an ROE is a process of estimation, and that process will
14 invariably include some degree of subjectivity. Subjective factors can influence any human
15 decision-making process, including the decisions of public regulatory commissions, and
16 lead to results that vary from objective methods.

**DIRECT TESTIMONY OF M. BANDYK ON BEHALF OF CUB
CASE NO. U-21291**

Figure 2: Awarded ROEs vs. Market Cost of Equity



A The above Figure 2 from direct testimony of David Garrett for MEC and CUB in case U-20836¹ compares the average ROE for U.S. stocks as a whole since 1990 to the ROEs for regulated electric and gas utilities awarded by public regulatory commissions over the same time period. It shows that the average awarded ROEs have been consistently above the market-based ROEs by about two percentage points in almost every year for over three decades.

For more evidence of this phenomenon, experts including utility attorney Steve Huntoon have also published evidence indicating that regulators tend to set ROEs above what the

¹ Case No. U-20836-0479, Direct Testimony of David J. Garrett, 8 TR 3880.

**DIRECT TESTIMONY OF M. BANDYK ON BEHALF OF CUB
CASE NO. U-21291**

1 market would bear, which I have submitted as Exhibit CUB-5.² Academics have also noted
2 the phenomenon of a growing premium of regulatory commission-awarded ROEs over the
3 rate of return on long-term Treasury bonds (the risk-free rate), and research has found that
4 this premium cannot statistically be explained by financial fundamentals, such as a change
5 in the equity or debt risk of the utilities in question.³

6 This premium has costs to consumers because it ensures that utilities collect a greater return
7 from customers than is justified by traditional ROE methodology. A 2023 paper published
8 by the Energy Institute at the University of California Berkeley's Haas School of Business
9 found that the cost to consumers from rates of return for electric and gas utilities that are
10 set above a market-based return reached around \$2-20 billion per year by 2020. I have
11 submitted that paper as Exhibit CUB-6.

12 A higher return implies higher risk, so the empirical result that awarded ROEs are higher
13 than market returns would imply that regulated utilities are riskier investments than the
14 market as a whole. But they are indeed not riskier. Consider the noncontroversial fact that
15 regulated utility returns tend to be less risky than the market as a whole. This phenomenon
16 can be observed simply by looking at the betas of regulated utility holding companies. Beta
17 is a measurement of the sensitivity of a stock's returns relative to those of the market as a

² Exhibit CUB-5, Steve Huntoon. "Nice Work If You Can Get It." *Fortnightly Magazine*, August 2016, last accessed August 29, 2023, available at <https://www.fortnightly.com/fortnightly/2016/08/nice-work-if-you-can-get-it>.

³ "This growing premium does not appear to be explained by traditional asset-pricing models, often in direct contrast to regulators' stated intent... However, absent some normative justification for this premium, it would appear that regulators are authorizing excessive returns on equity to utility investors and that these excess returns translate into tangible profits for utility firms." David Rode and Paul Fischbeck. "Regulated equity returns: A puzzle." *Energy Policy*, Oct. 2019.
<https://www.sciencedirect.com/science/article/abs/pii/S0301421519304690?via%3Dihub>

**DIRECT TESTIMONY OF M. BANDYK ON BEHALF OF CUB
CASE NO. U-21291**

1 whole. Utility holding company betas tend to be less than one, meaning that those stocks
2 are less sensitive to changes in overall market returns.

3 **Q If regulated utilities are less risky than the market, then why have regulated utilities**
4 **historically been awarded ROEs above market returns?**

5 **A** The remaining explanation is that public regulatory commissions have tended to accept
6 estimates for ROE that are above fair, market-based ROE estimates. In this case, DTE is
7 proposing an ROE of 10.25%, a significant increase from the 9.9% ROE authorized in its
8 last electric rate case (U-20940).

9 **Q Do you agree with this statement from Ms. Villadsen's testimony: "...the allowed**
10 **return on equity needs to be at least as high as the expected return offered by**
11 **alternative investments of equivalent risk or investors will choose these alternatives**
12 **instead. Otherwise, the utility's ability to raise capital and fund its operations will be**
13 **negatively impacted."**

14 **A** Yes, I do agree. I would add, however, that the corollary is true and important to point out:
15 the allowed return on equity should also be *no higher* than the expected return offered by
16 alternative investments of equivalent risk or ratepayers will be essentially taxed to provide
17 an excess return to investors. As I showed above, the evidence about how utility ROEs
18 have been set by regulatory commissions at an excessive premium above a market ROE
19 suggests that the bigger danger in this proceeding is that the ROE will be too high, not too
20 low.

**DIRECT TESTIMONY OF M. BANDYK ON BEHALF OF CUB
CASE NO. U-21291**

1 **Q** **Is Ms. Villadsen’s recommended ROE of 10.25% a “just and reasonable” return in**
2 **your view?**

3 **A** No. As I will argue below in the discussion of methods, I believe Ms. Villadsen’s
4 recommended ROE is inflated above what would be a fair return due to several
5 overestimated inputs into her DCF and CAPM analysis as well as her use of a Risk
6 Premium model that essentially recycles the overestimations of ROE by other regulatory
7 commissions.

8 **Q** **Would DTE Gas customers pay for an excessive return if the MPSC approves Ms.**
9 **Villadsen’s ROE in this case?**

10 **A** Yes. If the MPSC were to accept the utility’s request for a rate increase without changes,
11 DTE would collect about \$419.2 million from customers for a return on its rate base, based
12 on an overall rate of return of 6.04%⁴ and a total jurisdictional electric rate base of \$6.94
13 billion.⁵ If the ROE were instead the market-based ROE of 9.46% that I am recommending
14 in this case, that return would fall from \$419.2 million to \$396.3 million, resulting in
15 savings to customers of \$22.9 million on an annualized basis.⁶

⁴ DTE Exhibit A-14, Schedule D1.

⁵ DTE Exhibit A-13, Schedule C16.

⁶ This result is calculated by multiplying the rate base of \$6.94 billion by an overall rate of return of 5.71%, which is what the overall rate of return would be if 9.33% were used instead of 10.25% in Exhibit A-14 (MRB-1), Schedule D-1, p. 1. I show my calculation of the 5.72% overall rate of return in Exhibit CUB-9.

**DIRECT TESTIMONY OF M. BANDYK ON BEHALF OF CUB
CASE NO. U-21291**

1 **III. METHODS**

2 **Q What quantitative methods did you use to estimate the utility's ROE?**

3 **A** As I stated earlier in my testimony, arriving at a "just and reasonable" ROE requires the
4 use of the methods that are widely accepted in the financial community to estimate investor
5 perceptions of risk. My ROE estimate is based on the Capital Asset Pricing Model (CAPM)
6 and the Discounted Cash Flow (DCF) methods, which are probably the two most widely
7 accepted methods for calculating ROE. These are also two of the methods used by Ms.
8 Villadsen to develop her recommended ROE. I did not, however, use two of the methods
9 she used, for reasons I will explain. These two are the Empirical Capital Asset Pricing
10 Model (ECAPM) and the Risk Premium Model.

11 **Q Please summarize your ROE recommendation.**

12 **A** The results of my DCF and CAPM analyses and my resulting recommendation for the
13 utility's ROE in this case are below:

CAPM	9.14% ⁷
DCF	8.90% ⁸
Average of CAPM and DCF	9.10%
DTE ROE awarded in U-20940	9.90%
Recommendation	9.46%

14

⁷ See Exhibit CUB-7.

⁸ Exhibit A-14, Schedule D5.8, page 1.

**DIRECT TESTIMONY OF M. BANDYK ON BEHALF OF CUB
CASE NO. U-21291**

1 **Q** **Why are you recommending an ROE that is higher than any of the results found in**
2 **your financial models?**

3 **A** The average of my model results suggests that an ROE lower than 9.46% would be a
4 market-based cost of equity for DTE Gas. But DTE Gas is not a competitive business solely
5 answerable to market forces, which helps explain why its awarded ROE has historically
6 been significantly higher than the market-based cost of equity.

7 There is a degree of uncertainty in any financial model. In addition, any significant changes
8 in DTE Gas's ROE should be implemented gradually so as not to create unnecessary
9 instability in the company's market value, which is based in great degree on the outcomes
10 of regulatory proceedings like this one.

11 To account for modeling uncertainty and this principle of gradualism, my final
12 recommendation of represents the midpoint between the average result of my models and
13 the 9.90% ROE awarded to DTE Gas in its last rate case (U-20940).

14
15 **Q** **Please describe your application of the CAPM to estimate the ROE.**

16 **A** Please find my CAPM estimate in Exhibit CUB-7.

17 Ms. Villadsen's use of the CAPM formula is for the most part noncontroversial, and I have
18 no objection to the risk-free rate she selected, so I use the same rate in my CAPM formula.
19 Her use of the proxy group average beta as the basis for a beta that is unlevered and then
20 relevered at DTE Gas's proposed capital structure is also sound. Our results differ because
21 of one key input to the CAPM formula: the equity risk premium (ERP).

**DIRECT TESTIMONY OF M. BANDYK ON BEHALF OF CUB
CASE NO. U-21291**

1 **Q Please explain how you arrived at the ERP used in your CAPM formula.**

2 **A The ERP is an essential component of the CAPM formula. It represents the excess return**
 3 an investor would receive over the risk-free rate by investing in the broader equity market.
 4 The ERP is calculated as the market risk premium minus the risk-free rate. The market risk
 5 premium is an estimate of the return an investor can expect from investing in the stock
 6 market in general.

7 Ms. Villadsen's CAPM estimate for ROE is inflated by her choice of ERP for her Scenario
 8 1 CAPM analysis. This 7.17% ERP is the historical average premium of market returns
 9 over the income returns on government bonds from 1926 to 2022.

10 Historical estimates like this one have a flawed methodology that leads to an inaccurate
 11 estimate of market return. While historical estimates of ERP are indeed commonly used by
 12 the financial community, that popularity does not make them less flawed. As New York
 13 University Stern School of Business Professor Aswath Damodaran, one of the most highly
 14 respected and widely cited experts in finance and valuation, has written:

15 *Given how widely the historical risk premium approach is used, it is*
 16 *surprising how flawed it is and how little attention these flaws have*
 17 *received.⁹*

18 There are two main reasons for the flaw with this methodology. First, the historical estimate
 19 for ERP is extremely sensitive to the historical time period selected, meaning that the
 20 subjective judgment by the person making the estimate of which time period to collect
 21 market data for has an outsized impact on the ultimate result. To apply that issue to Ms.

⁹ Aswath Damodaran, "Estimating Equity Risk Premiums," Stern School of Business, accessed August 2023, available at <https://pages.stern.nyu.edu/~adamodar/pdfiles/papers/riskprem.pdf>.

**DIRECT TESTIMONY OF M. BANDYK ON BEHALF OF CUB
CASE NO. U-21291**

1 Villadsen's argument, the timeframe for her estimate from 1926 to 2022 produces a
2 different result than if the timeframe were some other subset of that nearly 100-year period.

3 Second, regardless of the time period selected, historical estimates of ERP are subject to
4 the problem of survivorship bias, where returns that go into historical ERPs tend to be those
5 from stocks that remain in the market, rather than those that drop out. This survivorship
6 bias effect tends to inflate historical ERPs.

7 **Q Are there any methods of estimating ERP not subject to these problems?**

8 **A** Yes. Dr. Damodaran suggests using an "implied equity risk premium" method:

9 The advantage of this approach is that it is market-driven and current, and does not require
10 any historical data. Thus, it can be used to estimate implied equity premiums in any market.

11 This approach values stocks in a market at the present value of dividends from each stock
12 growing at a constant rate.

13 Dr. Damodaran regularly publishes an estimate of the U.S. ERP based on this implied
14 equity premium approach. The ERP I used in my estimate is an average of this estimate
15 from Dr. Damodaran and ERP estimates from two other sources: First, the average U.S.
16 market risk premium identified by the 2023 IESE Business School survey of thousands of
17 finance and economics professors, analysts, and managers of companies. While described
18 as a "market risk premium," this number indicates the equity risk premium for the U.S.
19 market. Second, I used the recommended U.S. ERP from financial research firm Kroll for
20 2023. Kroll's recommended U.S. ERP is based on risk perceptions in the market and other
21 qualitative and quantitative inputs, such as an implied equity risk premium model.

**DIRECT TESTIMONY OF M. BANDYK ON BEHALF OF CUB
CASE NO. U-21291**

1 I note that the value of these ERP estimates is very close to the 5.72% value projected by
2 Bloomberg that Ms. Villadsen uses in her Scenario 2 CAPM analysis.

3 These ERP estimates are summarized in Exhibit CUB-8.

4 **Q Why did you use the average of multiple projected ERPs, instead of just one, such as**
5 **the Bloomberg estimate used by Ms. Villadsen in her Scenario 2 CAPM analysis?**

6 **A** The use of multiple different sources mitigates the risk of error from any one source.
7 Mitigating this risk is especially important when dealing with projections, since the future
8 is inherently uncertain, making any one source for a projected ERP subject to forecasting
9 error. This risk cannot be eliminated but can be significantly reduced by consulting
10 multiple sources each with their own methodologies for estimating ERP.

11 **Q Ms. Villadsen claims that the 7.17% historic risk premium is “more reasonable” than**
12 **the forward-looking Bloomberg estimate of 5.72%. Do you agree?**

13 **A** No. In addition to the methodological problems with the historic risk premium that I
14 explained above, I also see problems with her claim that the 7.17% is more reasonable
15 because it is closer to the 7.92% and 7.99% risk premiums she calculates in her Exhibit A-
16 14, Schedule D5.17. Those risk premiums are much higher than the risk premiums from
17 Exhibit CUB-8 that all come from widely-used, highly reputable sources that lack the
18 methodological problems that come with extrapolating a forward ERP from historic data.
19 Therefore, I discount her risk premiums from Schedule D5.17 because they are so much
20 higher than these other sources.

**DIRECT TESTIMONY OF M. BANDYK ON BEHALF OF CUB
CASE NO. U-21291**

1 **Q Why did you not use the ECAPM?**

2 **A The MPSC staff has historically rejected the ECAPM method as part of ROE analyses in**
3 rate cases.¹⁰¹¹

4 **Q Please explain your application of the Discounted Cash Flow (DCF) model to estimate**
5 **the Company's cost of equity.**

6 **A I endorse Panel B of Ms. Villadsen's DCF analysis, which uses a multi-stage approach**
7 with a perpetual growth rate of 3.9%, matching the forecasted long-term nominal U.S. GDP
8 growth rate.

9 **Q Why did you disregard Panel A of Ms. Villadsen's DCF analysis?**

10 **A Ms. Villadsen's simple DCF model lacks a long-term growth rate and relies only on a short-**
11 term growth rate. As I will explain, valuing a company's equity without a realistic
12 assumption about its long-term growth leads to an essentially meaningless outcome.

13 Ms. Villadsen's "long-term combined growth rate" is not truly a long-term rate in the sense
14 of what is demanded by the DCF model because it is based on a combination of 3-5 year
15 earnings growth rates projected by Reuters and Value Line.

16 When a DCF model uses a growth rate of no more than five years as its only growth rate,
17 the model's outcome is wildly unrealistic. If the growth rate used in the DCF model is
18 higher than that of the growth rate of the economy as a whole, that implies that in the long

¹⁰ For example, see Case No. U-20940, Direct Testimony of MPSC Staff Witness Joseph Ufolla, 5 TR 1869, lines 9-16.

¹¹ "This PFD notes that Consumers has not identified an order wherein the Commission has recognized let alone adopted the use of the ECAPM model, and this ALJ is unaware of any." <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000BCjcrAAD>.

**DIRECT TESTIMONY OF M. BANDYK ON BEHALF OF CUB
CASE NO. U-21291**

run, the Company would grow bigger than the entire U.S. economy. Such an outcome is theoretically impossible, as Dr. Damodaran has explained:

“[i]f a firm is a purely domestic company, either because of internal constraints . . . or external constraints (such as those imposed by a government), the growth rate in the domestic economy will be the limiting value.”¹²

Q Do you agree with Ms. Villadsen’s statement that her simple DCF model used in Panel A, which does not use a perpetual growth rate, “merits more weight” than the multi-stage DCF model used in Panel B, which does use a perpetual growth rate?

A No. The simple DCF model should not be considered toward the utility’s ROE. Ms. Villadsen’s only stated reason for preferring the simple DCF model to the multi-stage model is that the “forecasted long-term GDP growth rate is low, which may be a result of the perception that growth may slow in the near-term due to high financing costs or a possible slow-down in the economy.”

The long-term GDP growth rate being lower according to current forecasts than it has been in the past is not a reason to place lower weight on the multi-stage model. While forecasting the U.S. long-term growth rate is an uncertain process, as any prediction about the future is uncertain, it does not follow from that limitation of the multi-stage model that one should then prefer a much more flawed – indeed, fundamentally flawed – model in the form of the simple DCF model. Assuming a constant perpetual growth rate in which the utility would outrun the entire U.S. economy is unsound, not merely imprecise. Any lack of precision in the multi-stage model due to its reliance on a long-term growth forecast should be dealt

¹² Aswath Damodaran. *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset*, 3rd ed. John Wiley & Sons, Inc, 2012.

**DIRECT TESTIMONY OF M. BANDYK ON BEHALF OF CUB
CASE NO. U-21291**

1 with by comparing the multi-stage model to other models that are not fundamentally
2 flawed, such as the CAPM.

3 **Q Why did you not use the implied risk premium analysis (“Risk Premium Model”)**
4 **employed by Ms. Villadsen in your recommendation?**

5 **A** The Risk Premium Model as used by Ms. Villadsen should be disregarded because it
6 introduces into the calculation of ROE, a process that should be based on objective data as
7 much as possible, the reliance on ROEs set by other regulatory commissions. That
8 regulatory process of setting ROE is, as the research about excessive utility ROEs I
9 explained above reveals, not one that has empirically resulted in returns that would be set
10 by objective financial methodology.

11 Her risk premium is the spread between those ROEs historically set by other commissions
12 in rate cases and the risk-free rate. Therefore, the resulting risk premium she calculates is
13 as large as it is only in relation to the degree that regulatory commissions set ROEs at a
14 premium to what the ROEs would be using only objective financial methods. Because
15 academic research has shown the reliance on historic allowed returns to be hopelessly
16 distorted from what objective methods to determine a just and reasonable rate would find,
17 I disregard Ms. Villadsen’s Risk Premium approach.

18 In addition, another reason I did not use this method is because the result of its application
19 is divergent from the results from methods that, as Ms. Villadsen puts it, are “underpinned
20 by fundamental financial principles,” in contrast to the Risk Premium Model. In Michigan
21 rate cases, the CAPM method is a much more commonly-used method for estimating the
22 risk premium associated with a company compared to the Risk Premium Model used by

**DIRECT TESTIMONY OF M. BANDYK ON BEHALF OF CUB
CASE NO. U-21291**

1 Ms. Villadsen. The status of this Model as less preferable to the CAPM or DCF methods
2 is supported by Ms. Villadsen's application of the method to merely check the
3 reasonableness of the ROE ranges produced by her other methods.

4 The Risk Premium Model as used by Ms. Villadsen yields a 10.2% ROE, which is well
5 above the 9.14% I estimated through the CAPM and the 8.9% through the DCF method.
6 Since this result is so far above the more widely-used methods and at least one of these
7 methods already more directly estimates the risk premium, I discarded the Risk Premium
8 Model result as an outlier.

9 **IV. RECOMMENDATIONS**

10 **Q Please summarize your conclusions and recommendations to the Commission.**

11 **A** On behalf of MNSC, I recommend that the Commission find 9.46% as a just and reasonable
12 ROE for DTE's gas utility because the mainstream and commonly-used methods for
13 calculating ROE identify 9.46% as a market-based ROE for the utility. I am also
14 recommending an overall rate of return of 5.71% as a result of this ROE (see Exhibit CUB-
15 9).

16 **Q Does that complete your testimony?**

17 **A** Yes.

1 MR. BZDOK: Thank you, your Honor.
2 Nothing further.

3 JUDGE THOITS: All right. Is the parties
4 referred to as Frontline Organizations, are they present
5 and interested in binding in the testimony of their
6 exhibits -- excuse me -- of their witnesses and admission
7 of their exhibits?

8 MR. TEMPLETON: Yes, your Honor. It's
9 Mark Templeton here for Soulardarity, Urban Core
10 Collective, and We Want Green, Too, collectively referred
11 to as the Frontline Organizations, or FLO for this
12 hearing.

13 JUDGE THOITS: All right. Mr. Templeton,
14 thank you. If you could just go one witness at a time,
15 I'd appreciate it.

16 MR. TEMPLETON: I'd be happy do that,
17 your Honor. So on behalf of the Frontline Organizations,
18 I move to bind in the Direct written Testimony of Jackson
19 Koepfel. His direct written testimony consists of one
20 cover page and 73 pages of questions and answers.
21 Mr. Koepfel sponsored Exhibits FLO-1 through FLO-47,
22 inclusive, and I would move for the admission of those
23 exhibits. Also, Mr. Koepfel filed written rebuttal
24 testimony, consisting of one cover page and nine pages of
25 questions and answers. There were no exhibits as part of
Penn Reporting, LLC - lori.penn@yahoo.com

1 Mr. Koepfel's rebuttal testimony.

2 JUDGE THOITS: Are there any objections
3 to the admission of this testimony or these exhibits?

4 (No response.)

5 Hearing none, the Direct and Rebuttal
6 Testimony of Jason Koepfel is bound into the record, and
7 Exhibits FLO-1 through FLO-47 are admitted.

8 MR. TEMPLETON: Your Honor, if I may,
9 it's Jackson Koepfel and not Jason Koepfel, which was
10 what you just said, just to clarify the record.

11 JUDGE THOITS: No, I appreciate it. My
12 apologies. Thank you.

13 MR. TEMPLETON: Of course, your Honor.

14 (Testimony bound in.)

15 - - -

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE GAS
COMPANY** for authority to increase its rates,
amend its rate schedules and rules governing the
distribution and supply of natural gas, and for
miscellaneous accounting authority.

U-21291

ALJ Jonathan F. Thoits

DIRECT TESTIMONY OF JACKSON KOEPPPEL**ON BEHALF OF****SOULARDARITY, URBAN CORE COLLECTIVE, AND WE WANT GREEN, TOO****(COLLECTIVELY, FRONTLINE ORGANIZATIONS (FLO))**

May 7, 2024

1 **I. Introduction and Summary**

2 **Q: Please state your name, occupation, and business address.**

3 **A:** My name is Jackson Koeppel. I am an independent consultant, primarily focused on
4 working on energy regulatory issues for Soulardarity and We Want Green, Too. My
5 business address is 189 Monterey St, Highland Park, MI 48203.

6

7 **Q: On whose behalf are you submitting this direct testimony?**

8 **A:** I am testifying on behalf of Soulardarity, We Want Green, Too, and Urban Core Collective,
9 collectively the Frontline Organizations (FLO).

10

11 **Q: Please describe your work experience.**

12 **A:** I moved to Highland Park, Michigan in 2012 and co-founded Soulardarity, an
13 organization rooted in the Highland Park community, to organize for community-owned
14 solar streetlights and energy democracy. I served as the organization's primary staff and
15 founding Executive Director. Shimekia Nichols succeeded me as Executive Director of
16 Soulardarity in 2021. I have contributed to work locally, regionally, and nationally to
17 democratize and decarbonize our energy economy as an independent consultant. My
18 work has included developing original research, regulatory interventions, coordination of
19 state and regional networks, and development of implementation programs for energy
20 transition.

21

1 **Q: For what purpose was Soulardarity created?**

2 **A:** In 2011, DTE Energy repossessed more than 1,000 streetlights from Highland Park,
3 Michigan, a predominantly low-income and people-of-color city, after its municipal
4 government defaulted on its electric utility payments. A coalition of Highland Park
5 residents formed Soulardarity in 2012 to help alleviate this crisis by installing
6 community-owned, solar-powered streetlights in the city. Soulardarity's mission has
7 subsequently broadened to include energy education and advocacy for community solar
8 and greater equity in Michigan's energy generation and delivery systems. Through
9 activism and advocacy, Soulardarity emphasizes the particular needs, experiences, and
10 perspectives of low-income communities and communities of color.

11

12 **Q: What is Soulardarity's focus?**

13 **A:** Soulardarity's focus is improving access to affordable, clean energy for low-income
14 communities and communities of color, including women, children, the elderly, people
15 with disabilities, and others who live in poverty. As such, Soulardarity promotes solar
16 street lighting, solar bulk purchasing, energy education, job training, and expanding
17 access to clean energy. These efforts aim to improve the economic condition of low-
18 income communities, especially low-income communities of color, in southeast
19 Michigan. Soulardarity has developed partnerships with other Michigan stakeholders
20 interested in energy justice and affordability, including experienced solar installers, solar
21 developers, environmental justice advocates, and public health experts. Soulardarity also
22 advocates for equitable utility rates and services, including but not limited to investments
23 in reliability, safety, and energy waste reduction, on behalf of low-income communities

1 and communities of color. Finally, Soulardarity pushes for reducing the burdens of fossil-
2 fuel energy generation on low-income communities and communities of color and for just
3 transitions from the fossil-fuel energy economy to the clean energy economy.

4
5 **Q: For what purpose was We Want Green Too created?**

6 **A:** We Want Green, Too was created to develop programs to assist veterans with post-
7 traumatic stress disorder in in transforming their lives and communities as sustainability
8 leaders.

9
10 **Q: What is We Want Green, Too's focus?**

11 **A:** Early on, We Want Green, Too focused on giving veterans opportunities to work with
12 their hands on building projects. This effort began with an experimental, energy efficient
13 renovation for a home in Jackson, Michigan with four veterans. It continued with the
14 rebuilding of a blighted 2200 square foot home on Detroit's east side, incorporating
15 energy-efficient retrofits. These projects illustrate how to build homes that reduce utility
16 costs and increase health by creating spaces with healthy, clean indoor air. We Want
17 Green, Too's current projects include deconstructing three blighted buildings to create a
18 multi-family energy efficient housing unit, as well as launching solar and energy
19 efficiency job-training programs. Other programming includes get-out-the-vote outreach,
20 youth mentorship, crisis response, and direct employment and mental-health support for
21 veterans. We Want Green, Too has also formed collaborative partnerships with local
22 organizations such as The Villages Community Development Corporation, churches, and
23 other nonprofits to continue to understand community needs. We Want Green, Too is

1 also a member and partner of Michigan Environmental Justice Coalition (MEJC), which
2 engages in on-the-ground work to that promote energy justice and energy efficient
3 housing and fights against disinvestment, unemployment, and threats to community
4 health in Detroit's East Side.

5
6 **Q: For what purpose was Urban Core Collective created?**

7 **A:** Urban Core Collective (UCC), a 501(c)(3) organization, was founded in 2014 by six
8 organizations based in western Michigan. The six original organizations joined forces to
9 pursue the common goal of overcoming the effects of systemic racism by promoting
10 equal access to education, health, and economic prosperity. The three current
11 organizations comprising UCC are Baxter Community Center, Family Outreach Center,
12 Inc., and Urban League of West Michigan.

13
14 **Q: What is Urban Core Collective's focus?**

15 **A:** UCC exists to support historically marginalized communities by engaging in advocacy,
16 community organizing, and leadership cultivation that improves living conditions and the
17 distribution of power in the Greater Grand Rapids area. UCC's expertise lies in
18 explaining complex institutions and systems of power to local communities and in
19 gathering input about how these institutions and systems can better address community
20 needs. In particular, UCC focuses on democracy, emerging leaders, education justice, and
21 environmental justice. For instance, UCC partnered with the City of Grand Rapids to
22 carry out the Zero Cities Project, which sought to develop a roadmap toward a net zero
23 building sector by 2050. UCC engaged with residents about policy options, educated the

1 public on the utility industry, and served as an equity consultant on policy design. UCC
2 also conducted a survey to identify residents' knowledge of various energy services
3 related to energy efficiency and financial assistance. UCC also supports leaders of color
4 in the environmental space by creating affinity groups for persons of color to get outdoors
5 and discuss environmental issues relevant to them.

6
7 **Q: Have Soulardarity, We Want Green, Too, and UCC previously intervened in or**
8 **commented on an MPSC matter?**

9 **A:** Yes.

10 Soulardarity intervened in MPSC matter U-18232 and advocated, through
11 testimony and briefing, for the inclusion of community solar projects in DTE's
12 Renewable Energy Plan (REP) and for the accommodation of low-income, people-of-
13 color ratepayers in DTE's energy decision-making. Soulardarity filed a comment in
14 MPSC matter U-18418 regarding the proposed Integrated Resource Planning (IRP)
15 process and advocated that the process include more robust engagement with
16 stakeholders from low-income, people-of-color communities. Soulardarity also
17 commented during the MPSC Staff's development of the Distributed Generation Tariff in
18 MPSC matter U-18383 and advocated for changes that would increase transparency and
19 access to solar energy for low-income communities and communities of color.
20 Soulardarity joined a Response to Prior Comments in MPSC matter U-18076 concerning
21 DTE's application for Commission approval of a previous amended REP. Soulardarity
22 intervened in DTE's 2018 rate case, MPSC matter U-20162, and DTE's 2019 rate case,
23 MPSC matter U-20561, and advocated, through testimony and briefing, for a more

1 equitable rate design through the provision of increased resources in underserved
2 communities and for policies that promote access to distributed generation programs for
3 low-income and people-of-color ratepayers. Soulardarity has also intervened and raised
4 similar concerns in DTE's 2019 IRP proceeding, MPSC matter U-20471, DTE's Energy
5 Waste Reduction (EWR) proceeding, MPSC matter U-20373, DTE's Voluntary Green
6 Pricing (VGP) proceedings, MPSC matters U-20713 and U-20851, and DTE's Prepay
7 proceeding, MPSC matter U-21087.

8 Soulardarity and We Want Green, Too (collectively, the Detroit Area Advocacy
9 Organizations or DAAO) intervened in DTE Electric's 2022 Rate Case, MPSC matter U-
10 20836, DTE Electric's 2023 Rate Case, MPSC Matter U-21297, and DTE Electric's 2023
11 Integrated Resource Plan, MPSC Matter U-21193. The DAAO have also provided
12 comments and workgroup participation in the Energy Affordability and Accessibility
13 collaborative definitions subcommittee (following from the DAAO's intervention in U-
14 20836), DTE Electric's 2023 Distribution Grid Plan (MPSC matter U-20147), and the
15 Financial Incentives & Disincentives docket (MPSC matter U-21400).

16 Urban Core Collective intervened in Consumers Energy Company's application
17 for approval of an Integrated Resource Plan (U-21090). UCC intervened in Consumer
18 Energy's 2022 Rate Case (U-21224) and its 2023 Rate Case (U-21389). In the 2023 Rate
19 Case, UCC provided testimony on the benefits of community solar for low- and
20 moderate-income households and stated its intention to review Consumers Energy's
21 strawman proposal for community solar as part of the Settlement Agreement for Case No.

1 U-21224. UCC also commented on Consumers Energy's Distribution Grid Plan in U-
2 20147.

3 This case is the first joint intervention of Soulardarity, We Want Green Too, and
4 Urban Core Collective, collectively, the Frontline Organizations.

5
6 **Q: What is the purpose of your testimony?**

7 **A:** The purpose of my testimony is twofold: (1) to provide a critical analysis of DTE Gas's
8 rate case proposal through the lens of a just and equitable energy transition, and (2) to
9 propose specific disallowances, as well as programmatic and policy recommendations
10 that would increase equity in affordability, infrastructure quality, health, and technology
11 access.

12
13 **Q: How is your testimony structured?**

14 **A:** My testimony is organized into the following sections:

15 I. Introduction and Summary;

16 II. Principles of Analysis;

17 III. DTE Gas's Rate Proposal and Planning Principles Fail to Meet the Standards of a
18 Just and Equitable Energy Transition;

19 IV. The Commission Should Order Integrated Gas and Electric Distribution and
20 Resource Planning to Efficiently and Equitable Escape the Mid-Transition; and

21 V. The Commission Should Reject Recovery of Investments and Proposals Which
22 Create Perverse Incentives.

1 **Q:** Are you sponsoring any exhibits?

2 **A:** Yes.

3 FLO-1. DTE Energy Co., Annual Report (Form 10-K) (Feb. 8, 2024) (excerpt).

4 FLO-2. Karlee Weinmann, *Amid controversies, DTE Energy continues to spend*
5 *big in Michigan and nearly every lawmaker accepts*, ENERGY AND POLICY
6 INSTITUTE (Sept. 28, 2022), [https://energyandpolicy.org/dte-energy-](https://energyandpolicy.org/dte-energy-political-contributions-michigan/)
7 [political-contributions-michigan/](https://energyandpolicy.org/dte-energy-political-contributions-michigan/).

8 FLO-3. David Anderson, et al., *Strings Attached: How utilities use charitable*
9 *giving to influence politics and increase investor profits*, ENERGY AND
10 POLICY INSTITUTE (Dec. 2019), [https://energyandpolicy.org/strings-](https://energyandpolicy.org/strings-attached-how-utilities-use-charitable-giving-to-influence-politics-increase-investor-profits-dte-energy/)
11 [attached-how-utilities-use-charitable-giving-to-influence-politics-increase-](https://energyandpolicy.org/strings-attached-how-utilities-use-charitable-giving-to-influence-politics-increase-investor-profits-dte-energy/)
12 [investor-profits-dte-energy/](https://energyandpolicy.org/strings-attached-how-utilities-use-charitable-giving-to-influence-politics-increase-investor-profits-dte-energy/).

13 FLO-4. Energy and Policy Institute, *Michigan Energy First* (last accessed May 2,
14 2024), <https://energyandpolicy.org/michigan-energy-first/>.

15 FLO-5. Laura Frier, Delia Mayor, & Brett Zeuner, *Assessing the State of*
16 *Environmental Justice in Michigan* (May 2019),
17 [https://deepblue.lib.umich.edu/bitstream/handle/2027.42/149105/Assessin](https://deepblue.lib.umich.edu/bitstream/handle/2027.42/149105/AssessingtheStateofEnvironmentalJusticeinMichigan_344.pdf?sequence=1&isAllowed=y)
18 [gtheStateofEnvironmentalJusticeinMichigan_344.pdf?sequence=1&isAllo](https://deepblue.lib.umich.edu/bitstream/handle/2027.42/149105/AssessingtheStateofEnvironmentalJusticeinMichigan_344.pdf?sequence=1&isAllowed=y)
19 [wed=y](https://deepblue.lib.umich.edu/bitstream/handle/2027.42/149105/AssessingtheStateofEnvironmentalJusticeinMichigan_344.pdf?sequence=1&isAllowed=y).

20 FLO-6. EMILY GRUBERT & SARA HASTINGS-SIMON, *DESIGNING THE MID-*
21 *TRANSITION: A REVIEW OF MEDIUM-TERM CHALLENGES FOR COORDINATED*
22 *DECARBONIZATION IN THE UNITED STATES* (2022).

- 1 FLO-7. KARIN KIRK, WHICH STATE IS WINNING AT RENEWABLE ENERGY
2 PRODUCTION? (Feb. 23, 2022).
- 3 FLO-8. THROWING SHADE: 10 SUNNY STATES BLOCKING DISTRIBUTED SOLAR
4 DEVELOPMENT (2018).
- 5 FLO-9. VIBRANT CLEAN ENERGY, LLC, ELECTRIFICATION AND DECARBONIZATION
6 PATHWAYS FOR MICHIGAN (2022).
- 7 FLO-10. Andy Balaskovitz, *Utility-linked group seeks to dismantle net metering in*
8 *Michigan* (Mar. 4, 2019), [https://energynews.us/2019/03/04/utility-linked-](https://energynews.us/2019/03/04/utility-linked-group-seeks-to-dismantle-net-metering-in-michigan/)
9 [group-seeks-to-dismantle-net-metering-in-michigan/](https://energynews.us/2019/03/04/utility-linked-group-seeks-to-dismantle-net-metering-in-michigan/).
- 10 FLO-11. Erik Pohl, et al., *Distribution Grid Impact Study in Highland Park,*
11 *Michigan: Understanding Rooftop Solar, Behind-the-Meter Energy*
12 *Storage, Electric Vehicle Charging, and Building Electrification*, U.S.
13 DEP'T OF ENERGY, (2024), <https://www.nrel.gov/docs/fy24osti/87916.pdf>.
- 14 FLO-12. Weiwei Lin, et al., *Meta-analysis of the effects of indoor nitrogen dioxide*
15 *and gas cooking on asthma and wheeze in children*, 42 INT. J.
16 EPIDEMIOLOGY 1724 (2023).
- 17 FLO-13. Prudence Kunyangna & Beth Anderson, *Detroit: The Current Status of*
18 *Asthma Burden* (2021).
- 19 FLO-14. DTE Gas's Response to FLO's Third Discovery Request, FLODG-3.12.
- 20 FLO-15. DTE Gas's Response to FLO's Third Discovery Request, FLODG-3.13–
21 FLODG-3.15.
- 22 FLO-16. DTE Gas's Response to FLO's Third Discovery Request, FLODG-3.17.
- 23 FLO-17. DTE Gas's Response to FLO's Third Discovery Request, 3.19.

- 1 FLO-18. Courtney Lindwall, *Decarbonization: Why We Must Electrify Everything*
 2 *Even Before the Grid Is Fully Green* (Dec. 1, 2022),
 3 [https://www.nrdc.org/stories/why-we-must-electrify-everything-even-grid-](https://www.nrdc.org/stories/why-we-must-electrify-everything-even-grid-fully-green)
 4 [fully-green](https://www.nrdc.org/stories/why-we-must-electrify-everything-even-grid-fully-green).
- 5 FLO-19. Arjun Makhijani, *The Trouble with STRIDE: Meeting climate goals and*
 6 *addressing natural gas system stranded costs* (Dec. 2023),
 7 [https://ieer.org/wp/wp-content/uploads/2024/01/Natural-gas-stranded-](https://ieer.org/wp/wp-content/uploads/2024/01/Natural-gas-stranded-costs-and-climate-A-Maryland-case-study-2023-12.pdf)
 8 [costs-and-climate-A-Maryland-case-study-2023-12.pdf](https://ieer.org/wp/wp-content/uploads/2024/01/Natural-gas-stranded-costs-and-climate-A-Maryland-case-study-2023-12.pdf).
- 9 FLO-20. Isaac Sevier, *Building Decarbonization has a Natural Gas Pipeline*
 10 *Problem* (May 17, 2023),
 11 [https://www.climateandcommunity.org/building-decarb-natural-gas-](https://www.climateandcommunity.org/building-decarb-natural-gas-problem)
 12 [problem](https://www.climateandcommunity.org/building-decarb-natural-gas-problem).
- 13 FLO-21. DTE Gas's Response to FLO's Third Discovery Request, FLODG-3.9.
- 14 FLO-22. DTE Gas's Response to CEO's First Discovery Request, CEODG-1.15a.
- 15 FLO-23. DTE Gas's Response to MNSC's Fifth Discovery Request, MNSCDG-
 16 5.10b.
- 17 FLO-24. DTE GAS COMPANY, LOW CARBON ENERGY INFRASTRUCTURE
 18 ENHANCEMENT AND DEVELOPMENT GRANT PROPOSAL: EXPANSION OF
 19 NATURAL GAS DISTRIBUTION SYSTEMS IN BENZIE, MANISTEE, AND
 20 WEXFORD COUNTIES (2023).
- 21 FLO-25. DTE GAS COMPANY, LOW CARBON ENERGY INFRASTRUCTURE
 22 ENHANCEMENT AND DEVELOPMENT GRANT PROPOSAL: EXPANSION OF
 23 NATURAL GAS DISTRIBUTION SYSTEMS IN NEWAGO COUNTY (2023).

- 1 FLO-26. DTE GAS COMPANY, LOW CARBON ENERGY INFRASTRUCTURE
 2 ENHANCEMENT AND DEVELOPMENT GRANT PROPOSAL: EXPANSION OF
 3 NATURAL GAS DISTRIBUTION SYSTEMS IN DELTA COUNTY (2023).
- 4 FLO-27. DTE GAS COMPANY, LOW CARBON ENERGY INFRASTRUCTURE
 5 ENHANCEMENT AND DEVELOPMENT GRANT PROPOSAL: EXPANSION OF
 6 NATURAL GAS DISTRIBUTION SYSTEMS IN OSCEOLA COUNTY (2023).
- 7 FLO-28. DTE GAS COMPANY, LOW CARBON ENERGY INFRASTRUCTURE
 8 ENHANCEMENT AND DEVELOPMENT GRANT PROPOSAL: EXPANSION OF
 9 NATURAL GAS DISTRIBUTION SYSTEMS IN OCEANA COUNTY (2023).
- 10 FLO-29. DTE Gas's Response to CEO's First Discovery Request, CEODG-1.17.
- 11 FLO-30. DTE Gas's Response to FLO's Fifth Discovery Request, FLODG-5.1b,
 12 5.1c(i)-(iii), 5.2b, 5.2c(i)-(iii), 5.3b, 5.3c(i)-(iii).
- 13 FLO-31. DTE Gas's Response to FLO's Fifth Discovery Request, FLODG-5.1a,
 14 5.2a, 5.3a.
- 15 FLO-32. Trustwell™ Standard Definitional Document, IES (Sep. 1, 2020).
- 16 FLO-33. MIQ Standard, MIQ (last accessed May 1, 2024), [https://miq.org/the-](https://miq.org/the-technical-standard/)
 17 [technical-standard/](https://miq.org/the-technical-standard/).
- 18 FLO-34. NRDC et al., Comments to the MPSC on the Renewable Natural Gas
 19 Study Draft and June 29 Presentation (Aug. 3, 2022).
- 20 FLO-35. DTE Gas's Response to FLO's Third Discovery Request, FLODG-3.10a.
- 21 FLO-36. DTE Gas's Response to FLO's Third Discovery Request, FLODG3-10b.
- 22 FLO-37. Brian Allnutt, U.S. *Senators accuse DTE-chaired American Gas*
 23 *Association of Using Customer Money to Mislead Public*, PLANET

- 1 DETROIT (May 1, 2024), [https://planetdetroit.org/2024/05/natural-gas-dte-](https://planetdetroit.org/2024/05/natural-gas-dte-american-gas-association/)
 2 [american-gas-association/](https://planetdetroit.org/2024/05/natural-gas-dte-american-gas-association/).
- 3 FLO-38. DTE 501(c)(6) CONTRIBUTIONS AND LOBBYING EXPENSES (2023),
 4 [https://www.dteenergy.com/content/dam/dteenergy/deg/website/common/](https://www.dteenergy.com/content/dam/dteenergy/deg/website/common/about-us/company-information/corporate-governance/political-participation/DTE501Expenditures.pdf)
 5 [about-us/company-information/corporate-governance/political-](https://www.dteenergy.com/content/dam/dteenergy/deg/website/common/about-us/company-information/corporate-governance/political-participation/DTE501Expenditures.pdf)
 6 [participation/DTE501Expenditures.pdf](https://www.dteenergy.com/content/dam/dteenergy/deg/website/common/about-us/company-information/corporate-governance/political-participation/DTE501Expenditures.pdf).
- 7 FLO-39. DTE, POLITICAL PARTICIPATION (last accessed May 1, 2024),
 8 [https://www.dteenergy.com/us/en/residential/about-dte/corporate-](https://www.dteenergy.com/us/en/residential/about-dte/corporate-governance/political-participation.html)
 9 [governance/political-participation.html](https://www.dteenergy.com/us/en/residential/about-dte/corporate-governance/political-participation.html).
- 10 FLO-40. *About Us*, THE COALITION FOR RENEWABLE NATURAL GAS (last accessed
 11 May 6, 2024) <https://www.rngcoalition.com/thecoalitionforrng>.
- 12 FLO-41. Karl Dunkle Werner & Stephen Jarvis, Energy Inst. at Haas, Rate of
 13 Return Regulation Revisited (Energy Inst. Working Paper No. 329R,
 14 Revised Aug. 2023).
- 15 FLO-42. BEN STACY & TONY REAMES, URBAN ENERGY JUST. LAB, UNIVERSITY OF
 16 MICHIGAN, SOCIAL EQUITY IN STATE ENERGY POLICY: INDICATORS FOR
 17 MICHIGAN’S ENERGY EFFICIENCY PROGRAMS (2017).
- 18 FLO-43. HOME ENERGY AFFORDABILITY GAP REPORT 2022: MICHIGAN (2023).
- 19 FLO-44. AMERICAN COUNCIL FOR AN ENERGY EFFICIENT ECONOMY,
 20 UNDERSTANDING ENERGY AFFORDABILITY (Sep. 9, 2019).
- 21 FLO-45. DTE Gas’s Response to FLO’s Sixth Discovery Request, FLODG-6.11,
 22 6.12, 6.13.

FLO-46. ELECTRICITY CONSUMERS RESOURCE COUNCIL, REVENUE DECOUPLING
AND ITS ALTERNATIVES: AN INTERVENER’S GUIDE TO RETAIL
RATEMAKING AND POLICIES ON DECOUPLING (2009).

FLO-47. *MPSC Approves \$50M in Low-Carbon Energy Infrastructure Grants*,
MICH. PUB. SERV. COMM’N (June 9, 2023),
[https://www.michigan.gov/mpsc/commission/news-
releases/2023/06/09/mpsc-approves-\\$50m-in-low-carbon-energy-
infrastructure-grants](https://www.michigan.gov/mpsc/commission/news-releases/2023/06/09/mpsc-approves-$50m-in-low-carbon-energy-infrastructure-grants).

II. Principles of Analysis

Q: What principles inform your analysis of DTE Gas’s rate case proposal?

A: My analysis is guided by several principles: (1) assessing the business purpose of DTE Gas accurately and applying the “social interest principle” rather than the “profit maximization principle,” (2) creating a just and equitable energy transition, and (3) escaping the “mid-transition” period as expediently and equitably as possible. I will define and explain these principles in this section of testimony.

A. Social Interest Principle vs. Profit Maximization Principle

Q: How does DTE Gas describe its business purpose?

A: Company Witness Telang states that “DTE Gas’s overall business objective is to provide safe, reliable, cost-effective, and environmentally responsible natural gas service to its

customers and deliver reasonable and appropriate compensatory returns to DTE Energy shareholders while maintaining the Company's financial health."¹

Q: How would you describe DTE Gas's business purpose?

A: I would describe DTE Gas's business purpose as maximizing long-term profitability for DTE Energy shareholders.

Q: What evidence supports your claim that DTE Gas's business objective is the maximization of long-term profitability for DTE Energy shareholders?

A: To state the obvious, DTE Gas is a subsidiary of DTE Energy, a publicly traded and investor-owned corporation. While there have been recent debates about and attempts to broaden the set of interests that corporations serve, my understanding is that the primary duty of an investor-owned corporation is the maximization of profits for its shareholders.² While DTE's public communications assert a wide variety of goals, DTE Energy's filings with the Securities Exchange Commission are refreshingly direct on this point: "DTE Energy's strategy is to achieve long-term earnings per share growth with a strong balance sheet and attractive dividend."³

As a subsidiary of DTE Energy, DTE Gas pursues "safe, reliable, clean, and cost-effective natural gas service" only to the extent that regulation and popular or political pressure would otherwise limit its pursuit of profit maximization. Moreover, DTE Energy continuously seeks to limit the degree to which regulation and popular or political

¹ Telang Direct Testimony at 3–4.

² See, e.g., *Dodge v. Ford Motor Co.*, 204 Mich. 459, 507 (1919) ("A business corporation is organized and carried on primarily for the profit of the stockholders. The powers of the directors are to be employed for that end.").

³ Ex. FLO-1, DTE Energy Co., Annual Report (Form 10-K) (Feb. 8, 2024) (excerpt), at 6.

pressure can force it to prioritize the public interest over its own profits through political contributions,⁴ charitable giving,⁵ and “dark money” groups.⁶

Q: Please describe the Profit Maximization Principle and Social Interest Principle as you will use them in your testimony.

A: I will use the term Profit Maximization Principle (PMP) to describe what I understand to be the guiding value behind all elements of DTE Gas’s filing: the maximization of long-term profits for shareholders. I will use the term Social Interest Principle (SIP) to describe a contrary guiding value: the maximization of collective social benefit by assessing the full life cycle costs and benefits of energy decisions and distributing those costs and benefits equitably.

Q: How does DTE Gas attempt to connect “maintaining the Company’s financial health” with benefits to the “customers and the region”?

A: Company Witness Telang provides the number of employees, amount of spending with Michigan-based companies, and payment of property taxes as evidence of the connection between DTE Gas’s financial health and “benefits to customers and the region.”⁷ In other words, DTE Gas maintains that its financial health is necessary to achieve these benefits.

⁴ Ex. FLO-2, Karlee Weinmann, *Amid controversies, DTE Energy continues to spend big in Michigan and nearly every lawmaker accepts*, ENERGY AND POLICY INSTITUTE (Sept. 28, 2022), <https://energyandpolicy.org/dte-energy-political-contributions-michigan/>, at 1.

⁵ Ex. FLO-3, David Anderson, et al., *Strings Attached: How utilities use charitable giving to influence politics and increase investor profits*, ENERGY AND POLICY INSTITUTE (Dec. 2019), <https://energyandpolicy.org/strings-attached-how-utilities-use-charitable-giving-to-influence-politics-increase-investor-profits-dte-energy/>, at 3-7.

⁶ Ex. FLO-4, Energy and Policy Institute, *Michigan Energy First* (last accessed May 2, 2024), <https://energyandpolicy.org/michigan-energy-first/>, at 1.

⁷ Telang Direct Testimony at 7.

1 **Q: Is DTE’s explanation of the connection between its financial health and benefits to**
2 **the public complete or convincing?**

3 **A:** No. It is logically incomplete. DTE Gas merely identifies that the operation of a utility
4 that meets essential energy needs generates economic activity. DTE Gas neither
5 demonstrates that the scale of this economic activity is essentially related to its “financial
6 health,” nor does it demonstrate that this economic activity would be any more or less
7 beneficial if essential energy needs were met through another energy source, such as
8 electricity or geothermal, or by a public or cooperative entity.

9 Additionally, DTE Gas has not provided concrete evidence connecting its
10 financial health to the benefits it claims. This omission does not mean that there isn’t an
11 obvious connection between public benefits and the stable provision of essential services.
12 But DTE Gas does not support the linkage between DTE Gas’s financial health and
13 benefits to the public in the record.

14
15 **Q: How would DTE Gas’s approach change if it applied the social interest principle**
16 **rather than the profit maximization principle?**

17 **A:** As I will outline throughout this testimony, the future of the gas system has tremendous
18 implications for energy equity. DTE Gas proposes a plan to maximize profitable capital
19 investment in the gas system without regard for the long-term, systemic impacts of doing
20 so on its customer base, and especially on low-to-moderate income (LMI) and Black,
21 Indigenous, and People Of Color (BIPOC) communities. Applying the social interest
22 principle, conversely, would require DTE to conduct a rigorous analysis of the future of
23 the gas system, minimize capital investment in soon-to-be-replaced infrastructure, and

1 articulate and follow a clear plan for the equitable transition of LMI and BIPOC
2 communities to a modern, high-functioning, and electrified energy system.

3
4 **Q: How does this assessment inform your perspective on the actions the Commission**
5 **should take in this case?**

6 **A:** I do not take DTE's claim of social interest goals at face value, and the Commission
7 should not do so either. While there may be instances when DTE's goal of financial
8 health and profit maximization inadvertently aligns with social interests, it is the
9 Commission's responsibility to compel DTE as a publicly regulated utility to align its
10 actions with the social interest. I present my recommendations accordingly.

11
12 **B. Just and Equitable Energy Transition and Mid-Transition**

13 **Q: In general, what do you mean when you refer to a Just and Equitable Energy**
14 **Transition in your testimony?**

15 **A:** When I refer to a just and equitable energy transition throughout my testimony, I am
16 referring to a transition to a decarbonized energy system that repairs and improves
17 affordability, infrastructure quality, and technology access for frontline communities.

18
19 **Q: Please summarize the Just and Equitable Energy Transition framework utilized by**
20 **FLO in this case.**

21 **A:** The energy system is undergoing a radical transformation. Significant change is taking
22 place in the energy industry, driven largely by technological advancements, efforts to
23 mitigate the effects of climate change, and efforts to address environmental quality and

1 health. Collectively, these changes are commonly referred to as the energy transition.
 2 Presently, the distribution of burdens and benefits in the existing energy system is not
 3 equitable; LMI and BIPOC communities bear the greatest costs⁸ and receive the lowest
 4 benefits⁹ from the system. Addressing these inequities is the basis of a just energy
 5 transition. Fundamentally, the solutions to these issues must be developed in
 6 collaboration with impacted community members.¹⁰

7 FLO Witness Schott describes a robust framework of energy equity which
 8 highlights a four-point framework of recognition justice, procedural justice, distributive
 9 justice, and reparative justice. In analyzing the distributive justice and reparative
 10 components, FLO's framework for a Just & Equitable Energy Transition focuses on three
 11 key elements as they impact frontline communities:

12 **Affordability:** The cost of sufficient energy to meet household needs as a
 13 proportion of household income.

14 **Infrastructure Quality:** The reliability, safety, and technology capabilities of the
 15 infrastructure delivering energy.

⁸ Ex. FLO-5, Laura Frier, Delia Mayor, & Brett Zeuner, *Assessing the State of Environmental Justice in Michigan* (May 2019), https://deepblue.lib.umich.edu/bitstream/handle/2027.42/149105/AssessingtheStateofEnvironmentalJusticeinMichigan_344.pdf?sequence=1&isAllowed=y, at 111–113.

⁹ *Id.*

¹⁰ *In re Michigan Public Service Commission*, MPSC Case No. U-20959-0003, MPG Customer Education & Participation Workgroup – Final Report, (Mar. 25, 2022), available at: <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000002RDnKAAW>, at 1 (“This transition, however, requires more than just the ability for customers to have access to information regarding their energy usage. The energy transition requires shifting customers from passive end users of energy to active participants in their energy use, and in some instances, energy production and storage, and in the overall energy transition. As this change happens, moving customers along this spectrum from passive user to active user requires ensuring that customers have the knowledge, information, tools, and access to ensure their ability to successfully participate in this transition. This requires that customers have an awareness of utility offerings, the tools available to them to understand utility programs and make decisions in the best interest of them and their families, and access to the programs and decision-making processes that impact the programs available to them.”).

Technology Access: The ability of households to access clean energy, resilience measures, efficiency improvements, and other advances in energy technology.

The framework assumes, as a baseline, that the energy transition is happening. These three key measures offer a clear picture of whether the transition is achieving equity.

While utility proposals and regulatory history reinforce a zero-sum relationship between these factors, our framework posits that there is no equity and justice in the energy transition unless all three factors are improved.

The Commission has approved a formal definition of affordability: “A household has the resources to meet their home energy needs for heating, cooling and other uses in a healthy, sustainable, and energy-efficient manner without compromising a household’s ability to meet other basic needs.”¹¹ When MPSC Staff proposed this definition, DAAO and other parties submitted comments noting that the definition should focus on the actual cost of energy, which is within the Commission’s regulatory authority, rather than locating responsibility somewhere else.¹² FLO contends that it is just and reasonable for the Commission to focus on improving affordability in a general rate case by assessing the cost of energy, which is within the Commission’s purview. In other words, the Commission does not control or alter household income directly, but it can control the actual cost of energy, which is one part of the affordability equation. In this testimony, my usage of affordability will adhere to the Commission’s approved definition.

¹¹ *In re Michigan Public Service Commission*, MPSC Case No. U-20757, Order (Dec. 21, 2023), available at: <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000BD37gAAD>, at 36.

¹² *Id.* at 7, 36; see also *In re Michigan Public Service Commission*, Case No. U-20757-0002-CC, Letter to Commissioners Scripps and Peretick from Michigan Municipal Association for Utility Issues, Ecology Center, EcoWorks, Elevate, National Housing Trust, Natural Resources Defense Council, Soulardarity, We Want Green, Too (Jun. 15, 2023), available at: <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y0000088fg3AAA>.

1 **Q: Please summarize the concept of mid-transition as you will use it in this case.**

2 **A:** In a 2022 paper, Emily Grubert and Sara Hastings-Simon described the mid-transition as
3 follows:

4 the period during which energy supply... is (1) constrained by a goal of reducing
5 or eliminating greenhouse gas emissions and (2) comprised of fossil carbon-
6 emitting systems and zero-carbon systems that both exist at sufficient scale to
7 impose operationally relevant constraints on the other. That is, the mid-transition
8 is the period between two stable end points (where systems are largely operating
9 as they were designed and under conditions structured around their needs) during
10 which change is directional and coexisting systems must make compromises to
11 accommodate the other.¹³

12 In the context of Michigan's energy system and the instant case, I use the expression mid-
13 transition to refer to the period in which energy needs are served by an increasingly clean
14 and renewable portfolio, yet still substantially reliant on legacy fossil fuel resources.

15
16 **Q: Has Michigan entered the mid-transition?**

17 **A:** While Michigan lags behind most U.S. states in both adopting renewables¹⁴ and enacting
18 policies supportive of renewables,¹⁵ the systemic characteristics of the mid-transition
19 period are already firmly present in Michigan's regulations and policies.

20 One clear example is the legislative and regulatory history surrounding
21 compensation rates for distributed generation. Numerous models have indicated the need

¹³ Ex. FLO-6, EMILY GRUBERT & SARA HASTINGS-SIMON, DESIGNING THE MID-TRANSITION: A REVIEW OF MEDIUM-TERM CHALLENGES FOR COORDINATED DECARBONIZATION IN THE UNITED STATES (2022), at 3.

¹⁴ Ex. FLO-7, KARIN KIRK, WHICH STATE IS WINNING AT RENEWABLE ENERGY PRODUCTION? (Feb. 23, 2023), at 2.

¹⁵ Ex. FLO-8, THROWING SHADE: 10 SUNNY STATES BLOCKING DISTRIBUTED SOLAR DEVELOPMENT (2018), at 28.

1 for far more distributed clean energy generation than is currently operating on the
 2 system.¹⁶ While there is reasonable debate regarding the optimal amount of distributed
 3 clean energy generation, there is virtually no disagreement that it is going to play a
 4 significant role in the energy mix of the future.¹⁷ However, the fixation of regulatory and
 5 legislative actors on narrow and short-term cost-benefit and cost-of-service methods to
 6 manage the legacy energy system have led to backwards policy on the matter.

7 In 2016, the Michigan legislature killed net metering and ordered the Commission
 8 to replace it with the inflow-outflow tariff.¹⁸ The result of the MPSC proceedings
 9 implementing the legislation led to a compensation rate for distributed energy at around
 10 half of the retail rate of electricity.¹⁹ Not only did the utilities support these changes, but
 11 the MPSC Staff also supported them, the latter on the grounds that distributed generation
 12 (DG) customers should pay their “fair and equitable cost for use of the grid.”²⁰ Notably,
 13 the process did not define fair or equitable. MPSC Staff expressed concern about virtual
 14 grid defection resulting from net metering²¹ while acknowledging that the very reason
 15 this discussion was on the table is because “NEM hits at the core of an investor owned
 16 utility’s long term financial objectives.” Ultimately, the Commission approved inflow-

¹⁶ Ex. FLO-9, VIBRANT CLEAN ENERGY, LLC, ELECTRIFICATION AND DECARBONIZATION PATHWAYS FOR MICHIGAN (2022), at 13.

¹⁷ See generally *In re Michigan Public Service Commission*, MPSC Case No. U-18383-0024, Staff DG Report (Feb. 21, 2018), available at: <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t00000016WftAAE>.

¹⁸ MCL § 460.1173.

¹⁹ See *In re Michigan Public Service Commission*, MPSC Case No. U-18383-0024, Order (Apr. 18, 2018), at 13–15; *In re DTE Electric Company*, MPSC Case No. U-20162-0604, Order (May 2, 2019), at 167.

²⁰ *In re Michigan Public Service Commission*, MPSC Case No. U-18383-0024, Staff DG Report (Feb. 21, 2018), available at: <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t00000016WftAAE>, at 5.

²¹ *Id.* at 46.

1 outflow rates which credited DG customers at about half the retail rate and restricted the
2 expansion of distributed solar enabled by net metering.

3 One meta-narrative pushed by utilities and their surrogates in Michigan and
4 nationwide framed the pursuit of solar energy by higher-income, whiter communities as
5 occurring at the expense of others. This narrative allowed utilities to thwart rooftop solar
6 under the guise of a concern for equity.²²

7 In reality, the thwarting of rooftop solar created the opposite outcome. Customers
8 who can afford to install DG systems continue to do so and benefit from the investment,
9 albeit on a longer timeline and at a lower rate, while lower-income communities are
10 unable to benefit. Overall, DG deployment has been curtailed, and the customers and
11 communities most impacted are those with limited financial capabilities to invest in clean
12 energy, creating a race and class divide in clean energy access. The MPSC Staff report
13 referenced previously identified that the impact of net metering was to expand the solar
14 market.²³ The impact of ending it was precisely opposite.

15 This divide also perpetuates a deeper equity problem. DG requires a higher
16 voltage distribution grid to absorb DG at high penetration levels. Resting on the
17 assumption that lower-income communities will be slower to adopt DG, utilities will
18 prioritize wealthier, whiter areas for grid improvement over LMI/BIPOC communities. I

²² See Ex. FLO-10, Andy Balaskovitz, *Utility-linked group seeks to dismantle net metering in Michigan* (Mar. 4, 2019), <https://energynews.us/2019/03/04/utility-linked-group-seeks-to-dismantle-net-metering-in-michigan/>, at 1–2.

²³ *In re Michigan Public Service Commission*, MPSC Case No. U-18383-0024, Staff DG Report (Feb. 21, 2018), available at: <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t00000016WftAAE>, at 45.

1 provide more information about this deeper equity problem in my discussion of the
 2 Distribution Grid Impact Study from Highland Park below.

3
 4 **Q: How could regulators and legislators alter policies to take into account the mid-
 5 transition period?**

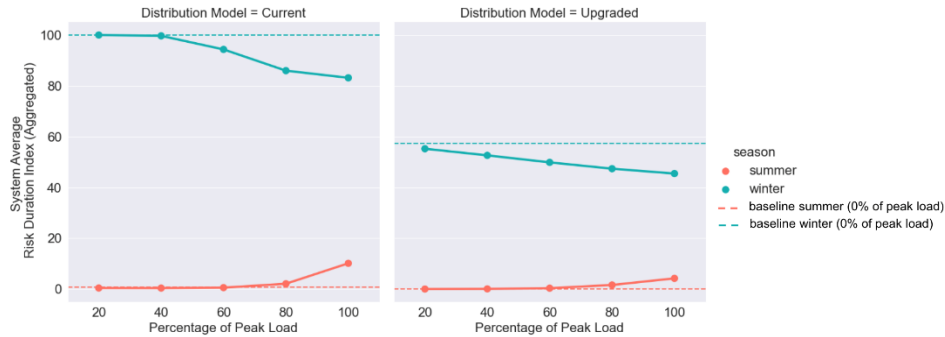
6 **A:** A policy approach to DG informed by mid-transition might aim for longer-term goals of
 7 expanding DG penetration to the levels indicated to be necessary by forward-thinking
 8 decarbonization modeling, particularly in communities suffering from poor reliability and
 9 affordability problems, such that the communities can rely on DG as a meaningful
 10 resource at scale. One way to achieve this is providing (1) better compensation rates for
 11 DG for all and (2) specific incentives for communities with implementation barriers to
 12 assure equitable, system-wide distribution of DG.

13
 14 **Q: How does this example about distributed electric generation relate to DTE Gas's
 15 rate case proposal?**

16 **A:** This example highlights the need for integrated gas and electric planning. As I will
 17 expand upon throughout testimony, the gas and electric systems are in dynamic relation
 18 to each other. This is highlighted by a recent Department of Energy study considering
 19 DER integration and line voltage conversion in Highland Park by modeling various
 20 scenarios of DER adoption and load growth from electrification.²⁴ Investing in the
 21 electric distribution system is essential to facilitate electrification while avoiding the

²⁴ See generally Ex. FLO-11, Erik Pohl, et al., *Distribution Grid Impact Study in Highland Park, Michigan: Understanding Rooftop Solar, Behind-the-Meter Energy Storage, Electric Vehicle Charging, and Building Electrification*, U.S. DEP'T OF ENERGY (Mar. 2024), <https://www.nrel.gov/docs/fy24osti/87916.pdf>.

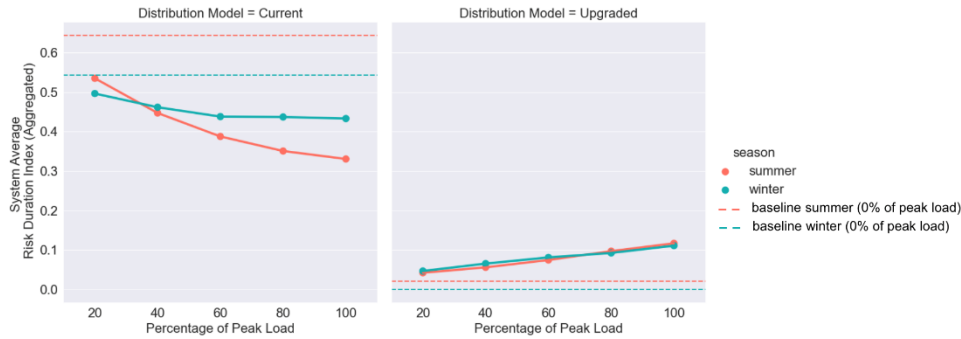
potential for unacceptable grid failure, particularly for the predominantly LMI and BIPOC communities served by the 4.8kV system.²⁵ According to this study, distributed resources such as solar and storage are critical resources for reducing wintertime grid risks in these high electrification scenarios, and they ameliorate resilience concerns for households experiencing poor reliability from the electric system.



Slide 48 of Distribution Grid Impact Study from Highland Park showing that higher penetrations of solar and storage reduce winter System Average Risk Duration Index in high electrification scenario²⁶

²⁵ *Id.*

²⁶ *Id.* at 48.



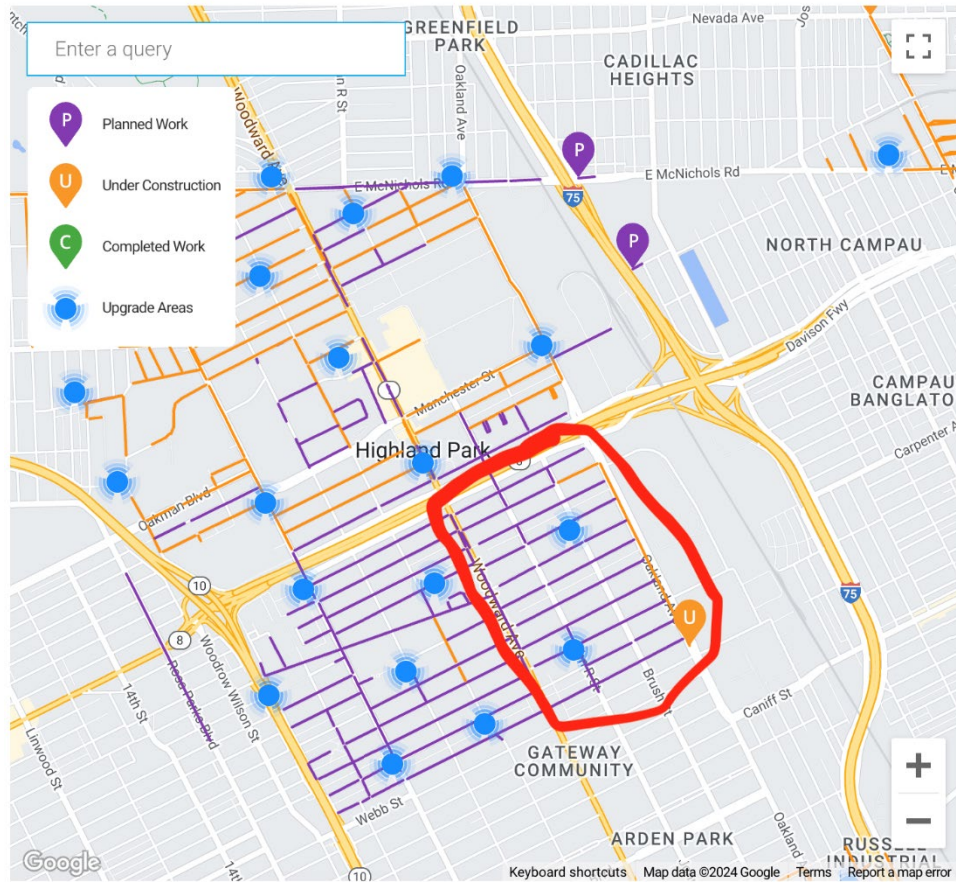
Slide 49 of Distribution Grid Impact Study from Highland Park showing that higher penetrations of solar and storage reduce summer and winter System Average Risk Duration Index in the base electrification scenario under the current electric grid²⁷

The modeled section of Highland Park's electric grid experiences some of the worst reliability in the service territory. This study indicates that there is a need for a multi-faceted strategy to improve reliability, including phased grid modernization and DG deployment. I have personally supported elders who live in this section through numerous power outages, which cause them great concern. While no similar complaints about the safety or reliability of the gas system serving that area have emerged, nonetheless, DTE Energy's subsidiaries DTE Gas and DTE Electric appear to have planned extensive improvement work for the gas system in this entire section in 2024, while deferring modernization of the electric grid to an unknown date.

Modernizing the electric grid and implementing DG would both directly address customer needs and fit the long-term trends in energy use, yet DTE's apparent priority is proactive maintenance of the gas system, which is not suffering from reliability problems. Without integrated planning and analysis that considers the dynamic relationships

²⁷ *Id.* at 49.

1 between things like DG policy and infrastructure planning, this type of imprudent
 2 prioritization will continue to occur.



3
 4 *DTE Natural Gas System Improvement Map,*

5 https://www.dteenergy.com/us/en/quicklinks/search/gas_map.html (Apr. 25, 2024).

6 *Relevant section circled in red.*

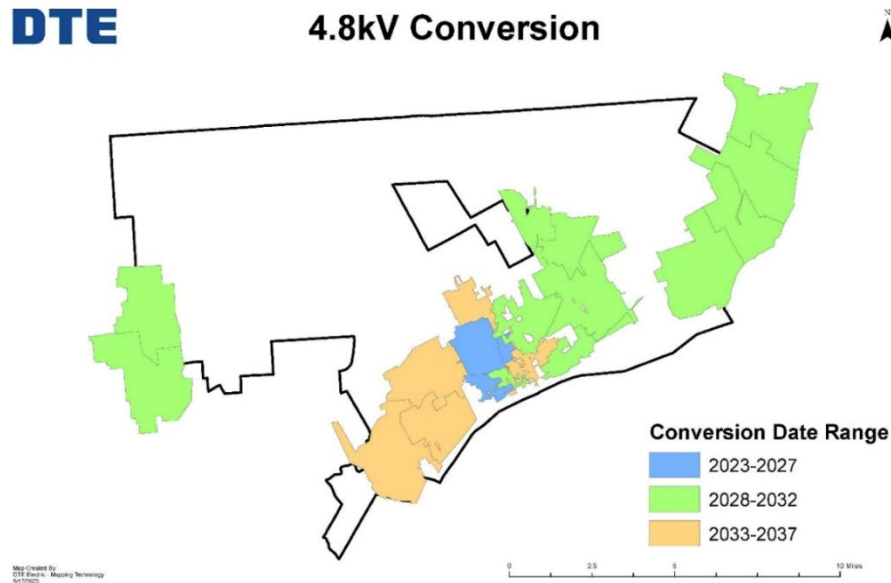


Figure 5. Planned 4.8kV Conversion and Arc Wire Removal Locations

From pg. 35 of the testimony of Dr. Joy Wang in Case U-21297, showing that there is no projected date for conversion from 4.8 kV to 13.2 kV for any of Highland Park's footprint.²⁸

Q: How do the concepts of a just and equitable energy transition and a mid-transition apply to your analysis of DTE Gas' rate case proposal?

A: Two legacy fossil fuel systems—the gas distribution system and the electric distribution system—currently serve ratepayers. Both systems are generally characterized by the one-way flow of extracted fossil resources to meet institutional, business, and household needs. Both systems are at operational odds with the emerging clean and renewable system, which is characterized by its omni-directional system in which distributed

²⁸ See *In re DTE Electric Company*, MPSC Case No. U-21297-0312, Staff Testimony- Wang Direct (Jun. 13, 2023), available at: <https://mi-psc.my.site.com/s/filing/a008y000003deCcAAI/u212970312>, at 35.

1 generation and storage of electricity is a significant resource, and electricity meets the
2 majority of energy needs.

3 The legacy system and the emerging system impose constraints on each other in
4 numerous ways. The most relevant constraint centers on the cost pressures affecting
5 investments in the gas distribution versus the electric distribution system. So long as
6 ratepayers rely on the gas distribution system for essential day-to-day needs, the gas
7 distribution system demands continuous investment for safe and reliable operation.
8 However, DTE Electric also meets energy needs through its electric distribution system.
9 Regrettably, the electric distribution system is measurably deficient, unsafe, and
10 unreliable, and DTE Electric is planning to request billions of dollars in the coming years
11 to improve the electric distribution system. It is inefficient to invest in parallel
12 distribution systems to meet energy needs. Narrow and short-term cost-benefit analyses
13 continue to lead DTE Electric and DTE Gas towards investing to keep both systems
14 functional, which extends the mid-transition period, instead of investing in the most
15 efficient transition possible. Moreover, DTE Gas is incapable of considering its own
16 obsolescence, as doing so would violate the profit maximization principle.

17
18 **Q: What other equity issues are exacerbated by the prolonged existence of the gas**
19 **system?**

20 **A:** The continued extraction, transportation, and end-use of gas have significant equity
21 impacts. As discussed by FLO Witness Justin Schott, the household use of gas has long
22 been demonstrated to increase the risk of asthma in children.²⁹ Notably, a 2021 study by

²⁹ See generally Ex. FLO-12, Weiwei Lin, et al., *Meta-analysis of the effects of indoor nitrogen dioxide and gas cooking on asthma and wheeze in children*, 42 INT. J. EPIDEMIOLOGY 1724 (2023).

1 the Michigan Department of Health and Human Services showed that there is a
 2 significantly higher prevalence of asthma for adults and children in Detroit than Michigan
 3 as a whole.³⁰

4 From a climate standpoint, life cycle analysis of gas use demonstrates that it is
 5 neither a bridge fuel, as the industry has long advocated, nor a climate solution. As I will
 6 discuss further, DTE's so-called Responsibly Sourced Gas proposal serves to increase
 7 and extend fossil gas extraction as there is no viable future in which the gas system is
 8 served entirely by climate-neutral gas, if such a thing is even actually possible. As a
 9 result, the disparate harms of climate change on frontline communities continue to be
 10 exacerbated.

11 Finally, the financial constraints of investing in parallel distribution systems cause
 12 a persistent zero-sum relationship between affordability, infrastructural quality, and
 13 technology access. Customer costs will continue to rise sharply for both gas and electric
 14 service, while investment is not focused on the modernization of homes and
 15 infrastructure of the most vulnerable communities and households.

16
 17 **Q: How should the application of a mid-transition framework impact planning**
 18 **decisions for the gas system?**

19 **A:** The Commission, DTE Energy, DTE Electric, and DTE Gas should apply a mid-
 20 transition framework in two ways. First, they should utilize longer-term cost-benefit
 21 analysis that integrates electric and gas planning to ensure that investments made in the
 22 gas system are truly efficient. Second, the Commission, DTE Energy, DTE Electric, and

³⁰ See Ex. FLO-13, Prudence Kunyangna & Beth Anderson, Michigan Dept. of Health and Human Services, *Detroit: The Current Status of Asthma Burden* (2021), at 5–6.

1 DTE Gas should focus on home repair, weatherization, and electrification of homes
2 instead of on continued investment in the gas distribution system. These measures create
3 long-term stacked benefits for the health, affordability, and safety of households while
4 shortening the mid-transition period and expediting the clean energy transition.

5
6 **Q: How should regulators think about cost-effectiveness in the mid-transition?**

7 **A:** It is critical to operationalize the understanding that the mid-transition period is
8 inefficient, and that minimizing inefficiency is a misguided goal in comparison to moving
9 quickly through this period.

10 Understanding this fact is fairly intuitive. If half of all people use electric vehicles
11 and half of all people use gasoline vehicles, for example, it is easy to see that it is more
12 costly to provide equally reliable parallel systems for gasoline and electric fueling,
13 compared to providing just one option. Even though only half of all vehicles use gasoline
14 or electric in this scenario, there must be sufficiently available electric charging and
15 gasoline refueling to meet the practical needs of both user bases. In contrast, if the
16 majority of vehicles were either electric or gasoline-fueled, the refueling infrastructure
17 for the less utilized resource could be scaled down.

18 Operationalizing this understanding, however, presents challenges to the accepted
19 regulatory culture and practice. Optimizing for the lowest possible net cost at every
20 moment, such as regulators attempt to do with DG as explained above, only serves to
21 extend the period in which mutually constraining systems continue to constrain each
22 other. Operationalizing a mid-transition analysis would require that all departments inside
23 the MPSC align and agree about the future of the energy system, open up regular

1 communication to ensure that policy decisions made in one area are not contra-indicated
2 by another, and apply longer-term and multi-issue frames to cost-benefit or cost of
3 service analyses. While such operationalization is challenging to achieve, it would yield
4 significant rewards for regulatory cohesion and long-term cost impacts to ratepayers.

5
6 **Q: In general, how does an expedited exit from the mid-transition impact justice and**
7 **equity in the energy transition?**

8 **A:** To summarize my points above, a faster movement through the mid-transition, and thus
9 the avoidance of long-term capital expenditures on parallel gas and electric systems,
10 would yield lower costs to ratepayers as a whole, make more resources available to invest
11 in frontline communities' homes and electric infrastructure, and avoid or reduce health
12 impacts for vulnerable communities.

13
14 **Q: How does continuing to support DTE Gas' goal of profit maximization during the**
15 **mid-transition period come at the expense of customers and communities?**

16 **A:** For DTE Energy, the holding company that owns DTE Gas, drawing out the mid-
17 transition generates more guarantee of profit. The longer the mid-transition period
18 continues, the longer DTE Gas can continue existing and making investments. Thus
19 ultimately, for DTE Energy and DTE Gas, supporting DTE Gas' goal of profit
20 maximization during the mid-transition allows DTE Gas to continue to exist at scale and
21 extract profits for shareholders from customers' and communities' pockets.

22 The presence of parallel gas and electric distribution systems, both of which
23 provide essential services to homes and businesses, diversifies the potential for

1 profitable—and excessive—capital investment. The longer the mid-transition extends, the
2 easier it is for DTE Energy to justify costly long-term investments into both systems.

3 These imprudent investments have the immediate impact of raising costs on customers.

4 Then, at whatever point DTE Energy finally retires the gas system, a longer
5 record of Commission approval of capital expenditures will provide DTE Energy with a
6 larger target for pursuing securitization and other methods to make ratepayers fiscally
7 liable for its willfully short-term thinking. Much as ratepayers are being forced to
8 shoulder the costs of securitizing the costs of retiring coal plants as a condition of the
9 transition of electricity production to clean and renewable sources, DTE Energy will aim
10 to condition the electrification transition similarly by requiring ratepayer or public
11 payouts for obsolete gas distribution infrastructure.

12 Given all of these considerations, without direct MPSC policy interventions,
13 neither DTE Gas nor DTE Energy is incentivized to consider a just and equitable
14 transition. Both entities will likely do everything in their powers to pursue the opposite
15 result. DTE Energy is quite clear on this in its annual filing with the Securities Exchange
16 Commission, stating that “DTE Gas is promoting the extension of its distribution system
17 to underserved markets and the increased use of natural gas furnaces, water heaters, and
18 appliances within its current customer base.”³¹
19

³¹ Ex. FLO-1, DTE Energy Co., Annual Report (Form 10-K) (Feb. 8, 2024) (excerpt), at 15.

1 **III. DTE Gas Rate Proposal And Planning Principles Fail To Meet the Standards of a**
 2 **Just and Equitable Energy Transition**

3 **Q: Please summarize the deficiencies of DTE Gas' approach to designing this rate**
 4 **proposal on which you will focus.**

5 **A:** I will focus on the following deficiencies in DTE Gas' rate proposal:

- 6 • DTE Gas fails to integrate gas and electric infrastructure planning;
- 7 • The Gas Distribution Plan and Gas Renewal Plan needlessly prolong the mid-
 8 transition by promoting the expansion of the gas system;
- 9 • The Responsibly Sourced Gas proposal has no verifiable benefits and ultimately
 10 leads to further fossil gas production and its associated harms;
- 11 • DTE inappropriately requests reimbursements for corporate memberships that
 12 harm consumers;
- 13 • Increasing Return on Equity prolongs the mid-transition by financially
 14 incentivizing additional gas infrastructure investment;
- 15 • DTE Gas fails to analyze housing quality as a core component of gas distribution
 16 system planning;
- 17 • DTE Gas misuses the term affordability and fails to produce any viable analysis
 18 of how it will address the affordability crisis; and
- 19 • The Investment Recovery Mechanism and the Revenue Decoupling Mechanism
 20 extend the mid-transition by disincentivizing customer energy waste reduction.

21

A. DTE Gas fails to integrate gas and electric infrastructure planning

Q: Does DTE Gas demonstrate integrated planning with DTE Electric?

A: No.

DTE Gas has not conducted a cost-benefit analysis comparing rapid retirement of DTE's gas system and electrification of all customers with the continued operation of DTE Gas's and DTE Electric's infrastructure.³² DTE Gas states that they have conducted processes to optimize cost-effectiveness of investments in distribution infrastructure and the combined customer impacts with DTE Electric,³³ but then immediately contradicts themselves by stating that DTE Gas and DTE Electric have had no communication with each other regarding their individual distribution investment planning processes³⁴ and that DTE Gas and DTE Electric develop their demand and sales forecasts independently.³⁵

Q: How does this failure to conduct integrated planning impede a just and equitable energy transition?

A: That electricity will be the primary source of supply to meet the vast majority of energy needs is widely understood to be an essential feature of the energy transition.³⁶ All other things being equal, the early adopters of electrification will be those with higher incomes who can absorb upfront costs and accept longer payback periods. As a result, low-income communities, which also trend towards being more substantially BIPOC communities

³² Ex. FLO-14, DTE Gas's Response to FLO's Third Discovery Request, FLODG-3.12.

³³ Ex. FLO-15, DTE Gas's Response to FLO's Third Discovery Request, FLODG-3.13-FLODG-3.15.

³⁴ Ex. FLO-16, DTE Gas's Response to FLO's Third Discovery Request, FLODG-3.17.

³⁵ Ex. FLO-17, DTE Gas's Response to FLO's Third Discovery Request, FLODG-3.19.

³⁶ Ex. FLO-18, Courtney Lindwall, *Decarbonization: Why We Must Electrify Everything Even Before the Grid Is Fully Green* (Dec. 1, 2022), <https://www.nrdc.org/stories/why-we-must-electrify-everything-even-grid-fully-green>.

1 and which have less capital to invest in electrifying, will be left with a gas distribution
 2 system with higher affordability burdens and continuing negative health impacts to its
 3 remaining users. I discuss a case study of this concern from Maryland later in my
 4 testimony. To avoid this inequitable energy transition, to ensure affordability,
 5 infrastructure quality, and technology access, and to avoid imprudent duplicate
 6 investments in the electric and gas distribution systems, the Commission must require
 7 integrated planning of electric and gas infrastructure.

8
 9 **Q: How are concerns about the reliability and safety of the electric system impacted by**
 10 **planning decisions in the gas system?**

11 **A:** DTE Electric's distribution grid plan projects \$9 billion of spending to improve reliability
 12 and integrate new technology over the next five years.³⁷ While a substantial sum, this
 13 figure pales in comparison to DTE Electric's \$20 to \$25 billion projected investment to
 14 modernize the entire 4.8kV system.³⁸ This plan also fails to include a clear trajectory
 15 towards a completely electric energy system, which will place further demand burdens on
 16 the electric system. To whatever extent the gas system continues to require proactive and
 17 long-term investment and investments in the electric and gas system are both ultimately
 18 backed by ratepayers or taxpayers, investment in the electric and gas systems are
 19 constrained by the ratepayers' and taxpayers' abilities to pay. More investment in the gas
 20 system reduces the available ratepayer or taxpayer resources available for electricity

³⁷ See DTE Exhibit A-12: DTE 2023 Distribution Grid Plan, Case No. U-21291 [hereinafter DTE Exhibit A-12: DTE 2023 Distribution Grid Plan], at 17. See also *In re Michigan Public Service Commission*, MPSC Case No. U-20147-0117, DAAO Comment (Mar. 15, 2024), available at: <https://mi-psc.my.site.com/sfc/servlet/shepherd/version/download/0688y00000CWa5oAAD>.

³⁸ See DTE Exhibit A-12: DTE 2023 Distribution Grid Plan, at 119.

1 infrastructure investment. Thus, the scale of investments in the gas system directly
 2 impacts the ability to achieve reliability, safety, and the integration of emerging
 3 technologies in the electric system.

4
 5 **Q: How does the reliability of the electric system directly impact gas users?**

6 **A:** Households that rely on gas for heating effectively have dual system reliance because the
 7 gas heating appliances rely on electric controls that shut down in the instance of an
 8 electric power outage. So, for a Highland Park or Detroit household served by DTE Gas
 9 and DTE Electric, the unreliability of the electric system is also the unreliability of access
 10 to heating, the most essential component of gas service for the health and safety of a
 11 home.

12
 13 **Q: How does the lack of integrated planning exacerbate equity concerns in frontline
 14 communities?**

15 **A:** Put succinctly: without major grid investment, frontline communities will be left behind
 16 the technology curve.

17 A recent United States Department of Energy analysis of a distribution grid circuit
 18 in Highland Park³⁹ highlights the scale of the barriers to achieving an equitable and just
 19 energy transition. As discussed in the comment of Soulardarity and We Want Green, Too
 20 on DTE Electric's Distribution Grid Plan.⁴⁰

21 Delaying voltage conversion prevents technology adoption essential for the clean
 22 energy transition. For example, Highland Park's low-voltage distribution system

³⁹ Ex. FLO-11, Erik Pohl, et al., *Distribution Grid Impact Study in Highland Park, Michigan: Understanding Rooftop Solar, Behind-the-Meter Energy Storage, Electric Vehicle Charging, and Building Electrification*, U.S. DEP'T OF ENERGY (Mar. 2024), <https://www.nrel.gov/docs/fy24osti/87916.pdf>, at 8–9.

⁴⁰ See DTE Exhibit A-12: DTE 2023 Distribution Grid Plan, at 15.

“may limit significant adoptions of clean-energy technologies,” and the DOE’s “model of the current 4.8kV system indicates it is not capable of supporting community-wide electrification efforts.” In a predicted widespread electrification modeling scenario, the legacy Highland Park 4.8kV distribution system causes increased “prevalence of voltage violations and thermal overloading on the current.” In Highland Park and other EJ communities, the consequences of electrification for customers served by the legacy 4.8kV substations “illustrate the need for system-wide upgrades to a 13.2 kV voltage class.” The distribution system conversion process therefore needs to be planned in conjunction with other grid investments like DERs to capitalize on their reliability and resiliency benefits. Electrification and adoption of DERs in EJ communities will necessitate distribution system conversion to higher voltage classes. In Highland Park, the Communities LEAP study found that “[l]ow to [m]oderate DER adoption does not adversely impact the grid but does improve undervoltage and asset overloading issues. However, these benefits are insufficient to defer upgrades. Higher DER penetration is shown to increase overvoltage and asset overloading in future electrification scenarios.”⁴¹

A study by the Abell Foundation in Maryland found that “Maryland is on a course of huge natural gas stranded costs” and that “[l]ow-income households, especially low-income renters, would bear the brunt of the skyrocketing rates because they are the most likely to be stuck with natural gas—and the ill-health and indoor air pollution that often go with it—compounding the inequities they already suffer.”⁴² The study also found that a major piece of Maryland legislation to permit and support the replacement of gas pipelines via a surcharge, which was not subject to the normal ratemaking process,⁴³ had achieved no measurable safety improvements, the primary concern cited in the passage of the legislation, while costing Maryland residents more than \$6 billion.⁴⁴

⁴¹ *In re Michigan Public Service Commission*, MPSC Case No. U-20147-0117, DAAO Comment (Mar. 15, 2024), available at: <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000CWa5oAAD>.

⁴² Ex. FLO-19, Arjun Makhijani, *The Trouble with STRIDE: Meeting climate goals and addressing natural gas system stranded costs* (Dec. 2023), <https://icer.org/wp/wp-content/uploads/2024/01/Natural-gas-stranded-costs-and-climate-A-Maryland-case-study-2023-12.pdf>, at 6.

⁴³ *Id.* at 8–9.

⁴⁴ *Id.* at 9.

1 Addressing the financial and infrastructural barriers caused by historical
2 inequities will be costly. The inefficiencies of uncoordinated parallel investment in the
3 gas and electric systems make the prompt redress of these inequities even costlier.
4

5 **Q: How could integrated gas and electric planning address equity?**

6 **A:** Coordinated infrastructure and business planning between gas and electric systems could
7 yield innovative approaches to rate structures and technology transformation. In the areas
8 where DTE Energy provides service through DTE Electric and DTE Gas, DTE could
9 conduct an analysis overlaying census tracts with high social vulnerability, aging electric
10 infrastructure, and aging gas infrastructure with the aim of converting entire swaths of
11 service territory from gas to electric. By eliminating long-term gas infrastructure
12 investment costs for these areas, DTE could focus financial resources on incentivizing
13 whole-home improvements to income-constrained households, household electrification,
14 and modernizing electric infrastructure. By targeting socially vulnerable areas, DTE
15 would ensure that those communities do not fall behind the curve of technological
16 change, but could rather lead it. To the extent that public funds are available for electric
17 infrastructure and such improvements, targeting socially vulnerable census tracts would
18 match Justice 40 priorities and enable coordination with various kinds of public spending.

19 Such an analysis would also need to be nested in a broader engineering analysis of
20 the gas distribution system to identify the scale at which conversion of entire sections of
21 service territory achieves operational and infrastructural cost reductions to avoid price
22 shocks to remaining natural gas customers. For example: if half of the households served
23 by a gas main electrify while half of the households remain dependent on gas, DTE Gas

1 must still maintain that gas main and will likely not experience a substantial reduction in
2 its operating or capital costs for that gas main. Conversely, if every household on a given
3 gas main converted to electricity, DTE Gas would be able to cease capital investment and
4 operational costs to provide gas to that entire main as a result of those households
5 electrifying. Identifying the precise opportunities to avoid these price shocks is beyond
6 the scope of this testimony. It requires financial and engineering information from DTE
7 Gas which is neither available to me nor within my expertise to utilize. Without such
8 analysis, however, the piecemeal retirement of the gas system will be chaotic and
9 disruptive to utilities and customers alike, and may be especially so to customers living in
10 socially vulnerable communities.

11 As discussed above, DTE Energy and DTE Gas are not incentivized to conduct
12 such analysis, a challenging fact considering that they control the financial and technical
13 information such analysis requires. It is unlikely DTE will embark on such a task or do it
14 effectively without clear regulatory and legislative direction on the matter that centers
15 goals of social equity.⁴⁵ That is why the Commission needs to recognize and correct this
16 planning deficiency in their order in the present case.

⁴⁵ Ex. FLO-20, Isaac Sevier, *Building Decarbonization has a Natural Gas Pipeline Problem* (May 17, 2023),
<https://www.climateandcommunity.org/building-decarb-natural-gas-problem>.

B. The Gas Distribution Plan and Gas Renewal Plan prolong the mid-transition by promoting expansion of the gas system

Q: Please define and summarize the Gas Delivery Plan (GDP) and Gas Renewal Program (GRP) as described by DTE Gas.

A: The GDP is a ten-year investment plan in natural gas infrastructure intended to provide safe and reliable service to approximately 1.3 million customers. The GDP includes: (1) DTE’s goals for the next decade of service, (2) an overview of major assets and operations, (3) the factors that drive investment, and (4) an identification of safety and reliability gaps between DTE’s “vision” and reality and “mitigating actions designed to close those gaps.”⁴⁶

The GRP is an eighteen-year plan to replace all “legacy mains” from the gas distribution system.⁴⁷ Legacy mains are cathodically unprotected steel mains that DTE states are less safe and less efficient.⁴⁸ DTE proposes that the new 2025–2029 IRM include the incremental revenue requirement associated with the GRP.⁴⁹

Q: Do either of these plans envision the eventual decommissioning of the gas distribution system?

A: No. DTE Gas has no specific date at which it plans to cease operations and has initiated no engineering analysis of how phased retirement would work.⁵⁰ In fact, DTE Gas projects increasing customer counts through 2028, which seems incongruent with

⁴⁶ Fedele Direct Testimony at 13–14; Ex. A-12, Schedule B5.6.

⁴⁷ Janness Direct Testimony at 15.

⁴⁸ See Ex. A-12, Schedule B5.6, at 45, 39; Janness Direct Testimony at 24. DTE proposes that the new 2025–2029 IRM include the incremental revenue requirement associated with the GRP. Telang Direct Testimony at 24.

⁴⁹ Telang Direct Testimony at 24.

⁵⁰ Ex. FLO-21, DTE Gas’s Response to FLO’s Third Discovery Request, to FLODG-3.9.

1 decommissioning and increased electrification. DTE Gas appears to studiously ignore the
2 prevalence of electrification as a central focus of decarbonization, stating that it is
3 “premature to speculate” on whether electrification will impact their demand over the
4 next thirty years.⁵¹ For any professional in the decarbonization space, this response is
5 laughably naive. DTE Gas punts to the lack of “guidelines or legislation”⁵² as the reason
6 for ignoring fully this rapidly emerging technology when making infrastructure
7 investments that will last decades. The MPSC should not, however, be surprised by this.
8 As I discussed in the prior section, DTE Energy’s annual SEC filing is explicit that DTE
9 Gas’s strategy is to expand gas service to more customers and encourage use of gas
10 appliances with its existing customer base.⁵³

⁵¹ Ex. FLO-22, DTE Gas’s Response to CEO’s First Discovery Request, CEODG-1.15a.

⁵² Ex. FLO-23, DTE Gas’s Response to MNSC’s Fifth Discovery Request, MNSCDG-5.10b.

⁵³ Ex. FLO-1, DTE Energy Co., Annual Report (Form 10-K) (Feb. 8, 2024) (excerpt), at 15.

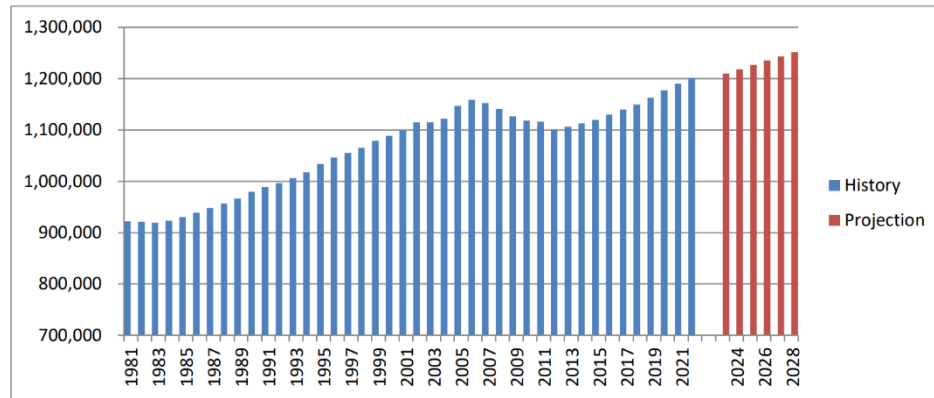


Chart from Exhibit A-15, Schedule E3, “Comparison of Historic and Projected Number of Residential Heating Customers”

Q: Is DTE Gas a neutral actor regarding gas demand?

A: No. DTE Gas is actively pursuing the expansion of the gas distribution system through grant funding from the MPSC, including community engagement referenced in their Gas Distribution Plan. As I discussed in my testimony in U-21297 regarding DTE Electric’s proposed Delivered Fuel Electrification Pilot, DTE Energy submitted five applications to the MPSC’s Low-Carbon Energy Infrastructure Enhancement and Development fund to subsidize gas line extensions throughout their service territory, in which DTE proposed to expand gas service to 2,472 homes and 173 businesses.⁵⁴ DTE should be seriously considering the possibility of decommissioning the gas system. Instead, it has actively

⁵⁴ Ex. FLO-24, DTE GAS COMPANY, LOW CARBON ENERGY INFRASTRUCTURE ENHANCEMENT AND DEVELOPMENT GRANT PROPOSAL: EXPANSION OF NATURAL GAS DISTRIBUTION SYSTEMS IN BENZIE, MANISTEE, AND WEXFORD COUNTIES (2023); Ex. FLO-25, DTE GAS COMPANY, LOW CARBON ENERGY INFRASTRUCTURE ENHANCEMENT AND DEVELOPMENT GRANT PROPOSAL: EXPANSION OF NATURAL GAS DISTRIBUTION SYSTEMS IN NEWAGO COUNTY (2023); Ex. FLO-26, DTE GAS COMPANY, LOW CARBON ENERGY INFRASTRUCTURE ENHANCEMENT AND DEVELOPMENT GRANT PROPOSAL: EXPANSION OF NATURAL GAS DISTRIBUTION SYSTEMS IN DELTA COUNTY (2023); Ex. FLO-27, DTE GAS COMPANY, LOW CARBON ENERGY INFRASTRUCTURE ENHANCEMENT AND DEVELOPMENT GRANT PROPOSAL: EXPANSION OF NATURAL GAS DISTRIBUTION SYSTEMS IN OSCEOLA COUNTY (2023); Ex. FLO-28, DTE GAS COMPANY, LOW CARBON ENERGY INFRASTRUCTURE ENHANCEMENT AND DEVELOPMENT GRANT PROPOSAL: EXPANSION OF NATURAL GAS DISTRIBUTION SYSTEMS IN OCEANA COUNTY (2023).

1 pursued public grant funding to expand the gas system where it would otherwise be
2 financially infeasible from rate recovery alone.

3
4 **Q: How does the GRP’s focus on “vulnerable and historically underserved”**
5 **communities exacerbate, rather than improve, equity issues?**

6 **A:** While having a veneer of equity, this focus ultimately serves to trap frontline
7 communities in the mid-transition. These communities need substantial investment to
8 modernize electric infrastructure.

9 When DTE Gas takes billions of dollars from ratepayers and invests that money
10 in reconstructing its distribution system, the opportunity is missed to invest those funds to
11 improve the health, safety, and home energy-efficiency in frontline communities in
12 preparation for a more substantially electric future. DTE Gas neither provides a cost-
13 benefit analysis comparing these trajectories nor addresses the long-term equity concerns
14 caused by frontline communities being the last to electrify.

15 In effect, underserved communities’ problem is a scaled-up version of what
16 individual households currently face when it comes time to replace an aging gas heating
17 system. Do they invest in an electric alternative, knowing that it may be more expensive
18 and complex now but will remain useful throughout its lifetime? Or do they purchase a
19 new gas appliance that will be obsolete long before the end of its useful life? The simple
20 economics of their inability to afford the transition makes the choice for vulnerable and
21 historically underserved households. DTE Gas insists on making the same choice for
22 these households on an infrastructure scale by funneling investment into and making

1 customers pay for neighborhood gas infrastructure which DTE Gas knows will be
2 obsolete long before the end of its useful life.

3 By making long-term investments in rebuilding two decrepit systems in parallel
4 instead of focusing on investing in a single, modernized electric system that can meet the
5 energy needs of these communities, DTE maximizes its profit potential by diversifying
6 its possible sources of revenue. The inevitable consequence of creating this profit-
7 maximizing parallel system reliance is stranded assets for which DTE Gas will certainly
8 try to hold ratepayers liable.
9

10 **Q: Is there evidence that DTE Gas is actually focusing investment on EJ communities?**

11 **A:** Not enough to validate the claim. DTE Gas admits in discovery that it has not analyzed
12 how much capital spending in this case is targeted to environmental justice
13 communities.⁵⁵ So it appears that DTE Gas’s claim around focusing on environmental
14 justice communities, much like the purported benefits of so-called “Responsibly Sourced
15 Gas” that I will discuss next, is a factually unsupported branding initiative.
16

17 **C. The Responsibly Sourced Gas proposal has no verifiable benefits and ultimately**
18 **leads to further fossil gas production and its associated harms.**

19 **Q: What is RSG according to DTE Gas?**

20 **A:** DTE describes RSG as “natural gas that has been verified by a third party to have met
21 specified environmental targets during production” and states that “certifications

⁵⁵ Ex. FLO-29. DTE Gas’s Response to CEO’s First Discovery Request, CEODG-1.17.

1 verifying lower methane emitting natural gas production will be considered for RSG
 2 purchases.”⁵⁶

3
 4 **Q: Please summarize DTE Gas’s proposal regarding Responsibly Sourced Gas (RSG).**

5 **A:** DTE Gas seeks a \$180,000 RSG premium expense for the 4,000,000 Dth of RSG
 6 purchases in the projected test period.⁵⁷ DTE Gas broadly characterizes its RSG
 7 selections as having lower methane emissions intensity than other sources of gas.

8
 9 **Q: Has DTE Gas presented a compelling case for the climate benefits of its RSG**
 10 **proposal?**

11 **A:** No.

12 First, DTE Gas has not committed to a specific certification process for RSG.⁵⁸

13 DTE Gas also acknowledges that there is no uniform certification process for RSG.⁵⁹

14 This means that the purported benefits, in the form of lower methane intensity, of these

15 RSG purchases are somewhere between difficult and impossible to verify. This lack of

16 basic information undermines any vision of RSG as a viable strategy to decarbonize the

17 Company’s operations.

18 Second, DTE Gas presents no compelling evidence that this purchase will

19 generate any meaningful climate benefits. DTE states that it is “still in the exploration,

20 analysis and development stages of developing a robust RSG purchase strategy.”⁶⁰ As my

⁵⁶ Telang Direct Testimony at 30.

⁵⁷ See Telang Direct Testimony at 30–31; Decker Direct Testimony at 46–47.

⁵⁸ Decker Direct Testimony at 40–41.

⁵⁹ *Id.* at 40.

⁶⁰ *Id.* at 48.

1 following discussion of DTE Gas's prior RSG purchases will illustrate, RSG is most
 2 appropriately regarded as a branding initiative rather than a remotely valid carbon
 3 reduction approach.

4
 5 **Q: Does DTE Gas demonstrate a strong understanding of the real social or**
 6 **environmental value of their prior RSG purchases?**

7 **A:** No. In response to discovery requests, DTE Gas admits that they do not know the
 8 geographic origin of their RSG purchase, whether they are fossil gas or fossil gas
 9 alternatives or anything about the method of extraction or feedstock.⁶¹ DTE Gas states
 10 that RFI responses were delivered verbally or by email and does not provide those
 11 responses.⁶² The Trustwell Platinum certificate which is used to validate two of these
 12 RSG purchases is not even based on an absolute measure of methane emissions or
 13 company practices—it merely identifies that the operators producing that gas are in the
 14 “top 10% of peers” regarding risk control and implementation.⁶³ The MiQ grading
 15 system utilized for one of the RSG purchases at least appears to be concerned with
 16 outcomes rather than peer comparison,⁶⁴ but DTE's lack of detailed information on their
 17 RSG purchases makes it impossible to independently verify whether the gas they are
 18 sourcing meets the conditions for the MiQ grade. They have not provided, nor do they
 19 seem to have even requested from the RSG sellers, any such background information.

⁶¹ Ex. FLO-30, DTE's Response to FLO's Fifth Discovery Request, FLODG-5.1b, 5.1c(i)-(iii), 5.2b, 5.2c(i)-(iii), 5.3b, 5.3c(i)-(iii) Discovery Response.

⁶² Ex. FLO-31, DTE's Response to FLO's Fifth Discovery Request, FLODG-5.1a, 5.2a, 5.3a.

⁶³ Ex. FLO-32, Trustwell™ Standard Definitional Document, IES (Sep. 1, 2020), at 5.

⁶⁴ See generally Ex. FLO-33, MIQ Standard, MIQ (last accessed May 1, 2024),
<https://miq.org/the-technical-standard/>.

Q. Is there any compelling case for carbon-neutral gas, either under the heading of RSG or Fossil Gas Alternatives (FGA)?

A: No. As discussed above, there is no uniform measure for RSG’s effectiveness in reducing methane intensity. Additionally, to whatever extent RSG is a fossil fuel, its extraction and utilization is inherently at odds with achieving a zero emissions future. The Commission studied Fossil Gas Alternatives, using the misleading industry branding of “Renewable Natural Gas,” at the legislature’s direction. The final report delivered by ICF, the Commission’s hired consultant, demonstrated only limited potential for RNG in the state of Michigan, representing only 6% to 15% of Michigan’s total natural gas use.⁶⁵ As stated in the comment of Natural Resources Defense Council, Michigan Environmental Council, Sierra Club, Strategen, and Energy Futures Group, “even under the most optimistic scenarios RNG will be incapable of displacing fossil gas on anything close to a 1:1 basis.”⁶⁶ Additionally, the actual life cycle emissions in the ICF report were not appropriately measured, which further undercuts the case for carbon-neutral gas.⁶⁷

Q: Has DTE Gas provided any support for the feasibility of a future gas distribution system that solely delivers carbon-neutral, non-fossil gas?

A: No. DTE Gas has provided no vision for how carbon-neutral, non-fossil gas at scale could replace its current fossil gas model. DTE Gas admits that is not feasible for the entire gas system to be served with RSG at this time,⁶⁸ and the Company cannot identify

⁶⁵ See *In re Michigan Public Service Commission*, MPSC Case No. U-21170-0003, Michigan Renewable Nature Gas Final Report (Sep. 28, 2022), available at: <https://mi-psc.my.site.com/s/filing/a008y000002cZY3AAM/u211700003>.

⁶⁶ Ex. FLO-34, NRDC et al., Comments to the MPSC on the Renewable Natural Gas Study Draft and June 29 Presentation (Aug. 3, 2022), at 1.

⁶⁷ *Id.* at 12.

⁶⁸ Ex. FLO-35, DTE Gas’s Response to FLO’s Third Discovery Request, FLODG-3.10a.

1 a time at which it would be feasible.⁶⁹ DTE Gas’s lack of a vision for how RSG/FGA gas
2 can fit into a decarbonized future underscores that the MPSC should not take these dead-
3 end approaches to reduce the “methane intensity” of the gas supply seriously. Instead, the
4 MPSC should understand that RSG/FGA are, at best, gold-plated, marginal forms of
5 harm reduction. DTE Gas attempts to rely on RSG/FGA’s slender harm-reductive
6 potential to support a massive proposition: that DTE Gas has some role in a decarbonized
7 future.

8
9 **Q: Given that there is no viable scenario in which DTE Gas solely delivers non-fossil**
10 **gas, what is the impact of approving ratepayer subsidy for these forms of gas?**

11 **A:** This approval would effectively bless the continued extraction, transportation, and
12 utilization of fossil gas with no reason to believe that doing so will meaningfully address
13 climate concerns. As there is no viable future for a completely carbon-neutral gas system,
14 RSG merely serves to “greenwash” the fossil gas supply—at ratepayer expense—in an
15 effort to justify continued investment in the gas distribution system. As discussed in prior
16 sections, these investments reinforce the mutual constraining dynamic of the gas and

⁶⁹ Ex. FLO-36, DTE Gas’s Response to FLO’s Third Discovery Request, FLODG-3.10b.

electric infrastructures, heightening cost burdens and the resulting affordability concerns without making any clear headway on climate mitigation or adaptation.

Q: How would a mid-transition-informed analysis aid the MPSC in considering DTE Gas's RSG proposal and this information?

A: The mid-transition approach should lead the MPSC to identify RSG as an ineffective half-measure. With the full scope of the energy decarbonization challenge in view, the Commission should focus on decarbonization through electrification measures instead. Whether methane gas is sourced "responsibly" or not, the overall methane intensity of the gas system is a major problem for climate, and moving beyond it will be a major engineering and affordability challenge. The MPSC should focus on this challenge and be wary of proposals to waste ratepayer resources on greenwashing measures like RSG.

D. DTE Inappropriately Requests Reimbursement for Corporate Memberships That Are Harmful to Ratepayers

Q: What does DTE Gas request for corporate memberships in this case?

A: DTE Gas requests at least \$730,000 for corporate memberships, but possibly more.

Company Witness Theresa Uzenski describes disallowances for corporate membership from the historic period totaling \$169,000,⁷⁰ which appear in the projected period operation and maintenance expenses under "Miscellaneous General Expenses."⁷¹ The total projected test period for this expense is \$2.796 million.⁷² Witness Uzenski

⁷⁰ Ex. A-3, Schedule C15, line 10.

⁷¹ Ex. A-13, Schedule C5.6, at 1, line 14.

⁷² *Id.*

1 states that “Exhibit A-3, Schedule C15 identifies allowable operating expenses for
 2 corporate memberships, and quantifies expenses unrelated to utility operations that are
 3 not recoverable,”⁷³ but the exhibit actually only does the latter, failing to quantify the
 4 allowable membership expenditures DTE Gas actually billed to ratepayers.

5 DTE Gas confirmed to Planet Detroit that its annual dues to the American Gas
 6 Association were \$730,000 in 2022, with \$36,000 disallowed for lobbying,⁷⁴ or
 7 approximately 4.9% of the total dues. In 2023, DTE reported \$737,235 in dues to the
 8 American Gas Association and \$30,000 to the Renewable Natural Gas Coalition, along
 9 with over \$300,000 to various Michigan-based chambers of commerce.⁷⁵

10 Though this reporting is not disaggregated between DTE Energy, DTE Electric,
 11 and DTE Gas, I can say confidently say that DTE Gas is requesting somewhere between
 12 \$737,235 and \$2.796 million in corporate membership dues.

13
 14 **Q: Does DTE provide any evidence to support the value of these memberships to**
 15 **ratepayers?**

16 **A:** None that is compelling. Company Witness Henry Decker discusses DTE Gas’s
 17 participation in various initiatives to track and report on methane intensity.⁷⁶ The only
 18 apparent result of these collaborations was the purchase of RSG and the proposal to

⁷³ Uzenski Direct Testimony at 18.

⁷⁴ Ex. FLO-37, Brian Allnutt, *U.S. Senators accuse DTE-chaired American Gas Association of using customer money to mislead public*, PLANET DETROIT, May 1, 2024, <https://planetdetroit.org/2024/05/natural-gas-dte-american-gas-association/>, at 4.

⁷⁵ Ex. FLO-38, DTE, 501(c)(6) CONTRIBUTIONS AND LOBBYING EXPENSES (2023), <https://www.dteenergy.com/content/dam/dteenergy/deg/website/common/about-us/company-information/corporate-governance/political-participation/DTE501Expenditures.pdf>, at 1. *See generally* Ex. FLO-39, Political Participation, DTE, (last accessed May 6, 2024), <https://www.dteenergy.com/us/en/residential/about-dte/corporate-governance/political-participation.html>.

⁷⁶ Decker Direct Testimony at 42.

1 purchase more, which I have demonstrated to be completely unsupported in its purported
2 climate benefits.

3 **Q: Are there reasons to be concerned that these memberships are actually harmful to**
4 **ratepayers?**

5 **A:** Yes.

6 *Planet Detroit* recently reported that the American Gas Association, of which
7 DTE CEO Jerry Norcia is Chair, has been an active advocate for expanding gas service,
8 resisting electrification and energy efficiency, and advocating for unproven carbon
9 capture and storage technologies as the backbone of the possibility of net zero gas.⁷⁷ The
10 Renewable Natural Gas Coalition is even more plainly biased, as it is a trade association
11 of gas pipeline companies with an obvious bias toward increasing gas production for the
12 industry it represents.⁷⁸

13 These organizations are organized in the interest of their members—natural gas
14 distributors and producers—and have a history of advocating for those interests whether
15 they align with ratepayer interests or not.

17 **Q: What should DTE Gas do to cure the information deficiency in this case?**

18 **A:** At minimum, DTE Gas should provide rebuttal testimony explaining what is included in
19 line 14 of page 1 of Exhibit A-13, Schedule C.5.6, specifically identifying the corporate
20 membership dues that are included in its request and the organizations to which it paid
21 those dues.

⁷⁷ Ex. FLO-37, at 2, 5–8.

⁷⁸ Ex. FLO-40, *About Us*, THE COALITION FOR RENEWABLE NATURAL GAS (last accessed May 6, 2024)
<https://www.rngcoalition.com/thecoalitionforrng>, at 1–2.

1
2 **Q: What should the Commission do about DTE Gas's corporate membership dues in**
3 **the instant case?**

4 **A:** Should DTE Gas fail to provide the aforementioned information, the Commission should
5 disallow the entire \$2.796 million of Miscellaneous General Expenses. Should DTE Gas
6 provide this breakdown, the Commission should disallow all corporate membership
7 expenses for lack of support in the record. At the bare minimum, the Commission should
8 disallow corporate membership expenses for the American Gas Association and any
9 other memberships that are formally controlled by and organized in the financial interest
10 of gas producers and distributors rather than ratepayers. Moving forward, the
11 Commission should require detailed documentation of corporate membership expenses
12 and the corresponding customer benefits as a condition of DTE Gas's next rate case
13 filing, as it did for DTE Electric in U-20836.⁷⁹
14

⁷⁹ *In re DTE Electric*, MPSC Case No. 20836, Order (Nov. 18, 2022), available at: <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y0000058ilbAAI>, at 308.

**E. Increasing Return on Equity for DTE Gas Prolongs the Mid-Transition by
Financially Incentivizing Gas Infrastructure Investment**

Q: Please describe and summarize the proposed changes to return on equity (ROE).

A: DTE Gas proposes increasing its ROE from 9.9% to 10.25%.⁸⁰

Q: Please describe your overall concerns about increasing DTE Gas's return on equity.

A: I am not an economist, but it is my general perspective that the utility industry is overcompensated. A 2023 study from the Energy Institute at Haas found that utilities charged customers between \$2 billion and \$20 billion in excess costs each year by 2020 resulting from rates of return being higher than the utilities' cost of capital and those higher rates resulting in excess capital spending.⁸¹

I believe that DTE Gas similarly is seeking a higher ROE than its cost of capital and those higher rates would result in excess capital spending by the Company.

Q: Why is DTE Gas's requested overcompensation especially concerning in the context of the mid-transition?

A: The public service commissions' overcompensation of utility shareholders is a general problem. The more utilities spend on capital, the more profit they make, creating a "capital bias" to spend more, even when it is not prudent. When utilities are overcompensated, this capital bias is thrown into overdrive at the expense of ratepayers. In the case of DTE Gas, the proposed overcompensation poses the additional harm of

⁸⁰ Villadsen Direct Testimony at 51.

⁸¹ Ex. FLO-41, Karl Dunkle Werner & Stephen Jarvis, Energy Inst. at Haas, Rate of Return Regulation Revisited (Energy Inst. Working Paper No. 329R, Revised Aug. 2023), at 37.

1 exacerbating and extending the mid-transition. The 2023 study from the Energy Institute
2 at Haas suggests that a one percentage point rise in the return on equity increases capital
3 investment by 5%.⁸² By overcompensating shareholders, the Commission would
4 encourage continued investment into a legacy system which, from the standpoint of a just
5 and equitable energy transition, must be systemically decommissioned.

6
7 **Q: Why should the MPSC reduce DTE Gas's ROE in the instant case to support a just**
8 **and equitable energy transition?**

9 **A:** A lower ROE for gas utilities relative to electric utilities disincentivizes capital
10 investment in gas infrastructure, investment that is incompatible with a decarbonized and
11 electrified future in which there is no or only a highly limited role for gas. Approving a
12 lower ROE for gas utilities relative to electric encourages parent companies like DTE
13 Energy to prioritize electrification and investment in electric infrastructure.

14
15 **Q: Does this mean that FLO would support a higher ROE for DTE Electric?**

16 **A:** No. Public service commissions overcompensate utilities in general, as I explained above.
17 This is equally a problem for how the MPSC treats DTE Electric's ROE. The MPSC
18 should take a critical eye to ROEs universally, while recognizing the unique problems

⁸² *Id.*

1 caused by incentivizing overinvestment in gas infrastructure and considering more
2 incisive action as a result.

3
4 **F. DTE Gas fails to analyze housing quality as a core component of gas distribution**
5 **system planning**

6 **Q: Why is housing quality an important component of energy system planning?**

7 **A:** The possibility of electrification is dependent upon the energy efficiency of housing
8 stock. In northern climates, inefficient homes will struggle to meet heating needs with
9 air-source heat pumps, one of the key technologies for electrifying home heating. Energy-
10 efficient housing is also critical to addressing the affordability crisis, as energy-inefficient
11 homes result in higher energy bills for the LMI ratepayers who overwhelmingly live in
12 them and receive proportionately less support from utility energy efficiency
13 programming.⁸³ Finally, if well utilized, state and federal investments to upgrade housing
14 quality and options, particularly for LMI households, will shift energy demand for
15 heating from gas to electric.

16
17 **Q: Does DTE Gas present any assessment of housing quality in its Gas Delivery Plan?**

18 **A:** No.
19

⁸³ Ex. FLO-42, BEN STACY & TONY REAMES, URBAN ENERGY JUST. LAB, UNIVERSITY OF MICHIGAN, SOCIAL EQUITY IN STATE ENERGY POLICY: INDICATORS FOR MICHIGAN'S ENERGY EFFICIENCY PROGRAMS (2017), at 2, 6.

1 **G. DTE Gas misuses the term affordability and fails to produce any viable analysis of**
 2 **how it will address the affordability crisis**

3 **Q: How does the MPSC define affordability?**

4 **A:** As my testimony discusses above, the Commission defines affordability as “[t]he extent
 5 to which a household has the resources to meet their home energy needs for heating,
 6 cooling and other uses in a healthy, sustainable and energy efficient manner without
 7 compromising a household’s ability to meet other basic needs.”⁸⁴

9 **Q: What is the affordability crisis?**

10 **A:** I use the phrase “affordability crisis” to refer to the fact that Michigan households are
 11 paying over \$2 billion per year more than they can afford for energy according to the
 12 annual Home Energy Affordability Gap report by Fisher, Sheehan, and Colton as of
 13 2022.⁸⁵ Low Income Home Energy Assistance Program allocations for Michigan do not
 14 even exceed \$150 million for the same time period.⁸⁶ For households below 50% of the
 15 poverty level, energy costs account for 38% of household income.⁸⁷

16 Energy is unaffordable now, and energy has not been becoming more affordable
 17 compared to historic baselines. It is an unrelenting crisis that requires appropriately
 18 urgent attention.

⁸⁴ *In re Response to COVID-19*, MPSC Case No. U-20757, Order (Dec. 21, 2023) [hereinafter U-20757 Order], available at: <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000BD37gAAD>, at 36.

⁸⁵ Ex. FLO-43, HOME ENERGY AFFORDABILITY GAP 2022: MICHIGAN (2023), at 2.

⁸⁶ *Id.* at 2.

⁸⁷ *Id.* at 1.

1 **Q: Does the Commission have the authority to address affordability?**

2 **A:** Yes, to some extent. The Commission has the authority to address affordability through
3 the regulation of the price of energy and the provision of various energy assistance
4 programs to households.⁸⁸

5
6 **Q: How does the MPSC's definition of affordability shape FLO's assessment of DTE
7 Gas' affordability measures?**

8 **A:** There is virtually no disagreement that energy burden—the percentage of household
9 income spent on energy—is one of the most essential measures of affordability. Per the
10 widely-utilized analysis of Fisher, Sheehan, and Colton, cumulatively, gas and electric
11 costs should not exceed 6% of household income to be considered affordable.⁸⁹ In its
12 motion adopting the affordability definition, the Commission identifies “residential
13 customers that experience high energy burdens” as one of the key constituencies who
14 should benefit from this work.⁹⁰

15 For DTE Gas to incorporate affordability into its analysis convincingly, it would
16 need to present evidence on current energy burdens and identify how the Company's
17 proposed actions in this case and its long-term strategy are on a trajectory to reduce
18 energy burdens.

19

⁸⁸ *In re Response to COVID-19*, MPSC Case No. U-20757, Letter from Mich. Mun. Ass'n for Util. Issues, Ecology Ctr., Elevate, Nat. Res. Defense Council, Souldarity, EcoWorks, We Want Green Too, and Nat'l Hous. Tr. (Jun. 16, 2023), available at: <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y0000088fg3AAA>, at 2–3.

⁸⁹ Ex. FLO-44, AMERICAN COUNCIL FOR AN ENERGY EFFICIENT ECONOMY, UNDERSTANDING ENERGY AFFORDABILITY (2019), at 2.

⁹⁰ U-20757 Order (Dec. 21, 2023) at 37.

1 **Q: Has DTE Gas presented any such evidence?**

2 **A:** No. DTE Gas did not conduct an analysis of its customers' financial resources or their
3 ability to pay.⁹¹ It did not identify an the affordability gap or determine how its rate
4 request would impact the affordability gap.⁹²

5
6 **Q: How does DTE Gas appear to understand the meaning of "affordability"?**

7 **A:** DTE Gas uses the words "affordable" and "affordability" throughout its testimony, but
8 not in a manner consistent with the Commission's definition. DTE Gas states that "[t]he
9 Company ensures gas service is available when customers need it and has a rigorous
10 planning process, formally captured in its Gas Delivery Plan, to ensure that the
11 Company's expenses are reasonably and prudently incurred keeping customer rates
12 affordable."⁹³

13 Despite this statement insisting otherwise, DTE Gas's GDP fails to consider
14 affordability because it does not consider a household's resources. DTE Gas has
15 presented no evidence of gas rates as a proportion of household income or expenses.
16 DTE Gas states that its Gas Delivery Plan "provides a ten-year overview from 2023
17 through 2033 of the Company's investment plan supporting a safe and reliable natural
18 gas system in an affordable and environmentally responsible way."⁹⁴ However, in the
19 affordability section of the Gas Delivery Plan,⁹⁵ DTE provides no analysis of the cost of
20 gas service in comparison to household income. In fact, DTE projects average household

⁹¹ Ex. FLO-45, DTE Gas's Response to FLO's Sixth Discovery Request, U-21291-FLODG-6.11–6.13.

⁹² Ex. FLO-45, DTE Gas's Response to FLO's Sixth Discovery Request, FLODG-6.11–6.13.

⁹³ Telang Direct Testimony at 4.

⁹⁴ Fedele Direct Tetimony at 4.

⁹⁵ Ex. A-12, Schedule B5.6 at 9.

gas bills to increase between now and 2033. Unless DTE Gas has data to suggest that household income will grow at a faster rate,⁹⁶ DTE's plan projects *greater* unaffordability over time.

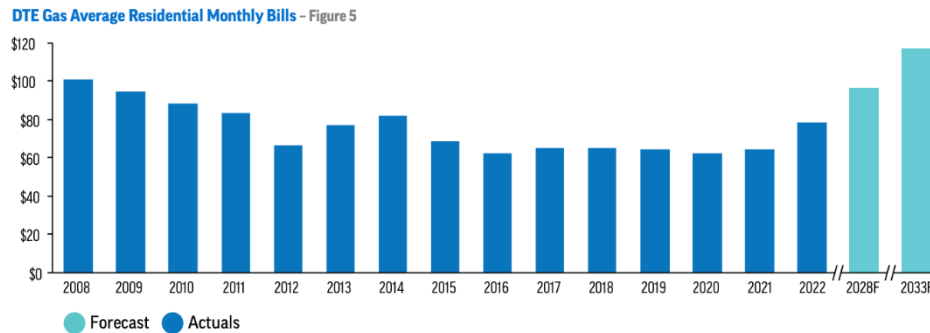


Chart From Exhibit A-12 Schedule B5.6, at 9, “DTE Gas Average Residential monthly Bills”⁹⁷

DTE Gas inappropriately uses cost as synonymous with affordability. The first paragraph of its page on affordability reads: “The affordability of delivered natural gas is a key priority for the Company and is top-of-mind for customers. The cost of delivering natural gas consists of two elements—the cost of the natural gas commodity and the cost to deliver it safely and reliably.”⁹⁸ There is no subsequent discussion of household income and resources. As the Commission has recognized in its definition of

⁹⁶ *Id.*

⁹⁷ This figure is reproduced from Ex. A-12, Schedule B5.6, at 9.

⁹⁸ Ex. A-12, Schedule B5.6, at 9.

1 affordability, cost alone is not an indicator of affordability, since affordability is
 2 determined by cost in relationship to the resources available to households.⁹⁹

3
 4 **Q: How does DTE Gas' misuse of the term affordability, in this case, hinder efforts to**
 5 **address affordability?**

6 **A:** DTE Gas's misuse of affordability is a not-so-successful sleight of hand. By listing its
 7 various efforts to address the *cost* of gas, the Company elides the fundamental problem:
 8 gas rates are already high, affordability is already at crisis levels, and the proposed
 9 changes in rates will make affordability worse. By raising affordability as a consideration
 10 but failing to engage with the trajectory of the affordability crisis honestly, DTE Gas
 11 misleads regulators and the public about the stark reality: the Company has no plan to
 12 address the affordability gap and apparently no intention to create one.

13
 14 **Q: How does DTE Gas's misuse of the term affordability specifically impact the mid-**
 15 **transition?**

16 **A:** DTE's Gas Delivery Plan explicitly connects the expansion of gas service to new
 17 customers to affordability, stating that "service expansion provides affordability benefits
 18 to all customers as it allows system operators like DTE Gas to spread fixed operating
 19 costs across a larger customer base."¹⁰⁰ Despite receiving grant funds from the MPSC for
 20 these gas line extensions, which are discussed on the following page,¹⁰¹ DTE Gas still
 21 projects increasing monthly gas costs for customers through 2033. Once again, DTE Gas

⁹⁹ U-20757 Order at 36.

¹⁰⁰ Ex. A-12, Schedule B5.6, at 28.

¹⁰¹ *Id.* at 29.

misuses the term affordability as a synonym for cost to lend a veneer of equity concern to its profit maximizing project of expanding and sustaining gas delivery indefinitely.

H. The Investment Recovery Mechanism and the Revenue Decoupling Mechanism extend the mid-transition by disincentivizing customer energy waste reduction.

Q: Please define and summarize DTE Gas’s proposals regarding the Investment Recovery Mechanism (IRM) and Revenue Decoupling Mechanism (RDM).

A: DTE Gas projects \$720.5 million of IRM capital expenditures from December 2022 through September 2025.¹⁰² Several IRM projects are among DTE Gas’s highest-cost projects.¹⁰³ DTE Gas is proposing four changes to IRM programs: (1) combine Gas Renewal Plan and Meter Assembly Check and Meter Move Out programs, (2) increase capital expenditure included in the IRM to reflect current spending levels, (3) implement yearly flexibility to support “accelerated risk mitigation projects,” and (4) include Corrosion Work order capital expenditures within the IRM.¹⁰⁴

DTE Gas requests continuing the RDM, which “eliminates the negative financial impact from the loss of energy sales resulting from EWR [Energy Waste Reduction] programs.”¹⁰⁵ The RDM reconciles approved projected revenue with actual weather-normalized revenues and provides either a credit (if revenue was above projections) or a

¹⁰² Fedele Direct Testimony at 22.

¹⁰³ *Id.* at 23.

¹⁰⁴ Janness Direct testimony at 6; see also *id.* at 49–50.

¹⁰⁵ Telang Direct Testimony at 20.

1 surcharge (if actual revenue was below projections) to the customer classes affected by
 2 the RDM.¹⁰⁶

3
 4 **Q: How does the IRM extend the mid-transition period at the expense of customers?**

5 **A:** The IRM removes the incentive for customers to use less gas by shifting greater
 6 proportions of the customer bill to flat costs. The IRM guarantees that the Company will
 7 continue to pour capital into the gas distribution system regardless of customer use
 8 patterns. As a result of approving the IRM, DTE Gas is incentivized to continue
 9 maximizing capital investments regardless of whether they are needed or beneficial to
 10 customers.

11
 12 **Q: What are the arguments that some make in favor of RDMs?**

13 **A:** Some posit that RDMs are useful tools for encouraging utilities to support and invest in
 14 reducing energy use.¹⁰⁷ By separating revenue from sales, utilities are freed from the
 15 desire to increase usage to boost their revenues.

16
 17 **Q: Does revenue decoupling appear to have been effective with DTE Gas?**

18 **A:** No. In MPSC Case No. U-21576, DTE Gas sought to reconcile 2023 revenue using the
 19 approved RDM.¹⁰⁸ In this case, DTE Gas shows that cumulative weather normalized
 20 volumes and revenues for the period exceeded the projections from MPSC Case No. U-

¹⁰⁶ *Id.* at 21.

¹⁰⁷ See Telang Direct Testimony at 20.

¹⁰⁸ *In re DTE Gas Company*, MPSC Case No. U-21576-0001, Application (Mar. 20, 2024), available at: <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000CbdetAAB>, at 2–4.

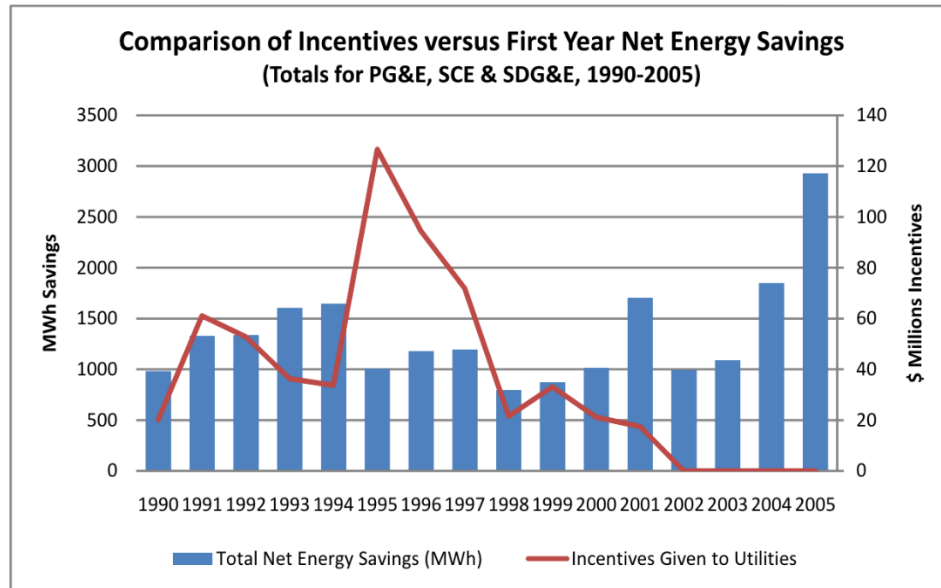
20940, leading to a credit.¹⁰⁹ If the purpose of the RDM is to encourage energy waste reduction, it seems that it has been ineffective in doing so. The statements in DTE Gas's SEC filings and Gas Delivery Plan which I have referenced throughout this testimony demonstrate that the Company's explicit strategy is to expand gas usage to new customers and within their existing customer base. If the purpose of the RDM is to get DTE Gas to embrace the reduction of gas use, it would appear that merely "removing the disincentive" has been inadequate.

This experience is consistent with those of other utilities in other jurisdictions. For example, a 2009 report from the Electric Consumers Resource Council showed a correlation between decoupling-related incentives and actual energy waste reduction in California from 1990 to 2005.¹¹⁰

¹⁰⁹ *In re DTE Gas Company*, MPSC Case No. U-21576-0001, Application (Mar. 20, 2024), available at: <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000CbdetAAB>, at Ex. A-8. *See also id.*, Ex. A-7 (calculating the credit); *id.*, Olsen Direct Testimony (Mar. 20, 2024), at 9 (explaining the calculations in Ex. A-7).

¹¹⁰ Ex. FLO-46, ELECTRICITY CONSUMERS RESOURCE COUNCIL, REVENUE DECOUPLING AND ITS ALTERNATIVES: AN INTERVENER'S GUIDE TO RETAIL RATEMAKING AND POLICIES ON DECOUPLING (2009), at 9.

1 *Chart from REVENUE DECOUPLING AND ITS ALTERNATIVES, Relationship Between*
 2 *Decoupling-Related Incentives and Energy Waste Reduction in California (1990–*
 3 *2005).*¹¹¹



4
 5
 6 **Q: If the RDM had been effective in reducing customer usage, would you be supportive**
 7 **of it?**

8 **A:** No. An RDM that is effective in reducing energy use will cause customers to experience
 9 higher surcharges as a result of effective utilization of EWR, because the RDM is
 10 expressly designed to cure DTE Gas’s losses from lower energy demand through a higher
 11 surcharge. To whatever extent an RDM removes DTE Gas’s “disincentive” to encourage
 12 EWR, the incentive for customers to take advantage of it is removed in precisely equal
 13 measure. Behaviorally, it is a zero-sum policy in that it generates exactly opposite

¹¹¹ *Id.*

1 behavior in customers and utilities. Financially, it serves primarily to protect utility
2 interests by guaranteeing a sustained level of revenue even if usage declines.

3
4 **Q: In sum, what do you see as the impact of the IRM and RDM?**

5 **A:** The overall effect of the IRM and RDM is to encourage DTE Gas to overspend on capital
6 while being insulated from the effect of customers choosing to use less gas. As a result,
7 they ultimately harm affordability and the potential for a just and equitable energy
8 transition.

9
10 **IV. The Commission Should Order Integrated Gas and Electric Distribution and**
11 **Resource Planning to Shorten the Mid-Transition Period and Accelerate an**
12 **Equitable Clean Energy Transition**

13 **Q: Please summarize the problems caused by the lack of integrated gas and electric**
14 **distribution planning.**

15 **A:** Independent utilities that provide gas and electric service separately are unable to
16 consider the full array of energy planning options because each utility focuses on
17 maximizing its own profits, rather than maximizing overall social welfare. It is also
18 impossible for advocates or regulators to develop consistent and holistic plans to address
19 energy needs without coordinated information access, planning, and execution.

1 **Q: What would the benefits of integrating gas and electric distribution and resource**
2 **planning be?**

3 **A:** In the context of the mid-transition period, integrated planning of electric and gas service
4 facilitates the optimization of the transition to a primarily electric energy future.
5 Integrated planning would include holistic cost-benefit analyses of different trajectories
6 for increasing electrification and phasing out the gas system.

7
8 **Q: What factors should be part of a comparative analysis between different energy**
9 **production and distribution scenarios?**

10 **A:** When comparing possible transition timelines and scenarios, comparative analyses
11 should include at least the following:

- 12 • **System cost:** The total projected cost—capital and operations—of the
13 integrated plan.
- 14 • **System funding:** The range and amount of different funding sources,
15 including public funding and resources other than rate-based expense.
- 16 • **Affordability:** The ability to distribute costs affordably under the integrated
17 plan.
- 18 • **Reliability:** The ability of the integrated plan to meet household energy needs
19 reliably. This must consider not only the relative reliability of the gas and
20 electric distribution systems over time, but also the degree to which customers
21 rely on those systems to meet essential needs like wintertime heating and
22 summertime cooling.

- **Safety:** The ability of the integrated plan to avoid impacts such as gas leaks, electrocution from downed wires, and other acute harms to ratepayers and communities from infrastructure failures.
- **Health:** The integrated plan's impact on health outcomes. This should include the impacts of energy production and distribution as well as health impacts related to the energy components of housing, such as the indoor air quality impacts of gas use and the overall health benefits of more efficient housing.
- **Climate emissions and resilience:** The integrated plan's effectiveness in reducing emissions and increasing community resilience to climate disruption.
- **Workforce Transition:** The integrated plan's ability to provide effective financial support to dispossessed workers from the legacy fossil fuel system, where appropriate, and retraining in the emerging system where appropriate.

Q: How is integrated planning consistent with Michigan Public Act (PA) 231¹¹²?

A: PA 231 enabled the Commission to consider health, environmental justice, climate, and affordability in utility integrated resource plans. While this legislation was a step in the right direction, achieving its intended outcomes is functionally impossible unless those same goals inform consideration of rate cases, energy waste reduction plans, and various stakeholder group processes. Integrating planning across gas and electric utilities helps to ensure that proceedings do not work at cross purposes.

¹¹² Mich. Pub. Acts 231, 102d Leg., Reg. Sess. (Mich. 2023).

1 **Q: How will integrated planning improve regulatory and legislative goals and efforts?**

2 **A:** Integrated planning will help the Commission and utilities to develop a clearer
3 understanding of where to apply public dollars in support of the energy transition and to
4 ensure that investments do not work at cross purposes.

5 There is currently an unprecedented upswing of federal and state funding
6 available for the energy transition. Investor-owned gas and electric utilities have and will
7 continue to pursue these opportunities alongside state and local governments, the private
8 sector, and community-based organizations. But without integrated planning, regulators
9 and legislators will lack the information necessary to commit these resources in a manner
10 that prioritizes social interest. Instead, the opportunity for transformative public
11 investment in the energy transition will be squandered on projects that are optimized to
12 benefit shareholders.

13 For example, the MPSC approved more than \$7 million of grants to DTE Gas to
14 support gas line extensions in 2023.¹¹³ While the MPSC also approved some funding for
15 various clean energy and electrification planning endeavors, a significant proportion of
16 the funding portfolio (about \$18 million of the nearly \$50 million total) for this program
17 supported gas line extensions and agricultural fossil gas alternatives.¹¹⁴

18 As I argue throughout my testimony, there does not appear to be any feasible
19 future in which the gas system will ever be carbon neutral. Thus, to whatever extent fossil
20 gas alternatives actually have life cycle climate benefits, their capacity to serve
21 Michigan's gas demand is limited at best. Yet, the MPSC allocated substantial amounts

¹¹³ Ex. FLO-47, *MPSC Approves \$50M in Low-Carbon Energy Infrastructure Grants*, MICH. PUB. SERV. COMM'N (June 9, 2023), [https://www.michigan.gov/mpsc/commission/news-releases/2023/06/09/mpsc-approves-\\$50m-in-low-carbon-energy-infrastructure-grants](https://www.michigan.gov/mpsc/commission/news-releases/2023/06/09/mpsc-approves-$50m-in-low-carbon-energy-infrastructure-grants), at 1.

¹¹⁴ *Id.*

1 of the funding that was specifically earmarked for climate solutions to what appear to be
2 dead-end strategies, narrowly comparing the cost and benefits between gas and propane
3 for end users rather than implementing a holistic decarbonization strategy.

4 In its application for grant funding, DTE Gas did not think holistically. DTE Gas
5 stated that “[t]he primary benefits are the annual savings to new gas customers in the cost
6 difference between natural gas and propane as a heating fuel.” DTE Gas claims that
7 individual customer energy costs will be reduced by 60%, CO2 emissions will be reduced
8 by 14%, and additional emission reductions will occur due to the decrease in truck traffic
9 for propane deliveries.¹¹⁵ Conspicuously missing is any comparison of the proposed gas
10 line extensions to electrification, which would also deliver emissions reductions and
11 affordability benefits for propane-heated households.

12 Without Commission direction and framework, gas companies will continue to
13 put forth narrow proposals for more gas infrastructure investment that lack comparative
14 analysis to options more aligned with a just and equitable energy transition. A clearly
15 articulated position by the Commission on the integrated futures of the gas and electric
16 systems would ensure a more uniform approach in the future. Otherwise, as discussed
17 earlier in my testimony, the Commission should expect DTE Gas and DTE Energy to
18 advocate for expanded gas infrastructure on the basis of their goal of profit maximization,
19 just as DTE Gas is seeking to do here.

¹¹⁵ Ex. FLO-24 at 3.

1 **Q: How will integrated planning improve activities outside the scope of the MPSC's**
2 **regulatory authority?**

3 **A:** Clear planning provides information about regulatory priorities to other actors that allows
4 them to maximize the impact of their activities. For example, the Whole Homes Whole
5 Community program, which emerged out of the settlement of the DTE Electric IRP,
6 could coordinate its home repair, weatherization, and solar + storage efforts with planned
7 electrification investments. The willingness of the private sector, philanthropy, and social
8 movements to invest time and energy in solving the complex coordination and
9 implementation challenges of the energy transition is directly impacted by the extent to
10 which those actors are able to understand the priorities of regulators and legislators.

11
12 **Q: In what manner could the Commission require such planning from utilities?**

13 **A:** The Commission has several options to press for more cohesive planning from utilities.
14 These are not mutually exclusive but should rather be considered a mutually reinforcing
15 set of possible actions.

16 Optimally, the Commission would open a specific docket to set standards for
17 unifying energy system planning across gas and electric utilities that would require all
18 regulated utilities to participate.

19 The Commission could also require utilities to conduct a comparative analysis of
20 gas infrastructure in a manner consistent with the legislative directive to consider
21 affordability in electric IRPs. Affordability, as defined by the Commission, cannot be
22 effectively measured via the resource cost of providing electricity alone. It would thus be
23 reasonable and prudent, in approving an electric IRP, to require electric utilities with

1 complementary gas utilities to demonstrate integrated planning and analysis of multiple
2 possible pathways on affordability.

3 The Commission could also order that when DTE Gas is considering
4 reconstructing an aging portion of the gas system, the Company must conduct a long-
5 term cost-benefit analysis comparing that reconstruction with alternatives such as
6 retirement of the section and investment into equitable electrification (including all state
7 and federal benefits) for all impacted customers.

8 Finally, the Commission could require that when an electric or gas utility files a
9 rate case or resource plan, any other utilities serving a substantial number of gas or
10 electric customers served by the same utility must be joined as parties to the case. This
11 would ensure that utilities are effectively obligated to be aware of and engage with plans
12 for the infrastructure investments of the other utilities that share the service territory.

13
14 **Q: Could the Commission engage in a study on this topic of its own initiative?**

15 **A:** Yes. Much as the Commission has completed studies by legislative order on Fossil Gas
16 Alternatives and Nuclear Energy, the Commission may conduct its own independent
17 study. Such an approach could significantly improve the Commission's understanding
18 and internal alignment on the appropriate assumptions and systemic goals to guide its
19 regulatory approach. Such a study should be intended to comprehend different possible
20 paths for energy transition and engage a wide array of technical experts, frontline
21 communities, and Michigan utilities to generate guiding principles for the energy
22 transition and the future of gas utilities.

1 **V. The Commission Should Reject Recovery of Investments and Proposals That**
2 **Increase Dependence on Fossil Gas Infrastructure.**

3 **Q: What specific investments and proposals should the Commission reject?**

4 **A:** The Commission should:

- 5 • Reject the proposed increase in Return on Equity and consider reducing the ROE;
- 6 • Reject the Revenue Decoupling Mechanism;
- 7 • Reject the Investment Recovery Mechanism, keeping distribution investments
- 8 organized primarily into volumetric rates;
- 9 • Reject the Responsibly Sourced Gas premium proposal;
- 10 • Reject DTE's reimbursement of corporate memberships;
- 11 • Reject infrastructure investments proposed in the Gas Delivery Plan and Gas Renewal
- 12 Plan oriented toward expansion of customer counts; and
- 13 • Reject infrastructure investments in the Gas Delivery Plan and Gas Renewal Plan that
- 14 go beyond basic safety improvements.

15

16 **Q: What else should the Commission order DTE Gas to do to correct the planning**
17 **deficiencies in their proposal?**

18 **A:** The Commission should order DTE Gas to:

- 19 • Conduct integrated infrastructure and equity analysis with DTE Electric and
- 20 Consumers Energy, and any other electric utility that has overlapping territory
- 21 with DTE Gas and;
- 22 • Require comparative cost-benefit analysis between electrification and gas system
- 23 reinvestment when sections of the gas system age out.

- 1 **Q:** **Does this conclude your written Direct Testimony?**
- 2 **A:** Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the of the Application of DTE
GAS COMPANY for authority to increase its
rates, amend its rate schedules and rules
governing the distribution and supply of natural
gas, and for miscellaneous accounting authority.

U-21291

ALJ Jonathan F. Thoits

REBUTTAL TESTIMONY OF JACKSON KOEPPPEL

ON BEHALF OF

**SOULARDARITY, URBAN CORE COLLECTIVE, AND WE WANT GREEN, TOO
(COLLECTIVELY, FRONTLINE ORGANIZATIONS (FLO))**

May 29, 2024

1 **I. Introduction and Summary**

2 **Q: Please state your name, occupation, and business address.**

3 **A:** My name is Jackson Koeppel. I am an independent consultant, primarily focused on
4 working on energy regulatory issues for Soulardarity and We Want Green, Too. My
5 business address is 189 Monterey St, Highland Park, MI 48203.

6
7 **Q: On whose behalf are you testifying?**

8 **A:** I am testifying on behalf of Soulardarity, Urban Core Collective, and We Want Green,
9 Too—collectively, the Frontline Organizations (FLO).

10
11 **Q: Are you the same Jackson Koeppel who provided direct testimony in this case?**

12 **A:** Yes.

13
14 **Q: Have your background or qualifications changed since then?**

15 **A:** No.

16
17 **Q: What is the purpose of your rebuttal testimony?**

18 **A:** I rebut the following witnesses in part with respect to the following topics:

- 19 • Staff Witness Braunschweig, with respect to MPSC Staff’s Recommendation on
20 the Low-Income Assistance (LIA) credit, and
21 • CEO Witness Cebulko, with respect to what data at a census block level needs to
22 be tracked and disclosed to ensure equity in the energy transition.

1 My lack of comment on any other witness's testimony does not constitute approval or
 2 support of their positions.

3
 4 **II. MPSC Staff's Recommendation on the Low-Income Assistance (LIA) credit**

5 **Q: What did DTE Gas propose regarding the LIA credit?**

6 **A:** The Company proposes to increase the LIA credit amount from \$30 to \$40 per month¹ with
 7 the goal of maintaining an LIA to offset approximately 70% of a customer's distribution
 8 charge.²

9
 10 **Q: What was MPSC Staff's reasoning for its alternative proposal?**

11 **A:** Staff proposes that the Commission "reject the Company's LIA credit increase proposal to
 12 allow this issue to continue to be more fully analyzed and addressed in the Commission's
 13 EAAC workgroup."³

14 Staff contends that this delay is necessary for three reasons. First, the Affordability,
 15 Alignment, and Assistance subcommittee (AAA) of the Energy, Affordability, and
 16 Accessibility Collaborative (EAAC) is still in the midst of a comprehensive reform of the
 17 LIA and Residential Income Assistance Service Provision (RIA) credits.⁴ Second,
 18 stakeholders have not yet received results from the Company's Payment Stability Pilot
 19 (PSP).⁵ Third, the EAAC has not completed the relevant Commission directives.⁶

20

¹ Direct Testimony of Rajan Telang, MPSC Case No. U-21291 at 29, lines 18-25.

² Direct Testimony of Jason Sparks, MPSC Case No. U-21201 at 18, lines 3-5.

³ Direct Testimony of Elaina Braunschweig, MPSC Case No. U-21291 at 9, lines 1-3.

⁴ *Id.* at 7, lines 5-8.

⁵ *Id.* at 4-5.

⁶ *Id.* at 8, lines 1-4.

1 **Q: Why is Staff’s reasoning and proposal insufficient?**

2 **A:** While I agree with Staff that “Michigan’s most vulnerable customers would benefit from
3 additional assistance” and that the Company does not provide “the comprehensive analysis
4 and diverse, collaborative input the Commission is looking for to inform utility energy
5 assistance changes,”⁷ I have two problems with Staff’s rationale.

6 First, I disagree with the assumption that the processes underway through the
7 EAAC will yield comprehensive reforms that actually meet household needs. As discussed
8 by FLO Witness Schott, there is “a lack of participation by households of color with lived
9 experience of energy insecurity” in EAAC processes.⁸ I have personally participated in the
10 meetings of the Definitions Subcommittee of the EAAC and experienced a similar lack of
11 participation and contributions from impacted households throughout the meetings, which
12 are overwhelmingly attended by MPSC Staff, utility staff, and service agency staff.
13 Witness Schott outlines that while some of the work of the EAAC and the AAA, in
14 particular, has been “important and constructive,”⁹ the work has failed to make measurable
15 progress on the affordability of energy, lacks the required urgency and clarity of direction
16 from the Commission to do so, and has historically not prioritized averting energy
17 shutoffs.¹⁰ Between these misaligned institutional priorities and the lack of direct
18 participation by impacted households, I am skeptical of the ability of these processes to
19 yield necessary and sufficient outcomes to address the unaffordability of energy.

⁷ *Id.* at 6, lines 10-13.

⁸ Direct Testimony of Justin Schott on Behalf of Frontline Organizations, MPSC Case No. U-21291 at 20, lines 10-11.

⁹ *Id.* at 71, line 8.

¹⁰ *Id.* at 70-78.

1 Second, Staff fails to consider the material urgency of these issues for impacted
 2 households. As discussed by Witness Schott and Witness Cira-Reyes, gas bills are not
 3 affordable for LMI customers, and the present assistance problems are woefully
 4 inadequate. While a broader restructuring of DTE Gas' programs is desired, Witness Cira-
 5 Reyes recommends that in the absence of such action that "the MPSC should expand the
 6 amount, enrollment, and transparency of the LIA credit."¹¹

7 In sum, continuing to delay increases to assistance out of regard for a procedurally
 8 unjust process that is unlikely to yield cohesive affordability reform, all while real
 9 customers suffer under unaffordable bills, is neither reasonable nor prudent.

10
 11 **Q: What do you recommend regarding the LIA credit?**

12 **A:** First, I recommend the Commission approve an increase in the LIA credit for DTE Gas
 13 customers to cover 70% of the typical monthly bill in line with the testimony of Witness
 14 Cira-Reyes.¹² In addition, the Commission should order DTE Gas to coordinate with all
 15 other electric utilities which serve their customers (including DTE Electric, Consumers
 16 Energy Company, Upper Peninsula Power Company, and others) and propose a plan for
 17 transitioning all assistance or affordability crediting available to cover part or all of a
 18 customer's gas bill to their electric bill in the instance that a household receiving assistance
 19 chooses to electrify.

¹¹ Direct Testimony of Sergio Cira-Reyes on Behalf of the Frontline Organizations, MPSC Case No. U-21291 at 24, lines 4-5.

¹² *Id.* at 26-27.

1 **Q: Why do you believe this is a prudent recommendation?**

2 **A:** First, it is responsive to the urgency of the issue for the Commission to approve increases
3 in assistance, while recognizing that more work needs to be done to have a cohesive and
4 coherent plan to address the affordability crisis. Second, I believe that an equitable energy
5 transition requires immediate actions responsive to the trend toward more electricity
6 utilization to meet household needs that are currently met with gas. DTE Gas and DTE
7 Electric are both seeking substantial increases in distribution system spending. From the
8 perspective of a household impacted by the affordability crisis, the absolute bill reduction
9 is what matters. By moving to consolidate affordability programs onto the electric side of
10 the bill, the Commission helps ensure that LMI households do not lose critical payment
11 support if they electrify.

12
13 **Q: Beyond these immediate actions, what else must be done to address the affordability**
14 **crisis in the context of the mid-transition?**

15 **A:** Expansion of the LIA alone is not sufficient, but it is at least directionally appropriate for
16 the mid-transition. To integrate this analysis fully, the Commission should order electric
17 and gas utilities to consolidate affordability planning to ensure that LMI customers retain
18 or increase their access to assistance during the electrification process.

19
20 **III. CEO Recommendation on Equity Mapping**

21 **Q: What is the CEO's recommendation on equity mapping?**

22 **A:** Witness Cebulko recommends that, in addition to the utilization of MiEJScreen, DTE Gas
23 measure several other indicators of equity at the census block level, including:

- 1 • The average energy burden of residential customers;
- 2 • The percentage of residential customers disconnected;
- 3 • The percentage of low-income residential customers that participated in one or more
- 4 energy assistance programs;
- 5 • The percentage of low-income residential customers that participated in a payment
- 6 plan;
- 7 • The percentage of residential customers enrolled in Shutoff Protection Plan; and
- 8 • The percentage of low-income residential customers that participated in the
- 9 Company's energy efficiency program.¹³

10 Witness Cebulko states that “calculating and then analyzing these indicators at the
 11 census block level can help the utility, Commission, stakeholders, and policymakers
 12 identify where there may be discrepancies in the system and can help inform planning
 13 and investment decisions to better serve low-income communities and communities with
 14 high populations of Black, Indigenous and People of Color.”¹⁴

15
 16 **Q: Do you agree with the CEO's request and rationale?**

17 **A:** While I agree in general, I also think that some additional factors need to be tracked at the
 18 census block level to ensure equity in the energy transition.

¹³ Refiled Direct Testimony of Brad Cebulko on Behalf of The Ecology Center, the Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar, MPSC Case No. U-21291 at 49-51.

¹⁴ *Id.* at 51, lines 14-18.

1 **Q: What other geographic data would you add to this mapping tool?**

2 **A:** The Commission should order DTE Gas to include the following in the proposed
3 mapping tool, tracked at the census block level:

- 4 ▪ The amount of capital investment in gas infrastructure (1) made over the past year,
5 (2) made over the past five years, (3) projected over the next year, and (4) projected
6 over the next five years;
- 7 ▪ The amount of capital investment in electric infrastructure (1) made over the past
8 year, (2) made over the past five years, (3) projected over the next year, and (4)
9 projected over the next five years;
- 10 ▪ The average age of gas distribution infrastructure, with comparison to industry-
11 expected lifespan;
- 12 ▪ The average age of electric distribution infrastructure, with comparison to industry-
13 expected lifespan;
- 14 ▪ The distribution system voltage of electric distribution infrastructure;
- 15 ▪ The hosting capacity of electric distribution infrastructure, both per capita and in
16 total;
- 17 ▪ Gas system reliability performance data;
- 18 ▪ Electric system reliability performance data, including but not limited to:
 - 19 ▪ All-Weather SAIDI;
 - 20 ▪ SAID Ex-MEDs;
 - 21 ▪ All-Weather CAIDI;
 - 22 ▪ CAIDI Ex-MEDs;

- All-Weather SAIFI; and
- SAIFI Ex-MEDs.

Q: Why is it appropriate to consider an order that includes data on electric infrastructure age, investment, and reliability in a gas rate case?

A: For households without backup electric power, an electricity outage also causes gas appliances that rely on electric controls to shut down. This means that home heating and cooling, the most essential household need met by the gas system, is also dependent on reliable electric infrastructure. Therefore, to address fully the reliability of gas service, the Commission and stakeholders must be able to assess the quality of the electric infrastructure as well. Furthermore, it will ultimately be essential to be able to compare the costs and benefits of investment in the two distribution infrastructures to ensure and appropriate efficient investment.

Q: Why is it appropriate to consider an order that includes data on electric infrastructure hosting capacity and voltage in a gas rate case?

A: When considering electric infrastructure hosting capacity, it is impossible to analyze whether there is equitable access to electrification for all customers and, as I argue in my initial direct testimony, to consider whether retirement of gas distribution segments and complete conversion of all customers to electric would be more prudent than continuing parallel investment.

Let's take as an example two census tracts, which both have aging gas infrastructure due for replacement. The first census tract is served by a 13.2kV electric

1 distribution circuit with a high hosting capacity per capita, and the second census tract is
2 served by a 4.8kV electric distribution circuit and low hosting capacity per capita. The
3 first tract faces lower cost barriers to electrification, as it is more likely to be able to
4 absorb the additional electric load, while the second census tract will likely require
5 voltage conversion to be able to electrify. However, it is likely that the 4.8kV census tract
6 also has older electric infrastructure which also requires hardening or conversation in the
7 near term anyway. While the 4.8kV census tract faces higher barriers, there may in fact
8 be a sound cost-benefit rationale for paying the higher cost of voltage conversion and
9 electrification to avoid the cost of gas infrastructure replacement and the interim
10 hardening costs. Further, by comparing this data to the equity measures proposed by
11 Witness Cebulko, it would be possible to identify target areas to prioritize this kind of
12 conversion where additional equity measures, such as targeted whole home improvement
13 programs for LMI residents would be necessary and just.

14 While this is a hypothetical example, it illustrates the essentially connected nature
15 of gas and electric planning. The Commission can, and should, order that such integrated
16 data be provided in the instant case.

17
18 **Q: Does this conclude your written Rebuttal Testimony?**

19 **A:** Yes.

1 MR. TEMPLETON: Our second witness was
2 Justin Schott. I move to bind in Mr. Schott's direct
3 written testimony, which consisted of one cover page and
4 90, as in nine-zero, pages of questions and answers. Mr.
5 Schott sponsored Exhibits FLO-101, or one hundred and
6 one, through FLO-167, or one-six-seven; and I move to
7 bind in that testimony and for the admission of those
8 exhibits.

9 JUDGE THOITS: Are there any objections
10 to the admission of this testimony or these exhibits?

11 (No response.)

12 Hearing none, the Direct Testimony of Mr.
13 Schott is bound into the record, and Exhibits FLO-101
14 through FLO-167 are admitted.

15 (Testimony bound in.)

16 - - -
17
18
19
20
21
22
23
24
25

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of DTE GAS	)	
COMPANY for authority to increase its	)	Case No. U-21291
rates, amend its rate schedules and rules	)	
governing the distribution and supply of	)	ALJ Jonathan F. Thoits
natural gas, and for miscellaneous	)	
accounting authority.	)	

DIRECT TESTIMONY OF JUSTIN SCHOTT

ON BEHALF OF

**SOULARDARITY, URBAN CORE COLLECTIVE, AND WE WANT GREEN, TOO
(COLLECTIVELY, FRONTLINE ORGANIZATIONS (FLO))**

May 7, 2024

1 **I. INTRODUCTION AND SUMMARY**

2 **Q: Please state your name, occupation, and business address.**

3 **A:** My name is Justin Schott. I serve as Director of the Energy Equity Project (EEP) and
4 Lecturer of Energy Justice, both through University of Michigan's School for Environment
5 and Sustainability. As a lecturer, I teach a graduate-level class to forty students each fall
6 semester. My business address is 440 Church St., Ann Arbor, MI 48109.

7
8 **Q: On whose behalf are you submitting testimony?**

9 **A:** I am submitting testimony on behalf of Frontline Organizations (FLO): Soulardarity, We
10 Want Green, Too, and Urban Core Collective.

11
12 **Q: Please summarize your educational background.**

13 **A:** I have an M.S. in Resource Policy and Behavior from University of Michigan (2006) and
14 a B.S. in Natural Resources from Cornell University (2002).

15
16 **Q: Please summarize your professional experience.**

17 **A:** I have served in my current role as Director of the Energy Equity Project since February
18 2021. My primary accomplishment has been convening a team of researchers, community
19 advocates, regulators, and utilities to develop and implement a standardized framework for
20 measuring and advancing equity in the energy system. The framework evaluates 148
21 potential metrics and considers demographic, historical, procedural, and distributional
22 aspects of equity and blends quantitative metrics with qualitative approaches. In leading
23 the development of the framework, I organized ten stakeholder-specific listening sessions

1 from May 2021–February 2022 that engaged more than 400 energy equity leaders across
2 the country. I recruited forty-five co-authors and advisors to serve on and support four
3 workgroups for fifteen months of intensive work reviewing listening session input and 148
4 proposed metrics and best practices, developing guiding principles, and writing chapters
5 representing each of the four pillars of energy justice. In all, I coordinated a highly
6 collaborative and participatory effort that was the result of more than 3,000 hours of
7 commitment from participants and workgroup members.

8 I have presented this work in over forty settings, including roundtables, panels,
9 advisory boards, public utility commission (PUC) proceedings, university classes, and
10 energy and climate conferences since May 2021. I have also been quoted by more than a
11 dozen public media sources, published opinion pieces, and submitted work to multiple
12 academic journals (as detailed in my CV).¹ Over the course of this work, I have become
13 intimately familiar with the scope of equity measurement and best practices to advance
14 equity in both regulatory and utility spaces. In recognition of the success of the Energy
15 Equity Project and my professional expertise, I received an appointment as a lecturer in the
16 School for Environment and Sustainability in 2022. I teach an interdisciplinary graduate
17 level course on energy justice to forty to forty-five students each fall semester.

18 Previously I served as Executive Director of EcoWorks, a Detroit nonprofit, from
19 June 2015 to November 2020. I was responsible for overseeing all aspects of financial
20 management, development, communications, and public relations, staff recruitment,
21 administrative operations, and risk management. I managed a team of thirty staff members

¹ Ex. FLO-101, Justin Schott CV & Summary of Qualifications.

1 with an annual budget of \$2.8 million. I also led research efforts to explore connections
2 between weatherization, health, and affordability, in partnership with Dr. Tony Reames,
3 the University of Michigan's Urban Energy Justice Lab, and other University of Michigan
4 faculty and institutes. From 2019–2020, I was an intervenor in DTE Energy's Energy
5 Waste Reduction biannual plans and successfully made the case to increase the budget for
6 single-family and multi-family low-income programs by \$10 million. My testimony drew
7 on the research conducted in partnership with Dr. Reames.

8
9 **Q: Have you testified before the Michigan Public Service Commission previously?**

10 **A:** Yes, I provided testimony to the Michigan Public Service Commission (MPSC, or the
11 Commission) regarding DTE Gas's and DTE Electric's 2019 Energy Waste Reduction
12 Reconciliation in MPSC Case Nos. U-20429 (Gas) and U-20373 (Electric).

13
14 **Q: Have you testified or provided comments in regulatory proceedings in other states?**

15 **A:** Yes, I provided testimony to the Kansas Corporation Commission regarding Energy's
16 filing in the Kansas Energy Efficiency Investment Act docket (2022), and to the Illinois
17 Commerce Commission for gas rate cases brought by Ameren and People's Gas (2023). I
18 also served as a witness in an Integrated Resource Plan proposed by Dominion Energy in
19 Virginia (ongoing).

20
21 **Q: Are you sponsoring any exhibits or workpapers in your testimony?**

22 **A:** Yes, I am sponsoring the following exhibits and workpapers:
23 FLO-101. Justin Schott CV & Summary of Qualifications

- 1 FLO-102. SHALANDA BAKER, SUBIN DEVAR & SHIVA PRAKASH, INITIATIVE FOR ENERGY
2 JUST., THE ENERGY JUSTICE WORKBOOK (2019)
- 3 FLO-103. Diana Hernández, *Understanding “Energy Insecurity” and Why It Matters to*
4 *Health*, SOC. SCI. & MED., no. 167, 2016
- 5 FLO-104. *In 2020, 27% of U.S. Households Had Difficulty Meeting Their Energy Needs*,
6 U.S. ENERGY INFO. ADMIN. (Apr. 11, 2022)
- 7 FLO-105. *Workgroups*, MICH. PUB. SERV. COMM’N (last accessed May 5, 2024)
- 8 FLO-106. MICH. PUB. SERV. COMM’N, EQUITY AND ENVIRONMENTAL JUSTICE TECHNICAL
9 ASSISTANCE, REQUEST FOR QUOTES (2024)
- 10 FLO-107. ENERGY EQUITY PROJECT, SCH. FOR ENV’T & SUSTAINABILITY, UNIV. OF MICH.,
11 ENERGY EQUITY PROJECT REPORT (2022)
- 12 FLO-108. *Low-Income Self-Sufficiency Plan*, DTE (last accessed Apr. 30, 2024)
- 13 FLO-109. Justin Schott, JS FLO Working Paper 1
- 14 FLO-110. DTE’s Response to FLO’s First Discovery Request, FLODG-1.18a
- 15 FLO-111. DTE’s Response to FLO’s First Discovery Request, FLODG-1.17
- 16 FLO-112. *Low-Income Programs*, DTE (last accessed May 4, 2024)
- 17 FLO-113. *Billing: Frequently Asked Questions*, DTE (last accessed May 4, 2024)
- 18 FLO-114. Sarah Alvarez, *The Obscure Utility Tax Detroiters Pay Each Month to Fund*
19 *the Police*, OUTLIER Media (Mar. 24, 2022)
- 20 FLO-115. DTE’s Response to FLO’s First Discovery Request, FLODG-1.2a & U-21291
21 FLODG-1.2a 10 Sample Residential Invoices
- 22 FLO-116. Sheri McWhirter, *DTE, Consumers Win \$231M in Approvals Despite*
23 *Reliability Woes*, MLIVE (Mar. 4, 2024)

- 1 FLO-117. Sarah Alvarez & Emily Hopkins, *She Didn't Know She Still Owed Money to*
 2 *Her Utility. Then 25% of Her Paycheck Was Gone*, PROPUBLICA (Aug. 19,
 3 2022)
- 4 FLO-118. Dominic J. Bednar & Tony G. Reames, *Recognition of and Response to Energy*
 5 *Poverty in the United States*, NATURE ENERGY
- 6 FLO-119. Janjala Chirakija, Seema Jayachandran & Pinchuan Ong, *Inexpensive Heating*
 7 *Reduces Winter Mortality* (Nat'l Bureau of Econ. Rsch., Working Paper
 8 No. 25681, 2019)
- 9 FLO-120. Michelle Graff, David M. Konisky, Sanya Carley & Trevor Memmott, *Climate*
 10 *Change and Energy Insecurity: A Growing Need for Policy Intervention*, 15
 11 ENV'T JUST, no. 2, 2022
- 12 FLO-121. Sonal Jessel, Samantha Sawyer & Diana Hernández, *Energy, Poverty, and*
 13 *Health in Climate Change: A Comprehensive Review of an Emerging*
 14 *Literature*, 7 FRONTIERS IN PUB. HEALTH, Dec. 2019
- 15 FLO-122. *Michigan*, CTRS. FOR DISEASE CONTROL & PREVENTION (last updated Sept. 12,
 16 2023)
- 17 FLO-123. *Heart Disease Mortality by State*, CTRS. FOR DISEASE CONTROL & PREVENTION
 18 (last updated Feb. 25, 2022)
- 19 FLO-124. Jeremiah Bohr & Anna C. McCreery, *Do Energy Burdens contribute to*
 20 *Economic Poverty in the United States? A Panel Analysis*, 99 SOC. FORCES,
 21 no. 1, Sept. 2020

- 1 FLO-125. Gopal K. Singh & Hyunjung Lee, *Marked Disparities in Life Expectancy by*
 2 *Education, Poverty Level, Occupation, and Housing Tenure in the United*
 3 *States*, INT’L J. OF MATERNAL & CHILD HEALTH & AIDS, no. 10, 2021
- 4 FLO-126. Justin Schott, JS FLO Working Paper 2
- 5 FLO-127. ARIEL DREHOBL & LAUREN ROSS, AM. COUNCIL FOR AN ENERGY-EFFICIENT
 6 ECON., LIFTING THE HIGH ENERGY BURDEN IN AMERICA’S LARGEST CITIES:
 7 HOW ENERGY EFFICIENCY CAN IMPROVE LOW INCOME AND UNDERSERVED
 8 COMMUNITIES (2016)
- 9 FLO-128. MARILYN A. BROWN, ANMOL SONI, MELISSA V. LAPSA & KATIE SOUTHWORTH,
 10 OAK RIDGE NAT’L LAB’Y, LOW-INCOME ENERGY AFFORDABILITY:
 11 CONCLUSIONS FROM A LITERATURE REVIEW (2020)
- 12 FLO-129. SANYA CARLEY, DAVID KONISKY & TREVOR MEMMOTT, ENERGY JUST. LAB,
 13 IND. UNIV., HOUSEHOLD ENERGY INSECURITY SURVEY, WINTER 2021–2022
 14 (2022)
- 15 FLO-130. Trevor Memmott, Sanya Carley, Michelle Graff & David M. Konisky,
 16 *Sociodemographic Disparities in Energy Insecurity Among Low-Income*
 17 *Households Before and During the COVID-19 Pandemic*, 6 *Nature Energy*, no.
 18 2, 2021
- 19 FLO-131. Ill. Com. Comm’n Docket Nos. 23-0068 & 23-0069, Colton Direct Testimony
 20 (May 9, 2023)
- 21 FLO-132. Rahul Agrawal Bejarano CV & Summary of Qualifications
- 22 FLO-133. *Quick Facts: Michigan*, U.S. CENSUS BUREAU (last accessed May 5, 2024)
- 23 FLO-134. Justin Schott, FLO JS Workpaper 3

1 FLO-135. Justin Schott, FLO JS Workpaper 4

2 FLO-136. Shuchen Cong, Destenie Nock, Yueming Lucy Qiu & Bo Xing, *Unveiling*
 3 *Hidden Energy Poverty Using the Energy Equality Gap*, 13 NATURE
 4 COMMUN, 2022

5 FLO-137. *Introduction*, HOME ENERGY AFFORDABILITY GAP (last accessed May 5, 2024)

6 FLO-138. Justin Schott, FLO JS Workpaper 5

7 FLO-139. REVISED QUARTERLY REPORT FOR 1ST, 2ND, AND 3RD QUARTERS OF 2023, DTE
 8 (2023)

9 FLO-140. DTE's Response to FLO's First Discovery Request, FLODG-1.3

10 FLO-141. Sarah Alvarez, *Lights Out: Profitable Utility Company Shut Off Electricity to*
 11 *Homes Hundreds of Thousands of Times*, PROPUBLICA (Mar. 18, 2022)

12 FLO-142. *FACT SHEET: Biden Administration Deploys American Rescue Plan Funds to*
 13 *Protect Americans from Rising Home Heating Costs; Calls on Utility*
 14 *Companies to Prevent Shut Offs This Winter*, WHITE HOUSE (Nov. 18, 2021)

15 FLO-143. Justin Schott, FLO JS Workpaper 6

16 FLO-144. DTE's Response to FLO's First Discovery Request, FLODG 1.2.b

17 FLO-145. DTE's Response to FLO's Fourth Discovery Request, FLODG-4.6b

18 FLO-146. Justin Schott, FLO JS Workpaper 7

19 FLO-147. Justin Schott, FLO JS Workpaper 8

20 FLO-148. DTE's Response to FLO's Fourth Discovery Request, FLODG-4.8a

21 FLO-149. DTE's Response to FLO's First Discovery Request, FLODG-1.9

22 FLO-150. DTE's Response to FLO's Sixth Discovery Request, FLODG-6.1, 6.2a, 6.2c,
 23 6.3, 6.5a, 6.8a, and 6.9a

- 1 FLO-151. Lebel et al., *Methane and NOx Emissions from Natural Gas Stoves, Cooktops,*
2 *and Ovens in Residential Homes*, 56 ENVIRON. SCI. TECHNOL. 2529 (2022)
- 3 FLO-152. Krasner et al. *Cooking with Gas, Household Air Pollution, and Asthma: Little*
4 *Recognized Risk for Children*, 83 J. ENVIRON. HEALTH 14 (2021)
- 5 FLO-153. MICH.N DEP'T OF HEALTH & HUM. SERVS., DETROIT: THE CURRENT STATUS OF
6 ASTHMA BURDEN (2021)
- 7 FLO-154. Excerpt from Ill. Com. Comm'n No. 23-0067, Order (Nov. 16, 2023)
- 8 FLO-155. NAT'L ENERGY ASSISTANCE DIRECTORS' ASS'N, SUMMARY OF STATE UTILITY
9 SHUT-OFF MORATORIUMS (2021)
- 10 FLO-156. *Low-Income Energy Policy Board*, MICH. PUB. SERV. COMM'N (last accessed
11 May 6, 2024)
- 12 FLO-157. AFFORDABILITY, ALIGNMENT, AND ASSISTANCE SUBCOMMITTEE, MICH. PUB.
13 SERV. COMM'N, PRESENTATION (Oct. 3, 2023)
- 14 FLO-158. AFFORDABILITY, ALIGNMENT, AND ACCESSIBILITY SUBCOMMITTEE GOALS
15 (2022)
- 16 FLO-159. AFFORDABILITY, ALIGNMENT, AND ACCESSIBILITY SUBCOMMITTEE KICK-OFF
17 (2021)
- 18 FLO-160. AFFORDABILITY, ALIGNMENT, AND ACCESSIBILITY SUBCOMMITTEE 11-10-2022
19 MEETING (2022)
- 20 FLO-161. AFFORDABILITY, ALIGNMENT, AND ACCESSIBILITY SUBCOMMITTEE 9-9-2021
21 MEETING (2021)
- 22 FLO-162. *Credits, Collections, and Arrearages Reports Monthly Dashboard*, ILL. COM.
23 COMM'N (last accessed May 6, 2024)

1 FLO-163. ACEVES GUZMAN, DECISION ADOPTING INTERIM RULES TO REDUCE
2 RESIDENTIAL CUSTOMER DISCONNECTIONS FOR CALIFORNIA-JURISDICTIONAL
3 ENERGY UTILITIES (2018)

4 FLO-164. Phase I Decision Adopting Rules and Policy Changes to Reduce Residential
5 Customer Disconnections for the Larger California-jurisdictional Energy
6 Utilities, Decision 20-06-003 (June 11, 2020)

7 FLO-165. *Winter and Covid-19 Shut-Off Moratoriums*, NATL ASS'N OF ENERGY
8 ASSISTANCE DIRECTORS (Mar. 15, 2021)

9 FLO-166. L.A. DEP'T OF WATER & POWER, MOTION TO DISCONTINUE SHUT-OFFS AS AN
10 ACCOUNT MANAGEMENT COLLECTION TOOL FOR CUSTOMERS ENROLLED IN
11 LADWP EZ-SAVE AND LIFELINE DISCOUNT PROGRAMS (2022)

12 FLO-167. SANYA CARLEY AND DAVID KONISKY, UTILITY DISCONNECTIONS DASHBOARD
13 (2023)

14
15 **Q: What is the purpose of your testimony?**

16 **A:** My testimony has several purposes. I discuss the purpose of each section of my testimony
17 below:

18 1. Part II: Introduce an energy equity framework that the Commission can use to evaluate
19 the merits of DTE Gas's proposed rate increase. Using a robust energy equity
20 framework to make decisions in rate cases and other PUC dockets has become a
21 national best practice. I present the four pillars of energy equity—recognition,
22 procedural, distributive, restorative—and recommend actions the MPSC can take to
23 address concerns in each pillar.

2. Part III: Analyze the extent of energy insecurity among DTE Gas's low-income customers and the harms they experience as a result of DTE Gas's excessive shutoff rates, aggressive collections practices, and insufficient efforts to promote energy affordability. I quantify disparities in energy burdens by race and income among DTE Gas's customers and present negative trends in customers' energy security and enrollments in affordable payment plans.
3. Part IV: Assess DTE Gas's approach and performance regarding energy insecurity experienced by its customers. I find that, despite multiple directives from the MPSC and the availability of cost-neutral opportunities to provide financial relief, DTE Gas has adopted a punitive approach to its customers who struggle to afford their energy bills.
4. Part V: Assess the MPSC's response to energy insecurity and unaffordability through previous dockets (especially MPSC Case No. U-20757, the "COVID-19 docket"), workgroup reports and minutes, and other public statements.
5. Part VI: Recommend structural affordability and energy security solutions that the MPSC can require from DTE Gas. The energy assistance programs DTE Gas offers serve a small fraction of eligible customers and have not reduced the incidence of shutoffs or customer debt. To the contrary, DTE Gas's efforts have demonstrated that without intervention, its low-income customers will continue to face serious financial and health consequences from the endemic of rising and unaffordable gas bills. My testimony includes seven recommendations that the MPSC should adopt to protect low-moderate income (LMI) customers and ensure lasting affordability.

1 **II. AN EQUITY FRAMEWORK FOR PUBLIC SERVICE COMMISSION**
 2 **EVALUATION AND DECISION-MAKING**

3 **Q: Please define energy equity and related concepts.**

4 **A:** In the last decade, the field of energy equity, also referred to as energy justice, has emerged
 5 as a particular subset of environmental justice. While environmental justice has
 6 traditionally focused on disproportionate exposure to pollution, “an energy just world
 7 involves [the] equitable sharing of benefits and burdens involved in the production and
 8 consumption of energy services. It is also one that is fair in how it treats people and
 9 communities in energy decision-making.”²

10 The Initiative for Energy Justice, which was co-founded by Shalanda Baker,
 11 currently Director of the U.S. Department of Energy’s (DOE) Office of Community Impact
 12 and Diversity, states four goals of energy justice:³

- 13 1. Advance **energy democracy**, defined as “the notion that communities should have a
 14 say and agency in shaping and participating in their energy future;”⁴
- 15 2. Alleviate **energy insecurity**, which entails the inability to meet basic household energy
 16 needs or compromising on other basic needs in order to access energy;⁵
- 17 3. Reduce **energy burden**, or the percentage of household income spent on energy;⁶ and
- 18 4. Alleviate **energy poverty**, “a lack of access to basic life-sustaining energy.”⁷

² Ex. FLO-102, SHALANDA BAKER, SUBIN DEVAR & SHIVA PRAKASH, INITIATIVE FOR ENERGY JUST., THE ENERGY JUSTICE WORKBOOK (2019), at 13 (citations omitted).

³ *Id.* at 10.

⁴ *Id.*

⁵ *Id.* at 14; see Ex. FLO-103, Diana Hernández, *Understanding “Energy Insecurity” and Why It Matters to Health*, SOC. SCI. & MED., no. 167, 2016, at 1, 2 (“Energy insecurity is defined here as ‘an inability to adequately meet basic household energy needs.’”).

⁶ Ex. FLO-102 at 10, 13.

⁷ *Id.* at 10, 14.

1 The U.S. Energy Information Administration (EIA) surveys multiple aspects of
 2 energy insecurity, including, foregoing other basic needs, receiving disconnection notices,
 3 and keeping the home at an uncomfortable or unsafe temperature.⁸ EIA surveys have
 4 shown that energy insecurity is widespread throughout the country, with “34 million U.S.
 5 households (27% of all U.S. households) report[ing] difficulty paying energy bills or
 6 report[ing] that they had kept their home at an unsafe temperature because of energy cost
 7 concerns” in 2020.⁹

8
 9 **Q: Please explain your use of the term “shutoff” instead of “disconnection.”**

10 **A:** Both “shutoff” and “disconnection” refer to the same action by DTE Gas of physically
 11 removing a customer’s access to energy. Choice of language is a powerful way to shift
 12 perspectives. A disconnection, the term used by DTE Gas and the Commission in some
 13 contexts, may connote an event that does less harm than a shutoff and is an act that is less
 14 personal and preventable. A shutoff, by contrast, and to many with lived experience, speaks
 15 more directly to the experience of people who are harmed and of the intentional act of
 16 depriving customers of a basic human right. The term disconnection serves to sanitize this
 17 extremely harmful practice, in much the same way that the passive phrase, “the officer’s
 18 weapon was discharged resulting in a fatality,” is different from the phrase, “the officer
 19 shot and killed the person.” The use of more technical-sounding, impersonal jargon is one
 20 of the ways in which utilities attempt to minimize the apparent harm of their actions; the

⁸ Ex. FLO-104, *In 2020, 27% of U.S. Households Had Difficulty Meeting Their Energy Needs*, U.S. ENERGY INFO. ADMIN. (Apr. 11, 2022), <https://perma.cc/2TUB-ZWSN>.

⁹ *Id.*

term shutoff paints a more accurate picture that reflects the experience of impacted households. To its credit, the MPSC predominantly uses the term shutoff; I use this term exclusively in testimony except in direct quotes or referencing program names.

Q: Why are you introducing concepts of energy equity into your analysis of DTE Gas's rate case?

A: The Commission has consistently expressed concern about households that face unaffordable energy bills and myriad forms of energy insecurity. The Commission oversees three different bodies to address these concerns: the Energy Waste Reduction Low-Income (EWR-LI) workgroup, the Energy Affordability and Accessibility Collaborative (EAAC), and the Low-Income Energy Policy Board (LIEPB) which serves as an umbrella for these efforts.¹⁰ The Commission and these three groups have each sought greater coordination among efforts to advance energy affordability and security, but to date, there has not been an overarching strategy to guide these efforts.

DTE Gas does not have a coherent approach to addressing energy affordability, and it appears it has no intentions of adopting one. Indeed, DTE Gas has not conducted any affordability analysis when it develops its rate requests, as indicated by the discovery responses from Witness Telang.¹¹

¹⁰ See Ex. FLO-105, *Workgroups*, MICH. PUB. SERV. COMM'N (last accessed May 5, 2024), <https://www.michigan.gov/mpsc/commission/workgroups>.

¹¹ See generally Ex. FLO-45, DTE's Response to FLO's Discovery Sixth Request, FLODG-6.11, 6.12, 6.13. Note that Witness Rajan Telang states three successive times that DTE does not have the elements of an overarching affordability strategy.

Both the Company and the Commission have effectively been responding to accelerating unaffordability and energy insecurity crises without an operating manual. To its credit, the MPSC recently recognized the need for a cohesive energy framework and approach by issuing a Request for Quotes for Equity and Environmental Justice Technical Assistance to “establish a framework that MPSC Staff and the Commission can apply broadly across all divisions of the MPSC and the Commission Office when assessing utility filings within its legal framework.”¹²

A. Overview of the Framework to Measure and Advance Energy Equity

Q: What is the Framework to Measure and Advance Energy Equity, and how does it apply to this docket and the work of the MPSC?

A: The Framework to Measure and Advance Energy Equity (“the Framework” or “the EEP Framework”), delineated in Exhibit FLO-107, is a compendium of research and an assessment of 148 potential energy equity metrics and best practices.¹³ The Framework was equitably developed by forty-five co-authors and advisors and the input of more than 400 stakeholders. The Framework was released in September 2022, has been applied by PUCs in Colorado, Illinois, and Oregon, and is under consideration in Virginia. It is designed to be applied by utilities, regulators, practitioners, and community organizations and has sector-specific guidance for each type of stakeholder.¹⁴ The Framework identifies

¹² Ex. FLO-106, MICH. PUB. SERV. COMM’N, EQUITY AND ENVIRONMENTAL JUSTICE TECHNICAL ASSISTANCE, REQUEST FOR QUOTES (2024), at 1.

¹³ Ex. FLO-107, ENERGY EQUITY PROJECT, SCH. FOR ENV’T & SUSTAINABILITY, UNIV. OF MICH., ENERGY EQUITY PROJECT REPORT (2022), at 9.

¹⁴ *Id.* at 10.

concrete action steps—both quantitative and qualitative—to advance each of the four dimensions of energy equity. The Framework adopts the “Four Pillars of Energy Justice”: Recognition, Procedural, Distributive, and Restorative.¹⁵

B. Recognition Justice Concerns

Q: Please define recognition justice.

A: EEP adopted the definition of Lee and Byrne: “Recognition justice emphasizes the need to understand different types of vulnerability and specific needs associated with energy services among social groups (especially marginalized communities).”¹⁶ Recognition justice requires identifying populations that have gone unnoticed and may face cumulative impacts from multiple burdens and historically compounding impacts over time.

Q: What concerns do you have in the proposed case from a recognition perspective?

A: Recognition justice requires a deep understanding of different communities—their histories, identities, housing, and energy consumption patterns.

First, I am concerned about the mostly uniform treatment of all low-income gas customers as if they were one class. A low-income customer is generally defined as any customer with a household income below 200% (or in some cases, below 150%) of the Federal Poverty Level (FPL).¹⁷ Binary income thresholds determine eligibility for a variety of DTE Gas’s energy assistance programs. Household income also comprises half of the

¹⁵ *Id.* at 177.

¹⁶ *Id.* at 32 (citing Joohee Lee & John Byrne, *Expanding the Conceptual and Analytical Basis of Energy Justice: Beyond the Three-Tenet Framework*, 7 FRONT. ENERGY RES. 99 (2019)).

¹⁷ *Id.* at 93, 109.

1 energy burden equation, as energy burden is calculated as the annual cost of energy divided
2 by annual gross income.¹⁸

3 Even among low-income customers, however, there is marked variation in energy
4 insecurity and energy burdens. If two households each have a total energy bill of \$3,000
5 annually but incomes of \$15,000 per year and \$30,000 per year, respectively, the household
6 earning \$15,000 per year has an energy burden twice as high (20% vs. 10%) as the \$30,000
7 household. There is almost no formal consideration by DTE Gas or the MPSC of these
8 differences, however. DTE Gas's Low-Income Self-Sufficiency Plan (LSP) is one
9 exception that further segments customers with incomes below 150% of FPL, although the
10 Company does not publish the fixed monthly rates that correspond to different income
11 bands on its LSP website nor in its direct testimony.¹⁹

12 Second, I am concerned that DTE Gas does not analyze why so few of its low-
13 income customers are enrolled in assistance programs like the Residential Income
14 Assistance (RIA) credit. The Company projects just 70,000 households will enroll in the
15 RIA,²⁰ 5.6% of DTE Gas's 1.25 million residential customers,²¹ despite 19.4% of Michigan
16 households (with similar income distribution to DTE Gas's service territory) falling below
17 150% of FPL.²² The Company affirms there are no limits to RIA enrollment²³ and that it
18 is not feasible to determine the number of eligible customers²⁴ (even though I was able to

¹⁸ *Id.* at 10.

¹⁹ *See generally* Sparks Direct Testimony at 7–10; Ex. FLO-108, *Low-Income Self-Sufficiency Plan*, DTE (last accessed Apr. 30, 2024), at 1–2.

²⁰ *See* Sparks Direct Testimony at 14, lines 5–6.

²¹ *See* Ex. A-15, Schedule E1, column o.

²² Ex. FLO-109, Justin Schott, JS FLO Working Paper 1.

²³ *See* Ex. FLO-110, DTE's Response to FLO's First Discovery Request, FLODG-1.18a.

²⁴ *See* Ex. FLO-111, DTE's Response to FLO's First Discovery Request, FLODG-1.17.

generate an estimate without difficulty). Conservatively, more than 400,000 DTE Gas LMI customers²⁵ should be receiving the RIA credit but do not because the Company fails to make efforts to enroll them. While DTE Gas states that it automatically enrolls customers receiving the Home Heating Credit (HHC), who are below 110% of FPL, in the RIA, the Company requires customers who are eligible but not receiving HHC to submit additional documents for verification.²⁶ Interestingly, for the November 2021–February 2022 heating months, total enrollment in the RIA averaged just 55,650 (as shown in Figure 1 below), which is 10,609 per month (16%) less than the monthly average for 2021–2022 in the heart of the heating season. Furthermore, RIA enrollment in 2022 was lowest in January and February of 2022; in 2021, June had the highest enrollment. RIA enrollment varies widely and unpredictably and is often not aligned with the greatest affordability struggles of the heating season.

Figure 1: RIA credits seasonal enrollments analysis.

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2020	71,573	50,856	56,053	48,048	46,677	51,780	58,494	61,169	61,109	61,649	58,215	68,620
2021	64,327	59,818	70,654	67,120	63,150	73,313	60,170	59,257	55,872	53,563	52,393	56,652
2022	56,101	57,452	78,112	66,479	72,181	76,175	70,635	78,701	73,237	74,845	72,047	77,941

Nov 2021 - Feb 2022 Average	55,650
Jan 2021 - Dec 2022 Average	66,258
Difference	10,609

The majority of customers who are eligible for this credit do not receive it, and DTE Gas forecasts a slight decline in monthly enrollment going forward from 2022.²⁷

²⁵ Calculation: 1.25 million residential customers * 19.4% below 150% FPL = 470,450 households eligible. Then subtract 70,000 for the number of enrollees in DTE's projects.

²⁶ Sparks Direct Testimony at 12–13.

²⁷ Sparks Direct Testimony at 13–14 (noting that DTE Gas is projecting an average of 70,000 customers per month, down from 71,159).

Without automated and simplified enrollment and with much of the information on how to enroll being buried—or altogether inaccessible on its website²⁸)—the RIA lacks accessible design and enrollment processes needed to be a reliable affordability solution for DTE Gas’s low-income customer base.

C. Procedural Equity Concerns

Q: Please define procedural equity.

A: According to the EEP Framework, “[p]rocedural measures focus on pathways to implement equitable processes, and program access focuses on expanding accessibility for communities to engage meaningfully.”²⁹ Procedural equity is about the ability of impacted communities to access and influence decision-making to secure positive outcomes for themselves.

Q: What concerns do you have in this case from a procedural perspective?

A: First, procedural equity is concerned with program access. Access to DTE Gas’s assistance programs is limited by multiple factors:

1. The number of available slots DTE Gas’s assistance programs is severely limited, as I noted above regarding the RIA credit.
2. Other than the enrollment in the RIA of customers receiving the Home Heating Credit, DTE Gas does not actively invite or enroll LMI customers to participate in programs

²⁸ See Ex. FLO-112, *Low-Income Programs*, DTE (last accessed May 4, 2024), <https://perma.cc/57WB-5CD8>.

²⁹ Ex. FLO-107 at 66.

1 such as LSP, LIA, shutoff protection, or Energy Waste Reduction (EWR) programs for
2 low-income households.³⁰ It would not be difficult for the Company to automatically
3 enroll eligible customers into the LIA credit or LSP, who say, already receive assistance
4 through the Low-Income Home Energy Assistance Program (LIHEAP) or Michigan
5 Energy Assistance Program (MEAP). As far as I can tell, DTE Gas does not make any
6 attempt to do this.

7 Information about these programs is very difficult to access and seems
8 intentionally opaque. For instance, DTE Gas does not the define the specific benefits
9 of LSP on its website.³¹ This uncertainty is likely to reduce customer interest in a
10 program that DTE Gas appears to tout as its flagship for achieving self-sufficiency.
11 Under the header for “How to Apply” on its website, for instance, DTE Energy does
12 not offer simple written instructions, but instead links a video that shows people who
13 are visibly affluent and appear mostly white³²—people whom many low-income
14 customers may perceive as unlikely to apply for assistance programs. The video starts
15 with a burdensome list of documents needed, rather than offering easy ways that a
16 household’s existing state and federal benefits, such as food assistance, could
17 automatically qualify them for programs. Two minutes into the video, DTE Energy
18 does note that a Michigan Department of Health and Human Services (MDHHS) award
19 letter can serve as proof of income, but the letter is not usable by low-income customers
20 to affirm their eligibility.

³⁰ See Cira-Reyes Direct Testimony at 35–38.

³¹ See Ex. FLO-113, *Billing: Frequently Asked Questions*, DTE (last accessed May 4, 2024), <https://perma.cc/5NFZ-96NH>.

³² See Ex. FLO-112 at 1.

- 1 3. For many years, multiple DTE Energy representatives have participated in bodies such
 2 as the EAAC, EWR-LI workgroup, LIEPB, Coalition to Keep Michigan Warm, and
 3 National Energy and Utility Affordability Coalition (NEUAC). Despite the clear
 4 awareness DTE Gas has had for many years, it has not made learning about or applying
 5 for its assistance programs easy. In fact, in its testimony, DTE Gas does not reference
 6 any efforts to work with impacted community members to improve the design of
 7 existing programs. Instead, DTE Gas appears to conduct meetings only to the meet the
 8 minimum standard required by settlement agreements and Commission orders.³³
- 9 4. There are procedural concerns with the MPSC’s approach to affordability and energy
 10 insecurity, too. EAAC reports, for instance, note a lack of participation by households
 11 of color with lived experience of energy insecurity.³⁴ The reports note the difficulty in
 12 recruiting organizations and households to participate, but these findings fail to
 13 recognize the reality for many LMI households and households of color: there is no
 14 compensation for people’s time or expenses, and there appears to be little prospect of
 15 swaying the priorities, strategies, or decision-making of these bodies. MPSC Staff
 16 requested that the Commission order the groups to pursue relationships in frontline

³³ See *In re Response to COVID-19*, MPSC Case No. U-20757, DTE Comments on Interim Staff Report (June 12, 2023) [hereinafter DTE Comments on Interim Staff Report], at 2–3. For example, DTE calls EWR outreach to RIA customers “unworkable” and “unlikely to be effective,” *id.* at 2, and states that it already has sufficient advertisement of low-income programs in place, *id.* at 3.

³⁴ See *In re Response to COVID-19*, MPSC Case No. U-20757, Energy, Affordability, and Accessibility Collaborative, Interim Progress Report (Dec. 17, 2021), at 11 [hereafter December 2021 EEAC Interim Report] (“Staff acknowledges that while the EAAC provided enhanced collaboration across the government, advocacy, human services and utility sectors, representation from high burden, historically marginalized communities was missing. In addition, the group lacked racial and ethnic diversity.”).

communities,³⁵ but had earlier reported difficulty actually doing so.³⁶ Regardless of the underlying causes for these problems or respectable efforts on the part of MPSC Staff, households that are most harmed by DTE Gas’s collections and shutoff practices are not represented in decision-making and have little voice in shaping the programs and credits to be more inclusive and effective for achieving affordability.

Not surprisingly, when frontline community organizations and impacted customers have little to no say in proceedings and their interests are not represented, assistance programs continue to be implemented in a way that does not actually address the roots of the problem nor reduce shutoffs or energy burdens.

D. Distributive Equity Concerns

Q: Please define distributive equity.

A: The EEP Framework’s “Distributive Equity” chapter begins: “Broadly speaking, distributional equity refers to how the benefits and harms of the energy system are distributed, and is closely aligned with the notion of ‘justice as fairness’ Low-income communities and Black, Indigenous, and People of Color (BIPOC) communities are much more likely to face exposure to environmental harms (e.g., toxic pollution, presence of polluting facilities []) and less likely to have access to environmental ‘goods’ like green space and parks.”³⁷

³⁵ See *In re Response to COVID-19*, MPSC Case No. U-20757, Energy, Affordability, and Accessibility Collaborative, Interim Progress Report (Mar. 17, 2023) [hereafter March 2023 EEAC Interim Report] at 72.

³⁶ See December 2021 EEAC Interim Report at 11.

³⁷ Ex. FLO-107 at 102 (citations omitted).

1 **Q: What concerns do you have in the proposed case from a distributive perspective?**

2 **A:** My first concern is overarching: DTE Gas resists the use of appropriate metrics that would
 3 reveal and could help mitigate distributive inequities. A critical feature of distributive
 4 equity is that is determined by *outcomes*, such as energy burdens and shutoffs, as opposed
 5 to outputs, which include program enrollments and the dollar value of bill credits. With a
 6 concern for disparities in outcomes, the underlying causes and motives that result in these
 7 disparities are only important to the extent they must be rectified. Whether a disparity in
 8 energy burdens based on race or income exists because of callous indifference or despite
 9 genuine concern and efforts to provide resources to struggling customers, the result for
 10 those customers is the same. In other words, from a distributive equity perspective, it is
 11 ultimately the magnitude of the disparity that is concerning more than the source of it.

12 Using more precise data, such as the prevalence of shutoffs by census tract, to
 13 identify disparities is necessary to remedy these disparities and is not intended to evaluate
 14 the Company's underlying intentions. DTE Gas, however, takes a defensive stance toward
 15 collaborating to illuminate distributive inequities, which is the first step needed to address
 16 them. For instance, in a response to Staff reporting recommendations in MPSC Case No. U-
 17 20757, DTE Gas and DTE Electric responded: "DTE appreciates the inclusion of its
 18 concern that geographical data may make it appear that certain areas are being targeted.
 19 DTE does not consider geographical data when disconnecting service or collecting
 20 arrearages from a customer."³⁸ It is essential to realize that disparities can occur without

³⁸ DTE Comments on Interim Staff Report at 4.

1 an underlying intention to inflict them. At this point, they require investigation and actions
2 to reverse the inequity.

3 My second distributive equity concern is the dramatic variation in how energy
4 burdens are distributed among DTE customers. More than 99% of Michigan households
5 earning above state median income (about 400% of FPL) have inexpensive energy burdens
6 of 3% of their income or less.³⁹ By contrast, 44% of Michigan households below 100% of
7 FPL have energy burdens above 20%,⁴⁰ which we consider catastrophic. Using income
8 alone, we demonstrate a sevenfold disparity in energy burdens. As discussed below,
9 disaggregation by race, occupancy status, and age of housing would likely exacerbate these
10 distributive inequities even further.

11 DTE Gas's proposed rate increase would disproportionately impact LMI
12 customers. The Company has requested a 9% increase for Class A residential customers.⁴¹
13 This 9% rate increase will exacerbate energy burdens for low-income customers that in
14 many cases already exceed 15%, while the vast majority of customers with incomes above
15 the median would still have energy burdens below 3%.⁴² Detroit residents in particular are
16 likely to suffer, as they are already taxed an extra 5% because of "the obscure utility tax
17 Detroiters pay each month to fund the police."⁴³ That's an extra \$150 per year for a typical

³⁹ Ex. FLO-109. Other than the 6% standard for an affordable energy burden, there is no standard nomenclature for describing energy burdens at different thresholds. EEP has adopted the following scale: 0-3%, "Inexpensive"; 3-6% "Affordable"; 6-9% "Moderately Unaffordable"; 9-12% "High"; 12-15%, "Severe"; 15-18% "Extreme"; >18% "Catastrophic."

⁴⁰ *Id.*

⁴¹ DTE Gas Rate Case Summary at 4.

⁴² I discuss this further *infra* in Part III regarding Figure 8: Michigan home energy affordability gap by income.

⁴³ Ex. FLO-114, Sarah Alvarez, *The Obscure Utility Tax Detroiters Pay Each Month to Fund the Police*, OUTLIER Media (Mar. 24, 2022), <https://perma.cc/JK3M-6N4B>, at 1; *see also* MCL §§ 141.1151–141.1177.

1 \$3,000 combined gas and electric bill. Being behind \$150 is evidently sufficient to trigger
 2 a shutoff notice. Four of the five samples of residential shutoff notices provided by DTE
 3 Gas represent customers who need to make payments in this ballpark: \$115 (Sample 6),
 4 \$172 (Sample 8), \$161 (Sample 9), \$168 (Sample 10).⁴⁴

5 Finally, I am concerned that DTE's proposed allocation of costs relies on a 30.3%
 6 increase in the fixed monthly customer charge, from \$13.50 to \$17.60, compared to a 9%
 7 increase to the overall bill.⁴⁵ Fixed charges are a disincentive to conserve energy when a
 8 lower proportion of the bill is allocated to supply and distribution charges. Increasing fixed
 9 charges can cancel out the hard-won savings families make by sacrificing heat and comfort
 10 or that they attain through beneficial EWR programs like whole home retrofits.

12 **E. Restorative Justice Concerns**

13 **Q: Please define restorative justice.**

14 **A:** Restorative justice emphasizes concern for future generations and the need to ensure that
 15 the structures and conditions that initially enabled harm or disparate impacts to occur are
 16 mitigated so that further harm is prevented.

18 **Q: What concerns do you have in the proposed case from a restorative perspective?**

19 **A:** My restorative justice concerns are epitomized in comments by MPSC Chairman Dan
 20 Scripps: "When meeting financial metrics counts for 16 times as much as meeting

⁴⁴ See Ex. FLO-115, DTE's Response to FLO's First Discovery Request, FLODG-1.2a & U-21291
 FLODG-1.2a 10 Sample Residential Invoices, at 2-5, 9-16.

⁴⁵ DTE Gas Rate Case Summary at 5.

1 reliability metrics, something is clearly out of whack.”⁴⁶ While concerns with DTE Gas’s
 2 performance and steady rate increases are widely known, the Company does not face
 3 consequences for providing service that is neither reliable nor affordable. As FLO Witness
 4 Jackson Koeppel states, DTE Gas continues to operate from the profit maximizing
 5 principle without structures to curb its behavior and restore protections and affordability to
 6 its customers.

7 Currently, the Consumer Billing Rules are the primary source of protection for LMI
 8 customers.⁴⁷ These rules, however, do not change DTE Gas’s responsibility to generate
 9 profits for its investors. There are neither rules nor financial penalties if a utility like DTE
 10 Gas causes disproportionate harms to communities of color or LMI households through
 11 aggressive shutoff and collections practices or dismal electric reliability performance,
 12 tactics which prevent households from using gas heating. DTE Gas and DTE Electric
 13 customers remain subject to repeated surprises like DTE Energy’s decision to sell customer
 14 debt for pennies on the dollar.⁴⁸ These actions perpetuate and exacerbate the harms that
 15 LMI communities have faced for decades and impede efforts to mitigate those harms in
 16 future generations.

⁴⁶ Ex. FLO-116, Sheri McWhirter, *DTE, Consumers Win \$231M in Approvals Despite Reliability Woes*, MLIVE (Mar. 4, 2024), <https://perma.cc/4G2E-K7ED>, at 3.

⁴⁷ See generally MCL §§ 460.101–460.169.

⁴⁸ Ex. FLO-117, Sarah Alvarez & Emily Hopkins, *She Didn’t Know She Still Owed Money to Her Utility. Then 25% of Her Paycheck Was Gone*, PROPUBLICA (Aug. 19, 2022), <https://perma.cc/56K5-83UH>, at 1.

F. Summary of Highest Equity Priorities Identified by EEP

Q: From an energy equity perspective, what should be the primary considerations for the MPSC when assessing requests for rate increases?

A: There is broad consensus that energy should be affordable to all residents regardless of income, occupancy status, housing stock, heating fuel, or other demographics (e.g., household size, race, age, disability, or medical condition). Over the course of ten EEP listening sessions in 2021, reducing or eliminating disconnections was the overwhelming priority raised by more than 400 people representing an array of sectors, including utilities, regulators, grassroots organizations, and nonprofit practitioners.⁴⁹ Other distributive equity priorities included reducing the maximum energy burden faced by any customers, reducing disparities in energy burdens, and reducing high energy burdens among BIPOC households.⁵⁰

Disconnections should be reserved for exceptionally rare circumstances such as utility theft, rather than being used as a response to the structural conditions that result in a large share of households simply being too poor to afford the costs of reasonable energy usage. Creating robust affordability programs and ensuring these programs reach all eligible households should be prioritized. Affordability programs, designed and scaled appropriately, can mitigate the underlying roots of unaffordable energy costs and a cycle of collection activities and disconnections.

⁴⁹ See Ex. FLO-107 at 29, 185–86.

⁵⁰ See *id.* at 171, 185–86.

1 **III. ENERGY INSECURITY AMONG DTE GAS'S LOW-INCOME HOUSEHOLDS**

2 **Q: Please describe this section of your testimony.**

3 **A:** In this Part, I summarize the extensive research on the topics of disconnections and energy
 4 insecurity and how these impact low-income and BIPOC households. I provide a national
 5 overview as well as more specific details of energy insecurity among DTE Gas's residential
 6 customers.

7
 8 **Q: What are the connections between energy insecurity, poverty, and health?**

9 **A:** Bednar and Reames, leading energy justice scholars, concluded: "Failing to acknowledge
 10 the risk or potential harm that may occur with living in sub-standard housing, or lack of
 11 household energy, should be regarded as a threat to national well-being and potential to
 12 rival other nations and spur economic growth."⁵¹

13 The implications of energy insecurity are stark. Disconnections, which stem from
 14 the combination of unaffordable gas and electric bills, can result in an array of health
 15 problems.⁵² These health problems include heat illness, cognitive and psychological
 16 impacts, respiratory impacts resulting from the loss of proper ventilation and from fumes
 17 that may be caused by heating with an oven or an improperly ventilated generator, and
 18 those that arise from the inability to refrigerate medicine or use medical equipment that

⁵¹ Ex. FLO-118, Dominic J. Bednar & Tony G. Reames, *Recognition of and Response to Energy Poverty in the United States*, NATURE ENERGY, no. 5, June 2020, at 6–7.

⁵² See Ex. FLO-119, Janjala Chirakija, Seema Jayachandran & Pinchuan Ong, *Inexpensive Heating Reduces Winter Mortality* (Nat'l Bureau of Econ. Rsch., Working Paper No. 25681, 2019), at 3–4.

requires electricity.⁵³ Indirect health issues arise from lack of access to hot water for proper hygiene.⁵⁴ Energy insecurity also adversely impacts health by worsening asthma, chronic stress, mental health, and heart conditions.⁵⁵ Energy insecurity, and shutoffs in particular, shorten life spans. In an extensive review on the impacts of natural gas prices on mortality, Chirakijja et al. found that a 42.0% decrease in gas prices was responsible for an overall reduction in winter mortality by 1.6%,⁵⁶ which equates to an annual decrease in mortality of 0.7%. Excess winter mortality “is mainly driven by circulatory and respiratory causes.”⁵⁷ Heart disease is the leading cause of death in Michigan.⁵⁸ Our state ranks ninth highest in the country.⁵⁹

Energy insecurity also significantly increases the risk that households will slide into and remain in poverty, which increases mortality risks. An energy burden above 10% increases a household’s likelihood of falling into and persist in poverty by 50–100%.⁶⁰ Statistically, once a household falls into poverty, the life expectancies of the household’s members are significantly reduced. Men and women living below 200% of FPL at age

⁵³ See Ex. FLO-120, Michelle Graff, David M. Konisky, Sanya Carley & Trevor Memmott, *Climate Change and Energy Insecurity: A Growing Need for Policy Intervention*, 15 ENV’T JUST, no. 2, 2022, at 76-77; Ex. FLO-103 at 6, 8.

⁵⁴ See Ex. FLO-121, Sonal Jessel, Samantha Sawyer & Diana Hernández, *Energy, Poverty, and Health in Climate Change: A Comprehensive Review of an Emerging Literature*, 7 FRONTIERS IN PUB. HEALTH, Dec. 2019, at 1, 5, 6, 11.

⁵⁵ See *id.* at 11; Ex. FLO-103 at 6.

⁵⁶ Ex. FLO 119 at 16.

⁵⁷ *Id.* at 14.

⁵⁸ See Ex. FLO-122, *Michigan*, CTRS. FOR DISEASE CONTROL & PREVENTION (last updated Sept. 12, 2023), <https://perma.cc/43WM-TJZV>, at 2.

⁵⁹ See Ex. FLO-123, *Heart Disease Mortality by State*, CTRS. FOR DISEASE CONTROL & PREVENTION (last updated Feb. 25, 2022), <https://perma.cc/Z48N-G8C3>, at 2–3.

⁶⁰ See Ex. FLO-124, Jeremiah Bohr & Anna C. McCreery, *Do Energy Burdens contribute to Economic Poverty in the United States? A Panel Analysis*, 99 SOC. FORCES, no. 1, Sept. 2020, at 1.

1 eighteen can expect their lives to be more than ten years shorter than people living at more
2 than 400% of FPL.⁶¹

3
4 **Q: What is the scope of the impacts from energy insecurity, nationally and in Michigan?**

5 **A:** In the United States, 27.2% of households experience some form of energy insecurity.⁶²
6 The Pulse Survey, conducted biweekly by the U.S. Census since the start of COVID-19,
7 includes three questions about energy insecurity. As the report for February 6 to March 4,
8 2024 finds, 33.2% of Michigan households reported some frequency of foregoing other
9 basic needs (including 49.0% of Hispanic and 46.7% of Black households), 19.9% reported
10 keeping the home at an unsafe or uncomfortable temperature, and 25.8% reported being
11 unable to pay the energy bill in full.⁶³

12 Energy insecurity is *highly variable* by population. Multiple studies have confirmed
13 that energy insecurity impacts LMI, Black, and Hispanic households, and households with
14 children, especially under six years old, disproportionately.⁶⁴

⁶¹ See Ex. FLO-125, Gopal K. Singh & Hyunjung Lee, *Marked Disparities in Life Expectancy by Education, Poverty Level, Occupation, and Housing Tenure in the United States*, INT’L J. OF MATERNAL & CHILD HEALTH & AIDS, no. 10, 2021, at 1, 3–6.

⁶² Ex. FLO-104 at 1.

⁶³ These figures are located in column C of Ex. FLO-126, Justin Schott, JS FLO Working Paper 2.

⁶⁴ See, e.g., Ex. FLO-127, ARIEL DREHOBL & LAUREN ROSS, AM. COUNCIL FOR AN ENERGY-EFFICIENT ECON., *LIFTING THE HIGH ENERGY BURDEN IN AMERICA’S LARGEST CITIES: HOW ENERGY EFFICIENCY CAN IMPROVE LOW INCOME AND UNDERSERVED COMMUNITIES* (2016), at 19; Ex. FLO-128, MARILYN A. BROWN, ANMOL SONI, MELISSA V. LAPSAS & KATIE SOUTHWORTH, OAK RIDGE NAT’L LAB’Y, *LOW-INCOME ENERGY AFFORDABILITY: CONCLUSIONS FROM A LITERATURE REVIEW* (2020), at 23; Ex. FLO-129, SANYA CARLEY, DAVID KONISKY & TREVOR MEMMOTT, ENERGY JUST. LAB, IND. UNIV., *HOUSEHOLD ENERGY INSECURITY SURVEY, WINTER 2021–2022* (2022), at 4; see also Ex. FLO-130, Trevor Memmott, Sanya Carley, Michelle Graff & David M. Konisky, *Sociodemographic Disparities in Energy Insecurity Among Low-Income Households Before and During the COVID-19 Pandemic*, 6 *Nature Energy*, no. 2, 2021, at 1.

1 This trend can be seen in Michigan as well. Consider that energy insecurity is
2 experienced more by:

- 3 • Women (36.8%) than men (29.4%);
- 4 • Black (46.7%), Hispanic (49.0%), biracial, non-Asian, and nonwhite descent
5 (53.0%) than whites (25.3%);
- 6 • Young people ages eighteen to twenty-four (60.3%) than people over sixty-five
7 (15.6%);
- 8 • People with less education (e.g., without high school diplomas, 55.5%) than people
9 with bachelor's degrees (19.0%);
- 10 • Households with children (40.0%) than without (29.9%); and
- 11 • People with a disability (46.0%) than without (30.5%).⁶⁵

12 In other words, while energy insecurity is on average a concern for one-third of
13 Michiganders, households of marginalized groups face rates of energy insecurity between
14 50 and 350% higher than their better-off counterparts.

15 This data is also largely reflective of DTE Gas customers. DTE Gas's territory
16 spans about half the state and includes a mix of rural, urban, and suburban communities.
17 While not a perfect reflection of Michigan's demographics and experiences of energy
18 insecurity, I believe the Pulse Survey data accurately reflects the same trends in disparities
19 experienced by DTE Gas customers.

20

⁶⁵ Ex. FLO-126.

1 **Q: How does energy insecurity among DTE Gas customers now compare to 2020, during**
 2 **the start of the pandemic?**

3 **A:** In 2020, there was widespread acceptance of COVID-19 as an “unanticipated emergency”
 4 and the authority of the Commission for “active participation” in addressing the crisis.⁶⁶
 5 But the fact is that even though the pandemic has subsided, the conditions of energy
 6 insecurity that made COVID-19 more perilous still persist.

7 Energy insecurity in Michigan, as measured by the Pulse Survey (Figures 2–4), has
 8 increased slightly since mid-2021, when the surveys began. Each of these factors increases
 9 the likelihood of a shutoff. While shutoffs may have been *even more harmful* during the
 10 height of the pandemic, my testimony concludes that the consequences of shutoffs during
 11 “normal” times can be dire.

⁶⁶ *In re Response to COVID-19*, MPSC Case No. U-20757, Order (Apr. 15, 2020), at 3 [hereinafter Apr. 15, 2020 U-20757 Order].

Figure 2: Michigan households foregoing basic needs, July 2021–Oct. 2023.⁶⁷

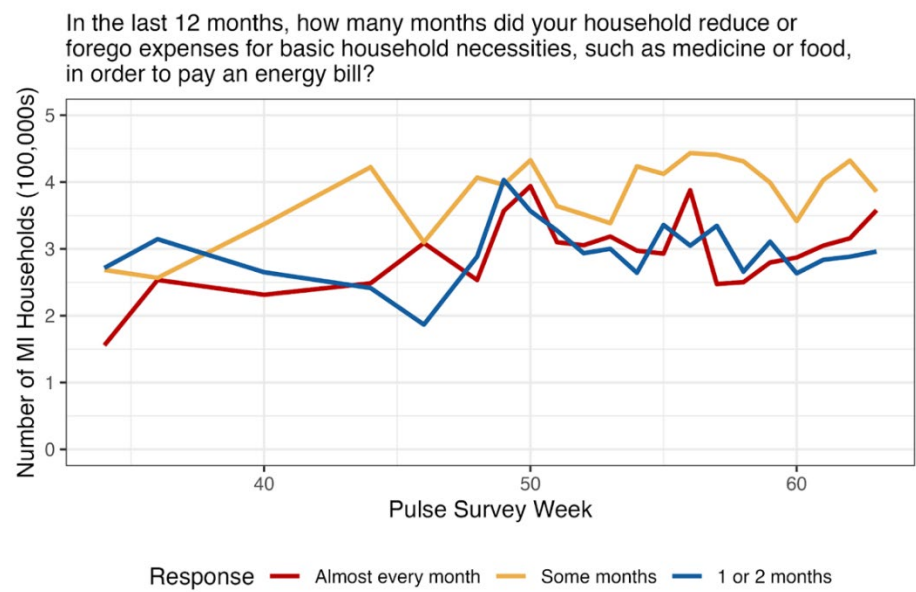
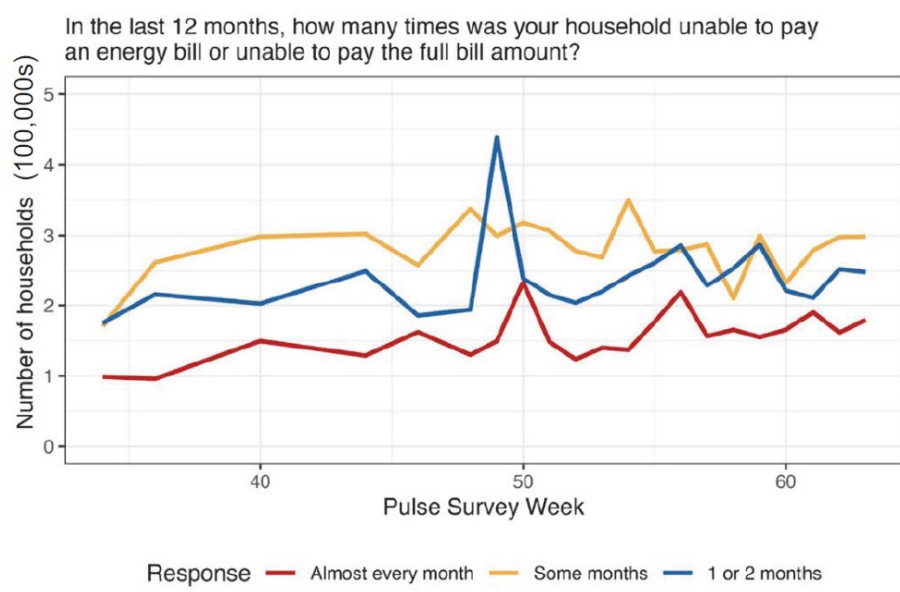


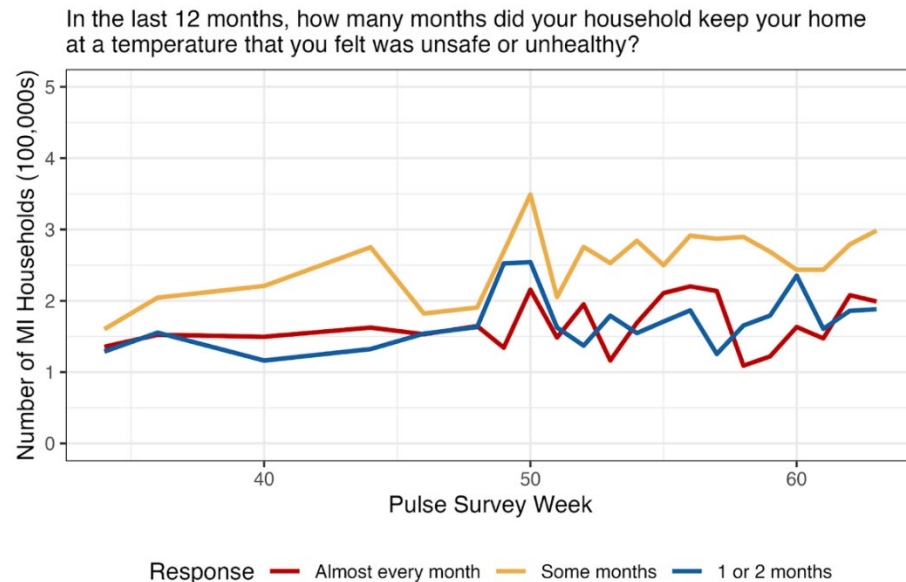
Figure 3: Michigan households unable to pay the bill, July 2021–Oct. 2023.⁶⁸



⁶⁷ This figure is based on data from the Pulse Survey (available at <https://www.census.gov/programs-surveys/household-pulse-survey/datasets.html>); the code used to analyze the data and generate these results is contained in pulse_survey_results.Rmd at https://github.com/Energy-Equity-Project/DTE_analysis/tree/main.

⁶⁸ This figure is based on data from the Pulse Survey (available at <https://www.census.gov/programs-surveys/household-pulse-survey/datasets.html>); the code used to analyze the data and generate these

Figure 4: Michigan households keeping homes at unsafe temperatures,
July 2021–Oct. 2023.⁶⁹



Q: How do you determine if a household cannot reasonably afford to pay its energy bill?

A: An array of energy affordability advocates have established that spending no more than 6% of household income on energy is affordable.⁷⁰ This 6% energy burden threshold was established by considering that households should spend no more than 30% of their

results is contained in pulse_survey_results.Rmd at https://github.com/Energy-Equity-Project/DTE_analysis/tree/main.

⁶⁹ This figure is based on data from the Pulse Survey (available at <https://www.census.gov/programs-surveys/household-pulse-survey/datasets.html>); the code used to analyze the data and generate these results is contained in pulse_survey_results.Rmd at https://github.com/Energy-Equity-Project/DTE_analysis/tree/main.

⁷⁰ Ex. FLO-129 at 22.

1 incomes on all costs of housing and that energy should comprise no more than one-fifth of
 2 total housing costs.⁷¹ For natural gas, a 3% burden is considered affordable.⁷²

3
 4 **Q: How do DTE Gas's customers experience energy injustice?**

5 **A:** Energy injustice is a national problem, with about one-third of Americans experiencing
 6 some form of energy insecurity.⁷³ Unfortunately, DTE Gas's reporting on indicators of
 7 energy insecurity and energy injustice is limited, so in some cases, I present statewide data
 8 as the best available source.

9 Here, I highlight two aspects of energy injustice: (1) energy insecurity and
 10 (2) disconnections. These are not the only forms of energy injustice DTE Gas customers
 11 face. The proximity to fossil fuel infrastructure, lack of access to incentives and rebates for
 12 energy efficiency and clean energy, disproportionate rates of power outages, and limited
 13 access to clean energy jobs and business contracts are additional concerns for which data
 14 is less readily available.

15 In Michigan, affordable energy burdens that cost less than 6% of income are
 16 disproportionately distributed among white households. My colleague Rahul Agrawal
 17 Bejarano, Lead Data Scientist at Energy Equity Project,⁷⁴ analyzed DOE energy burden
 18 data by census tract. The results show that BIPOC households, which comprise 26% of the

⁷¹ *Id.* at 20.

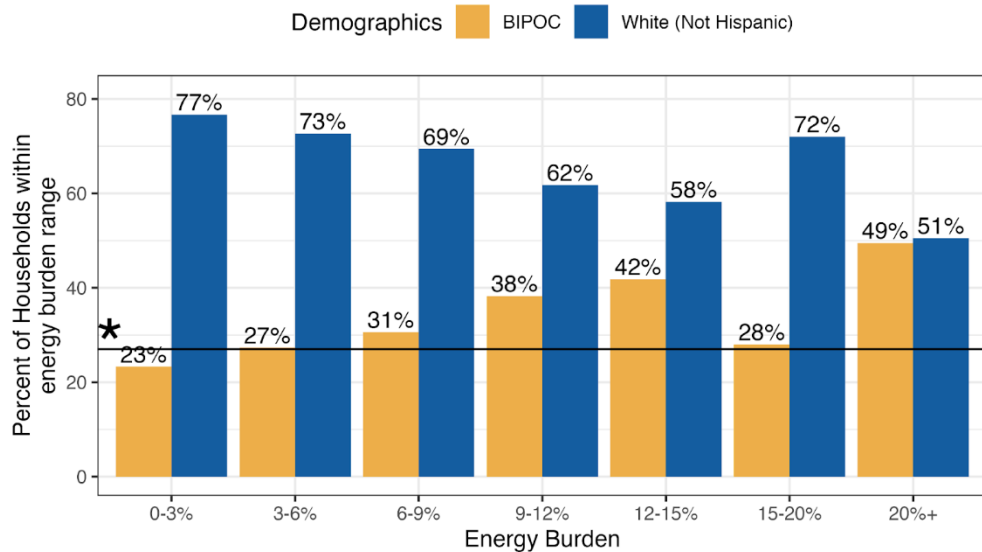
⁷² Gas and electric costs in MI are close enough to equivalent that an even split for affordability purposes makes sense. Ex. FLO-131, Ill. Com. Comm'n Docket Nos. 23-0068 & 23-0069, Colton Direct Testimony (May 9, 2023), at 14–15.

⁷³ Ex. FLO-126 at 1. From the data, 71.8 million (34.3%) households report reducing or foregoing basic necessities at least one or two months out of 209.3 million households reporting. *Id.*

⁷⁴ Ex. FLO-132, Rahul Agrawal Bejarano CV & Summary of Qualifications.

Michigan population,⁷⁵ represent a disproportionate share of energy burdens above 6%, as shown below.

Figure 5: Distribution of energy burdens distribution by race and income.⁷⁶



*Expected BIPOC levels as 27% of Michigan households are BIPOC

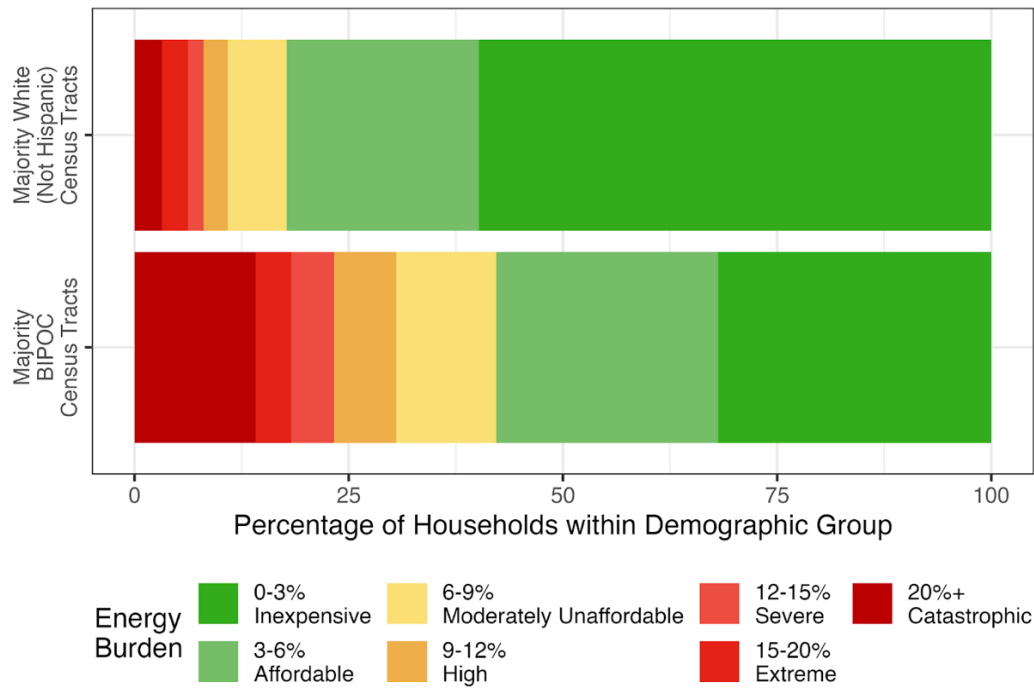
Furthermore, households in majority BIPOC census tracts are 2.4 times more likely to have an energy burden that exceeds 6% and 2.9 times more likely to have an energy burden greater than 12%. For 23% of households in majority BIPOC census tracts, energy

⁷⁵ Ex. FLO-133, *Quick Facts: Michigan*, U.S. CENSUS BUREAU (last accessed May 5, 2024), <https://perma.cc/DFN9-WKP5>, at 1. The percentage of those who are white Alone, and not Hispanic or Latino, is 74.0%. *Id.*

⁷⁶ This figure is based on energy burden data available from the U.S. Department of Energy Low-income Energy Affordability Data (<https://www.energy.gov/scep/slsc/lead-tool>); Michigan census tract information from the U.S. Census Bureau (<https://www.census.gov/cgi-bin/geo/shapefiles/index.php?year=2010&layergroup=Census+Tracts>); and DTE service territory data (<https://atlas.eia.gov/datasets/f4cd55044b924fed9bc8b64022966097/explore?filters=eyJJOQU1FIjpbIkRURSBFTEVDVFJJQyBDT01QQU5ZII19&location=42.911225%2C-81.880048%2C6.78>). The code used to analyze the data and generate these results is contained in `Doe_lead_profiles_fpl.Rmd` at https://github.com/Energy-Equity-Project/DTE_analysis/tree/main.

1 burdens exceed 12% to 20% of income, which we categorize as “severe” to
2 “catastrophic.”⁷⁷

3
4 *Figure 6: Energy burden distribution among majority BIPOC vs. white census tracts in*
5 *Michigan.*⁷⁸



6
7 Consequently, in census tracts with incomes below 150% of FPL and extreme
8 energy burdens above 20%, the median Black population is 92%.⁷⁹ Ninety percent (163

⁷⁷ Ex. FLO-134, Justin Schott, FLO JS Workpaper 3.
⁷⁸ This figure is based on energy burden data available from the U.S. Department of Energy Low-income Energy Affordability Data (<https://www.energy.gov/scep/slsc/lead-tool>); Michigan census tract information from the U.S. Census Bureau (<https://www.census.gov/cgi-bin/geo/shapefiles/index.php?year=2010&layergroup=Census+Tracts>); and DTE service territory data (<https://atlas.eia.gov/datasets/f4cd55044b924fed9bc8b64022966097/explore?filters=eyJJOQU1FIjpbIkRURSBFTEVDVFJJQyBDT01QQU5ZII19&location=42.911225%2C-81.880048%2C6.78>). The code used to analyze the data and generate these results is contained in Doe_lead_profiles_fpl.Rmd at https://github.com/Energy-Equity-Project/DTE_analysis/tree/main.
⁷⁹ I calculated the median Black population based on the values in the rightmost column of Figure 7.

out of 181) of these tracts are located in Wayne County, which is within DTE's electric-gas combination service territory.⁸⁰

*Figure 7: Percent Black population among the most energy burdened, low-income census tracts.*⁸¹

Location	Energy Burden (% income)	Avg. Annual Energy Cost (\$)	Household Income	Black/African American (% pop.)
Census Tract 5112, Wayne County	49	\$3,536	\$7,221	93
Census Tract 5382, Wayne County	45	\$3,869	\$8,589	94
Census Tract 5301, Wayne County	42	\$2,900	\$6,931	99
Census Tract 5231, Wayne County	39	\$3,009	\$7,651	18
Census Tract 5313, Wayne County	39	\$3,000	\$7,622	94
Census Tract 1527, Oakland County	38	\$2,658	\$7,036	3
Census Tract 9854, Wayne County	36	\$3,174	\$8,764	0
Census Tract 5451, Wayne County	35	\$2,793	\$7,996	97
Census Tract 5452, Wayne County	35	\$3,524	\$10,192	100
Census Tract 5002, Wayne County	32	\$3,491	\$10,818	99
Census Tract 5071, Wayne County	32	\$3,137	\$9,934	96
Census Tract 5190, Wayne County	31	\$2,910	\$9,438	90
Census Tract 5265, Wayne County	30	\$2,896	\$9,738	81
Census Tract 5393, Wayne County	30	\$3,537	\$11,758	100
Census Tract 5113, Wayne County	29	\$3,709	\$12,639	39
Census Tract 5333, Wayne County	29	\$3,109	\$10,810	91
Census Tract 5391, Wayne County	29	\$3,591	\$12,206	98
Census Tract 5406, Wayne County	29	\$2,752	\$9,399	78
Census Tract 5074, Wayne County	28	\$3,152	\$11,401	97
Census Tract 5303, Wayne County	28	\$3,990	\$14,065	97

⁸⁰ Ex. FLO-135, Justin Schott, FLO JS Workpaper 4 (data from Climate and Economic Justice Screening Tool, noted in rows 4–5). I filtered for Michigan census tracts with energy burdens above 20%. In rows 934–38, I did a count showing 163 out of 181 of these high energy burden tracts are located in DTE territory.

⁸¹ See Ex. FLO-135.

1 We also identified severe disparities in energy burdens on the basis of income. Our
 2 data indicates that 59% of DTE gas and electric residential customers⁸² earning less than
 3 30% of Area Median Income⁸³ (AMI) have extreme energy burdens of 15% or more. Of
 4 note, many of these households are likely already using less energy than they need.⁸⁴
 5 Moreover, 45% of Michigan households earning less than \$25,000 keep their home at an
 6 unsafe or uncomfortable temperature, and 35% of households earning from \$25,000–
 7 \$34,999 also do so.⁸⁵

8 Another metric commonly used to assess affordability is the Home Energy
 9 Affordability Gap (HEAG),⁸⁶ which represents the cost above an affordable 6% energy
 10 burden that a household pays. For example, if a household earning \$20,000 can afford a
 11 6% energy burden of \$1,200, then if this household faced an annual bill of \$3,000, it would
 12 have a HEAG of \$1,800. Michigan households below 30% of AMI with energy burdens
 13 above 15% face HEAGs that are nearly \$2,000 more than they can afford annually, as
 14 shown in Figure 8 below.

⁸² This is inclusive of both DTE Gas and DTE Electric customers; we did not have data for DTE Gas customers alone to conduct the analysis.

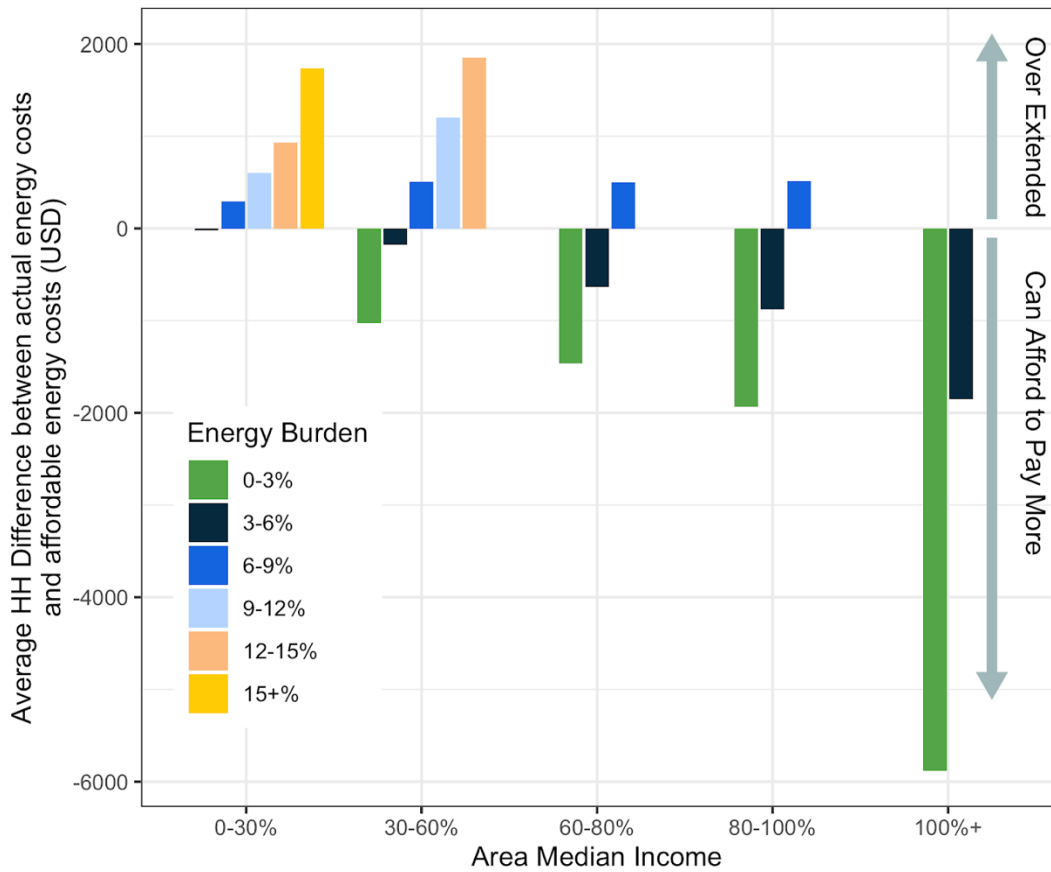
⁸³ This is close to 100% of FPL, depending on household size.

⁸⁴ Ex. FLO-136, Shuchen Cong, Destenie Nock, Yueming Lucy Qiu & Bo Xing, *Unveiling Hidden Energy Poverty Using the Energy Equality Gap*, 13 NATURE COMM'NS, 2022, at 1, 2.

⁸⁵ Ex. FLO-126, Justin Schott, JS FLO Working Paper 2.

⁸⁶ Ex. FLO-137, *Introduction*, HOME ENERGY AFFORDABILITY GAP (last accessed May 5, 2024), <https://perma.cc/5GX4-BDWX>, at 1.

Figure 8: Michigan home energy affordability gap by income.⁸⁷

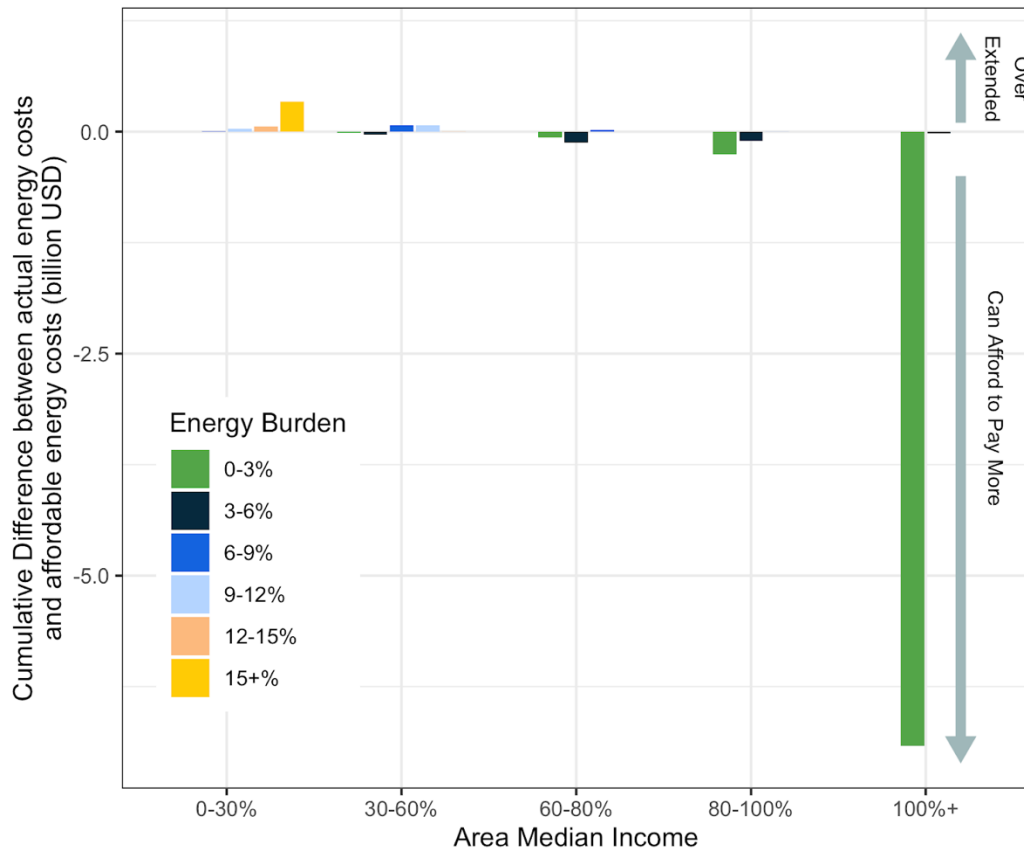


Households that have affordable energy burdens have negative HEAGs—they can afford to spend more than they actually do on energy. Figure 8 shows that households above 100% AMI and with energy burdens below 3% could afford to spend \$5,800 more per year than they currently do on energy and still have an affordable energy burden of less than 6%.

⁸⁷ This figure is based on energy burden data available from the U.S. Department of Energy Low-income Energy Affordability Data (<https://www.energy.gov/scep/slsc/lead-tool>); Michigan census tract information from the U.S. Census Bureau (<https://www.census.gov/cgi-bin/geo/shapefiles/index.php?year=2010&layergroup=Census+Tracts>); and DTE service territory data (<https://atlas.eia.gov/datasets/f4cd55044b924fed9bc8b64022966097/explore?filters=eyJJOQU1FIjpbIkRURSBFTEVDVFJJQyBDT01QQU5ZII19&location=42.911225%2C-81.880048%2C6.78>). The code used to analyze the data and generate these results is contained in `Doe_lead_profiles_ami.Rmd` at https://github.com/Energy-Equity-Project/DTE_analysis/tree/main.

Collectively, as shown in Figure 9, there is a \$6.9 billion net surplus of what Michigan households above 100% AMI can afford to pay to achieve a 6% energy burden. It would take just 8.7% of this surplus to eliminate the combined \$601 million home energy affordability gap experienced by all customers with energy burdens above 6%.

Figure 9: Collective surplus and deficit of home energy affordability gaps.⁸⁸



⁸⁸ This figure is based on energy burden data available from the U.S. Department of Energy Low-income Energy Affordability Data (<https://www.energy.gov/scep/slsc/lead-tool>); Michigan census tract information from the U.S. Census Bureau (<https://www.census.gov/cgi-bin/geo/shapefiles/index.php?year=2010&layergroup=Census+Tracts>); and DTE service territory data (<https://atlas.eia.gov/datasets/f4cd55044b924fed9bc8b64022966097/explore?filters=eyJJOQU1FIjpbIkRURSBFTEVDVFJJQyBDT01QQU5ZII19&location=42.911225%2C-81.880048%2C6.78>). The code used to analyze the data and generate these results is contained in `Doe_lead_profiles_ami.Rmd` at https://github.com/Energy-Equity-Project/DTE_analysis/tree/main.

1 In sum, the distributive inequities of energy burdens by race and class can be
 2 easily rectified through a modest reallocation of costs among low-income vs. non-low-
 3 income customers. I return to this point in my recommendations to MPSC in Part VI.

4
 5 **Q: What is the relationship between energy burdens and shutoffs?**

6 **A:** Shutoffs are the result of unaffordable energy burdens. When they cannot pay their energy
 7 bills, many households make the painful decision to forego other basic needs and to
 8 underconsume energy—keeping their homes at unreasonably cold or hot temperatures that
 9 harm their physical and mental health.⁸⁹ Because of the patterns of shuffling between which
 10 essential needs a household can afford and how much discomfort it can tolerate, it is
 11 important to note that, by the time DTE Gas or DTE Electric shuts off service, a household
 12 has likely already endured a series of struggles.

13 Because we do not have geographic data about shutoffs, we cannot analyze the
 14 relationship between energy burden and shutoffs directly. With DTE Gas, in particular,
 15 *monthly* energy burdens vary significantly due to winter bills that may be two to three times
 16 higher than summer bills. A household that has a 15% annual energy burden may have a
 17 25% or 30% monthly energy burden during the winter months. Shutoffs by DTE Gas and
 18 DTE Electric increase in early spring when winter bills come due, peaking in March each
 19 year (e.g., 25,106 in March 2021, 10,933 in August 2021).⁹⁰ This seasonal spike in energy

⁸⁹ Ex. FLO-107 at 1, 6.

⁹⁰ Ex. FLO-138, Justin Schott, FLO JS Workpaper 5. In order to determine the peaks, I added DTE Electric's 22,977 shutoffs (cell C28) and DTE Gas's 2,129 shutoffs (cell C31) for March 2021. For August 2021, I added DTE Electric's 9,138 shutoffs (cell C39) and DTE Gas's 1,785 shutoffs (cell C42).

1 burdens and the corresponding shutoffs make robust affordability measures even more
2 critical for vulnerable households.

3
4 **Q: Please explain how DTE Gas reports shutoffs and any challenges you encountered**
5 **with its reports.**

6 **A:** DTE Gas reports shutoffs on both a quarterly and monthly basis in response to two orders
7 from MPSC Case Nos. U-20757⁹¹ and U-18120.⁹² The number of shutoffs initiated by
8 DTE was not immediately clear to me due to confusing nuances in the reporting measures
9 and practices of each report. Prior to the order in MPSC Case No. U-20757, DTE reported
10 shutoffs on a quarterly basis.⁹³ Beginning with MPSC Case No. U-20757, DTE began to
11 report on arrearages, enrollments in affordable payment plans, reconnections, and shutoffs
12 on a monthly basis.⁹⁴ The shutoff reports, however, actually reflect the “[t]otal number of
13 residential premises that were disconnected from 11/1/2019 to the last day of the reporting
14 month that have not been restored as of [the last day of the reporting period]. It is not the
15 number of any residential disconnects for any given month.”⁹⁵ Importantly, what is
16 presented on the MPSC Utility Customer Database, per Figure 10 below, as the number of
17 monthly disconnections is actually the net number of customers who lost service and have
18 not had service restored. This visual makes it appear that monthly shutoffs never exceeded
19 10,000, but this is not the case. As shown below in Figure 11, when analyzing the Quarterly

⁹¹ See generally Apr. 15, 2020 U-20757 Order.

⁹² See generally *In re Billing of Residential & Nonresidential Customers*, MPSC Case No. U-18120, Order (Apr. 28, 2017).

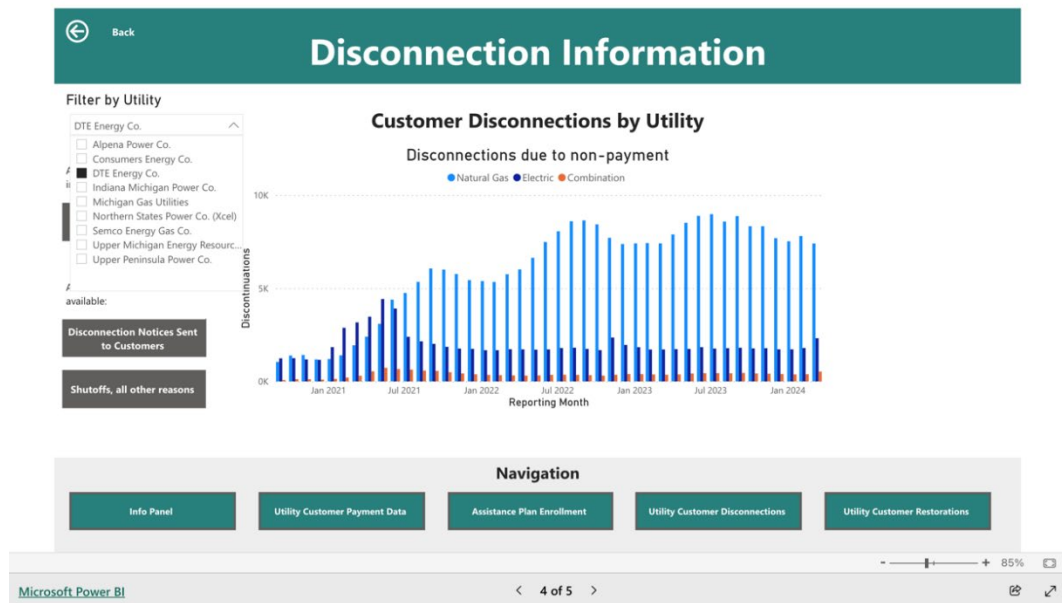
⁹³ See generally, e.g., Ex. FLO-139, REVISED QUARTERLY REPORT FOR 1ST, 2ND, AND 3RD QUARTERS OF 2023, DTE (2023) (providing a sample quarterly report submitted by DTE).

⁹⁴ *In re Response to COVID-19*, MPSC Case No. U-20757, MPSC Order (July 23, 2020), at 3.

⁹⁵ Ex. FLO-140, DTE’s Response to FLO’s First Discovery Request, FLODG-1.3, at 2.

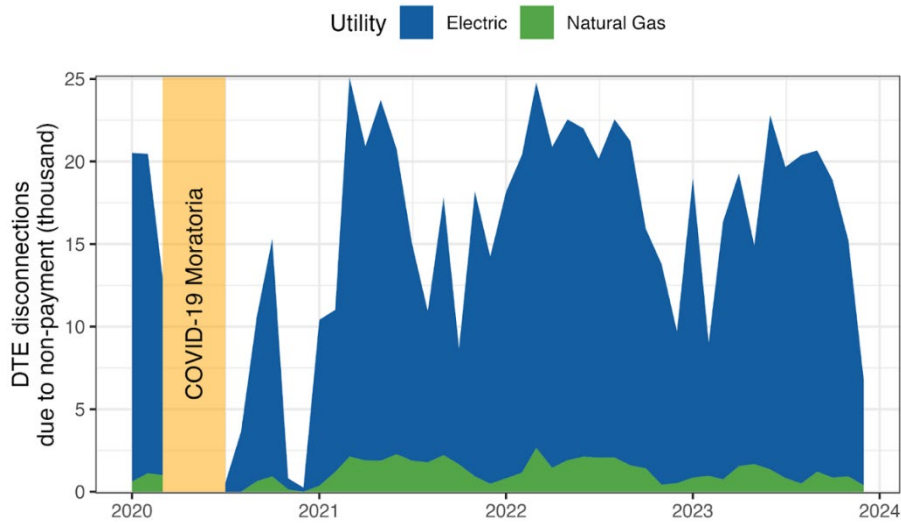
1 Reports, Mr. Agrawal Bejarano found that DTE shut off customers more than 20,000 times
 2 in many months, and 717,121 times between 2020 and 2023, even accounting for the brief
 3 voluntary pause from March–June 2020.

4 *Figure 10: DTE monthly shutoffs as presented on the MPSC website.⁹⁶*



⁹⁶ *Disconnection Information: Customer Disconnections by Utility*, MICH. PUB. SERV. COMM’N (last accessed Apr.16, 2024), <https://www.michigan.gov/mpsc/regulatory/reports/other/utility-customer-data>.

Figure 11: Actual monthly shutoffs by DTE, 2020–2023.⁹⁷



*Based on DTE Quarterly Report to MPSC Case U-18120, Rule 460.151

Q: What is the magnitude and trend of shutoffs conducted by DTE?

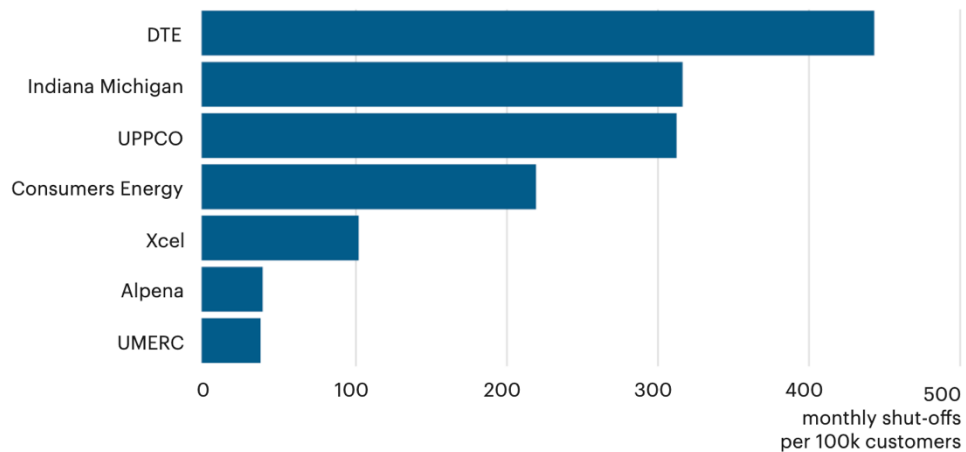
A: As I noted above, DTE Energy shut off customers more than 717,000 times from 2020 to 2023. DTE's shutoffs, both the rate and total number, far exceed even the practices of its investor-owned peers. For example, Figure 12 below shows that DTE Electric shut off customers at twice the rate of Consumers Energy.

⁹⁷ This figure is based on DTE Quarterly Reports submitted to the docket in MPSC Case No. U-18120 (<https://mi-psc.my.site.com/s/global-search/U-18120%20%20DTE%20Quarterly>); the code used to analyze the data and generate these results is contained in `dte_quarterly_results.Rmd` at https://github.com/Energy-Equity-Project/DTE_analysis/tree/main.

Figure 12: DTE shutoff rates vs. peer utilities.⁹⁸

DTE's Rate of Shut-offs Outpaced Others During Pandemic

From April 2020 to December 2021, DTE's average monthly shut-offs for nonpayment per 100,000 customers far outpaced Michigan's other investor-owned electricity providers.



Agnel Philip/ProPublica. Source: Michigan Public Service Commission.

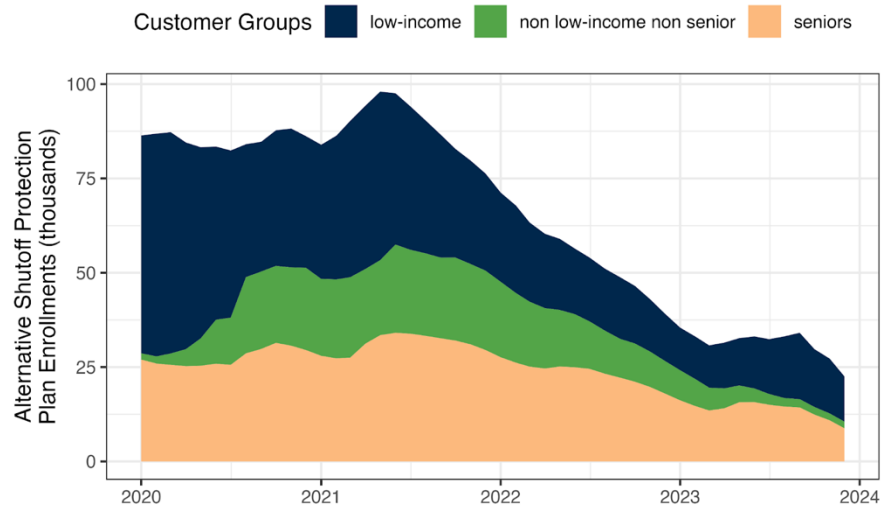
DTE's shutoff totals and rates have remained fairly steady through this period as a whole, with notable seasonal spikes seen in Figure 10 above.

Q: How do shutoffs correspond to enrollment in affordable payment plans?

A: Enrollment in DTE's affordable payment plans has declined precipitously, dropping 63% between 2020 and 2023, according to Figure 13 below. The reason for this decline is not clear.

⁹⁸ Ex. FLO-141, Sarah Alvarez, *Lights Out: Profitable Utility Company Shut Off Electricity to Homes Hundreds of Thousands of Times*, PROPUBLICA (Mar. 18, 2022), <https://www.propublica.org/article/lights-out-profitable-utility-company-shut-off-electricity-to-homes-hundreds-of-thousands-of-times>, at 1.

Figure 13: Declining enrollment in shutoff protection plans, 2020–2023.⁹⁹



*Based on DTE Quarterly Report to MPSC Case U-18120, Rule 460.151

IV. ASSESSING DTE'S APPROACH TO ENERGY AFFORDABILITY AND SECURITY

Q: Do you have any concerns about how DTE Gas assigns the responsibility for its energy affordability programs?

A: Yes. The Director of Revenue Management and Protection, a position held by Witness Jason Sparks, is responsible for programs that may be at odds with each other. Managing collections and theft focuses on maximizing customer payments and penalizing noncompliance. However, the position held by Witness Sparks also oversees low-income programs, which, in theory, aim to provide holistic support for customers who cannot

⁹⁹ This figure is based on DTE Quarterly Reports submitted to the docket in MPSC Case No. U-18120 (<https://mi-psc.my.site.com/s/global-search/U-18120%20DTE%20Quarterly>); the code used to analyze the data and generate these results is contained in `dte_quarterly_results.Rmd` at https://github.com/Energy-Equity-Project/DTE_analysis/tree/main.

1 afford their bills.¹⁰⁰ By assigning both punitive and supportive approaches to the role in
 2 which Witness Sparks serves, DTE creates a position that inherently has a conflict of
 3 interest. DTE tasks the person in Witness Sparks's role with juggling these competing
 4 interests, which means the Company structurally cannot commit to address the needs of
 5 energy affordability fully.

6
 7 **Q: How does DTE describe affordability issues?**

8 **A:** Witness Sparks mentions energy affordability in several different contexts. For example,
 9 Witness Sparks describes the energy affordability gap experienced by customers earning
 10 minimum wage.¹⁰¹ Witness Sparks also considers a range of affordability definitions,
 11 including a living wage calculation from the Massachusetts Institute of Technology that is
 12 specific to the Detroit Metro Statistical Area, multiple thresholds of the Federal Poverty
 13 Level, and ALICE (Asset Limited, Income Constrained, Employed) households.¹⁰²

14 However, Witness Sparks's characterization of the number of households
 15 consistently unable to afford their DTE bills is misguided. He states that households
 16 earning less than 250% of FPL will be unable to afford their bills consistently, which is a
 17 reasonable assumption.¹⁰³ However, he references a figure of at least 1% of Detroit
 18 customers being unable to pay their bills.¹⁰⁴ However, data from the Pulse Survey and
 19 LEAD Tool shows that the number of customers unable to pay their bills in Detroit is likely

¹⁰⁰ See Sparks Direct Testimony at 1–2.

¹⁰¹ *Id.* at 9–10.

¹⁰² *Id.* at 10, lines 8–18.

¹⁰³ *Id.* at 10, lines 5–8.

¹⁰⁴ *Id.* at 10, lines 3–5.

much higher. In March 2024, 33.2% of Michigan residents reported foregoing basic needs to pay their energy bill for at least one or two months in the last year.¹⁰⁵

Thus, while DTE appears to have a general awareness of poverty and affordability metrics, it has not translated this knowledge into a cohesive understanding of energy insecurity among DTE customers.

Q: Does DTE take a systematic approach to addressing energy insecurity and unaffordability?

A: No. By “systematic approach” to addressing unaffordability, I mean programs that would enable the vast majority, if not all, LMI customers to achieve a steady energy burden below 6% of income. Initially, this would entail tracking and transparently reporting changes in customers’ energy bills due to requested rate increases and comparing those to income—ideally at the household level or alternatively using robust and readily available census tract data from five-year estimates of the American Community Survey of the U.S. Census. A systematic approach would also involve more granular evaluation of shutoffs and how customer assistance program enrollments result in reduced energy bills and shutoffs.

While DTE lists seven goals of its energy assistance programs,¹⁰⁶ the Company does not define these goals clearly or connect them to measurable objectives. Witness Sparks describes the outputs of such programs (e.g., the number of enrollees in LSP), with

¹⁰⁵ See Ex. FLO-126, at 7. Energy Insecurity in Michigan (U.S. Census Pulse Survey) downloaded from the February 6 March 4, 2024, cycle. In the Michigan tab of the Excel file, I divided the number of customers foregoing another basic necessity almost every months, some months, or one or two months by the number reporting they never forego basic necessities in order to pay their energy bills; I excluded nonreporters from this calculation.

¹⁰⁶ Sparks Direct Testimony at 4–6.

1 little appreciation of the impact these programs have in fostering durable affordability and
 2 energy security. If DTE used a systematic approach, the Company would report meaningful
 3 progress by using metrics such as the reduction in the number of customers with severe or
 4 extreme energy burdens or the reduction in bills for households participating in EWR-LI
 5 programs.

6
 7 **Q: Does DTE’s current lack of a systematic approach align with the Company’s stated**
 8 **goals of its energy assistance programs?**

9 **A:** No. Witness Sparks states that “[t]he foremost objective is to ensure that customers,
 10 particularly those with low incomes, have continued access to essential energy.”¹⁰⁷
 11 However, if the Company were in fact doing everything in its power to prevent shutoffs,
 12 both its energy assistance programs and its shutoff and collection practices would look very
 13 different, as discussed more in depth below.

14
 15 **Q: Does DTE effectively make customers aware of available credits or support their**
 16 **enrollment in these programs?**

17 **A:** No. Despite DTE’s assertion that it already consistently advertises its low-income
 18 programs on its website, the Company’s website makes no mention of the LIA credit.¹⁰⁸ In
 19 addition, the Company provides information about the RIA credit only toward the bottom
 20 of a long list of programs, and the only link provided is to submit documents for eligibility

¹⁰⁷ *Id.* at 4, lines 18–20.

¹⁰⁸ On its website, there is not a simple link to apply, and the LIA Credit is not included in the list of fifteen programs with dropdowns at the bottom of the page). *See generally* Ex. FLO-112.

1 verification. DTE provides no instructions on how to request enrollment. This is a
 2 significant barrier and poor design if the goal is to maximize the program's outreach,
 3 accessibility, and uptake.

4
 5 **Q: How would you characterize DTE's attitude toward its energy assistance programs?**

6 **A:** In a word, I would characterize DTE's attitude as "resistant." In its response to the EAAC's
 7 Interim Report, DTE Energy used terms like "unworkable" on multiple occasions.¹⁰⁹ The
 8 Company focused on why programs could not be expanded or why, in the Company's
 9 opinion, it is already doing enough and does not need to consider expanding or creating
 10 new programs.

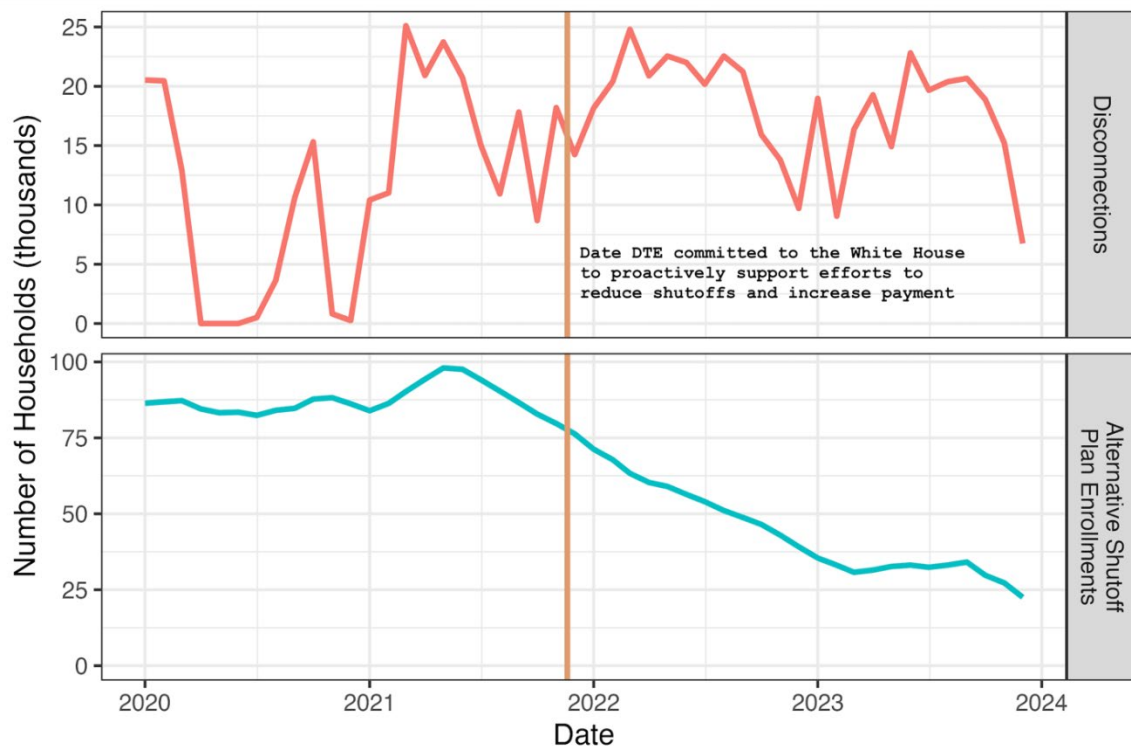
11 DTE's practices run counter to its promises. DTE Energy was one of seven utilities
 12 that committed in November 2021 to the White House to take five steps to reduce shutoffs
 13 and the hardship of energy insecurity.¹¹⁰ These steps included commitments to identify,
 14 directly screen and notify all potentially eligible recipients; to expedite assistance to
 15 vulnerable households; and to stop shutoffs to households in the process of applying for
 16 assistance.¹¹¹ Instead, DTE Energy oversaw an increase in the net number of unrestored
 17 customers while cutting enrollments in affordable payment plans by nearly two-thirds (as
 18 shown in Figure 14 below).

¹⁰⁹ DTE Comments on Interim Staff Report at 2.

¹¹⁰ Ex. FLO-142, *FACT SHEET: Biden Administration Deploys American Rescue Plan Funds to Protect Americans from Rising Home Heating Costs; Calls on Utility Companies to Prevent Shut Offs This Winter*, WHITE HOUSE (Nov. 18, 2021), <https://perma.cc/F89D-3C2H>, at 1.

¹¹¹ *Id.* at 1–2.

Figure 14: DTE worsens energy insecurity after commitment to White House.¹¹²



This example underscores the fact that DTE’s commitments on paper to address the affordability crisis, whether to MPSC or the White House, can have little bearing on its subsequent actions. FLO Witnesses Cira-Reyes and Koepfel provide additional examples of how DTE’s actions do not align with the spirit or the letter of the services they are responsible for providing.

Q: Has DTE opposed efforts to access data on shutoffs?

A: Yes. DTE Energy opposed data transparency in MPSC Case No. U-20757.¹¹³ In public comments, DTE Energy noted that it had filed detailed comments on data reporting by zip

¹¹² Ex. FLO-138; Ex. FLO-143, Justin Schott, FLO JS Workpaper 6.

¹¹³ DTE Comments on Interim Staff Report at 4.

code and census tract in MPSC Case No. U-20959 and argued that it would be duplicative to address such reporting in case U-20757.¹¹⁴

Q: Based on your review of sample shutoff notices provided by DTE, what is your assessment of DTE’s efforts to support customers in reducing shutoffs?

A: It is clear that many customers cannot afford the payments DTE demands to avert shutoffs. I illustrate several challenges DTE fails to address by reviewing just five residential sample shutoff notices DTE provided in Discovery Response U-21291 FLODG-1 2.a 10 Sample Residential Invoices.¹¹⁵

The problems I observed in this sample include:

1. Not all of the bills provide due dates to avoid shutoffs.
2. Despite the assertion by Witness Sparks that “[r]esidential customer bills contain information on what customers can do to avoid any pending shut off including pathways to energy assistance,”¹¹⁶ the bills provide no information about programs that customers may be eligible for or strategies to reduce their bills.
3. The bills do not provide the fees for reconnection.
4. The payment amounts required to prevent a shutoff vary substantially, as shown below in Figure 15.
5. The deposit requirements to restore service once a shut off has occurred vary substantially, as shown below in Figure 16.

¹¹⁴ *Id.*

¹¹⁵ *See generally* Ex. FLO-115.

¹¹⁶ Ex. FLO-144, DTE’s Response to FLO’s First Discovery Request, FLODG 1.2.b, at 1.

Figure 15: Inconsistencies in amounts due to prevent shutoffs.¹¹⁷

Sample #	Prior Balance	New Charges	Amount Due (Prior Balance plus New Charges)	Total Balance	% Due (Amount Due divided by Total Balance)	Fixed Gas Charge
06	\$114.74	\$147.11	\$114.74	\$261.85	43.8%	\$13.50
07	\$476.85	\$654.17	\$408.23	\$1,132.02	36.1%	\$13.50
08	\$175.22*	\$63.35	\$171.95	\$238.95	72.1%	\$13.50
09	\$200.71	\$129.43	\$161.04	\$330.14	48.8%	\$13.50
10	\$378.79	\$83.21	\$167.68	\$462.00	36.3%	\$4.50

* Sample 08 indicates a "Current Surcharge Buyout Amount" of \$3,450.77.

Figure 16: Inconsistencies in deposits to restore service.¹¹⁸

Sample #	Past Due Gas	Past Due Electric	Deposit to restore	% of Balance (Deposit to restore divided by the sum of past due gas and past due electric)
06	\$82.63	\$84.39	\$106.00	40.4%
07	\$262.52	\$145.71	\$80.00	7.1%
08	Not provided		\$121.00	50.6%
09	\$119.27	\$41.77	Not provided	
10	\$181.28	\$30.90	\$108.00	23.4%

Q: Please explain the impacts of DTE's procedure of collecting deposits.

A: Customers who have struggled to pay their bills and either accrue debt or experience a shutoff (or both) can be required to make a deposit payment in order to continue or restore service.¹¹⁹ DTE appears to universally apply the maximum deposit amount allowed by the MPCS's Consumer Billing Rules, which is twice the customer's average monthly bill.¹²⁰

¹¹⁷ The data is sourced from Ex. FLO-115.

¹¹⁸ The data is sourced from Ex. FLO-115.

¹¹⁹ See MCL § 460.111.

¹²⁰ *Id.* § 460.111(1)(a).

1 Due to the financial challenges that LMI customers face, LMI customers are much
 2 more likely to have DTE require deposits from them than from non-LMI customers. As a
 3 result, deposits are largely assessed from LMI customers.

4 For an LMI customer who was already unable to stave off a shutoff, it is a serious
 5 burden to be required to deposit twice the standard monthly bill before having service
 6 restored. As FLO Witness Cira-Reyes notes, deposit requirements often lead customers to
 7 turn to predatory “payday” lenders who can charge interest rates of between 10% and 30%
 8 so that customers can get their essential utilities turned back on to heat their homes and
 9 water and to supply other appliances such as stoves, ovens, and dryers.¹²¹

10
 11 **Q: Do you have any observations about the deposits collected by DTE and what they**
 12 **reveal about energy burden?**

13 **A:** Yes. According to information provided by DTE Witness Hatsios, the average amount of
 14 a deposit has risen sharply since 2020 for the most impacted quintile and decile of
 15 customers.¹²² From 2020 to 2023, the median deposit stayed roughly flat around \$155 per
 16 customer, reflecting a total annual DTE gas bill of \$1,264. For customers above the
 17 eightieth percentile in deposit amounts, the average deposit increased by 31%, from \$274
 18 to \$360.¹²³ For customers above the ninetieth percentile, the average deposit increased by
 19 27%, from \$347 to \$440.¹²⁴ Figure 17 below shows these disproportionate increases.

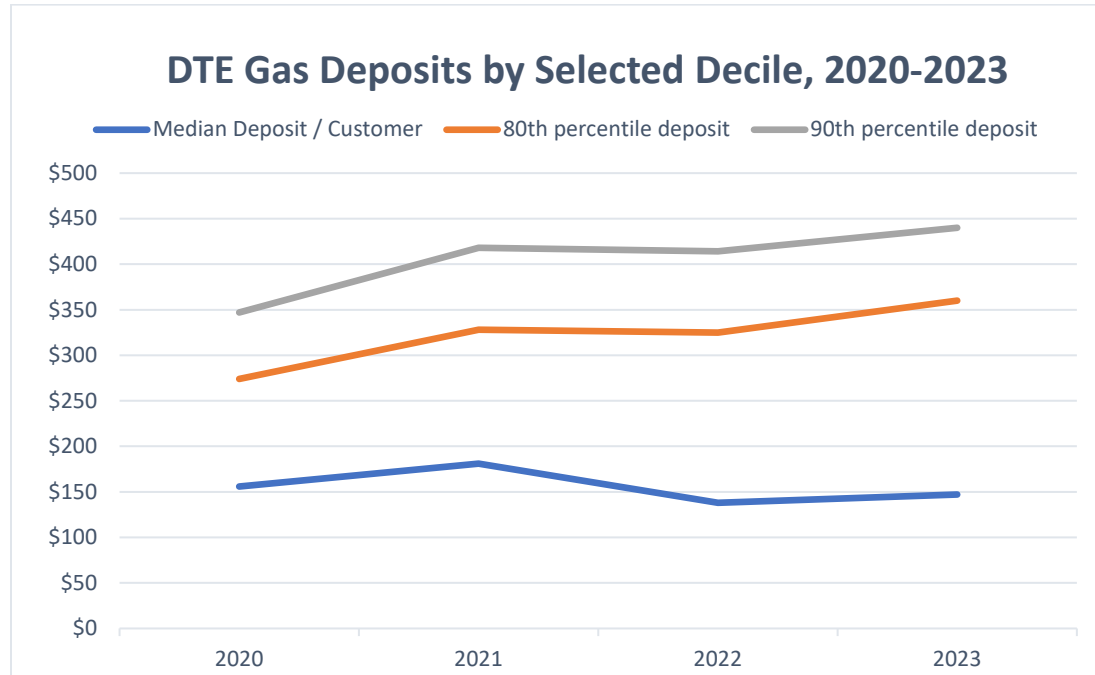
¹²¹ See Cira-Reyes Direct Testimony pt. III.

¹²² See Ex. FLO-145, DTE’s Response to FLO’s Fourth Discovery Request, FLODG-4.6b.

¹²³ Assuming the average deposit is two months of the total annual bill, I multiply the deposit by six will equal the total bill. The average deposit for this group reflects an average 2023 DTE Gas bill of \$2,160.

¹²⁴ The average deposit for this group reflects a 2023 DTE Gas bill of \$2,640.

Figure 17: Disproportionate increase in deposits for the most burdened customers.¹²⁵



I reiterate that these bills are for gas service *only*. For a Michigan household with a single earner working full-time at minimum wage (\$10.33 per hour), these annual gas (only) bills would represent an energy burden of 10.5% for customers above the eightieth percentile of deposits and 12.8% for those above the ninetieth percentile.¹²⁶

Because gas burdens average at about 37.5% of total energy burdens for households below 150% of FPL,¹²⁷ I estimate that a household with one minimum wage income¹²⁸ has a total energy burden (gas and electric) of 28.0% at the eightieth percentile of deposits and

¹²⁵ Ex. FLO-145 (data); Ex. FLO-146, Justin Schott, FLO JS Workpaper 7 (calculations).

¹²⁶ For this calculation, 2,000 hours (40 hours per week for 50 weeks) multiplied by \$10.33 per hour equals an annual income of \$20,660. Dividing annual gas bills by annual income yields the gas energy burden.

¹²⁷ Ex. FLO-147, Justin Schott, FLO JS Workpaper 8.

¹²⁸ A household with one minimum wage income is equivalent to 100% of FPL for a household of two.

1 34.1% at the ninetieth percentile. **The total energy burden for these households is 4.7**
 2 **and 5.8 times greater than the 6% affordability threshold, respectively.**

3 DTE, however, says it does not consider or track whether any of these customers
 4 participate in EWR or other assistance programs¹²⁹ even though analysis to identify
 5 extreme customer vulnerabilities is not particularly difficult or technical. As evidenced by
 6 DTE's 859 pages of direct testimony and scores of accompanying budgets and
 7 spreadsheets, DTE chooses instead to apply its analytical capabilities to making the case
 8 for yet another rate increase, which would bring the total rate increase to 52% since
 9 2017.¹³⁰ If it used just a scant amount of its technical analytical prowess for equity analysis,
 10 the Company could readily identify customers who are vulnerable to shutoffs and other
 11 punitive collections and marshal important resources to support them.

12
 13 **Q: Is DTE taking any steps to address location-specific energy affordability struggles**
 14 **customers face?**

15 **A:** DTE does not appear to be doing so. DTE states that it "does not track arrears by zip code,
 16 census tract, census block group, or circuit."¹³¹

17 For a service territory that covers half the state and serves 1.3 million customers,
 18 failing to identify pockets of severe and extreme energy burdens strikes me as negligent. It
 19 is common sense that the experiences of households in the Osborn neighborhood of Detroit

¹²⁹ Ex. FLO-148, DTE's Response to FLO's Fourth Discovery Request, FLODG-4.8aii.

¹³⁰ Witness Sparks states that customers using 10 Mcf following the Commission's U-17999 Order (Dec. 9, 2016) had a monthly bill of \$44. Sparks Direct Testimony at 17, lines 12–16. If the Commission approved the proposed rate increase in U-21291, Witness Sparks states customers would spend \$67 for 10 Mcf per month, which reflects a 52% increase.

¹³¹ Ex. FLO-149, DTE's Response to FLO's First Discovery Request, FLODG-1.9, at 1.

are categorically different from those of a household in suburban Bloomfield Hills, in rural Lake County (lower peninsula) or Iron Mountain (upper peninsula).

DTE's response indicates that the Company applies a one-size-fits-all approach to its energy assistance programs. Throughout my testimony, I have detailed the results and impacts that stem from the distanced, non-data-driven approach DTE takes to program design.

Q: What is your critique of DTE's approach to the Low-Income Self-Sufficiency Plan in this case and in general?

A: The LSP is a two-year program that freezes payments that are past due, eliminates future late charges, and provides a monthly arrears credit.¹³² From 2015–2022, excepting the 2019–2020 COVID-19 program year, LSP enrolled an average of 32,533 customers but graduated just 3,816 annually.¹³³

Conceptually, reducing arrearages over time is valuable, but it is still contingent upon an affordable bill and consistent bill payment by the customer. DTE has not demonstrated that the LSP terms result in an affordable energy burden (less than 6% of income). Evaluation of LSP and other assistance programs should be based first and foremost on affordability outcomes and their impact on shutoffs.

If the goal of LSP is to ensure “sustained energy” access,¹³⁴ the program performs poorly. DTE shuts off a very significant portion of customers despite the assistance

¹³² Sparks Direct Testimony at 7, lines 10–19.

¹³³ Sparks Direct Testimony at 9 tbl.2.

¹³⁴ *See id.* at 7, line 17 (“While participating in the plan, customers have the benefit of sustained energy.”).

provided. Below I reproduce an inverted version of Witness Spark's Table 1¹³⁵ to show that an average of 16% of customers still suffer disconnections. There is no trend of annual improvement. Perhaps with modifications LSP could perform better, but it is clearly not a long-term solution in its current form.

*Figure 18: LSP failure rate.*¹³⁶

LSP Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Av g
%	20	19	8%	12	9%	11	33	15	18	19	16
Disconnected	%	%		%		%	%	%	%	%	%

DTE claims that its "experience has demonstrated that prioritizing the application of the low-income credit towards a long-term program like LSP yields the best outcomes in terms of self-sufficiency and minimizing missed payments."¹³⁷ Sparks elaborates that the LIA credit is only offered to LSP customers in order to strategically pair these two forms of assistance.¹³⁸

The data, however, shows that no amount of program pairings mitigate the extremely high shutoff rates that DTE executes on LSP participants. In fact, the data in Figure 19 shows the highest shutoff rates for customers who are concurrently enrolled in LSP, LIA, RIA and shutoff protection. It is not clear whether DTE is unaware of or poorly interprets its own data or chooses to construct a narrative that is not grounded in this reality.

¹³⁵ *Id.* at 8 tbl.1.

¹³⁶ This data was adapted from Sparks Direct Testimony at 8 tbl.1, LSP Success Rate 2013-2022.

¹³⁷ Sparks Direct Testimony at 15.

¹³⁸ *Id.*

Figure 19: Shutoff rates for customers enrolled in multiple assistance programs.¹³⁹

LSP Program Year Shut-off rate	2018			2019			2020			2021			2022		
	Combo	Elec only	Gas only	Combo	Elec only	Gas only	Combo	Elec only	Gas only	Combo	Elec only	Gas only	Combo	Elec only	Gas only
a. LSP & shutoff															
0-75	10%	11%	6%	11%	10%	5%	9%	10%	6%	12%	10%	7%	13%	11%	6%
76-110	8%	9%	4%	9%	6%	5%	7%	7%	9%	10%	8%	3%	10%	8%	2%
111-150	8%	7%	3%	9%	7%	2%	8%	9%	11%	10%	8%	8%	10%	10%	5%
b. LSP and LIA & shutoff															
0-75	10%	11%	5%	11%	10%	4%	9%	10%	6%	11%	9%	7%	13%	11%	6%
76-110	8%	9%	0%	9%	7%	5%	7%	7%	9%	10%	8%	2%	10%	8%	2%
111-150	8%	7%	2%	9%	7%	3%	8%	9%	12%	9%	7%	7%	10%	9%	4%
c. LSP and RIA & shutoff															
0-75	14%	0%	6%	12%	18%	4%	20%	21%	8%	22%	22%	14%	23%	21%	8%
76-110	13%	0%	6%	9%	13%	6%	17%	14%	14%	20%	16%	7%	17%	15%	4%
111-150	14%	0%	5%	10%	17%	2%	19%	17%	15%	20%	19%	11%	17%	20%	7%
d. LSP and HHC & shutoff															
0-75	10%	0%	4%	11%	0%	2%	8%	0%	4%	10%	0%	3%	12%	0%	3%
76-110	8%	0%	3%	10%	0%	0%	5%	0%	16%	7%	0%	0%	8%	25%	0%
111-150	7%		5%	9%		0%	6%	0%	15%	8%		6%	11%	0%	3%
e. LSP + HHC + LIA & shutoff															
0-75	10%	0%	9%	11%		1%	7%		4%	9%	0%	1%	11%		3%
76-110	8%		0%	10%		0%	5%		17%	7%	0%	0%	7%		0%
111-150	8%		11%	8%		0%	5%		17%	8%		6%	11%	0%	3%
f. LSP + HHC + RIA & shutoff															
0-75	11%		4%	12%	0%	3%	16%	0%	5%	19%	0%	7%	20%	0%	5%
76-110	9%		3%	10%	0%	0%	12%	0%	16%	15%	0%	0%	14%	25%	0%
111-150	8%		4%	10%		0%	13%	0%	22%	14%		13%	16%	0%	4%
g. LSP + LIA + RIA & shutoff															
0-75	14%	0%	7%	12%	19%	3%	20%	22%	8%	22%	23%	12%	22%	23%	8%
76-110	13%	0%	0%	9%	13%	6%	17%	12%	14%	20%	16%	7%	17%	16%	4%
111-150	14%	0%	0%	9%	17%	2%	18%	15%	16%	19%	20%	10%	16%	21%	6%
h. LSP + LIA + RIA + HHC & shutoff															
0-75	11%		13%	12%		2%	15%		5%	18%		2%	19%		4%
76-110	9%		0%	10%		0%	12%		17%	15%		0%	13%		0%
111-150	8%		0%	8%		0%	11%		25%	15%		17%	16%		4%

Q: What is your critique of DTE's approach to the Low-Income Assistance Credit (LIA) in this case and in general?

A. DTE offers the LIA to customers below 150% of FPL.¹⁴⁰ The credit is currently \$30 per month.¹⁴¹

DTE states that the LIA was designed to reduce "typical" customer bills by 68%.¹⁴²

DTE states that the typical customer bill is an average of \$44 per month, which equates to \$528 annually, based on consumption of 10 Mcf per month.

However, according to the DOE's Low-Income Energy Affordability Data (LEAD) tool and data,¹⁴³ the actual annual bill for natural gas for households below 150% of the

¹³⁹ This figure is a screenshot from Ex. DTE-A25, Schedule O1, sponsored by Witness Sparks.

¹⁴⁰ Sparks Direct at 14, lines 12-14.

¹⁴¹ *Id.* at lines 10-11.

¹⁴² *Id.* at 17, lines 12-16.

¹⁴³ See Ex. FLO-14. The data is filtered for households that use natural gas as their primary heating source.

1 FPL is \$837, significantly more than DTE's "typical" customer bill. Assuming an annual
2 cost of gas of \$837, the current \$30 monthly credit would be actually offset only
3 approximately 43% of a customer's bill, not the 68% as DTE's scenario suggests.

4 In the current rate case, DTE recognizes that rates are higher than when the LIA
5 was first proposed. Specifically, Witness Sparks notes that DTE failed to increase the LIA
6 credit in the past couple of rate cases, significantly reducing the value of the LIA credit.¹⁴⁴

7 Despite the Company identifying these shortcomings, DTE is not proposing to
8 increase the credit enough to address them. In response to its total proposed bill increase
9 of \$23 per month (a 52% increase) for the same volume of gas, the Company proposes to
10 increase the credit only to \$40.¹⁴⁵ If the Commission approves DTE's rate increase and the
11 LIA credit is raised to \$40, the credit will reduce a 10 Mcf / month bill by only 60%,
12 meaningfully lower than the original 68% reduction. As such, DTE, having recognized its
13 failure to update the LIA credit, is effectively proposing to reduce the proportional value
14 of the LIA credit, from 68% to 60%. In addition to this effective decrease, DTE also
15 proposes to reduce the number of customers enrolled from a monthly average of 38,000 in
16 2022 to 33,000, further diminishing the credit's effectiveness.¹⁴⁶

¹⁴⁴ Sparks Direct Testimony at 17, lines 12–23.

¹⁴⁵ *Id.* at 17, lines 23–25.

¹⁴⁶ *Id.* at 14, lines 14–16.

Q: What is your critique of DTE’s approach to the Residential Income Assistance (RIA) Credit in this case and in general?

A: The RIA credit is similar to the LIA credit but less robust; it currently offsets the monthly customer gas charge of \$13.50 per month.¹⁴⁷ In this rate case, DTE is proposing to raise it to \$17.60 per month.¹⁴⁸ The credit is open to customers earning less than 150% of FPL,¹⁴⁹ or \$30,660 per year for a two-person household.

DTE projects an average monthly enrollment of 70,000 customers in the credit, a slight decline from the average monthly enrollment of 71,159 in 2022.¹⁵⁰ Customers must re-enroll each year by submitting annual income verification.¹⁵¹ As Witness Sparks notes in Table 3, RIA enrollments fluctuate widely¹⁵² and have decreased significantly during winter months. These variations may occur because program participation requires annual re-qualification and submission of documents.

In terms of its dollar value, which is \$162 per year for participating customers, the RIA is beneficial but will not come close to closing the home energy affordability gap, identified earlier. As displayed in Figure 8 above, many low-income households have a Home Energy Affordability Gap that exceeds \$1,000 more than they could afford to pay if their energy burdens were capped at 6%. The RIA would relieve just one-sixth of the portion of the bill that households are unable to afford.¹⁵³

¹⁴⁷ *Id.* at 12, lines 15–17.

¹⁴⁸ *Id.* at 14, lines 5–7.

¹⁴⁹ *Id.* at 12, lines 15–17.

¹⁵⁰ *Id.* at 13–14.

¹⁵¹ Ex. FLO-112 at 4.

¹⁵² Sparks Direct Testimony at 14 tbl.3.

¹⁵³ *See also* DTE Comments on Interim Staff Report at 2 (stating that “[it] does not refer RIA recipients to EWR as part of its process” and that “[r]eferring customers as they are enrolled is unlikely to be effective”).

1 Sustained enrollment in RIA would be increasingly important if the Commission
 2 approves DTE's proposed increase in monthly fixed charges from \$13.50 currently to
 3 \$17.60, which is a 30.4% increase.¹⁵⁴

4
 5 **Q: What is your critique of DTE's proposal with respect to the Demand Response (DR)**
 6 **Pilots?**

7 **A: DTE is proposing to discontinue the two pilots as part of the settlement from MPSC Case**
 8 **No. U-20462.**¹⁵⁵

9 My primary critique is that DTE did not set up the pilot to do adequate program
 10 evaluation; it is, therefore, impossible to know if the program was a success or not. In a
 11 series of revealing discovery responses, Witness Decker explained that the Company did
 12 not track separately the costs of the different pilot activities, did not retain information
 13 about who participated in stakeholder design meetings, did not define success, did not use
 14 a control group, did not forecast load reductions or calculate the change in usage per
 15 participant.¹⁵⁶ In sum, DTE did not design the pilot for effective evaluation.

16 Based on the information that was collected, it was promising in at least some
 17 communities. Alpena participants, for instance, reduced therm usage by 10% on the energy
 18 action day called on March 3, 2022.¹⁵⁷

¹⁵⁴ Sparks Direct Testimony at 14, lines 5–7.

¹⁵⁵ Decker Direct Testimony at 78–83.

¹⁵⁶ See generally Ex. FLO-150, DTE's Response to FLO's Sixth Discovery Request, FLODG-6.1, 6.2a, 6.2c, 6.3, 6.5a, 6.8a, and 6.9a.

¹⁵⁷ Decker Direct Testimony at 82 tbl.12.

1 To see the Company recommend discontinuing the DR program is not surprising,
2 and it is hard to see how the Company conducted the pilot with any intention of success
3 and converting it to a full program afterward, regardless of the mixed results it observed.
4

5 **Q: What is your critique of DTE’s approach to the Payment Stability Plan (PSP) Pilot in**
6 **this case and in general?**

7 **A:** In 2022 and 2023, DTE adopted the PSP pilot, a Percentage of Income Payment Plan
8 (PIPP) that was similar in design to Ohio’s PIPP.¹⁵⁸ Having a percentage of income
9 payment plan is a step in the right direction.

10 However, the Company needs to provide more assistance to more people more
11 quickly through an improved PIPP. Presently, the Company used an unaffordable 10%
12 energy burden as the target for combination customers (67% above the affordability
13 threshold of a 6% burden) and 6% gas only burden (2x the affordability threshold of a 3%
14 gas-only burden);¹⁵⁹ these burdens need to be lowered to more like 6% in total or 3% for
15 gas only. Furthermore, the Company neither has concrete plans to expand the pilot to a
16 certain number of customers nor does it have any firm timelines for when it will seek
17 approval of an amended or replacement program.¹⁶⁰ Instead, the Company should seek an
18 expanded number of participants promptly.
19

¹⁵⁸ See Sparks Direct Testimony at 1112.

¹⁵⁹ *Id.* at 11, lines 9–13.

¹⁶⁰ *Id.* at 12, lines 1–6.

Q: DTE says it is “not feasible” to define the number of customers eligible for LSP, RIA, and LIA.¹⁶¹ Do you agree with that?

A: No, I disagree for two reasons. First, while it may involve a little bit of work, DTE is at least in possession of the number of customers who receive bill payment assistance from the Michigan Energy Assistance Program (MEAP), LIHEAP, and other human service agency programs. At a minimum, that information should be sufficient to help determine most customers eligible for the Low-Income Assistance (LIA) credit.

Second, if DTE is not reviewing the number of customers eligible for its programs, it should. DTE needs to demonstrate much better awareness of its customer base demographics. Income and age data from the U.S. Census is readily available and easily compiled by census tract. DTE should at least understand the approximate number of customers who are eligible for these beneficial assistance programs so that it can improve its marketing and increase enrollments. If DTE had any intention to reduce customer arrears, shutoffs, or to graduate people from LSP, identifying customers who could benefit seems like low-hanging fruit and an obvious starting point.

Q: To provide some context, how does DTE’s spending on affordability compare to its spending on marketing?

A: The budget for the RIA and LIA Credits—\$23.2 million¹⁶²—is less than half the projected price of DTE Gas’s marketing—\$57.0 million.¹⁶³ While I could not find the total cost of

¹⁶¹ Ex. FLO-110, at 1.

¹⁶² Uzenski Direct Testimony at 45, lines 6–9.

¹⁶³ Decker Direct Testimony at 84, lines 19–20.

1 the Low-Income Self-Sufficiency Program or the Payment Stabilization Pilots in DTE's
2 current testimony, LSP appears to be on the order of the LIA credit. In other words, DTE
3 is spending approximately 50% more to promote the expansion of natural gas, an energy
4 source Michigan must transition from to meet its climate goals, than on affordability
5 programs. These marketing costs include an extensive DTE campaign to promote "cooking
6 with gas," despite the well-known hazards to respiratory health¹⁶⁴ and the disproportionate
7 prevalence of childhood asthma in DTE's home community of Detroit.¹⁶⁵ Through the rate
8 base, residential customers will be investing 50% more in marketing amenities like the
9 holiday-themed natural gas truck pictured below in Figure 21, than they are investing in
10 programs to support low-income customers.

¹⁶⁴ See generally Ex. FLO-151, Lebel et al., *Methane and NOx Emissions from Natural Gas Stoves, Cooktops, and Ovens in Residential Homes*, 56 ENVIRON. SCI. TECHNOL. 2529 (2022); Ex. FLO-152, Krasner et al. *Cooking with Gas, Household Air Pollution, and Asthma: Little Recognized Risk for Children*, 83 J. ENVIRON. HEALTH 14 (2021).

¹⁶⁵ See Ex. FLO-153, MICH.N DEP'T OF HEALTH & HUM. SERVS., DETROIT: THE CURRENT STATUS OF ASTHMA BURDEN (2021), at 5.

Figure 20: DTE “cooking with gas” promotional tweet.¹⁶⁶



Figure 21: Image of a DTE natural gas marketing truck.¹⁶⁷



¹⁶⁶ @DTE_Energy, Screenshot (May 3, 2024), https://twitter.com/DTE_Energy/status/1753467316170272847.

¹⁶⁷ @DTE_Energy, Screenshot (Dec. 17, 2023), https://twitter.com/DTE_Energy/status/1736431061712752776.

Q: Could you provide examples of what a systematic approach to energy affordability and security could look like for DTE?

A: Yes. As context, DTE's current baseline is 717,121 shutoffs between 2020 and 2023, with little change in the overall trend since ramping up shutoffs in mid-2020.¹⁶⁸ As discussed above, its energy assistance programs do not currently ensure uninterrupted access to energy.

Thus a systemic approach to reducing these shutoffs could include:

1. Enacting an immediate moratorium on all shutoffs not related to theft or unauthorized use. The MPSC does not require DTE to initiate shutoffsDTE has the existing authority to offer alternatives to customers, report any revenue reductions as uncollectable, and propose alternative approaches to the MPSC.
2. Defining measures of success, namely a reduction in shutoffs and a reduction in the number of customers with energy burdens above 6%. The Company should prioritize eliminating the highest energy burdens (i.e. above 20%) and then continuing to lower the maximum burdens among DTE customers until the universal 6% standard is achieved. Defining measures of success would also identify data needed to assess whether there are disparate outcomes by race, income, location, or participation in assistance and EWR programs that merit additional investments, engagement strategies, etc.

¹⁶⁸ See Ex. FLO-138. Workpaper 5 pulled all of the PDF reports DTE Gas provided between 2020 and 2023 and converted them to .csv format. These reports included monthly shutoff totals (actual shutoffs, not net unrestored shutoffs) separately for gas and electric. I summed column B to get 717,121 shutoffs during this period.

3. Proposing a comprehensive affordability strategy. The Company should use its position to accelerate the development of affordability rate structures, such as PIPPs and Low-Income Discount Credits that have been proven effective in other states such as Illinois.¹⁶⁹
4. Creating a unified affordability program that reduces customer arrearages and enables customers to afford their bills, ideally a PIPP that ensures no customer spends more than 3% of income on gas and no more than 6% of income on energy in total. Or, in the absence of a unified program or until one can be implemented, expanding existing bill assistance programs significantly and increasing the marketing of these programs substantially.
5. Creating systems that prioritize outreach, enrollment, and program evaluations to maximize the effectiveness of the above programs. Evaluation efforts should assess disparities in who participates and differences in outcomes by specific vulnerable populations and lead to the development of approaches to address those differences.

Q: Is this a reasonable expectation that DTE develops systematic approaches to affordability?

A: I believe it is. Witness Sparks acknowledges that reducing low-income customers' struggles to pay their bills is in the self-interest of the Company and is mutually beneficial.¹⁷⁰ DTE has extensive strategic planning expertise among its leadership. The

¹⁶⁹ See Ex. FLO-154, Excerpt from Ill. Com. Comm'n No. 23-0067, Order (Nov. 16, 2023), at 2–5.

¹⁷⁰ Sparks Direct Testimony at 14, lines 14–15. (“This integrated approach can yield sustainable solutions that benefit both the Company and its low-income customers.”).

1 Company uses data driven approaches to an array of business operations, EWR, and
2 integrated resource planning. Providing affordable and reliable service to low-income
3 customers is a core responsibility of DTE. This responsibility can only be fulfilled by
4 developing alternatives to the current assistance programs. The record is clear that the
5 current programs are failing too many customers, leaving them in financial crisis,
6 compounding late fees, interest, and deposits, and subjecting them to the frequent threat
7 and experience of shutoffs. The Company can do better, and the Commission should make
8 it do so.

9
10 **V. ASSESSING THE MPSC’S RESPONSE TO ENERGY INSECURITY, SHUTOFFS,**
11 **AND THE AFFORDABILITY CRISIS**

12 **Q: Please summarize this section of your testimony.**

13 **A:** In this Part, I consider the MPSC’s response to affordability challenges and shutoffs, what
14 it has and has not done to regulate DTE and ensure energy is accessible to all customers.

15
16 **Q: Has the MPSC been sufficiently prioritizing affordability?**

17 **A:** I do not believe so. Like dozens of other PUCs, the MPSC’s mandate requires that it judge
18 utilities’ requests according to multiple criteria. These criteria include safety, reliability,
19 affordability, and “just and reasonable” rates for both the customer and the utility.
20 Understandably, there can be no compromises around safety, which is the bedrock of a
21 centralized energy transmission and distribution system, and, generally, safety is well-
22 regulated.

1 Unfortunately, energy affordability has long been considered more of a luxury than
 2 an imperative. There is widespread evidence from both Commission rulings and DTE
 3 energy assistance programs that the Commission does not view ensuring true affordability
 4 as critical. In the Commission's COVID-19 order in MPSC Case No. U-20757, for
 5 instance, despite affirming its authority to take swift actions to protect customers, the
 6 Commission's shutoff moratorium was voluntary.¹⁷¹ DTE complied for just over three
 7 months and resumed shutoffs shortly after.¹⁷² Some commissions in other states maintained
 8 shutoff protections for significantly longer.¹⁷³

10 **Q: Please summarize the MPSC's recent efforts to address shutoffs and unaffordability.**

11 **A:** Since the start of COVID-19, the MPSC has tasked three different bodies (Energy
 12 Affordability and Accessibility Collaborative, Energy Waste Reduction Low-Income
 13 Workgroup, and the Low-Income Energy Policy Board) with studying the issues and
 14 proposing solutions.¹⁷⁴ These bodies are led by MPSC staff and are comprised primarily
 15 of energy affordability advocates and practitioners as well as utility representatives.

¹⁷¹ Apr. 15, 2020 U-20757 Order at 9–10.

¹⁷² See Ex. FLO-141 at 1.

¹⁷³ See Ex. FLO-155, NAT'L ENERGY ASSISTANCE DIRECTORS' ASS'N, SUMMARY OF STATE UTILITY SHUT-OFF MORATORIUMS (2021), at 1–2.

¹⁷⁴ See Ex. FLO-105, at 1–3; Ex. FLO-156, *Low-Income Energy Policy Board*, MICH. PUB. SERV. COMM'N (last accessed May 6, 2024), <https://www.michigan.gov/mpsc/commission/workgroups/low-income-energy-policy-board>, at 2.

1 The Commission set timelines for the EAAC, in particular, to report on its work.¹⁷⁵

2 The EAAC submitted interim reports on its work in December 2021¹⁷⁶ and March 2023.¹⁷⁷

3 Stakeholders, including regulated utilities, were given time to respond with comments.¹⁷⁸

4 The Commission responded to the Staff interim reports and stakeholder comments
5 in proceeding orders, leading to the efforts I describe below.
6

7 **Q: What progress was made toward energy security through these proceedings?**

8 **A:** Some of the work completed by the EAAC was important and constructive. For instance,
9 the EAAC initiated monthly reporting requirements for shutoffs notices, arrearages,
10 reconnections, and the net number of customers without service.¹⁷⁹ Another positive
11 outcome was the Commission's adoption of a definition of energy affordability. The
12 Commission defined energy affordability as "[t]he extent to which a household has the
13 resources to meet their home energy needs for heating, cooling and other uses in a healthy,
14 sustainable and energy efficient manner without compromising a household's ability to
15 meet other basic needs."¹⁸⁰
16

¹⁷⁵ See *In re Response to COVID-19*, MPSC Case No. U-20757, Order (Dec. 21, 2023) [hereinafter Dec. 21, 2023 U-20757 Order], at 44; *In re Response to COVID-19*, MPSC Case No. U-20757, Order (Feb. 18, 2021) [hereinafter Feb. 18, 2021 U-20757 Order], at 16; *In re Response to COVID-19*, MPSC Case No. U-20757, Order (Feb. 10, 2022), at 14–15.

¹⁷⁶ See generally *In re Response to COVID-19*, U-20757, EEAC Interim Report (Dec. 17, 2021)(available at <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000001VqhIAAS>).

¹⁷⁷ See generally *In re Response to COVID-19*, U-20757, EEAC Interim Report (Mar. 16, 2023) (available at <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000007DkxqAAC>).

¹⁷⁸ See, e.g., DTE Comments on Interim Status Report.

¹⁷⁹ Feb. 18, 2021 U-20757 Order at 21.

¹⁸⁰ Dec. 21, 2023 U-20757 Order at 36.

1 **Q: From these efforts, did the EAAC make measurable progress on unaffordable energy**
2 **burdens or shutoffs?**

3 **A:** No. The EEAC has failed to make measurable progress on unaffordability and shutoffs.

4 First, the EAAC has focused extensively on process improvements, coordination,
5 definitions, and outputs such as program enrollments, rather than outcomes like measurable
6 reductions in energy burdens. It has not suggested quantitative approaches to measuring
7 energy unaffordability or insecurity, and the Commission has not ordered it to do so. I have
8 reviewed the content of the EAAC website, including reports, meeting notes, and
9 presentations. It strikes me that the EAAC serves as a body that has worked primarily to
10 establish definitions and principles. It has not explicitly communicated a priority to
11 minimize or eliminate shutoffs. The Affordability, Alignment and Accessibility (AAA)
12 subcommittee of the EEAC, for instance, largely does not discuss shutoffs, as I explain
13 further below.

14
15 **Q: How would you characterize the EAAC's concern for preventing shutoffs?**

16 **A:** Serious discussion of how to reduce or prevent shutoffs and ensure households' continuous
17 access to heat and electricity is largely absent from the materials of the EAAC. The goals
18 and guiding principles of EAAC's AAA subcommittee, illustrated in Figure 22 and Figure
19 23 below, do reference items such as "promot[ing] energy affordability" and "[t]reating
20 customers with dignity, enabling them to live comfortably, and not penalizing customers
21 for an inability to pay their bills." However, it appears that the AAA Subcommittee has not
22 undertaken any serious discussion of how to reduce or prevent shutoffs—as with the EAAC
23 more broadly.

Figure 22: “Shared Goals” of the AAA subcommittee.¹⁸¹

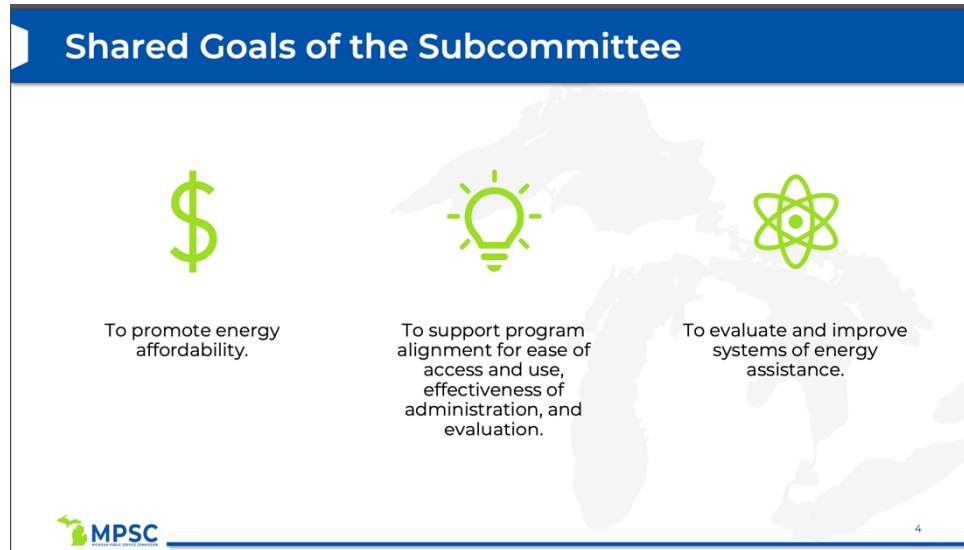
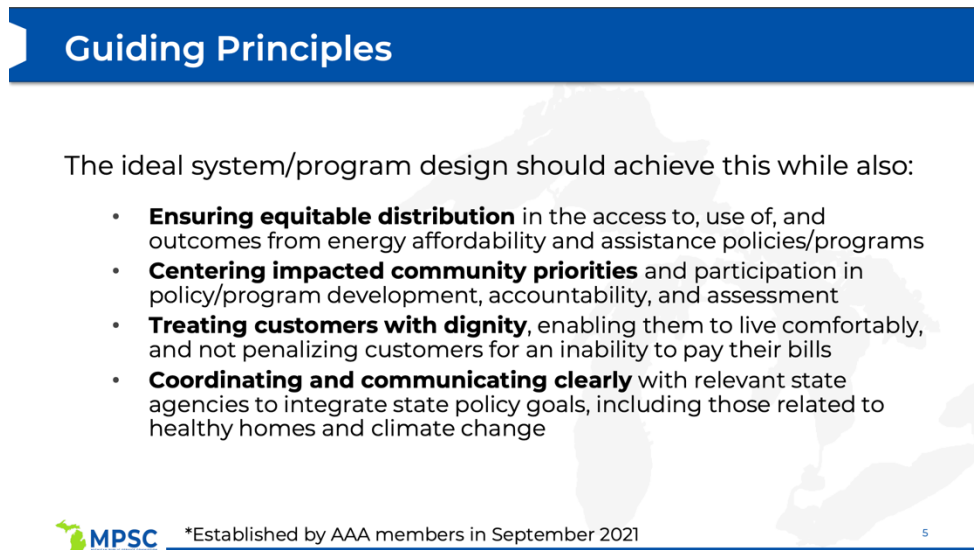


Figure 23: “Guiding Principles” of the AAA subcommittee.¹⁸²



¹⁸¹ See Ex. FLO-157, AFFORDABILITY, ALIGNMENT, AND ASSISTANCE SUBCOMMITTEE, MICH. PUB. SERV. COMM’N, PRESENTATION (Oct. 3, 2023), at 4.

¹⁸² *Id.* at 5.

1 After reviewing meeting minutes, the detailed AAA subcommittee goals,¹⁸³ and the
 2 reports to Staff, it is clear that minimizing shutoffs and achieving affordable (6%) energy
 3 burdens have not been EAAC priorities and have garnered a fraction of the attention given
 4 to other issues and priorities. The AAA subcommittee was tasked with “analyzing
 5 collections processes and disconnections.”¹⁸⁴ Actually working on this goal, however, was
 6 not a priority for any of the subcommittee members, as indicated by survey results from its
 7 November 10, 2022, meeting.¹⁸⁵ This may be because the subcommittee, like the EAAC
 8 as a whole, in my understanding, is comprised primarily of MPSC staff and professional
 9 staff at utilities and other organizations instead of residents with lived experience.
 10 Furthermore, as shown in Figure 24 below, the AAA subcommittee’s kickoff did not even
 11 list addressing shutoffs—by far one of the greatest threats to life and generational
 12 poverty—as an option for members to prioritize. After identifying shutoff analysis as a
 13 potential task, the topic is almost entirely absent from future meeting presentations. Instead,
 14 the committee is focused on issues like the “customer journey” to secure assistance, a
 15 landscape analysis of programs, and internal structure, charge, and processes.¹⁸⁶ It is my
 16 understanding that in the subcommittee has taken up work on the LIA credit design. Each
 17 of these has value, but they are not oriented toward reducing the number of households
 18 with high energy burdens. Not surprisingly, the evidence presented by Staff and the

¹⁸³ See generally Ex. FLO-158, AFFORDABILITY, ALIGNMENT, AND ACCESSIBILITY SUBCOMMITTEE GOALS (2022).

¹⁸⁴ Ex. FLO-159, AFFORDABILITY, ALIGNMENT, AND ACCESSIBILITY SUBCOMMITTEE KICK-OFF (2021), at 4.

¹⁸⁵ Ex. FLO-160, AFFORDABILITY, ALIGNMENT, AND ACCESSIBILITY SUBCOMMITTEE 11-10-2022 MEETING (2022), at 7.

¹⁸⁶ *Id.* at 4.

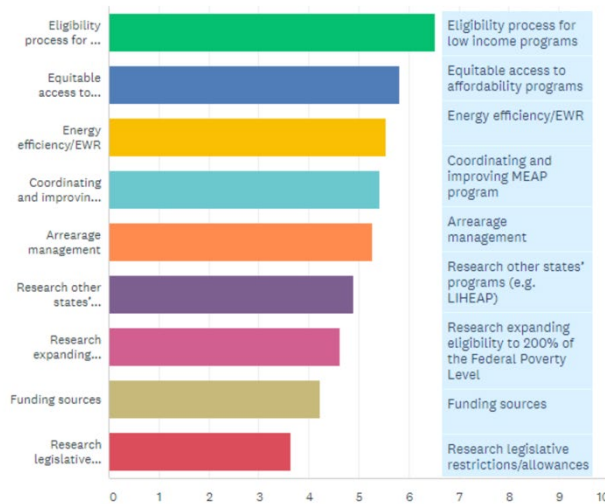
responses from stakeholders have not seriously considered pathways to universal affordability and reducing shutoffs to a mechanism of last resort.

Figure 24: No option for AAA subcommittee members to prioritize shutoffs.¹⁸⁷

Survey Results: Priority List

Rank the following areas of focus for prioritization in the December report:

Answered: 28 Skipped: 0



Q: What views has the Commission expressed about the urgency of what you present as a crisis of energy insecurity and unaffordability, which disproportionately harms BIPOC households?

A: Through its actions, the Commission has expressed that it believes that the energy insecurity and unaffordability crisis is not urgent. In its December 21, 2023 Order in MPSC Case No. U-20757, for instance, “[t]he Commission [] agree[d] with the Staff that it is not appropriate to prematurely approve permanent PIPP programs.”¹⁸⁸ Instead, in the same

¹⁸⁷ Ex. FLO-161, AFFORDABILITY, ALIGNMENT, AND ACCESSIBILITY SUBCOMMITTEE 9-9-2021 MEETING (2021), at 9.

¹⁸⁸ Dec. 21, 2023 Order at 5.

1 Order, the Commission committed to “implement[ing] a proceeding in 2024 to continue
2 and expand its review of these pressing issues,” citing Public Act 231 (2023) as an impetus
3 behind this commitment.¹⁸⁹ This language suggests that the Commission is not treating the
4 crisis of energy insecurity and unaffordability with sufficient urgency, resulting in delays
5 that cause real harm to people and communities.

6
7 **Q: How has the MPSC addressed the data gaps you are facing in your data analysis?**

8 **A:** To its credit, MPSC staff advised additional reporting by census tract and zip code, a
9 recommendation approved in the Commission’s December 21, 2023, Order, despite
10 protests by DTE Electric that such reporting would be burdensome.¹⁹⁰ A timeline for such
11 reporting, however, was not included in the Order. Because DTE Electric is already
12 submitting other reports by zip code and census tract, as the MPSC noted, and DTE Gas
13 should already be aware of this requirement, I request that the MPSC require DTE Gas to
14 begin producing such reports as soon as possible, but no later than 90 days after the
15 Commission order.

16 I will note that the MPSC also removed the initial monthly reporting requirements
17 in the Order described above, shifting to only quarterly reporting of shutoffs and collection
18 metrics.¹⁹¹ Quarterly reports are not sufficient, in my opinion, to observe trends such as
19 spikes in shutoffs when other assistance programs run out of funds or during periods of
20 extreme weather, such as heat waves in the electric context and extreme cold in the gas

¹⁸⁹ *Id.* at 6.

¹⁹⁰ *Id.* at 28.

¹⁹¹ *Id.* at 22.

1 context. Monthly reporting by census tract, as IOUs in Illinois do,¹⁹² is a national best
2 practice

3
4 **Q: Do you agree with the Commission's approach and timelines for addressing the**
5 **current crisis?**

6 **A:** No. Unfortunately, the Commission has not moved quickly with actions that can provide
7 immediate relief for low-income customers. Taking a patient, multiyear approach to
8 creating a robust, state-specific PIPP would be reasonable *if* sufficient safeguards were
9 available in the interim. But they are not. This means that thousands of customers who face
10 severe and extreme energy burdens will forego other basic necessities, keep their homes at
11 unsafe temperatures to conserve energy, and face the threat and the actuality of shutoffs.

12 I would support a longer PIPP development process if the Commission
13 implemented an interim solution, such as a moratorium on shutoffs, an automatic
14 expansion of LIA and RIA to all eligible customers, and an expansion of an approach that
15 combines LSP with other efficiency and assistance programs for the most energy-burdened
16 households.

17 As of now, the EAAC and LIEPB, among other bodies that have been tasked with
18 addressing energy affordability concerns over the years, have not generated outcomes that
19 result in measurable reductions for customers with energy burdens above 6%. There may
20 be good reasons for limited progress, such as the capacity of volunteer boards, the

¹⁹² See generally Ex. FLO-162, *Credits, Collections, and Arrearages Reports Monthly Dashboard*, ILL. COM. COMM'N (last accessed May 6, 2024), <https://www.icc.illinois.gov/industry-reports/credit-collections-and-arrearages-reports/monthly-dashboard> (showing a drop down menu to see data shared monthly).

composition and expertise of its members, the desire to be inclusive, questions about authority and timelines, the competing interests introduced by utility representatives, or squeamishness to confront utilities about unforgiving shutoff and collections practices. But regardless of the reasons, these boards, which have now been working for more than two years, have produced only modest impacts. Regardless, so far, it is the Commission's position to continue to defer to these groups—that the EAAC and LIEPB should hold the reins to create solutions for what could easily amount to an additional two years. That does not seem to reflect an honest assessment of the current situation. What has been the fate of customers who depend on utility regulation to have any hope of staving off the impacts of shutoffs and energy poverty?

In the absence of immediate action, waiting an additional eighteen months before rolling out a PIPP plan is to know that the harms of energy poverty will continue to be allowed. Importantly, the Commission has already recognized in the U-20757 Order that rulings in contested dockets like rate cases are superior paths to assigning the task of identifying and designing solutions to workgroups like the EAAC.¹⁹³

Q: How would you recommend the Commission consider this evidence about the limited effectiveness of the EAAC to measurably reduce energy burdens or shutoffs?

A: I am not the first to make the point. The Michigan Energy Efficiency for All Network (MEEFA) made it in briefing, and the Commission supported this in its December 21,

¹⁹³ Dec. 21, 2023 U-20757 Order at 6–7 (“MEEFA states that ‘the Commission should also rule whenever possible on issues in contested dockets rather than referring them to workgroups’ . . . The Commission agrees with this recommendation.”).

2023, Order.¹⁹⁴ I am reiterating the shortcomings of the EAAC in the hopes that the Commission does not merely leave the affordability outcomes to another proceeding. The Commission has an opportunity and, I believe, a responsibility to consider these elements of affordability as part of the current rate increase proposed by DTE Gas and to implement interim solutions that provide relief while potential additional long-term solutions are developed through committee work and other dockets.

VI. RECOMMENDATIONS TO THE MPSC

Q: Please summarize this section of your testimony.

A: The MPSC has the authority to provide immediate relief to the most vulnerable customers and those with the lowest incomes. The MPSC has an existing blueprint for taking action to address critical customer concerns through its series of orders in the COVID-19 docket (MPSC Case No. U-20757). These actions would align closely with the Commission's mandate to ensure just and reasonable rates. Furthermore, given FLO's concerns about the potential for racial discrimination and inconsistent customer treatment, suspending shutoffs would also allow the MPSC to further investigate these concerns and provide customer protections against potential statutory violations by DTE.

I recommend the Commission do everything in its power to mitigate the ongoing crises of unaffordability and shutoffs, the harms that result from these crises on customers' health and well-being, and the disproportionate impacts to BIPOC households and

¹⁹⁴ *Id.*

1 residents of Wayne County—Detroit, Hamtramck, and Highland Park specifically. These
2 recommendations include:

- 3 1. Ordering an immediate pause on shutoffs until the Commission receives and analyzes
4 census tract and zip code data from DTE for the metrics currently included in its
5 quarterly reports;
 - 6 2. Ordering an extended moratorium on shutoffs if disparities in customer treatment by
7 race, income, location, or any other demographic variable are identified with census
8 tract or zip code data;
 - 9 3. Setting a limit on the maximum energy burden of 6% of income for all customers, and
10 ordering DTE, Staff, the EAAC, and interested stakeholders to propose measurable
11 pathways to achieve this goal;
 - 12 4. Requiring DTE to size its existing affordability and assistance programs to align with
13 the number of customers who are eligible;
 - 14 5. Requiring DTE to integrate best practices regarding Percentage of Income Payment
15 Plans (PIPPs) and similarly structured programs and accelerate the transition of its
16 current PSP pilot to a full program scoped to meet customer need;
 - 17 6. Improving data collection and reporting formats by requiring continued monthly
18 reporting of shutoff and collections data, as opposed to quarterly reporting, and by
19 including census tract data for all current metrics; and
 - 20 7. Rejecting all nonessential spending by the Company, especially spending that is
21 counter to the goals of affordability, health, climate, environmental justice, and
22 uninterrupted access to energy.
- 23

1 **Q: What are your recommendations to the MPSC regarding shutoffs?**

2 **A:** First, I recommend that the MPSC initiate an immediate pause on shutoffs as it collects
3 further information through DTE's data reports and docket U-21570 initiated in response
4 to PA 231.¹⁹⁵ Second, I recommend that the MPSC adopt an extended moratorium on
5 shutoffs if the analysis of this forthcoming data identifies entrenched inequities,
6 insufficient affordability programs, or a sustained risk to public health.

7
8 **Q: What is your rationale for an immediate pause on shutoffs?**

9 **A:** I recommend MPSC issue a moratorium on disconnection, with associated customer
10 protections against late fees, additional deposits, and reconnection fees.

11 I have identified numerous distributive inequities throughout my testimony that
12 indicate disparate outcomes for customers on the basis of race and income. In other words,
13 DTE is causing immediate and disproportionate harm to BIPOC and LMI households. The
14 public lacks sufficient data to further identify similar disparities that may exist on the basis
15 of income. The MPSC has an obligation to ensure fair treatment by DTE for all customers.
16 The only way I see to ensure fair treatment and guard against the worst impacts of severe

¹⁹⁵ MICH. PUB. ACTS 231 § 6aa: "(2) Not later than June 1, 2024, the commission shall open a proceeding to consider options to expand opportunities for public engagement in its decision-making processes and procedures with respect to all of the following:

(a) The accessibility and transparency of the commission's decision-making processes.

(b) Opportunities for participation in the commission's decision-making processes, especially by low-income residential customers, residential customers that experience high energy burdens, and individuals and communities impacted by commission decisions.

(c) The responsiveness of commission decisions to community needs and priorities.

(3) Not later than June 1, 2024, the commission shall open a proceeding to investigate opportunities for improving the process by which it reviews applications filed under section 6a."

1 and extreme energy burdens in the short term is to institute a pause until conclusions from
 2 further analysis, both quantitative and qualitative, can be reached.

3 This recommendation follows the model established by the California Public
 4 Utilities Commission (CPUC). The CPUC concluded:

5 The Commission has implemented policies and procedures to reduce gas
 6 and electric utility service disconnections; however, the rate of customer
 7 disconnections continues to rise. Accordingly, the instant rulemaking has
 8 been instituted with the goal of developing policies and rules to reduce the
 9 statewide level of gas and electric service disconnections for nonpayment
 10 by residential customers. This decision adopts interim rules to take effect
 11 immediately on an emergency basis to provide rapid relief while we
 12 consider longer term solutions.¹⁹⁶

13 Furthermore, the CPUC found “PG&E and SCE failed to show in opening
 14 comments that the interim rules will result in any incremental costs to them[.]”¹⁹⁷
 15 suggesting that these rules to reduce shutoffs could have little impact on utility companies
 16 while providing benefits to LMI customers.

17
 18 **Q: How and when would the second phase of your recommendations—an extended**
 19 **moratorium on shutoffs—be implemented?**

20 **A:** I believe no customers should be deprived of access to energy, a basic human need, on the
 21 basis of race, income, where they live, or any other demographic variable over which they
 22 have little or no control. Simply being too poor should not sentence a household to the
 23 cycle of figuring out which basic needs to forego, letting their homes reach temperatures

¹⁹⁶ Ex. FLO-163, ACEVES GUZMAN, DECISION ADOPTING INTERIM RULES TO REDUCE RESIDENTIAL CUSTOMER DISCONNECTIONS FOR CALIFORNIA-JURISDICTIONAL ENERGY UTILITIES (2018), at 3.

¹⁹⁷ *Id.* at 10.

1 that are dangerously cool or hot to conserve energy, or paying hefty late fees, interest, and
2 deposits to reconnect for an uncertain amount of time before the next cycle begins.

3 There is enough money in the customer base so that no one faces an energy burden
4 above 6% or a disconnection. Achieving this robust level of distributive and restorative
5 equity will require exploring all options to reduce customer bills, maximize assistance,
6 leverage new sources to enhance energy efficiency and beneficial electrification,
7 restructuring regressive customer charges, and ensuring that all customer classes pay their
8 fair share to ensure universal access to affordable energy.

9 The CPUC is a good model. Following its docket to investigate and analyze the
10 issue deeply and to allow robust stakeholder participation, the CPUC made a number of its
11 interim rules permanent. Notably, the CPUC determined “it is reasonable to impose
12 restrictions prohibiting disconnections of residential utility service until the utility has
13 offered to enroll the residential customer all applicable benefit programs administered by
14 the utility.”¹⁹⁸

15 An extended moratorium need not result in increasing customer debt or a financial
16 burden to other customers or the Company. DTE has assistance programs in place that are
17 directionally sound—if EWR-LI programs and affordability offerings, especially the PSP
18 pilot, were calibrated to achieve a maximum 6% energy burden, households would make
19 consistent payments on a bill they could reasonably afford. Expanding these programs
20 would have very modest costs to other ratepayers, who, when above median income, are

¹⁹⁸ Ex. FLO-164, Phase I Decision Adopting Rules and Policy Changes to Reduce Residential Customer Disconnections for the Larger California-jurisdictional Energy Utilities, Decision 20-06-003 (June 11, 2020), at 1.

1 more likely to have sufficient means to return a share of the benefits of energy efficiency
 2 programs they have received over time. There would be savings to the rate base from
 3 reduced uncollectibles and the large collections infrastructure DTE operates (the cost of
 4 which is unknown). A moratorium on shutoffs would motivate improvements and
 5 efficiency within the current patchwork of low-income credits and programs.

6 It is in the interests of all parties to work toward agreement on the most robust
 7 disconnection protections as early as possible. The alternative, to knowingly allow
 8 disconnection from the basic necessity of energy and natural gas which we all use every
 9 day to survive, is cruel. In assessing why Americans have collectively failed to eliminate
 10 extensive poverty despite our overflowing collective wealth, scholar, MacArthur genius,
 11 Pulitzer Prize-winning author of *Evicted* Matthew Desmond suggests:

12 We like it [poverty]. It's the rudest explanation, I know, which is probably why
 13 we cloak it behind all sorts of justifications and quick evasions....If this is our
 14 design, our social contract, then we should at least own up to it. We should at
 15 least stand up and profess, *Yes, this is the kind of nation we want*. What we cannot
 16 do is look the American poor in the face and say, *We'd love to help you, but we*
 17 *just afford to*, because that is a lie.¹⁹⁹

18
 19 **Q: What precedents are there for shutoff moratoria?**

20 **A:** The MPSC has direct experience when it turned to a shutoff moratorium, albeit voluntary,
 21 to protect public health during the start of the pandemic. The Commission laid out the
 22 rationale for that moratorium in its April 2020 Order in MPSC Case No. U-20757.²⁰⁰ DTE
 23 abided by the voluntary request for about three months.²⁰¹ Furthermore, forty states enacted

¹⁹⁹ MATTHEW DESMOND, *POVERTY, BY AMERICA* 101–02 (2023).

²⁰⁰ Apr. 15, 2020 U-20757 Order.

²⁰¹ Ex. FLO-141 at 1.

1 some form of a moratorium during the COVID-19 pandemic, and the majority of states
 2 continued their moratoria a year or longer, well into 2021.²⁰² The Los Angeles Department
 3 of Water and Power, the largest municipal utility in the country, voted unanimously in
 4 November 2022 to approve a permanent moratorium on shutoffs.²⁰³

5 The MPSC has other elements of a moratorium already in place, such as winter
 6 protection for seniors and low-income customers on a budget billing plan and for customers
 7 with documented medical conditions.²⁰⁴

8
 9 **Q: Could you recommend ways that DTE could use whatever resources it has to more**
 10 **effectively target households in the most burdened communities?**

11 **A:** Yes. Below is an example of how, using census tract data, DTE could propose an equitable
 12 distribution of benefits based on the percentiles for energy burden, federal indicators of
 13 disadvantaged census tracts used for Justice40,²⁰⁵ and the percentage of households below
 14 either 100% or 200% of FPL. In Figure 25 below, I have provided a matrix providing an
 15 example of how benefits could be maximized to protect vulnerable households such that

²⁰² Ex. FLO-165, *Winter and Covid-19 Shut-Off Moratoriums*, NATL ASS'N OF ENERGY ASSISTANCE DIRECTORS (Mar. 15, 2021), <https://neada.org/wintercovid19moratoriums/>.

²⁰³ Ex. FLO-166, L.A. DEP'T OF WATER & POWER, MOTION TO DISCONTINUE SHUT-OFFS AS AN ACCOUNT MANAGEMENT COLLECTION TOOL FOR CUSTOMERS ENROLLED IN LADWP EZ-SAVE AND LIFELINE DISCOUNT PROGRAMS (2022), at 1.

²⁰⁴ See MCL § 460.9r; see also Ex. FLO-167, SANYA CARLEY AND DAVID KONISKY, UTILITY DISCONNECTIONS DASHBOARD (2023), at 1.

²⁰⁵ Justice40 is an initiative created by President Joe Biden's Executive Order 14008 that requires federal agencies to ensure that 40% of the benefits of covered programs be distributed to "disadvantaged" census tracts. The White House's Council on Environmental Quality (CEQ) created the Climate and Economic Justice Screening Tool (CEJST) to define disadvantaged tracts. CEJST establishes thresholds for twenty-nine indicators; exceeding any threshold qualifies a tract as disadvantaged. The number of thresholds exceeded is a good measure of a community's exposure to environmental injustices. For more information, see <https://www.whitehouse.gov/environmentaljustice/justice40/> (Justice 40) and <https://screeningtool.geoplatform.gov/en/methodology#3/33.47/-97.5>.

the greatest share goes to the most vulnerable customers. In this example, I segment census tract vulnerability based on percentile buckets in these four categories (e.g., the second to fifth percentile is one bucket), and suggest specific program allotments that could align with vulnerability levels. I present this example to show that a robust, quantitative approach to achieving distributive equity is feasible and straightforward.

Figure 25: Sample approach to equitable distribution of program benefits based on census tract vulnerabilities.

Census Tract Variable	Top 2%	Benefits	2-5%	Benefits	5-10%	Benefits	10-25%	Benefits
Energy burden	21.5%	Automatic enrollment for the entire census tract	15.4%	Opt out based on MDHHS enrollments; reserve 15% of remaining slots (5x)	12.7%	Enrollment qualifies for 3 years; reserve 15% of remaining slots (3x)	8.2%	Priority outreach; reserve 30% remaining slots (2x)
# CEJST thresholds	10.2		10.2		8.4		3.8	
HH below 200% FPL	61.1%		60.8%		52.8%		43.1%	
HH below 100% FPL	39.5%		35.6%		28.6%		20.3%	

Q: Your third recommendation is to limit energy bills to 6% of income. How would this work?

A: Requiring a comprehensive affordability program, such as a PIPP, is an essential complement to a pause or moratorium on shutoffs. Indeed, the Commission has already approved a number of pilot programs that limit payments to a percent of income. For example, in 2022, the MPSC approved a pilot by Consumers Energy that sets a fixed monthly payment for gas and electricity that is set to 6% of income.²⁰⁶ The MPSC has also approved DTE's PSP pilot, but unfortunately, as discussed above, this program sets the combined gas and electric burden at 10% of income, which is not affordable.

²⁰⁶ *In re Consumers Energy*, MPSC Case No. U-21021, Order (Feb. 10, 2022).

1 Most importantly, the PIPP must be extended to all customers with energy burdens
 2 that exceed 6% of income and any DTE gas-only customers with gas burdens above 3% of
 3 income. These energy burdens are most concentrated among households with incomes
 4 below 60% of AMI,²⁰⁷ but a number of households with incomes between 60% and 100%
 5 AMI also have unaffordable energy burdens. DTE could include a billing insert that
 6 indicates income eligibility for each customer and the actions required to enroll in the PIPP
 7 based on the last twelve billing months,

8
 9 **Q: Is there precedent for a PUC to establish an affordability mechanism as part of a gas**
 10 **rate case?**

11 **A:** Yes. The Illinois Commerce Commission reviewed a series of proposals for a low-income
 12 discount credit (LIDC) in five gas rate cases in 2023. Ultimately, the Commission adopted
 13 a five-tiered LIDC that applies to the entire customer bill.²⁰⁸ The tiers were calibrated so
 14 that every household has an affordable gas energy burden of not more than 3% of
 15 income.²⁰⁹ This new structure that was created by an ICC order was not contingent upon
 16 any other elements of the rate cases.

²⁰⁷ See *supra* fig.8.²⁰⁸ See Ex. FLO-154 at 4.

²⁰⁸ See Ex. FLO-154 at 4.

²⁰⁹ *Id.* at 6.

Q: What would be a reasonable timeline for the MPSC to research affordability structures for DTE Gas customers in this rate case?

A: Fortunately, the MPSC has already done significant work to convene stakeholders around affordability, through the LIEPB, which coordinates the work of the EAAC and EWR-LI.²¹⁰ The members of these bodies have considerable experience, community relationships, and technical expertise to submit considerations and recommendations on affordability structures within ninety to 120 days. The MPSC might take another sixty days to review, summarize, and provide Staff input on the proposals received from the LIEPB, the EAAC, the EWR-LI, and other interested parties. A Commission order could reasonably be expected within nine months of initiating the proceeding. Utilities might have another 180 days to implement the program.

Q: Please summarize your recommendations regarding data collection and reporting.

A: I recommend that the MPSC reinstate the monthly reporting requirements that it initially repealed in MPSC Case No. U-20757.²¹¹ Monthly reporting is critical to track trends and differentiate seasonal energy burdens that are typically twice as high in winter, particularly for DTE Gas customers.

Second, I recommend that the MPSC set a firm timeline for DTE to begin these reports by census tract and zip code. Assuming DTE already has this data available, the Company could produce reports within thirty to sixty days.

²¹⁰ See Ex. FLO-156.

²¹¹ Dec. 21, 2023 U-20757 Order.

1 Third, I recommend that the MPSC require DTE to provide all reports in publicly
2 accessible and analyzable format, namely .csv or .xlsx. In many cases, DTE provides only
3 PDFs which cannot easily be converted. These files require extensive cleaning, which
4 materially burdens intervenors and introduces further opportunities for error.

5
6 **Q: What are your recommendations regarding fixed charges?**

7 A: MPSC should reject DTE's request to increase the fixed monthly customer charge by
8 30.4%.²¹² I believe that using *income-based* fixed charges to advance equity is worthy of
9 further exploration by the Commission (and the Michigan Legislature), but because it is
10 not an immediate option, the choice to reject a fixed fee increase is the most equitable
11 option in this rate case.

12
13 **Q: Please summarize your recommendations regarding the reduction of nonessential**
14 **spending.**

15 A: The investments in additional low-income programs such as PIPP can be offset by
16 disallowing spending not compatible with affordability and public health. While not the
17 focus of my testimony, I support the recommendations of my colleague FLO Witness
18 Jackson Koeppel to restrict DTE spending on aggressive investments in the gas system that
19 must be decommissioned in the near future as well as restrict exorbitant IT and marketing
20 investments.

²¹² Ex. A-16, Schedule F2, at 2.

1 I am especially concerned about DTE's marketing of natural gas for cooking and
2 ask the MPSC to ban this spending. Harm to health, particularly to children with asthma,
3 has been well documented.²¹³ The scientific consensus is particularly important in areas of
4 DTE's service territory like Detroit, where asthma rates are relatively high and climbing.
5 Asthma rates are 16% among Detroit adults compared to 11% in other Michigan adults,
6 and they are 14.6% among Detroit's children, which is 74% higher than those of children
7 outside of Detroit (8.4%).²¹⁴ It is imperative that the transition away from natural gas
8 happen as soon as possible, not just for the climate but especially for degraded indoor air
9 quality that results from natural gas stoves.

10 Multiple public authorities have taken similar steps to protect the public health by
11 banning smoking in public facilities. I recommend that the MPSC follow this lead for the
12 health of DTE customers by using its existing authority to bar DTE from marketing natural
13 gas stoves and cooking to any customer. Furthermore, in light of these urgent public health
14 concerns, I recommend that the MPSC revisit earlier decisions allowing DTE to incentivize
15 gas stoves and ask DTE to rebudget all incentives toward other EWR programs. I would
16 support further actions by the Commission to accelerate incentives specifically to help
17 households, especially those in pockets of high asthma and respiratory disease rates,
18 transition from gas to electric or induction stoves.

19
20 **Q: Does this conclude your written Direct Testimony?**

21 **A:** Yes.

²¹³ See generally Ex. FLO-151; Ex. FLO-152.

²¹⁴ See Ex. FLO-153.

1 MR. TEMPLETON: Thank you, your Honor.

2 Our third witness was Sergio Cira-Reyes. Mr. Reyes filed
3 written direct testimony consisting of one cover page and
4 42 pages of questions and answers. I will note that the
5 question and, the single question and answer on page 37
6 and 38 is confidential and it's subject to the
7 nondisclosure agreement. Mr. Cira-Reyes also sponsored
8 Exhibits FLO-201, or two-zero-one, through FLO-242, or
9 two-four-two, inclusive. The Exhibit FLO-239, or
10 two-three-nine is subject to the NDA. And, you know, in
11 terms of the confidential testimony and the confidential
12 exhibit, those will of course be filed directly and only
13 with those who have signed the NDA.

14 JUDGE THOITS: All right. Are there any
15 objections to the admission of this testimony or these
16 exhibits? (No response.)

17 Hearing none, the Direct Testimony of
18 Mr. Cira-Reyes is bound into the record, with the
19 exception of pages 37 and 38 which are bound into the
20 confidential record; and Exhibits FLO 209 through
21 FLO-242, excluding FLO-239, are admitted into the public
22 record, Exhibit FLO-239 is admitted into the confidential
23 record.

24 (Public testimony bound in.)

25 - - -

(Confidential testimony found on Page 1190 of the
Confidential Record.)

- - -

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of DTE	)	
GAS COMPANY for authority to increase	)	Case No. U-21291
its rates, amend its rate schedules and rules	)	
governing the distribution and supply of	)	ALJ Jonathan F. Thoits
natural gas, and for miscellaneous	)	
accounting authority.		

NON -CONFIDENTIAL DIRECT TESTIMONY OF SERGIO CIRA-REYES**ON BEHALF OF**

SOULARDARITY, URBAN CORE COLLECTIVE, AND WE WANT GREEN, TOO
(COLLECTIVELY, FRONTLINE ORGANIZATIONS (FLO))

May 7, 2024

1 **I. INTRODUCTION AND SUMMARY**

2 **Q: Please state your name, occupation, and business address.**

3 **A:** My name is Sergio Cira-Reyes, and I serve as the Climate Justice Catalyst at Urban Core
4 Collective (UCC), a nonprofit organization based at 413 Hall St. SE #1, Grand Rapids,
5 Michigan, 49507.

6
7 **Q: Have you participated in any previous Michigan Public Service Commission**
8 **(MPSC, or the Commission) proceedings?**

9 **A:** Yes, I provided (1) direct and rebuttal testimony in MPSC Case No. U-21389 for
10 Consumers Energy's rate case, (2) direct and rebuttal testimony in MPSC Case No. U-
11 21090 for Consumers Energy's Integrated Resource Plan (IRP), (3) direct testimony in
12 MPSC Case No. U-21224 for Consumers Energy's rate case, and (4) direct testimony in
13 MPSC Case No. U-21374 for Consumers Energy's Voluntary Green Pricing case. I also
14 led the development of UCC's strategy and positions regarding the settlements in U-21224
15 and U-21090.

16
17 **Q: Please describe your education and work experience.**

18 **A:** I lived in Los Angeles until I was twenty years old, when I transferred from community
19 college to Calvin College in Grand Rapids, Michigan, to study psychology and social work
20 from 2000 to 2002. Afterward, I worked simultaneously at a residential treatment facility
21 for minors and as a part-time translator for the courts. In 2010, I started work as a school
22 social worker and for a local organization called West Side Collaborative in Grand Rapids.
23 I have worked for UCC for the past several years, first as the Director of Community

1 Engagement and now in my current role as Climate Justice Catalyst, in which I lead the
2 organization's environmental justice efforts.

3 My approximately two decades of experience in both direct service roles and
4 systems change work allow me to understand the challenges faced by low-income
5 communities and communities of color, as well as the systems that limit their opportunities.
6

7 **Q: On whose behalf are you testifying?**

8 **A:** I am testifying on behalf of Urban Core Collective, Soulardarity, and We Want Green, Too.
9 Collectively, the groups are referred to as the Frontline Organizations (FLO) in this MPSC
10 proceeding.
11

12 **Q: What is Urban Core Collective?**

13 **A:** UCC is a 501(c)(3) organization founded in 2014 by six organizations based in western
14 Michigan. The three organizations comprising UCC are Baxter Community Center, Family
15 Outreach Center, Inc., and Urban League of West Michigan. The organizations pursue the
16 common goal of overcoming the effects of systemic racism by promoting equal access to
17 education, economic prosperity, health, power, and influence.¹ During my time at UCC, I
18 have worked with UCC's past and present member organizations and their constituents in
19 a variety of capacities, including by facilitating multiple public meetings, participating in
20 panels for our Transformational Leadership Programs, and participating in the interview
21 and selection process for this program for employees of our member organizations, among

¹ Ex. FLO-201, *About the Collective*, URB. CORE COLLECTIVE (last accessed Apr. 6, 2018),
<https://www.urbancorecollective.org/about>, at 1.

1 other activities. Additionally, since beginning my current role as Climate Justice Catalyst,
2 I have helped intervene in MPSC proceedings on behalf of UCC, as I noted above.
3

4 **Q: Can you provide examples of UCC's work regarding climate, energy, and the**
5 **environment?**

6 **A:** In 2019, UCC partnered with the City of Grand Rapids to carry out the Zero Cities Project
7 sponsored by the U.S. Sustainability Directors Network. This project sought to develop a
8 roadmap toward a net zero building sector by 2050. UCC's role involved engaging
9 residents on policy options, educating the public on the utility industry, and serving as an
10 equity consultant on policy design.² UCC also conducted a consumer survey on residential
11 energy services, receiving approximately 120 responses from residents who were primarily
12 renters, low-income, or Black, Indigenous, and People of Color (BIPOC).³ This survey
13 helped to identify residents' knowledge of various energy services related to energy
14 efficiency and financial assistance.⁴

15 In 2019, UCC and a group of City of Grand Rapids staff, community leaders, issues
16 experts, and environmental justice advocates formed the Community Collaboration on
17 Climate Change (C4) to develop a plan for climate justice in Grand Rapids.⁵ UCC's priority
18 as a member of C4 is to ensure equity is a central component of the group's work.

² See Ex. FLO-202, C4, ZERO CITIES PROJECT & HEZERO: MPSC EWR – LI MEETING (2021), at 11; see also Ex. FLO-203, C4 PLANNING TEAM, COMMUNITY COLLABORATION ON CLIMATE CHANGE (C4) (2021), at 10.

³ See Ex. FLO-202 at 42.

⁴ See *id.* at 44.

⁵ See *id.* at 4.

1 In 2022, UCC obtained a grant to conduct more community organizing and improve
2 voter access. We hired two new team members dedicated to this work to highlight energy
3 issues when working on voter engagement. From this grant, we have increased voter
4 turnout and have plans to continue this work through the 2024 election. We also have
5 implemented methods to use climate justice as a mechanism for voter turnout. As a result
6 of this improved voter turnout, we have seen increased climate messaging by political
7 candidates.

8 UCC intervened in Consumers Energy's IRP case (MPSC Case No. U-21090) and
9 partnered with Empower Michigan—a coalition of Michigan organizations that worked
10 together to increase public participation in the IRP process before the MPSC. UCC held a
11 public meeting on September 2021, in southeast Grand Rapids—in a zip code where the
12 population is approximately 30% Black and approximately 30% Latino—to provide
13 information to attendees about the IRP process. We discussed how the Commission works
14 and informed members of the public of the opportunities they had in presenting their
15 opinions to the Commission. UCC signed the IRP settlement in MPSC Case No. U-21090.
16 Of particular importance to UCC were the settlement agreement's provisions related to the
17 establishment of a fund to assist low-income customers; data-gathering improvements
18 related to environmental and energy justice; and increased engagement with the public
19 regarding utility planning.⁶

20 UCC also supports leaders of color in the environmental space by creating affinity
21 groups for persons of color to get outdoors and to discuss environmental issues relevant to
22 them.

⁶ See *In re Consumers Energy Company*, MPSC Case No. U-21090, Order (June 23, 2022), at 7–8.

1 I am knowledgeable about these activities and have participated in them as UCC's
2 lead staffer on environmental and energy issues. Working so closely with community
3 members has allowed me to understand the broad range of challenges they face and how
4 energy intersects with these challenges and concerns.

5
6 **Q: How else does UCC advocate for community members' interests?**

7 **A:** Outside of UCC's climate work, UCC has also worked on community engagement,
8 education justice, democratic participation, and public safety in Grand Rapids. For
9 instance, UCC convened a workgroup consisting of residents, neighborhood association
10 representatives, City of Grand Rapids officials and employees, and members of the clergy
11 to design a framework for how the City of Grand Rapids should engage with the public
12 when there are new development projects. As part of this project, UCC conducted in-person
13 meetings in Spanish and English and conducted multiple surveys. In education justice,
14 UCC is working with the Grand Rapids Public Schools as process monitors and is auditing
15 the district's strategic planning process. UCC is helping to inform the engagement process
16 to ensure that members of the public—including advocates and impacted communities—
17 can elevate their voices and shape outcomes. UCC's democratic participation work focuses
18 on increasing voter registration and raising awareness of voting procedures. UCC's work
19 in public safety has involved hosting multiple meetings with stakeholders in the community
20 who are interested in holding our local police department accountable and developing
21 strategies to empower residents to take ownership of their own safety. Finally, UCC has
22 leadership development programs for emerging leaders both within the community and
23 within our organization.

1 In sum, UCC's expertise lies in explaining complex institutions and systems of
2 power to local communities and in gathering input about how these institutions and systems
3 can better address community needs. Through this work, UCC is an effective advocate for
4 meaningful change and institutional accountability.

5
6 **Q: Why is UCC intervening in this case?**

7 **A:** UCC advocates for the interests of low-and-moderate income (LMI) and BIPOC
8 communities. As I establish in the following sections of this testimony, LMI and BIPOC
9 households often face an enormous burden in paying their gas bills. These households are
10 particularly vulnerable to the impacts of energy insecurity, which will only be exacerbated
11 by DTE Gas's call for higher rates. Where the threat of shutoff looms, these vulnerable
12 households are forced to make difficult cuts on consumption or face a shutoff; both of these
13 options deal considerable harm to households. These issues affect our community
14 members.

15
16 **Q: Please provide an overview of the topics you will discuss in your testimony.**

17 **A:** Part II discusses the importance of Energy Democracy, a core ideal that underlies much of
18 FLO's work. Part III discusses affordability and its impacts on LMI and BIPOC
19 communities. I first begin by noting the high prices and instability that occur in the gas
20 context, then I discuss how this volatility harms LMI and BIPOC communities through the
21 threat of shutoffs and the resulting impacts if a shutoff does occur. Part IV discusses how
22 the Company fails to alleviate the above impacts by failing to (1) ensure its bills are
23 affordable for residents and (2) proactively reach out to and educate ratepayers how its bill

assistance and billing programs function and how to enroll in them. Furthermore, I discuss how the Company's community outreach generally fails ratepayers.

Q: Are you sponsoring any exhibits?

A: Yes, I am sponsoring the following exhibits.

FLO-201. *About the Collective*, URB. CORE COLLECTIVE (last updated Apr. 6, 2018), <https://www.urbancorecollective.org/about>.

FLO-202. C4, ZERO CITIES PROJECT & HEZERO: MPSC EWR – LI MEETING (2021).

FLO-203. C4 PLANNING TEAM, COMMUNITY COLLABORATION ON CLIMATE CHANGE (C4) (2021).

FLO-204. GRIDWORKS, CALIFORNIA'S GAS SYSTEM IN TRANSITION: EQUITABLE, AFFORDABLE, DECARBONIZED, AND SMALLER (2019), https://gridworks.org/wp-content/uploads/2019/09/CA_Gas_System_in_Transition.pdf.

FLO-205. Michelle Graff, *Addressing Energy Insecurity: Policy Considerations for Enhancing Energy Assistance Programs*, HELIYON, Feb. 2024, <https://www.ncbi.nlm.nih.gov/pmc/articles/PMC10850901>.

FLO-206. *U.S. Energy Insecure Households Were Billed More for Energy Than Other Households*, U.S. ENERGY INFORMATION ADMIN. (May 30, 2023), <https://www.eia.gov/todayinenergy/detail.php?id=56640>.

FLO-207. FISHER, SHEEHAN & COLTON, MICHIGAN 2022: HOME ENERGY AFFORDABILITY GAP (2023), available as "Michigan 2022 HEAG Fact Sheet"

1 at <http://www.homeenergyaffordabilitygap.com/downloads/2022>

2 [_Released_Apr23/ZIP_Archives/2022_Michigan.zip](#).

3 FLO-208. *QuickFacts: Grand Rapids City, Michigan*, U.S. CENSUS BUREAU (2023),

4 <https://www.census.gov/quickfacts/fact/table/grandrapidscitymichigan/IPE120>

5 [222#IPE120222](#).

6 FLO-209. URB. CORE COLLECTIVE, EQUITY ASSESSMENT TOOL: ZERO CITIES PROJECT 5

7 (2020).

8 FLO-210. *QuickFacts: Kent County, Michigan*, U.S. CENSUS BUREAU (2023),

9 <https://www.census.gov/quickfacts/fact/table/kentcountymichigan/PST045223>.

10 FLO-211. FISHER, SHEEHAAN & COLTON, MICHIGAN 2022: HOME ENERGY

11 AFFORDABILITY GAP (2023), available as “Michigan HEAG2022 XL Detail”

12 at http://www.homeenergyaffordabilitygap.com/downloads/2022_Released

13 [_Apr23/ZIP_Archives/2022_Michigan.zip](#).

14 FLO-212. SELAH GOODSON BELL ET AL., CTR FOR BIOLOGICAL DIVERSITY, ENERGY &

15 POL’Y INST. & BAILOUTWATCH, POWERLESS IN THE UNITED STATES: HOW

16 UTILITIES DRIVE SHUTOFFS AND ENERGY INJUSTICE (2021).

17 FLO-213. Nicole Goodkind, *Predatory Lenders are Making Money off Rising Gas and*

18 *Food Prices*, CNN (June 30, 2022), <https://www.cnn.com/2022/06/23/>

19 [business/money/payday-predatory-lending-inflation-gas/index.html](https://www.cnn.com/2022/06/23/business/money/payday-predatory-lending-inflation-gas/index.html).

20 FLO-214. *Payday Lending in America: Who Borrows, Where They Borrow, and Why*,

21 PEW. (July 19, 2012), <https://www.pewtrusts.org/en/research-and->

22 [analysis/reports/2012/07/19/who-borrows-where-they-borrow-and-why](https://www.pewtrusts.org/en/research-and-analysis/reports/2012/07/19/who-borrows-where-they-borrow-and-why).

1 FLO-215. *Predatory Lending*, NAT'L ASS'N OF CONSUMERS ADVOCATES (July 19, 2012),
 2 <https://www.consumeradvocates.org/for-consumers/predatory-lending/>.

3 FLO-216. *Quality of Housing*, U.S. DEP'T OF HEALTH & HUM. SERVS. (last updated Aug.
 4 6, 2022), [https://health.gov/healthypeople/priority-areas/social-determinants-](https://health.gov/healthypeople/priority-areas/social-determinants-health/literature-summaries/quality-housing)
 5 [health/literature-summaries/quality-housing](https://health.gov/healthypeople/priority-areas/social-determinants-health/literature-summaries/quality-housing).

6 FLO-217. Rohith Teja Mittakola et al., *Drivers of Natural Gas Use in U.S. Residential*
 7 *Buildings*, 10 SCI. ADVANCES 6 (2024).

8 FLO-218. *Midwest Homes, Notably Older Homes, Consumer More Natural Gas Than*
 9 *Most Other States*, U.S. ENERGY INFORMATION ADMIN. (Aug. 7, 2023),
 10 [https://www.eia.gov/todayinenergy/detail.php?id=57321&src=%E2%80%B9](https://www.eia.gov/todayinenergy/detail.php?id=57321&src=%E2%80%B9%20Consumption%20%20%20%20%20%20Residential%20Energy%20Consumption%20Survey%20(RECS)-b2)
 11 [%20Consumption%20%20%20%20%20%20Residential%20Energy%20Cons](https://www.eia.gov/todayinenergy/detail.php?id=57321&src=%E2%80%B9%20Consumption%20%20%20%20%20%20Residential%20Energy%20Consumption%20Survey%20(RECS)-b2)
 12 [umption%20Survey%20\(RECS\)-b2](https://www.eia.gov/todayinenergy/detail.php?id=57321&src=%E2%80%B9%20Consumption%20%20%20%20%20%20Residential%20Energy%20Consumption%20Survey%20(RECS)-b2).

13 FLO-219. U.S. ENERGY INFORMATION ADMIN., TABLE HC11.1 HOUSEHOLD ENERGY
 14 INSECURITY, 2020 (2023),
 15 [https://www.eia.gov/consumption/residential/data/2020/hc/pdf/HC%2011.1.p](https://www.eia.gov/consumption/residential/data/2020/hc/pdf/HC%2011.1.pdf)
 16 [df](https://www.eia.gov/consumption/residential/data/2020/hc/pdf/HC%2011.1.pdf).

17 FLO-220. WORLD HEALTH ORGANIZATION, WHO HOUSING AND HEALTH GUIDELINES
 18 (2018), [https://www.ncbi.nlm.nih.gov/books/NBK535293/](https://www.ncbi.nlm.nih.gov/books/NBK535293/pdf/Bookshelf_NBK535293.pdf)
 19 [pdf/Bookshelf_NBK535293.pdf](https://www.ncbi.nlm.nih.gov/books/NBK535293/pdf/Bookshelf_NBK535293.pdf).

20 FLO-221. Diana Hernández, *Understanding 'Energy Insecurity' and Why It Matters to*
 21 *Health*, 167 SOC. SCI. & MED. 1 (2016).

22 FLO-222. DTE's Response to FLO's Second Discovery Request, FLODG-2.3b–2.4b.

23 FLO-223. DTE's Response to FLO's First Discovery Request, FLODG-1.18c.

- 1 FLO-224. DTE's Response to FLO's First Discovery Request, FLODG-1.18a.
- 2 FLO-225. DTE's Response to FLO's First Discovery Request, FLODG-1.17.
- 3 FLO-226. DTE's Response to FLO's Second Discovery Request, FLODG-2.1.
- 4 FLO-227. DTE's Response to FLO's Third Discovery Request, U-21291 FLODG-3.5d
- 5 03 Payment Assist Bill Insert 2023-24.
- 6 FLO-228. *Low-Income Programs*, DTE (last accessed May 4, 2024),
- 7 <https://perma.cc/AX5K-FGYX>.
- 8 FLO-229. DTE's Response to FLO's Third Discovery Request, FLODG-3.4b–3.4c.
- 9 FLO-230. DTE's Response to FLO's Third Discovery Request, U-21291 FLODG-3.6a
- 10 Gas_LIA-LSP and non-LSP.
- 11 FLO-231. DTE's Response to FLO's Third Discovery Response, FLODG-3.1a–3.1b.
- 12 FLO-232. DTE's Response to FLO's Third Discovery Response, FLODG-3.2.
- 13 FLO-233. DTE's Response to FLO's Second Discovery Request, FLODG 2.6a.
- 14 FLO-234. DTE's Response to FLO's First Discovery Request, FLODG-1.19.
- 15 FLO-235. DTE's Response to FLO's First Discovery Request, FLODG-3.3a–3.3b.
- 16 FLO-236. DTE's Response to FLO's Seventh Discovery Request, FLODG-7.1b.
- 17 FLO-237. *What Is Average Speed of Answer? Strategies and Calculation*, CALL CTR.
- 18 STUDIO (Jan. 5, 2024), [https://callcenterstudio.com/blog/what-is-average-](https://callcenterstudio.com/blog/what-is-average-speed-of-answer-strategies-and-calculation/)
- 19 [speed-of-answer-strategies-and-calculation/](https://callcenterstudio.com/blog/what-is-average-speed-of-answer-strategies-and-calculation/).
- 20 FLO-238. *Michigan Energy Assistance Program Frequently Asked Questions*, MICH.
- 21 PUB. SERV. COMM'N (last accessed May 4, 2024), [https://www.michigan.gov/-](https://www.michigan.gov/-/media/Project/Websites/mpsc/consumer/meap/MEAP_FAQs.pdf?rev=2ba17357b585490195c365457037102c)
- 22 [/media/Project/Websites/mpsc/consumer/](https://www.michigan.gov/-/media/Project/Websites/mpsc/consumer/meap/MEAP_FAQs.pdf?rev=2ba17357b585490195c365457037102c)
- 23 [meap/MEAP_FAQs.pdf?rev=2ba17357b585490195c365457037102c](https://www.michigan.gov/-/media/Project/Websites/mpsc/consumer/meap/MEAP_FAQs.pdf?rev=2ba17357b585490195c365457037102c).

FLO-240. DTE's Response to FLO's Third Discovery Request, U-21291 FLODG-3.5a-c
2021-2024 CAD CRF POP UPS.

FLO-241. *BudgetWise Billing*, DTE (last accessed Apr. 19, 2024), <https://www.dteenergy.com/us/en/business/billing-and-payments/payment-programs/bwb.html>.

FLO-242. DTE's Response to FLO's Fourth Discovery Request, FLODG-4.1d.

II. ENERGY DEMOCRACY

Q: How do you define “energy democracy”?

A: The core of “energy democracy” is that ratepayers must have a voice in determining how their energy is generated and distributed and that LMI and BIPOC ratepayers and communities have ownership of distributed resources.

Q: How does your conception of energy democracy relate to this case?

A: As I will discuss more below, understanding affordability and equity is critical in the context of the transition away from natural gas and towards electrification. As electrification occurs, communities that do not electrify are forced to pay for the fixed costs of maintaining the gas distribution infrastructure. As more and more households leave the gas system, these fixed system costs become increasingly unaffordable for those who remain. And because the households with the capital and cash flow to electrify are

1 typically wealthier and whiter, BIPOC and LMI households will likely be stuck with the
2 gas system and its increasingly unaffordable costs.⁷

3 Many LMI and BIPOC communities cannot afford to transition from gas
4 appliances to electric ones on their own, but they also will not be able to support
5 financially the last vestiges of the gas industry either. Thus, the need to have these voices
6 in the discussion is of paramount importance to an equitable energy transition. By
7 introducing these perspectives in this proceeding, FLO hopes to create a more inclusive,
8 just transition that addresses community concerns.

9
10 **Q: Do you have any concerns regarding DTE Gas’s approach to customer education of**
11 **MPSC proceedings?**

12 **A:** The Company does not educate its customers proactively about these MPSC proceedings.
13 In recent years, the Commission has made strides in improving community awareness of
14 rate cases and other MPSC proceedings. For instance, in December 2022, the MPSC
15 approved a settlement agreement in Case No. U-21224. In the agreement, Consumers
16 Energy agreed to “schedule a customer outreach within three weeks after the date of
17 filing its next electric rate case.”⁸ There are still shortcomings with Consumer Energy’s
18 customer outreach, which I have argued in previous MPSC proceedings.⁹ However, it is

⁷ Ex. FLO-204, GRIDWORKS, CALIFORNIA’S GAS SYSTEM IN TRANSITION: EQUITABLE, AFFORDABLE, DECARBONIZED, AND SMALLER (2019), https://gridworks.org/wp-content/uploads/2019/09/CA_Gas_System_in_Transition.pdf, at 7–9.

⁸ *In re Consumers Energy*, MPSC Case No. U-21224, Settlement Agreement (Dec. 22, 2022), at 10.

⁹ See *In re Consumers Energy*, MPSC Case No. U-21389, U-21389-0225, Cira-Reyes Direct Testimony (Aug. 29, 2023), at 23 (“Only one table at [Consumer Energy pilot outreach] had information about the instant case and solicited public comments from community members, while the rest of the tables provided information about assistance programs.”).

undeniable that the Commission’s order in U-21224 provided a crucial step in advancing energy democracy. The last time DTE Gas filed a rate case was 2021.¹⁰ In that order, the Commission was silent on customer outreach. Thus, while electric rate cases have become increasingly publicized and accessible to the public, gas cases have lagged behind in awareness. The virtues of public participation, namely customer education on the drivers of rate increases and input into projects that are in the public’s interest, are equally valid in the gas context as the electric context.¹¹

Going forward, the Commission should order that the Company schedule customer outreach, as it did in MPSC Case No. U-21224.

III. AFFORDABILITY

Q: What are some of the challenges faced by LMI and BIPOC customers when it comes to their gas bills?

A: LMI and BIPOC customers are more likely to experience energy insecurity than wealthier, whiter customers.¹² Energy insecurity is driven by a combination of factors, including (1) economic energy insecurity as a result of high and unpredictable gas bills and (2) physical energy insecurity as a result of “deficiencies in the infrastructure of a

¹⁰ See generally *In re DTE Gas Company*, MPSC Case No. U-20940, Order (Dec. 9, 2021).

¹¹ See, e.g., *In re Consumers Energy*, MPSC Case No. U-21224, Settlement Agreement (Dec. 22, 2022), at 10.

¹² See, e.g., Ex. FLO-205, Michelle Graff, *Addressing Energy Insecurity: Policy Considerations for Enhancing Energy Assistance Programs*, HELIYON, Feb. 2024, <https://www.ncbi.nlm.nih.gov/pmc/articles/PMC10850901>, at 2–3; Ex. FLO-206, *U.S. Energy Insecure Households Were Billed More for Energy Than Other Households*, U.S. ENERGY INFORMATION ADMIN. (May 30, 2023), <https://www.eia.gov/todayinenergy/detail.php?id=56640>, at 1–2; see also Schott Direct Testimony, Part III.

home.¹³ Both economic and physical energy insecurity present significant harm to LMI, BIPOC residents, including by often putting these residents in positions where they must choose to forego other essential needs.¹⁴

Q: Are DTE Gas's monthly bills affordable for LMI customers?

A: No, DTE Gas's monthly bills are not affordable for LMI customers, resulting in significant economic energy insecurity for many LMI customers. Currently, LMI residents, who are least able to afford their energy bills, are paying the highest proportion of their incomes toward their energy bills. Although DTE Gas offers some programs that purport to address the affordability crisis, these programs fall far short of the needs of LMI customers. DTE Gas's current programs include: the Low-Income Self-Sufficiency Program (LSP), Low-Income Assistance (LIA) credit, Residential Income Assistance (RIA) credit, and Payment Stability Plan (PSP) pilot.¹⁵

As Witness Schott explains further, LMI residents are more likely to face high and unaffordable gas bills and higher disconnection rates.¹⁶ According to the 2022 Home Energy Affordability Gap report, energy burdens are 38% on average for Michigan households below 50% FPL, 20% for households between 50% and 100%, 14% for households between 100% and 125%, 11% for households between 125% and 150%, 9 % for households between 150% and 185%, and 8% for households between 185% and

¹³ Ex. FLO-205 at 2.

¹⁴ *See id.* The "strategies employed to alleviate the effects of economic and physical energy insecurity" are referred to as coping energy insecurity. *Id.*

¹⁵ *See* Sparks Direct Testimony at 4.

¹⁶ *See* Schott Direct Testimony, Parts III and IV.

200%.¹⁷ These numbers are astoundingly high.¹⁸ It is well established at that an energy burden above 6% is unaffordable.¹⁹ As Witness Schott explains further, an energy burden above 9% is “high”; an energy burden above 15% is “severe”; and an energy burden above 18% is “catastrophic.”²⁰

In Kent County, Michigan, where Urban Core Collective is based,²¹ approximately one in four households are below 200% of the Federal Poverty Level (FPL) and face high or severe energy burdens.²² A recent analysis found that, in 2022, 11,839 households were below 50% of the FPL and experienced home energy burdens on average of 37%.²³ Kent County households between 50% and up to 100% of the FPL

¹⁷ Ex. FLO-207, FISHER, SHEEHAN & COLTON, THE HOME ENERGY AFFORDABILITY GAP 2022: MICHIGAN (2023), available as “Michigan 2022 HEAG Fact Sheet” at http://www.homeenergyaffordabilitygap.com/downloads/2022_Released_Apr23/ZIP_Archives/2022_Michigan.zip, at 1.

¹⁸ In total, Michigan households spend nearly \$2.1 million more on their energy bills than they can afford. *Id.* at 2.

¹⁹ See Schott Direct Testimony, Part III.

²⁰ See Schott Direct Testimony, Part III.

²¹ In Grand Rapids, specifically, the 2022 median household income is approximately \$61,600, and 19% of people live in poverty (below 100% FPL). Ex. FLO-208, *QuickFacts: Grand Rapids City, Michigan*, U.S. CENSUS BUREAU (2023), <https://www.census.gov/quickfacts/fact/table/grandrapidscitymichigan/IPE120222#IPE120222>, at 2. These numbers breakdown disproportionately by race/ethnicity. For Black residents in Grand Rapids, for example, the 2019 median household income was only \$34,343, and the median income for Hispanic and Latinx residents was \$43,442. Ex. FLO-209, URB. CORE COLLECTIVE, EQUITY ASSESSMENT TOOL: ZERO CITIES PROJECT (2020), at 5.

²² As of 2022, there were approximately 252,694 households in Kent County, Michigan. Ex. FLO-210, *QuickFacts: Kent County, Michigan*, U.S. CENSUS BUREAU (2023), <https://www.census.gov/quickfacts/fact/table/kentcountymichigan/PST045223>, at 1. Approximately 66,826 of these households were below 200% FPL. Ex. FLO-211, FISHER SHEEHAN & COLTON, Michigan 2022: Home Energy Affordability Gap (2023), available as “Michigan HEAG2022 XL Detail” at http://www.homeenergyaffordabilitygap.com/downloads/2022_Released_Apr23/ZIP_Archives/2022_Michigan.zip, at 20.

²³ Ex. FLO-211 at 2. This was equivalent to a shortfall (“affordability gap”) of \$2,609 per household or almost \$31 million across all households below 50% FPL. *Id.*

(14,254 households) experienced energy burdens of 19.7% on average.²⁴ Energy burdens were 13.2% on average for the 9,297 households between 100% and up to 125% FPL²⁵ and 10.8% for the 9,521 households between 125% and up to 150% FPL.²⁶ According to the same analysis, households between 150% and up to 200% FPL continue to experience energy burdens of more than 6%.²⁷ For all households below 200% FPL (66,826 households), the total “affordability gap” was \$110.4 million—meaning these Kent County residents were charged \$110.4 million more than what they could afford on energy.²⁸ This affordability gap problem is not unique to Kent County. Instead, it persists across DTE Gas’s service territory.²⁹

Adding to the economic insecurity is LMI residents’ higher vulnerability to the volatility in gas bills and prices. Although all residents’ gas bills fluctuate on a seasonal basis (with higher bills in the winter months) and on a year-to-year basis (depending on the global gas market),³⁰ LMI residents are least equipped to financially cope with these types of volatility. Thus, LMI residents are often left to “bear[] the brunt” of the volatility.³¹ And, because LMI residents—many of whom live paycheck to paycheck and

²⁴ *Id.* at 5. This amounts to an affordability gap of another \$31 million across all households between 50% and 99% FPL.

²⁵ *Id.* at 8. The affordability gap was approximately \$16 million. *Id.*

²⁶ *Id.* at 11. The affordability gap was approximately \$13 million. *Id.*

²⁷ *Id.* at 14 (showing an energy burden of 8.8% and affordability gap of approximately \$15 million for households between 150% and 184% FPL); *id.* at 17 (showing an energy burden of 7.7% and affordability gap of approximately \$4.6 million for households between 185% and 200% FPL).

²⁸ *Id.* at 20.

²⁹ See Schott Direct Testimony, Part III.

³⁰ See Ex. FLO-212, SELAH GOODSON BELL ET AL., CTR FOR BIOLOGICAL DIVERSITY, ENERGY & POL’Y INST. & BAILOUTWATCH, POWERLESS IN THE UNITED STATES: HOW UTILITIES DRIVE SHUTOFFS AND ENERGY INJUSTICE (2021), at 21–22.

³¹ See *id.* at 19.

month to month—often cannot afford or keep up with these sudden bill increases, it puts them at a higher risk of a gas shutoff.

Q: What are some impacts of economic energy insecurity on LMI households?

A: When LMI households face high energy burdens, they often must make tradeoffs with spending on other essentials, such as groceries and healthcare. For example, many households may be forced to decide whether to “heat or eat.” According to one study, households in Michigan making less than \$50,000 per year often reduce their spending on essentials such as food and medicine in order to afford their energy bill.³² LMI households are confronted with these difficult choices at twice the rate of non-LMI households.³³ For those in the position of needing to choose between heat and other necessities, there are no good choices. Households who must make tradeoffs between the cost of energy, food, and healthcare may, for example, experience significant health issues as well as higher healthcare costs in the long term.

Where tradeoffs are not possible, some residents may turn to predatory payday lending institutions. Predatory payday lending is a growing concern among LMI households across the nation as they struggle to pay for necessities like food and gas as a result of inflation.³⁴ While we typically think of loans as being used for one-time expenditures, a study by Pew Research indicates that for first-time borrowers, 69% were

³² See *In Re Consumers Energy*, MPSC Case No. U-21389, U-21389-0225, Cira-Reyes Direct Testimony (Aug. 29, 2023), at 16.

³³ See *id.*

³⁴ See Ex. FLO-213 Nicole Goodkind, *Predatory Lenders are Making Money off Rising Gas and Food Prices*, CNN (June 30, 2022) <https://www.cnn.com/2022/06/23/business/money/payday-predatory-lending-inflation-gas/index.html>, at 3.

1 using loans to cover recurring payments including utilities, rent, and food.³⁵ These loans
 2 can have enormous interest rates. Payday loans common include a loan charge anywhere
 3 from “\$10–\$30 for every \$100 borrowed, so a \$500 loan would include an extra \$50–
 4 \$150.”³⁶ For households that are already struggling to pay their bills, that interest
 5 severely cuts into their limited financial resources, feeds predatory bill collection
 6 practices, and further forces households into poverty.

7 If a household is ultimately unable to pay its gas bills, a shutoff can further
 8 exacerbate existing financial challenges. Residents may be forced to pay a deposit or
 9 reconnection fee, on top of the monthly gas bill that they already could not afford.
 10 Moreover, once residents lose access to heating or appliances such as stoves and dryers,
 11 they may be forced to spend more on alternatives. For those with gas stoves and ovens,
 12 for example, shutoffs can cut off their ability to cook for themselves using the groceries
 13 they have already bought. This places a heightened strain on residents to seek food
 14 elsewhere, requiring further expenses related to transportation and takeout or delivery
 15 services. Such spending inhibits one’s ability to save up to return service.

16
 17 **Q: How does physical energy insecurity make LMI and BIPOC communities**
 18 **particularly vulnerable to the above problems?**

19 **A:** A disproportionate number of LMI and BIPOC residents live in homes with poor
 20 insulation and poor energy efficiency, resulting in higher gas usage than these residents

³⁵ Ex. FLO-214, *Payday Lending in America: Who Borrows, Where They Borrow, and Why*, PEW. (July 19, 2012) <https://www.pewtrusts.org/en/research-and-analysis/reports/2012/07/19/who-borrows-where-they-borrow-and-why>, at 2.

³⁶ Ex. FLO-215, *Predatory Lending*, NAT’L ASS’N OF CONSUMERS ADVOCATES (July 19, 2012), <https://www.consumeradvocates.org/for-consumers/predatory-lending/>, at 2.

would otherwise require.³⁷ Various factors contribute to the problem of physical energy insecurity, including the age and quality of a building.³⁸ As one 2024 study of the Midwest concluded, for example, factors like insulation related to the age of the house are critical in assessing the gas consumption temperature threshold. . . . The presence of well-insulated buildings plays a crucial role for gas consumption in this region.”³⁹

First, wealthier households tend to consume less gas than poorer households. One study found that wealthier households consume 57% less gas for heating than poorer households, “[d]espite [wealthier households] living in larger and single-family houses.”⁴⁰ This difference is often driven by the age of a home, with poorer households being more likely to live in older homes.⁴¹ In the Midwest, one study found that homes built since 2010 consumed 48.9 MMBtu of natural gas on average for space heating while the average for homes built before 1950 was 74.9 MMBtu.⁴² Similarly, “[o]f the midwestern homes built before 1970, 27% reported having poor or no insulation,

³⁷ Ex. FLO-205 at 1, 2 (defining vulnerable populations as “historically marginalized communities and tenants,” and finding that “[n]ational, regional, and local research reveals vulnerable populations disproportionately experience both economic and physical energy insecure conditions.”); *see also id.* (“[T]hose reporting physical energy insecurity (e.g., poor insulation) were more likely to experience economic energy insecurity . . .”); Ex. FLO-216, *Quality of Housing*, U.S. DEP’T OF HEALTH & HUM. SERVS. (last updated Aug. 6, 2022), <https://health.gov/healthypeople/priority-areas/social-determinants-health/literature-summaries/quality-housing>, at 2 (“[L]ow-income families may be more likely to live in older homes and homes with greater risks that can impact health outcomes. For example, these homes may be under-insulated, lack air conditioning, and cost more to heat, leaving homes too hot or too cold, which has been linked to poorer health outcomes.”).

³⁸ Ex. FLO-209 at 4; Ex. FLO-217, Rohith Teja Mittakola et al., *Drivers of Natural Gas Use in U.S. Residential Buildings*, 10 SCI. ADVANCES 1 (2024), at 6.

³⁹ Ex. FLO-217 at 6.

⁴⁰ *Id.* at 8.

⁴¹ Ex. FLO-216 at 2.

⁴² Ex. FLO-218, *Midwest Homes, Notably Older Homes, Consume More Natural Gas Than Most Other States*, U.S. ENERGY INFORMATION ADMIN. (Aug. 7, 2023), [https://www.eia.gov/todayinenergy/detail.php?id=57321&src=%E2%80%B9%20Consumption%20%20%20%20%20Residential%20Energy%20Consumption%20Survey%20\(RECS\)-b2](https://www.eia.gov/todayinenergy/detail.php?id=57321&src=%E2%80%B9%20Consumption%20%20%20%20%20Residential%20Energy%20Consumption%20Survey%20(RECS)-b2).

1 compared with just 11% of homes built since 1970.”⁴³ For U.S. households as a whole,
 2 energy expenditures per square foot were \$1.00 for “well/adequately insulated” homes
 3 yet \$1.23 for “poorly/not insulated” homes.⁴⁴

4 Second, those living in older homes, including and especially LMI residents, are
 5 more likely to be energy insecure and face additional problems as a result. As reported in
 6 one 2020 U.S. Energy Information Administration survey, those living in older housing
 7 stock are more likely to face energy insecurity, reduce or forgo food or medicine to pay
 8 their energy costs, leave their home at unhealthy temperatures, and receive disconnection
 9 notices.⁴⁵ Of those with no or poor insulation, approximately 47% report experiencing
 10 energy insecurity and approximately 18% reported receiving a disconnection notice.⁴⁶

11 Low quality housing stock becomes a vicious cycle when residents are faced with high
 12 energy burdens. A high bill drives residents into lower-quality homes whose rent they can
 13 afford, but this often in turn drives up the residents’ utility bills. Third, the inability to heat
 14 one’s home, due to the unaffordability of energy, is hazardous to health. Cold air
 15 temperatures negatively impact health by “inflam[ing] lungs and inhibit[ing] circulation,
 16 increasing the risk of respiratory conditions, such as asthma attacks or symptoms,
 17 worsening of chronic obstructive pulmonary disease (COPD), and infection.”⁴⁷ When
 18 humans are exposed to prolonged cold indoor air temperatures, they tend to exhibit

⁴³ *Id.* at 2.

⁴⁴ Ex. FLO-206 at 2.

⁴⁵ Ex. FLO-219, U.S. ENERGY INFORMATION ADMIN., TABLE HC11.1 HOUSEHOLD ENERGY INSECURITY, 2020, at 2 (2023), <https://www.eia.gov/consumption/residential/data/2020/hc/pdf/HC%2011.1.pdf>.

⁴⁶ *Id.* at 3. These figures compare to approximately 22% who report energy insecurity with well or adequate insulation and 8% who report having received a disconnection notice. *Id.*

⁴⁷ Ex. FLO-220, WORLD HEALTH ORG., WHO HOUSING AND HEALTH GUIDELINES (2018), https://www.ncbi.nlm.nih.gov/books/NBK535293/pdf/Bookshelf_NBK535293.pdf, at 52.

1 “increased blood pressure, asthma symptoms and poor mental health,” which tends to
2 lead to an increase in winter mortality.⁴⁸

3 Although Michigan’s Winter Protection Plan (WPP) restricts gas utilities from
4 shutting off gas service between November 1 and March 31,⁴⁹ the program does not
5 include all types of residents (such as those who fall right above the income thresholds)
6 or cold periods outside of these windows. As a result, when the Company shuts off gas to
7 a house that is not eligible for shutoff protections via WPP, there is a serious risk,
8 especially in winter, of contributing to negative health outcomes.

9
10 **Q: How does coping with unaffordable energy bills contribute to psychological**
11 **distress?**

12 **A:** Unaffordable energy bills contribute to psychological stress in both children and adults.
13 One study found that energy insecurity was linked to stress associated with family
14 disruption, societal stigma, and residential instability.⁵⁰ One respondent in that study
15 noted the following: “I went into a depression, you know, ‘cause I’m trying to show them
16 my bill and everything and don’t nobody ever have funds for me.”⁵¹ The authors of the
17 study concluded that “these results should be used to inform larger epidemiological
18 studies to validate the links between energy insecurity. . . and mental health.”⁵² Hopefully

⁴⁸ *Id.*

⁴⁹ *See* MCL 460.9r.

⁵⁰ *See generally* Ex. FLO-221, Diana Hernández, *Understanding ‘Energy Insecurity’ and Why It Matters to Health*, 167 SOC. SCI. & MED. 1 (2016).

⁵¹ *Id.* at 20.

⁵² *Id.* at 9.

research can be further advanced in this area, but it is clear that negative health impacts stemming from energy insecurity are harming residents.

IV. DTE GAS’S BILL ASSISTANCE AND BILLING PROGRAMS ARE DEFICIENT

Q: What bill assistance and billing programs does DTE Gas currently operate?

A: DTE Gas operates several bill assistance programs, including the Low-Income Self-Sufficiency Plan,⁵³ Low-Income Assistance credit,⁵⁴ and Residential Income Assistance credit.⁵⁵ From 2022 to 2023, DTE Gas also offered a Payment Stability Plan pilot program.⁵⁶ In addition to the above bill assistance programs, DTE Gas separately operates its “BudgetWise” billing program.⁵⁷

A. Bill Assistance Programs

Q: What is your view on the effectiveness of these various assistance programs?

A: As a whole, DTE Gas’s collection of various assistance programs is ineffective and does not address the underlying problems with the Company’s unaffordable gas bills. DTE Gas states that one of the goals of its assistance programs is “[e]mpowerment and [s]elf-[s]ufficiency” in order to “equip customers with the tools to afford the actual costs of their energy consumption over time.”⁵⁸ However, the programs as proposed are drastically insufficient to meet that goal. Instead, they largely keep customers in a

⁵³ Sparks Direct Testimony at 7–10.

⁵⁴ *Id.* at 14–18.

⁵⁵ *Id.* at 12–14.

⁵⁶ *Id.* at 10–12.

⁵⁷ *See* Hatsios Direct Testimony at 14.

⁵⁸ Sparks Direct Testimony at 5.

1 perpetual state of financial distress. Many of DTE Gas's programs appear to be designed
2 to provide short-term assistance to customers to help them get back on their feet once
3 they've fallen behind on their bills, but programs such as these do nothing to make DTE
4 Gas's bills affordable in the first instance—before customers begin falling behind and
5 suffer the negative impacts of struggling to afford energy. Without tying bill assistance to
6 what customers can actually afford, these assistance programs will not address the core
7 issue: for many, DTE Gas is charging unaffordable prices to heat their homes.

8
9 **Q: Given your view that DTE Gas's assistance programs are ineffective, how do you**
10 **recommend the MPSC address the affordability problem?**

11 **A:** In order to begin addressing the affordability gap, DTE Gas must replace its various,
12 disjointed assistance programs with one unified, central program that ensures customers
13 are not paying more for their energy bills than they can afford. Simply implementing
14 incremental and marginal changes to DTE Gas's current amalgamation of programs, as
15 DTE Gas and the MPSC have done in the past, is itself insufficient to address the scope
16 of the affordability gap. Indeed, the scope of the affordability problem, as laid out by
17 Witness Schott, suggests that DTE Gas's assistance programs are woefully insufficient.⁵⁹

18 While I strongly recommend that the MPSC direct DTE Gas to restructure its
19 assistance programs, in the absence of this necessary restructuring, I have proposed
20 below some other changes that the MPSC should approve. These changes would
21 materially improve the assistance programs that DTE Gas currently runs.

⁵⁹ See Schott Direct Testimony, Part IV.

Q: Please summarize your specific recommendations to the MPSC, in the absence of a broader restructuring of DTE Gas’s assistance programs.

A: Should the MPSC choose to continue allowing DTE Gas to run its amalgamation of assistance programs, I recommend the below: (1) the MPSC should expand the amount, enrollment, and transparency of the LIA credit; (2) the MPSC should clarify that the purpose of the RIA credit is to cover 100% of each bill’s monthly customer charge and that LIA participation should not disqualify customers from receiving the RIA credit; (3) finish summary of our asks]. I discuss each in turn below.

Q: Please describe the Low-Income Assistance credit.

A: The MPSC first approved a \$30 LIA credit for eligible low-income customers beginning in MPSC Case No. U-17999.⁶⁰ At the time of its 2017 implementation, the \$30 credit covered approximately 68% of the customer’s typical monthly bill—defined as the “customer and distribution charges.”⁶¹ Since its inception, only customers with household incomes below 150% FPL and who maintain “eligible low-income status” may receive the LIA credit.⁶² However, DTE Gas states that it prioritizes LSP participants for the LIA,⁶³ meaning that customers who would otherwise qualify for the LIA credit are not receiving the credit. As of the last rate case, the LIA credit has remained at \$30 but covered only 58% of a customer’s bill.⁶⁴ In the instant case, DTE Gas proposes to

⁶⁰ Sparks Direct Testimony at 17; *In re DTE Gas Co.*, MPSC Case No. U-17999, Order (Dec. 9, 2016), at 61–63.

⁶¹ Sparks Direct Testimony at 17.

⁶² *See id.* at 14.

⁶³ *Id.* at 15.

⁶⁴ *Id.* at 17.

1 increase the credit to \$40, which would cover approximately 60% of a customer's bill.⁶⁵

2 DTE Gas states, however, that it "plans to maintain an LIA that will offset approximately
3 70%" of these costs in the future.⁶⁶ In terms of enrollment, DTE Gas accounts LIA
4 enrollment of 33,000 customers in its current rate request.⁶⁷

5
6 **Q: What are your concerns and recommendations regarding the LIA credit?**

7 **A:** My concerns with DTE Gas's LIA proposal relate to its amount, enrollment, and
8 advertising. As a result of these concerns, I have outlined the following
9 recommendations: (1) the MPSC should require DTE Gas to increase the amount of the
10 credit to an amount equivalent to at least 70% of a typical customer's monthly bill now;
11 (2) the MPSC should approve funding for expanded enrollment so that the program will
12 match the number of eligible customers; and (3) the MPSC should direct DTE Gas to
13 advertise adequately and conduct meaningful outreach on the LIA credit. I discuss each
14 below.

15 First, DTE Gas's proposed LIA amount is unjustifiably low, especially in relation
16 to the Company's current rate request. Because the LIA credit has remained the same
17 fixed dollar amount (\$30) since its inception, it has waned in value over the last seven
18 years. While DTE Gas considered raising the credit to cover the equivalent of 68% of a
19 customer's bill⁶⁸—the original value of the LIA credit—the Company has chosen to

⁶⁵ *Id.*

⁶⁶ *Id.* at 18.

⁶⁷ *Id.* at 14.

⁶⁸ *Id.* at 17.

1 propose an increase in the instant case that would cover only 60% of the bill.⁶⁹ This is
 2 neither just nor reasonable.

3 When asked why DTE Gas has not proposed a credit that would cover 70% of a
 4 customer's bill in this case, DTE Gas listed four reasons. First, DTE Gas referenced a
 5 Commission preference for "gradualism," arguing that raising the credit to an amount
 6 less than 70% of a customer's bill in the current case would be preferable to the
 7 Commission.⁷⁰ Second, DTE Gas noted that it was uncertain whether the Commission
 8 would approve a rate increase, and thus was unsure what level of credit would be
 9 necessary to cover 70% of a customer's bill.⁷¹ Third, DTE Gas noted that the LIA credit
 10 that DTE Electric currently provides is \$40.⁷² Finally, DTE Gas states that \$40 is
 11 approximately 70% of the current rates approved in the last rate case.⁷³ As such, DTE
 12 Gas believed that this number was the number most likely to be "acceptable to all
 13 parties."⁷⁴

14 None of these reasons are sufficient justifications for DTE Gas to provide a credit
 15 that would cover less than 70% of an average customer's typical bill. As discussed above,
 16 DTE Gas customers are currently suffering from an affordability crisis that has a real
 17 impact on people and communities. As DTE Gas has already suggested that it supports a
 18 credit that covers 70% of the bill,⁷⁵ prolonging the suffering of LMI customers by
 19 slowing down the implementation would be unjust and unreasonable. The fact that the

⁶⁹ See *id.* at 17–18. The 60% figure was calculated from the numbers provided by DTE Gas.

⁷⁰ Ex. FLO-222, DTE's Response to FLO's Second Discovery Request, FLODG-2.3b–2.4b, at 1.

⁷¹ *Id.*

⁷² *Id.*

⁷³ *Id.*

⁷⁴ *Id.*

⁷⁵ Sparks Direct Testimony at 18.

1 rates to be approved in this case are unknown is irrelevant; the Commission will know
 2 what rate it is approving when it makes its determination and will be capable of setting
 3 the credit at 70% of the average customer's bill. Even if the Commission were, for some
 4 reason, not able to calculate the credit, the Commission could still order the Company to
 5 provide an LIA credit that covers 70% of the typical customer's bill and require the
 6 Company to complete the calculation. A credit that covers less than 70% of a typical
 7 customer's bill is not "acceptable to all parties;" it is manifestly unacceptable to
 8 customers suffering under unaffordable energy prices, whose relief would be delayed if
 9 the Commission declined to increase the credit appropriately.

10 Second, DTE Gas's proposed LIA enrollment cap is inadequately low. DTE Gas
 11 currently rejects customers for the LIA credit even though the customers meet the
 12 requirements that the Company has identified as those in need of the program.⁷⁶ The
 13 MPSC should allow any LIA-eligible customer to receive the credit, rather than allow
 14 DTE Gas to allocate it to only some of the customers who are eligible for and need the
 15 credit. Moreover, DTE Gas's proposal to account for only 33,000 customers in its current
 16 request is nonsensical given that LIA enrollment has trended closer to 38,000 customers
 17 over time.⁷⁷ In the past, the Commission has stated that it finds the LIA program
 18 "valuable" and that it "encourages the [C]ompany to continue the enrollment of interested
 19 customers."⁷⁸ To encourage such enrollment, in 2020, the Commission authorized DTE
 20 Gas to track enrollments up to 50,000 for LIA "to be booked as a regulatory asset."⁷⁹ As

⁷⁶ Ex. FLO-223, DTE's Response to FLO's First Discovery Request, FLODG-1.18c, at 1.

⁷⁷ See *infra* tbl.1.

⁷⁸ *In re DTE Gas Co.*, MPSC Case No. U-20561, Order (May 8, 2020), at 180. The Order similarly encouraged continued enrollment for the RIA credit. *Id.* at 181.

⁷⁹ *Id.* at 180–81.

shown in Table 1, however, DTE Gas has refused to enroll more than 40,000 customers in the LIA credit since 2020. To explain its enrollment numbers, DTE Gas states that “LIA credit enrollment and distribution is limited by what is recoverable through rates Changes to any of the programs are subject to MPSC approval.”⁸⁰ Thus, as acknowledged by DTE Gas, the MPSC can expressly approve in the rate base sufficient funding to account for enrollment for all LIA-eligible customers to remedy this enrollment problem⁸¹—and the MPSC should do so. For enrollment beyond this number, the MPSC should authorize DTE Gas to defer these additional expenses.

Table 1: LIA Customer Enrollment 2020–2023.⁸²

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
2020	32,686	26,471	34,706	34,726	34,935	38,553	36,884	36,726	36,541	36,762	33,427	40,122	35,212
2021	36,368	33,564	40,044	38,417	36,254	43,019	38,162	40,089	38,287	36,165	35,986	39,373	37,977
2022	39,403	33,755	42,422	36,674	38,533	40,191	36,010	39,593	36,568	37,061	35,311	38,891	37,868
2023	39,052	33,964	42,341	34,764	40,788	38,796	36,662	41,345	39,481	38,710	34,973	35,562	38,037
Avg	36,877	31,939	39,878	36,145	37,628	40,140	36,930	39,438	37,719	37,175	34,924	38,487	37,273

Third, DTE Gas does not advertise properly or conduct sufficient outreach for its LIA credit. A look at DTE Gas’s 2023–2024 “Payment Assistance Programs” brochure,⁸³ as well as at brochures from the last few years, reveals that the LIA credit is not listed as a possible assistance option. Similarly, DTE Gas’s “Payment Assistance Programs” webpage does not list the LIA.⁸⁴ DTE Gas explains that it chose not to include the credit

⁸⁰ Ex. FLO-224, DTE’s Response to FLO’s First Discovery Request, FLODG-1.18a, at 1.

⁸¹ DTE Gas states that “[i]t is not feasible to provide the percentage of eligible residential customers for LSP, RIA, and LIA.” Ex. FLO-225, DTE’s Response to FLO’s First Discovery Request, FLODG-1.17, at 1. But Witness Schott argues that DTE has the ability and resources to calculate these figures. *See* Schott Direct Testimony, Part IV.

⁸² Table 1 is based on the enrollment figures provided by DTE Gas. *See* Sparks Direct at 15; Ex. FLO-226, DTE’s Response to FLO’s Second Discovery Request, FLODG-2.1.

⁸³ Ex. FLO-227, DTE’s Response to FLO’s Third Discovery Request, U-21291 FLODG-3.5d 03 Payment Assist Bill Insert 2023-24.

⁸⁴ *See generally* Ex. FLO-228, *Low-Income Programs*, DTE (last accessed May 4, 2024), <https://perma.cc/AX5K-FGYX>.

1 on either the brochure or website because of the credit's enrollment cap.⁸⁵ This is a poor
 2 reason not to advertise the LIA, and keeping this program secret from customers prevents
 3 otherwise LIA-eligible customers from even inquiring about the credit due to lack of
 4 knowledge. While DTE Gas states that it aims to pair LSP participants with the LIA
 5 credit,⁸⁶ a majority of customers receiving the LIA credits have not been LSP participants
 6 since at least 2020.⁸⁷ This leaves one to wonder how these non-LSP customers come to
 7 find out about the LIA credit; DTE Gas does not provide an explanation.⁸⁸

8 Given that the Company does not provide materials about the LIA to customers in
 9 the mail or online and that the Company does not volunteer LIA information over the
 10 phone, as FLO Witness Toyia Watts explains, the allocation of LIA credits is somewhat
 11 of a mystery.⁸⁹ And I have strong doubts that DTE Gas is enrolling customers in the LIA
 12 credit in an equitable manner—and almost certainly not in a way that uniformly targets
 13 those most in need of the program. The MPSC should require greater transparency from
 14 DTE Gas, including by requiring DTE Gas to list enrollment information in all assistance
 15 program marketing and to adopt an equitable, written enrollment policy.

⁸⁵ Ex. FLO-229, DTE's Response to FLO's Third Discovery Request, FLODG-3.4b–3.4c.

⁸⁶ See Sparks Direct Testimony at 15.

⁸⁷ Ex. FLO-230, DTE's Response to FLO's Third Discovery Request, U-21291 FLODG-3.6a Gas_LIA-LSP and non-LSP (showing 60% non-LSP enrollment in 2023, 58% non-LSP enrollment in 2022, 58% non-LSP enrollment in 2021, and 66% non-LSP enrollment in 2020).

⁸⁸ DTE merely explains that strategically pairing LIA and LSP is beneficial to a completely random allocation, see Sparks Direct Testimony at 15–16, but it does not explain how it allocates LIA credits among non-LSP customers.

⁸⁹ See Watts Direct Testimony, Part III.

1 **Q: Please describe the Residential Income Assistance credit.**

2 **A:** As a result of MPSC Case No. U-15985, DTE Gas offers residential customers—who are
 3 on Rate A and below 150% FPL—an RIA credit of \$13.50 to cover their “monthly
 4 customer charge[s].”⁹⁰ DTE Gas automatically enrolls anyone who receives a Home
 5 Heating Credit (HHC), State Emergency Relief, or other one-time assistance into the
 6 RIA,⁹¹ However, I understand that DTE Gas prevents customers who are already
 7 receiving the LIA credit from also receiving the RIA credit.⁹² In the instant case, DTE
 8 Gas is proposing to raise the RIA to the Company’s newly proposed monthly customer
 9 charge (\$17.60).⁹³

10

11 **Q: What are your concerns and recommendations regarding the RIA credit?**

12 **A:** As an initial matter, I support DTE’s proposal to increase the RIA credit amount to its
 13 new monthly customer charge of \$17.60. Although I support the increase, I have at least
 14 two concerns.

15 First, I worry that the RIA credit has become or will become less valuable over
 16 time. Specifically, I am concerned about how DTE Gas’s Infrastructure Recovery
 17 Mechanism (IRM) surcharge⁹⁴ impacts RIA participants. While the LIA credit amount is
 18 applied to the entire bill (including the IRM surcharge),⁹⁵ the RIA credit is generally only
 19 tied to the monthly customer charge.⁹⁶ Thus, DTE has diluted the value of the RIA credit

⁹⁰ Telang Direct Testimony at 29; Sparks Direct Testimony at 12.

⁹¹ Sparks Direct Testimony at 12.

⁹² *See id.* at 12 (“Customers may not receive both the gas RIA and gas LIA credit at the same time.”).

⁹³ *Id.* at 14.

⁹⁴ *See* Uzenski Direct Testimony at 63.

⁹⁵ Ex. FLO-231, DTE’s Response to FLO’s Third Discovery Response, FLODG-3.1a–3.1b, at 1.

⁹⁶ Ex. FLO-232, DTE’s Response to FLO’s Third Discovery Response, FLODG-3.2. at 1.

1 with the introduction of the separate IRM surcharge, since the RIA credit now covers a
 2 lower percentage of customers' overall bills. In response, the MPSC should ensure that
 3 the RIA credit—or another credit—be increased sufficiently to cover the incremental
 4 IRM-related charges that customers now must pay.

5 Second, I am concerned that DTE Gas is unfairly excluding customers who are
 6 already receiving the RIA credit from also receiving the LIA credit. Both the RIA and
 7 LIA credits are intended to offer relief to low-income customers, but the LIA credit offers
 8 approximately two to three times the relief that the RIA credit offers. As a result of
 9 customers' RIA status, I worry that DTE may be obscuring information about customers'
 10 LIA eligibility or otherwise informing these customers that there is no other assistance
 11 program available. As part of ordering DTE Gas to increase the LIA credit to cover all
 12 eligible customers, the MPSC should also direct DTE Gas to provide both the LIA and
 13 the RIA credits to all otherwise eligible customers.

14
 15 **Q: Please describe DTE's Payment Stability Plan pilot.**

16 **A:** As required by MPSC Case No. U-20929, DTE developed a Percentage of Income
 17 Payment Plan (PIPP) pilot.⁹⁷ The Company ran its PIPP pilot, the Payment Stability Plan
 18 (PSP), between 2022 and 2023.⁹⁸ Customers at or below 200% FPL were eligible to
 19 enroll and begin receiving energy bills that reflected a certain percentage of their income,
 20 rather than a dollar amount based on usage.⁹⁹ For customers who received either a DTE

⁹⁷ *In re DTE Gas Co. & DTE Electric Co.*, MPSC Case No. U-20929, Order at 1 (Apr. 21, 2021).

⁹⁸ Sparks Direct Testimony at 11.

⁹⁹ *See id.*

Gas or DTE Electric bill, their bill totaled 6% of their household gross income.¹⁰⁰ For customers who received both DTE Gas and DTE Electric bills, their bills totaled 10% of their household gross income.¹⁰¹ The pilot enrolled a total of 2,223 customers.¹⁰²

DTE Gas has stated that the pilot had “present[ed] positive outcomes.”¹⁰³ The Company further stated that “PSP cohorts have improved on time payment by over 21% leading to an average 43% net arrears reduction.”¹⁰⁴

Q: What are your concerns and recommendations regarding PSP?

A: While I am hopeful about the future of PIPPs such as the PSP, I am concerned that DTE Gas’s evaluation process regarding its PSP pilot remains slow, preventing residents in need from accessing the benefits of such a program. As studies and DTE Gas’s initial pilot results show, PIPPs are one of the most effective types of affordability-driven programs that a utility can offer since they can cap residents’ energy bills at a fixed portion of their income.¹⁰⁵ While DTE Gas should take the time to evaluate its pilot results—in coordination with interested stakeholders such as FLO, the EEAC workgroup participants, and other organizations and agencies—the MPSC should ensure that the evaluation and proposal for next steps are not unnecessarily delayed.

¹⁰⁰ *Id.*

¹⁰¹ *Id.*

¹⁰² Ex. FLO-233, DTE’s Response to FLO’s Second Discovery Request, FLODG-2.6a, at 1.

¹⁰³ Sparks Direct Testimony at 11.

¹⁰⁴ *Id.*

¹⁰⁵ See, e.g., *In re DTE Electric Co.*, MPSC Case No. U-20836, MPSC Staff Witness Braunschweig Rebuttal Testimony, 8 TR 5283 (stating that PIPP programs are an “industry-recognized effective way to address energy affordability issues”).

1 In the instant case, the Company has outlined its “next steps” regarding PSP as
 2 “organizing collaborative meetings with essential stakeholders, including the Energy
 3 Affordability and Accessibility Collaborative (EEAC) subcommittees, partner utilities,
 4 and community agencies.”¹⁰⁶ The Company has further stated that it “anticipates
 5 providing recommendations regarding the PSP pilot by December 31, 2024.”¹⁰⁷

6 However, to date, DTE has not organized any collaborative meetings to evaluate
 7 the pilot results. “[N]o future dates” for meetings “have been discussed.”¹⁰⁸

8 To ensure that DTE Gas proposes next steps regarding the PSP in a timely
 9 manner, I recommend that the MPSC require the Company to present a formal proposal
 10 for a full-scale PIPP program no later than December 31, 2024. Witness Schott explains
 11 several other opportunities for PIPP expansion.¹⁰⁹

12
 13 **Q: Please describe the Low-Income Self-Sufficiency Program (LSP).**

14 **A:** The LSP is a two-year program that “eliminates any future late payment charges” and
 15 freezes all “past due energy charges . . . while the customer receives a monthly arrears
 16 forgiveness credit.”¹¹⁰ Customers are eligible for LSP if their income is at or below 150%
 17 FPL, their energy consumption does not exceed certain limits, their arrears do not exceed
 18 \$3,000, and their State Emergency Relief is approved.¹¹¹ DTE Gas measures success
 19 (program “graduation”) by the number of participants who reach an arrears balance of

¹⁰⁶ Sparks Direct Testimony at 12.

¹⁰⁷ Ex. FLO-234, DTE’s Response to FLO’s First Discovery Request, FLODG-1.19, at 1.

¹⁰⁸ Ex. FLO-235, DTE’s Response to FLO’s First Discovery Request, FLODG-3.3a–3.3b.

¹⁰⁹ See Schott Direct Testimony, Parts IV, V and VI.

¹¹⁰ Sparks Direct Testimony at 7.

¹¹¹ *Id.* at 7–8.

1 zero within twenty-four months.¹¹² The Company states that LSP participants are
2 automatically enrolled in the LIA credit.¹¹³
3

4 **Q: What are your concerns and recommendations regarding LSP?**

5 **A:** The overall structure, success metrics, and customer support regarding LSP are flawed.
6 As described further by Witness Schott, while LSP does help certain customers escape
7 large past-due balances, the program does nothing to enable customers to begin affording
8 their energy bills in the future.¹¹⁴ Many customers fall behind on their energy bills and
9 rack up overdue charges because the bills themselves are not affordable in the first place.
10 Once a customer “graduates” from LSP, however, they return to attempting to pay the
11 same unaffordable bills that allowed them to accrue arrears in the first place. Thus, LSP
12 is merely a Band-Aid solution that often re-creates the same cycles of poverty for
13 customers over time. This is concerning given that DTE Gas appears to tout LSP as
14 “comprehensive.”¹¹⁵ Rather than direct MEAP funding toward these short-term fixes, the
15 MPSC should focus on creating a program, like an expanded PIPP, that helps customers
16 achieve true affordability in both the short and long terms.
17

¹¹² *Id.* at 8.

¹¹³ *Id.* at 15.

¹¹⁴ See Schott Direct Testimony, Part IV.

¹¹⁵ See Sparks Direct Testimony at 7.

1 **Q: In general, is DTE’s current customer service sufficient for addressing the needs of**
 2 **customers regarding the unaffordability of bills?**

3 **A:** No. I spoke with numerous community organizers here in Kent County, and they report a
 4 similar fact pattern. Customers experience issues with DTE’s customer service lines, be it
 5 an issue with payment, a shutoff notice, or seeking information on assistance programs.
 6 Although the Company boasts an Average Speed of Answer (ASA) in 2023 of 64
 7 seconds,¹¹⁶ customers who call DTE Gas often report they faced long wait times far
 8 above one minute and have had difficulties getting hold of customer service
 9 representatives empowered to help them. Often, to resolve an issue, customers are forced
 10 to turn to organizations such as Kent County Community Action (KCCA) for assistance.
 11 In a significant number of circumstances, the situation is only resolved when a case
 12 worker calls on a customer’s behalf. This suggests that getting a hold of someone is often
 13 predicated on taking time out of one’s day to meet with a case worker, explain the
 14 situation, and hope for resolution through these third-party means.

15 Poor customer service is not unique to Kent County residents. As Witness Watts
 16 testifies, her experience with DTE Gas in the Detroit area has been poor.¹¹⁷ While this
 17 evidence is anecdotal, evidence across these two different locations in DTE’s service area
 18 leads me to believe that the problem is real and widespread.

¹¹⁶ Ex. FLO-236, DTE’s Response to FLO’s Seventh Discovery Request, FLODG-7.1b. ASA measures time from when a customer enters a hold queue to when a human answers the phone. *See* Ex. FLO-237, *What Is Average Speed of Answer? Strategies and Calculation*, CALL CTR. STUDIO (Jan. 5, 2024), <https://callcenterstudio.com/blog/what-is-average-speed-of-answer-strategies-and-calculation/> (defining ASA as the time it takes for a human to answer the phone upon being placed on hold. “It starts ticking when the call enters the waiting line. It stops when an actual human answers.”). The MPSC requires that ASA be less than or equal to ninety seconds. *See generally* Ex. FLO-236.

¹¹⁷ *See* Watts Direct Testimony, Part III.

While the utility support services that county entities such as KCCA provide are important, DTE Gas cannot rely on these caseworkers to operate its customer service branch on its behalf. Customers who are most likely to encounter issues such as shutoff notices are those who are already in financial hardship. Taking time to meet with a case worker detracts from customers' ability to work and earn the money to pay their utility bills in the first place. Ease of access to customer dispute resolution thus is an issue of justice. DTE's practices enhance the cycle of poverty when customers fall behind on their bills, call to avoid shutoffs, and take time off work to resolve their issues with case workers, thus putting them further behind on essential bills.

Q: Are customers sufficiently educated on the resources available to them?

A: No. Based on my conversations with KCCA case workers as well as my review of DTE Gas's customer service script, customers are not sufficiently educated on the resources available to them.

First, in my conversations with caseworkers at KCCA, I learned that KCCA often would inform residents of their payment assistance options as DTE Gas customers. Frequently, residents are surprised to hear of the options available to them. For instance, a number of customers were unaware that they could call and place a ten-day hold on their accounts as part of their application to receive State Emergency Relief (SER).¹¹⁸ At present, DTE Gas does not provide a cohesive list of all protections, procedures, and

¹¹⁸ Ex. FLO-238 *Michigan Energy Assistance Program Frequently Asked Questions*, MICH. PUB. SERV. COMM'N (last accessed May 4, 2024), https://www.michigan.gov/-/media/Project/Websites/mpsc/consumer/meap/MEAP_FAQs.pdf?rev=2ba17357b585490195c365457037102c, at 7.

services that customers can obtain. Even in places that do centralize some information on assistance programs, customers are expected to call nonprofits and governmental entities to discern the programs to which they are entitled.¹¹⁹ As I noted above, the more time that residents who are struggling to pay their bills require to conduct research and determine which programs are available to them, the more they are likely to fall behind on work or other life obligations such as childcare or education.

¹¹⁹ See generally Ex. FLO-228.

Q: Do you have any concerns with DTE’s Customer Assistance Days (CADs), Customer Resource Fairs (CRFs), and Pop-Up events?

A: Yes. DTE Gas does not host virtual or in-person customer assistance events nearly as frequently or comprehensively as it should. Two things struck me as odd about the list of CADs, CRFs, and Pop-Up events since 2021 that the Company provided.¹²³

First, according to the list, DTE Gas has not hosted an in-person event in the Grand Rapids area between 2021 and 2024.¹²⁴ The overwhelming majority of in-person events occur in the Detroit metro area.¹²⁵ While I support hosting events in the Detroit area, the MPSC should ensure that the Company is making its in-person customer assistance events available to a broader range of residents within the Company's service territory. Moreover, all of DTE Gas’s planned events for the rest of 2024 are scheduled for only one site, the Northwest Activity Center in Detroit.

Second, all of the past and planned events were scheduled for weekdays during the daytime.¹²⁶ As FLO Witness Watts explains, this approach is not sufficiently flexible for LMI customers—for whom many of these assistance events would be most critical.¹²⁷

¹²³ See Ex. FLO-240, DTE’s Response to FLO’s Third Discovery Request, U-21291 FLODG-3.5a-c 2021-2024 CAD CRF POP UPS.

¹²⁴ *Id.*

¹²⁵ *Id.*

¹²⁶ *Id.*

¹²⁷ See Watts Direct Testimony, Part III.

To ensure that more customers can access DTE’s assistance, the MPSC should direct DTE to make a proportion of the Company’s assistance events available to residents on weekends and weekday evenings.

*Table 2: DTE Gas customer assistance events (CADs, CRFs, Pop-Ups) by location and year.*¹²⁸

Site	Location	2021	2022	2023	2024 Complete	2024 Planned	Total
Booker T Dozier Recreation Center	Inkster, MI (Detroit Metro)	0	0	1	0	0	1
Cares of Farmington Hills	Farmington Hills, MI (Detroit Metro)	0	0	1	0	0	1
Considine Center	Detroit, MI	0	1	1	0	0	2
Fellowship Chapel	Detroit, MI	0	0	1	0	0	1
Ford Resource & Engagement Center East	Detroit, MI	0	0	0	1	0	1
Gethesemane Missionary Baptist Church	Westland, MI (Detroit Metro)	0	0	0	1	0	1
Heilmann Recreation Center	Detroit, MI	0	0	0	1	0	1
La Sed	Detroit, MI	0	0	1	0	0	1
Northwest Activity Center	Detroit, MI	0	0	8	3	7	18
River Rouge High School	River Rouge, MI (Detroit Metro)	0	1	0	0	0	1
Samaritan Center	Detroit, MI	0	0	5	0	0	5
Thompson Community Center	Warren, MI	0	0	0	1	0	1
Veterans Resource Fair Greater Grace	Detroit, MI	0	0	1	0	0	1
Virtual	N/A	3	6	0	0	0	9
Washatenaw Community Action Agency	Ann Arbor, MI	0	0	2	0	0	2
Total		3	8	21	7	7	46

B. Billing Program

Q: Please describe the BudgetWise billing program.

A: The BudgetWise Billing program is designed to enable customers to spread the average annual cost of their energy bills across all twelve months of the year, in order to make customers’ “monthly bills more predictable.”¹²⁹ Any customer may enroll in the program. DTE Gas states that it “calculate[s] [a customer’s] monthly payment by taking the energy usage and bill amount at [the customer’s] current residence for the last 12 months” and then [using] the average amount to determine [the customer’s] monthly payment.”¹³⁰

DTE Gas states that it reviews customers’ energy usage quarterly and adjusts customers’

¹²⁸ This table was generated using data provided by DTE Gas in Ex. FLO-240.

¹²⁹ Ex. FLO-241, *BudgetWise Billing*, DTE (last accessed Apr. 19, 2024), <https://www.dteenergy.com/us/en/business/billing-and-payments/payment-programs/bwb.html>, at 1.

¹³⁰ See *id.*

1 bills as needed.¹³¹ According to the Company, a quarterly adjustment is made if a
 2 customer's "average usage has increased or decreased by 10%" relative to "the last
 3 rolling-12 months of the customer's energy usage."¹³² After twelve months, enrolled
 4 customers have a "settlement month" in which DTE Gas credits or settles any
 5 overcharges or undercharges.¹³³

6
 7 **Q: What are your concerns and recommendations regarding BudgetWise?**

8 **A:** All too often, we have seen the severity of how much settlement amounts can impact
 9 unsuspecting customers. The suddenness of these amounts may be in part due to poor
 10 customer education, which I explore below. However, settlement amounts can sometimes
 11 double a resident's monthly bill, which I have learned from speaking to other Grand
 12 Rapids community members. This is possibly due to how the settlement amount is
 13 calculated. Because the Company adjusts your monthly bill only if you exceed 10% of
 14 your usage relative to the test year, it is possible to have a near-miss every month. This
 15 may result in an exorbitant settlement month bill. For example, if a customer uses more
 16 than 9% of last year's use, then a quarterly adjustment is not triggered, but this balance is
 17 still counted against the customer for settlement. Thus, a settlement month could be as
 18 high as 108% of a normal month's bill. This bears out anecdotally as well. As FLO
 19 Witness Toyia Watts notes, she often cannot afford the bill she receives during her
 20 settlement month.¹³⁴ For a program whose intended purpose is to alleviate the stress of

¹³¹ See *id.* at 2.

¹³² Ex. FLO-242, DTE's Response to FLO's Fourth Discovery Request, FLODG-4.1d, at 1.

¹³³ *Id.*

¹³⁴ See Watts Direct Testimony, Part III.

seasonal price variation, it does not seem to serve its currently advertised function for many LMI residents. In fact, enrolling customers in a program that promises it will protect them from exactly the sort of bill surprises that the program perpetuates gives customers a false sense of security.

I recommend that the Commission inquire into how exactly BudgetWise functions and the challenges that LMI customers have with their settlement payments. Moreover, the Commission should order DTE to cap settlement month charges at a certain threshold to address affordability challenges. This threshold should be tailored such that settlement month payments are tethered to what the household can afford to pay.

Q: What concerns do you have about DTE’s communications regarding BudgetWise?

A: The Company’s communication regarding BudgetWise has been poor and inadequate. We have heard numerous reports from our community members that the Company has been unclear in its communication about BudgetWise. For example, and as mentioned above, many customers were surprised that their bills increased at all (and to such an extent) during the winter months. However, it was their understanding that price fluctuations were to be relatively stable under the program.

The MPSC should direct DTE Gas to inform customers more clearly about the intricacies of the program. On the Company’s website, the Company explains that BudgetWise “review[s] your energy usage every three months to determine if your monthly amount needs to be adjusted . . . [Y]our BudgetWise Billing amount may increase or decrease each quarter.”¹³⁵ So, while the Company does disclaim that a

¹³⁵ Ex. FLO-241 at 2.

1 customer's bill may change over the year, the Company does not sufficiently explain how
2 that bill will change and by what amounts. I only learned about the 10% rule via
3 discovery in this case. Similarly, the Company says on its website that customers who
4 "are undercharged [] will need to settle the difference" for the purpose of Settlement
5 Months.¹³⁶ This language relies on an understanding of quarterly review procedures,
6 which is itself unclear. The concept of a near miss, which I caution above and which
7 many in my community experience, results in the blind-siding of many community
8 members. The Company's failure to explain settlement months clearly results in
9 unexpectedly large bills at the end of the year, which counteracts the program's stated
10 purpose of "avoiding seasonal ups and downs."¹³⁷ These surprisingly large settlement
11 month bills are unfair and unjust.

12
13 **Q: Does this conclude your written Direct Testimony?**

14 **A:** Yes.

¹³⁶ *Id.*

¹³⁷ *Id.* at 1.

1 (Transcript continues following Page 1233 of the
2 Confidential Record.)

3 - - -

4 MR. TEMPLETON: Thank you, your Honor. I
5 just have one more witness and some exhibits agreed with
6 DTE in lieu of cross.

7 So our fourth and final witness is Toyia
8 Watts, that's T-o-y-i-a, Watts. She filed direct written
9 testimony consisting of one cover page and 16 pages of
10 questions and answers. Ms. Watts sponsored Exhibits FLO
11 301 through FLO-305, inclusive. And so I move for the
12 binding in of Ms. Watts' testimony and the admission of
13 her exhibits.

14 JUDGE THOITS: Are there any objections
15 to the admission of this testimony and these exhibits?
16 (No response.)

17 Hearing none, the Direct Testimony of
18 Toyia Watts is bound into the record, and Exhibits
19 FLO-301 through FLO-305 are admitted.

20 (Testimony bound in.)

21 - - -

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of DTE GAS	)	
COMPANY for authority to increase its	)	Case No. U-21291
rates, amend its rate schedules and rules	)	
governing the distribution and supply of	)	ALJ Jonathan F. Thoits
natural gas, and for miscellaneous	)	
accounting authority.	)	

DIRECT TESTIMONY OF TOYIA WATTS

ON BEHALF OF

**SOULARDARITY, URBAN CORE COLLECTIVE, AND WE WANT GREEN, TOO
(COLLECTIVELY, FRONTLINE ORGANIZATIONS (FLO))**

May 7, 2024

1 **I. INTRODUCTION AND SUMMARY**

2 **Q: Please state your name, occupation, and business address.**

3 **A:** My name is Toyia Watts. I am the President of the Charlevoix Village Association. My
4 address is 2475 Baldwin Street, Detroit, MI 48214.

5

6 **Q: Have you participated in any previous Michigan Public Service Commission (MPSC)**
7 **proceedings?**

8 **A:** No.

9

10 **Q: Please describe your education and professional background.**

11 **A:** I was born and raised in the City of Detroit. I graduated from Martin Luther King Jr. Senior
12 High School and attended Wayne County Community College. I have been doing
13 community work for more than twenty-four years. In 2000, I started a community
14 organization on the East Side of Detroit that eventually became the Charlevoix Village
15 Association (CVA). I am currently the CVA President and am still deeply involved in the
16 organization.

17

18 **Q: Can you provide examples of the types of work that the Charlevoix Village**
19 **Association does?**

20 **A:** I originally started getting people together in the East Side neighborhood to help us
21 understand gentrification and make sure that the neighborhood is changing for us. We don't
22 want the neighborhood to change without true community engagement and involvement in

1 the process. Otherwise, changes are made to appeal to newcomers, not to the people who
2 are already there.

3 To make sure that our voices are being heard, we go to the City of Detroit's
4 Planning Commission and City Council meetings. We do a lot of outreach to elected
5 officials to make sure that they know that we're still here. We also look at things like the
6 water rate, the DTE rates, and the alley lights to make sure that people can keep their
7 homes and stay in our community.

8
9 **Q: Are you a DTE customer?**

10 **A:** Yes. I have been a DTE electricity and gas customer since 2000. When my mother passed
11 in 2000, I changed the DTE account into my name.

12 I have contacted DTE on a variety of occasions regarding the gas it provides. For
13 example, I called DTE once because I smelled gas at one of the lots by our house. When I
14 called DTE, however, the Company did not take immediate steps to address the issue.
15 Instead, it seemed like the Company ignored the problem. While DTE did eventually put
16 some flags in the yard of the house with the leak, the smell of gas did not go away. I
17 thought, "Why does DTE want our houses to blow up?" I eventually had to call the
18 Michigan Public Service Commission about the leak, and only then did I see DTE arrive
19 to fix the leak and smell.

1 **Q: Please provide an overview of the topics you will discuss in your testimony.**

2 **A:** I am testifying about the negative experiences I have had with DTE Gas. DTE Gas can do
3 much better for the people in the community, and my experiences are relevant to the
4 Commission's consideration of DTE's rate increase request.

5
6 **Q: What is your relationship with We Want Green, Too (WWG2)?**

7 **A:** I am working to educate myself and the community on issues like energy efficiency and
8 home upgrades. These are also issues that are important to WWG2, so I recently met Gloria
9 Lowe, the CEO and Founder of WWG2.

10

11 **Q: How have you organized your testimony?**

12 **A:** In Part II of my testimony, I will discuss my concerns with gas affordability. In Part III, I
13 will describe my negative experiences with DTE Gas's services, including a lack of
14 adequate bill assistance programs.

15

16 **Q: Are you sponsoring any exhibits?**

17 **A:** Yes. I am sponsoring the following exhibits.

18 FLO-301. DTE's Response to FLO's Third Discovery Request, U-21291 FLODG-3.5d
19 03 Payment Assist Bill Insert 2023-24.

20 FLO-302. *Customer Resource Fairs*, DTE (last accessed 5/2/2024),
21 <https://perma.cc/NLS3-BMTY>.

22 FLO-303. DTE's Response to FLO's Third Discovery Request, U-21291 FLODG3.5-a-c
23 2024-2024 CAD CRF POP UPS.

1 FLO-304. DTE's Response to FLO's Second Discovery Request, FLODG-2.3b.

2 FLO-305. DTE's Response to FLO's Second Discovery Request, FLODG-2.4a.

3
4 **II. CONCERNS WITH AFFORDABILITY**

5 **Q: In your view, are DTE Gas's bills affordable?**

6 **A:** No. DTE Gas's bills are not affordable. I participate in the BudgetWise billing program,
7 receive the Home Heating Credit, and am enrolled in the Low-Income Self-Sufficiency
8 Program (LSP), but none of these programs has worked sufficiently for me. DTE Gas puts
9 the onus on the customer to figure out which programs are available, how they work, and
10 how to enroll (or re-enroll) in them. And this has been stressful. Even with my enrollment
11 in these three programs, I end up with large, unexpected bills—sometimes \$300 to \$400 at
12 the end of every year—that I can't pay. My overall impression is that DTE Gas is not very
13 concerned about whether its customers can afford their bills.

14
15 **Q: What appliances in your household require gas?**

16 **A:** My heating, stove, and dryer all rely on gas.
17

18 **Q: How much do you spend on your DTE bill?**

19 **A:** I spend about \$250 to \$300 each month on my total DTE bill, which includes both gas and
20 electric. Starting a couple of years ago, I now also pay about \$35 each month to participate
21 in DTE's Home Protection Plus (HPP) program, an appliance repair service that the
22 Company offers.
23

1 **Q: What percentage of your income do you spend on your utility bill?**

2 **A:** Because my monthly income is around \$1,100, I spend about 23% to 27% of my income
3 on my utility bill each month, not including HPP. My DTE bill sucks up so much of my
4 income.

5
6 **Q: Have you ever had to choose between keeping your gas on and other needs?**

7 **A:** Yes, I constantly make tradeoffs in what I can afford. For example, I have bought fewer
8 groceries than I knew I needed, fallen behind on other bills to keep my gas bills current,
9 and put off maintaining my house. I have one specific memory of asking myself how much
10 I had left to buy groceries and seeing only \$40 in my hand. I need to pay for things such as
11 my prescription medications, tissues, and dish detergent, but I also need my utilities. So
12 that's something that I must figure out every month.

13 I also try not to heat my house too high in the winter to avoid my gas bill from
14 getting too high. I'm nearly seventy years old, and I would ideally like to keep my
15 temperature at 72°F in the winter, but I often allow it to stay cooler than that. My house is
16 very old, so it costs a lot to heat up my house in the first place.

17

18 **Q: How would you describe the insulation of your home?**

19 **A:** My house is not insulated well. My dad was lucky to be able to afford the house in the
20 1940s after World War II and bought the house for \$8,000. But, because it was built a long
21 time ago, it was always poorly insulated. For example, if you put a lighter to the window,
22 the cold air coming through would move the flame. To keep the gas bill low and the house
23 warmer in the winter, I used to stick plastic bags from the grocery store on the windows.

1 In 2014, I was finally able to upgrade my windows through a weatherization program run
2 through the City of Detroit. Today, my priorities are insulating the attic and basement and
3 upgrading the bricks and foundation, among other weatherization fixes. These are tasks
4 that I want to do eventually, but I can't afford them with my utility bill being so high. In
5 the meantime, I live with the insulation that I have—even if that means paying higher gas
6 bills as a result.

7
8 **Q: Have you ever had your gas service shut off?**

9 **A:** No. I have never had my gas shut off, but I am always afraid that DTE will shut me off one
10 day if I cannot keep up with my bills.

11 I remember that when my mother first passed, I received a notice that DTE would
12 shut off my gas soon if I didn't pay the remaining balance. I had to somehow come up with
13 \$150 to keep my gas on, which I did not have. In a matter of days, I made many stressful
14 phone calls to foundations, nonprofits, and government agencies to try to find money for
15 the shortfall. While I was ultimately able to avoid a shutoff in that instance, I know it could
16 happen again.

17 With the rate increases that I have been hearing about, I am even more worried. I
18 just read an article about a DTE Electric rate hike of \$360 million. I am worried that the
19 increase is going to make my electric bill more unaffordable and that, because of this case,
20 the gas portion of my bill will also become more unaffordable. I live with my twenty-five-
21 year-old daughter, and I always think, "What am I supposed to tell her?" We simply cannot
22 afford these bills, which get higher and higher every time I look.

1 **III. LACK OF ADEQUATE ASSISTANCE**

2 **Q: Do you recall ever receiving a pamphlet or brochure about DTE’s “Payment**
3 **Assistance Programs”?**¹

4 **A:** No. I can’t remember a recent time when I received a pamphlet or brochure from DTE
5 about its assistance programs—either through mail or email. Usually, I try to be proactive
6 about finding these programs in the first place—for example, I visit DTE’s website from
7 time to time to see if the Company is running any new programs—so I would have
8 remembered if DTE had sent me information about assistance programs.

9 Even if DTE is sending us brochures, it’s not sending them to us nearly as
10 frequently as it should be. It would be easy for me to miss if DTE is sending the brochures
11 only once a year or burying them within a package of other materials—and I’m sure other
12 customers have that problem, too.

13 In my experience, DTE does a poor job of communicating with customers about its
14 various assistance programs.

15
16 **Q: Have you ever contacted DTE because you could not afford your monthly bills?**

17 **A:** Yes, I have called DTE to ask about any programs they might have to help me afford my
18 monthly bills. The only program I was told about was BudgetWise billing to help spread
19 the cost of my bills across the year. DTE did not inform me of any other program that I
20 might be eligible for that might help reduce the overall amount of my bill. I was not sure
21 what to do, so I contacted the Michigan Department of Health and Human Services

¹ See generally Ex. FLO-301, DTE’s Response to FLO’s Third Discovery Request, U-21291 FLODG-3.5d 03
Payment Assist Bill Insert 2023-24.

1 (MDHHS). Only then was I able to get enrolled in the LSP program and learn about the
2 Home Heating Credit. In the future, I plan on continuing to reach out to MDHHS and other
3 welfare support to help me with paying my bills since I do not expect to receive help paying
4 my bills directly from DTE.

5 DTE's testimony may sound great when it says that its "call center analysis are
6 trained to engage with customers and provide guidance on the most suitable options,"² but,
7 in my experience, this is far from the truth for the Company's actual customers.
8

9 **Q: Please describe your experience with the BudgetWise program.**

10 **A:** I first enrolled in the BudgetWise program in 2000. When my mother passed and I became
11 the DTE customer, the DTE bills were too high. I reached out to DTE over the phone, and
12 the only program they told me about was the BudgetWise program. I enrolled.

13 The BudgetWise program has a settlement month charge, where DTE reviews my
14 account and settles the difference between the energy I used and the money they charged
15 me. The settlement month charge is really challenging and stressful. Once a year, I have to
16 figure out where I am going to get the extra \$300 or \$400 to pay my remaining bill in order
17 to get re-enrolled in the program. The settlement charge is not affordable. It stresses people
18 out.
19

20 **Q: Please describe the HHC program and your experience with it.**

21 **A:** Since about 2019, I have received the HHC. I first learned about the program through
22 MDHHS and have worked with the Accounting Aid Society each year to ensure I receive

² Sparks Direct Testimony at 13.

1 the credit. I used to get close to \$1,000 a year through the program. It was a big check back
2 in the day. Now, I receive little checks once a year for something in the ballpark of \$18 or
3 \$32, for example, or occasionally up to \$50, like this year. These amounts are nowhere
4 close to the amount I am spending on my heating each month—let alone each year.

5
6 **Q: Please describe LSP and your experience with it.**

7 **A:** With the help of MDHHS, I enrolled in LSP in or around 2022. I have been enrolled in the
8 program twice—for almost three years at this point. The program is a two-year program
9 designed to allow “vulnerable customers to make affordable monthly payments.”³ It
10 attempts to do so by “eliminat[ing] any future late payment charges” and freezing “past
11 due charges . . . while the customer receives a monthly arrears forgiveness credit.”⁴ Toward
12 the end of my first two years, I realized that my enrollment was about to expire and that
13 my bills were going to revert to the same amounts that I could not afford prior to my
14 enrollment in LSP. What’s the next option, I asked. But it looked like there were no other
15 options to help pay down my bills. I then extended my LSP enrollment for another two
16 years because I thought nobody had any other program in place for people like me.

17
18 **Q: DTE states that it has a high “graduation” rate for its LSP customers. What does this**
19 **mean to you?**

20 **A:** I am not sure what DTE means by “graduation.” I recently received a letter in the mail
21 telling me that I “graduated” from the program, but DTE’s program has never made me

³ *Id.* at 7.

⁴ *Id.*

1 feel like a “graduate.” The LSP program has helped me while I was enrolled, but it has *not*
2 put me in a place where I can now afford my bills in the future. Without LSP, my bills will
3 be just as unaffordable as they were beforehand. As I explained above, this is why I need
4 to re-enroll in LSP.

5
6 **Q: Please describe your experience trying to get re-enrolled in LSP.**

7 **A:** Enrolling in LSP is difficult. I called DTE the week of April 29th, for example, to try to
8 get re-enrolled in the program, but the Company said I needed to go through other
9 organizations to get enrolled. Over the course of thirty minutes, DTE’s customer service
10 representative could not provide me with any information about whether or how I could
11 re-enroll in LSP, nor did the representative answer any additional questions about LSP or
12 another available assistance program. All she could do was tell me about BudgetWise and
13 give me a list of organizations and their phone numbers. I felt as if she was saying, “You
14 can get off the phone now. Hurry up. I’ve told you all that I know.” Now, I must spend a
15 lot of time following up with different organizations. DTE has testified that the Company
16 has a “dedicated team of customer advocates [] ready to assist customers while enrolled in
17 LSP,”⁵ but what about after I have “graduated”? Based on my experience, DTE’s customer
18 service representatives have not been trained to support the needs of customers or answer
19 basic questions about the Company’s programs.

20 DTE acknowledges that, “[o]nce [] customers ha[ve] left the support of LSP, they
21 may find themselves experiencing challenges making consistent monthly payments and

⁵ *Id.*

1 fall back into a crisis situation.”⁶ This is exactly what is happening to me and what I suspect
 2 is happening for many other “graduated” participants. In response to these challenges, DTE
 3 simply states that “[t]hese types of scenarios stress the importance of exploring affordable
 4 payment options that go beyond 24 months and even beyond the 150% FPL requirements.
 5 The PSP pilot is an option to address long term energy affordability.”⁷ However, the PSP
 6 pilot has ended, and DTE has yet to share with me any information about any potential
 7 other affordable payment options it offers.

8
 9 **Q: Prior to preparing to provide testimony, had you ever heard about DTE’s Customer**
 10 **Assistance Days (CADs), Customer Resource Fairs (CRFs), or similar pop-up**
 11 **assistance events?**

12 **A:** No. I had never heard of any of these events, and I have never been to one of the events to
 13 my knowledge. On DTE’s website, I could not find any information about future CADs or
 14 CRFs. For example, now that I am looking at DTE’s “Customer Resource Fairs” page, it
 15 looks like there are no future events listed on the public webpage for the Company’s “2024
 16 Schedule.”⁸ As of the beginning of May 2024, I similarly could not find any information
 17 online about any of DTE’s future CADs.

18 Based on the list of past and planned CADs, CRFs, and pop-ups that DTE provided
 19 in discovery,⁹ DTE can do better. It looks like DTE has recently begun increasing the
 20 frequency of these events—DTE held three events in 2021, eight in 2022, twenty-one in

⁶ *Id.* at 9.

⁷ *Id.* at 10.

⁸ Ex. FLO-302, *Customer Resource Fairs*, DTE (last accessed 5/2/2024), <https://perma.cc/NLS3-BMTY>, at 1.

⁹ Ex. FLO-303, DTE’s Response to FLO’s Third Discovery Request, U-21291 FLOG3.5-a-c 2024-2024 CAD CRF POP UPS.

2023, and seven so far in 2024.¹⁰ However, DTE should hold more in-person and virtual events and publicize each more broadly, including on the Company's website and in further coordination with on-site partners. Currently, DTE plans on holding seven events between May and November of this year, but all of these will be in person at the Northwest Activity Center (in Detroit) on a weekday during the day. DTE should offer more flexible options regarding timing and location. For example, all of DTE's past events between 2021 and 2024 have, in fact, occurred during the day on weekdays, which can make it difficult or impossible for many folks to attend.

Q: Prior to preparing to provide testimony, had you ever heard about DTE's Payment Stability Plan (PSP) pilot?

A: No.

Q: Prior to preparing to provide testimony, had you ever heard about DTE's Residential Income Assistance (RIA) credit?

A: No.

Q: Prior to preparing to provide testimony, had you ever heard about DTE's Low-Income Assistance (LIA) credit?

A: No.

¹⁰ *Id.*

1 **Q: DTE states that it automatically enrolls all LSP participants in the LIA credit. Does**
2 **that sound familiar to you?**

3 **A:** No. Prior to preparing to provide this testimony, I had never heard about the LIA credit, let
4 alone the fact that I was already supposed to receive the credit. This speaks to DTE's lack
5 of education and outreach. Looking at my latest bill now, I see that there is a "Special Low
6 Income Credit" of \$30 on my bill. I assume that is the LIA credit, though it is confusing
7 that DTE has come up with different labels for all these programs.

8
9 **Q: DTE states that it automatically enrolls all HHC participants in the RIA credit. Does**
10 **that sound familiar to you?**

11 **A:** No. Prior to preparing to provide this testimony, I did not know that HHC participants
12 would be automatically enrolled in the RIA credit. Based on my latest bill, however, it
13 looks like I do not receive the RIA credit. I assume this is because of DTE's policy that
14 "[c]ustomers may not receive both the gas RIA and gas LIA credit at the same time."¹¹ But
15 I do not understand why customers eligible for both cannot receive both; in my opinion,
16 they can and should.

17

¹¹ Sparks Direct Testimony at 12.

Q: When DTE began the LIA credit program, the LIA credit was \$30 and covered approximately 68% of a typical monthly bill.¹² Today, the credit is still \$30 but covers only approximately 58% of a typical bill, according to DTE.¹³ DTE is proposing to increase the credit to \$40, to cover approximately 60% of a typical bill.¹⁴ What are your thoughts on this change?

A: I am glad that DTE is proposing increasing the credit, but increasing the credit by only \$10 is really a slap in the customer's face. It makes me upset to know that DTE has allowed the value of the LIA credit to decrease over time and now does not want to restore the credit to its original value, which would be at least 68% of a typical bill. The concern that DTE expressed was "gradualism."¹⁵ But what gradualism concerns are there? Will customers be too shocked when they see a larger credit? Please shock us, if that is the case. What's the purpose of keeping the increase to only \$10 when DTE's own analysis suggests that a larger credit would be necessary to restore the LIA's original value?¹⁶ In fact, DTE states that it "plans to maintain an LIA that will offset approximately 70%" of a customer's typical bill,"¹⁷ but the Company "does not have a timeline of when it will propose a 70% LIA credit."¹⁸ DTE should make this change now.

¹² *Id.* at 17.

¹³ *Id.*

¹⁴ *Id.*

¹⁵ Ex. FLO-304, DTE's Response to FLO's Second Discovery Request, FLODG-2.3b ("The first reason is gradualism. Many times the Commission prefers to implement changes gradually. Proposing a \$10 increase as opposed to a \$15 increase would allow for a more gradual change.").

¹⁶ See Sparks Direct Testimony at 17.

¹⁷ *Id.* at 18.

¹⁸ Ex. FLO-305, DTE's Response to FLO's Second Discovery Request, FLODG-2.4a.

1 **Q: In your view, are DTE’s various assistance programs effective?**

2 **A:** No, DTE’s various assistance programs are not effective. First, as I stated previously, DTE
3 does not educate customers properly on what these programs do and who may be eligible,
4 leaving customers in need to fend for themselves in trying to come up with the money and
5 resources to prevent a shutoff. Second, DTE’s various programs are half-baked and
6 confusing. Even when I try to self-educate on the kinds of programs available, it is difficult
7 to keep up with and keep straight all the different types of programs. They all have different
8 names and acronyms, eligibility thresholds, timelines, goals, and degrees of support, which
9 further builds on the confusion.

10

11 **Q: What are your recommendations regarding DTE’s assistance programs?**

12 **A:** At the end of the day, I just need my monthly bill to be affordable. It would be easier and
13 simpler if DTE had one unified program that helped me pay the portion of my bill that I
14 can’t afford—such as a Percentage of Income Payment Plan (PIPP). Ideally, the MPSC
15 would require DTE to enroll me in these programs automatically and keep me enrolled—
16 at least without the significant hassle that I currently undergo. The MPSC should also
17 ensure that DTE’s customers always know how each of its programs works, in a proactive
18 and frequent manner, unlike today’s reality. Because I do not use my email frequently—as
19 with many people in the community—DTE should ensure that this kind of information is
20 shared openly and frequently over the phone and through mailed materials, in addition to
21 email and online platforms.

22 DTE can do much better for the people in the community. We often don’t know
23 what they’re doing. They need to take the time to communicate with us and educate us

1 about what they're doing, especially regarding how customers can reduce the high bills
2 that DTE sends our way each month.

3

4 **Q: Does this conclude your written Direct Testimony?**

5 **A: Yes.**

1 MR. TEMPLETON: And finally, your Honor,
2 in lieu of conducting cross-examination of DTE witnesses,
3 the Frontline Organizations and DTE agreed for the
4 admission of certain exhibits; those exhibits have been
5 uploaded to the SharePoint site for the past couple of
6 days, no other party has registered any concerns with
7 those exhibits. Those exhibits are FLO-401 through
8 FLO-414. The Exhibit 413 is confidential. So I move for
9 the admission into the public record of FLO-401 through
10 412 and FLO 414, and for admission into the confidential
11 record FLO-413; and of course, FLO 413 will only be
12 served on those parties who signed the, parties and
13 persons who signed the confidentiality agreements.

14 JUDGE THOITS: All right. Are there any
15 objections to the admission of these exhibits? (No
16 response.)

17 Hearing none, Exhibits FLO-401 through
18 FLO-412 and FLO-414 are admitted, and Exhibit FLO-413 is
19 admitted to the confidential record.

20 MR. TEMPLETON: That is all I have on
21 behalf of the Frontline Organizations. Thank you very
22 much, your Honor.

23 JUDGE THOITS: Thank you. Is ABATE ready
24 to bind in?

25 MR. CAMPBELL: Yes, your Honor. Thank
Penn Reporting, LLC - lori.penn@yahoo.com

1 you. And we had three witnesses in this proceeding; do
2 you want me to take them one at a time?

3 JUDGE THOITS: I would appreciate that,
4 thank you.

5 MR. CAMPBELL: O.K. So at this time, on
6 behalf of the Association of Businesses Advocating Tariff
7 Equity, I'd move to bind in and admit into the record the
8 testimony of ABATE witnesses Jessica York, Colin
9 Fitzhenry, and Chris Walters, along with their associated
10 exhibits.

11 Ms. York's direct testimony consists of a
12 cover page, a table of contents, 37 pages of questions
13 and answers, and an Appendix A setting out her
14 qualifications; and along with her direct testimony,
15 Ms. York sponsored Exhibits AB-1 and AB-2. Ms. York's
16 revised rebuttal testimony consists of a cover page, a
17 table of contents, and 10 pages of questions and answers;
18 and along with her rebuttal testimony, Ms. York sponsored
19 Revised Exhibit AB-19.

20 JUDGE THOITS: All right. Are any
21 objections to the binding in of this testimony or
22 admission of these exhibits? (No response.)

23 Hearing none, the Direct and Rebuttal
24 Testimony of Jessica York is bound into the record, and
25 Exhibits AB-1, AB-2, and AB-19 are admitted.

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

(Testimony bound in.)

- - -

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of DTE GAS
COMPANY for authority to increase its
rates, amend its rate schedules and rules
governing the distribution and supply of
natural gas, and for miscellaneous
accounting authority

Case No. U-21291

Direct Testimony and Exhibits of

Jessica A. York

On behalf of

Association of Businesses Advocating Tariff Equity

May 7, 2024



In the matter of the Application of DTE GAS)
 COMPANY for authority to increase its)
 rates, amend its rate schedules and rules)
 governing the distribution and supply of) Case No. U-21291
 natural gas, and for miscellaneous)
 accounting authority)

1 or "Company"). They primarily take service under DTE's Extra Large Transportation
2 ("Rate XLT") service tariff and Extra-Extra Large Transportation ("Rate XXLT") service
3 tariff.

4 **Q PLEASE BRIEFLY SUMMARIZE ABATE'S WITNESSES IN THIS PROCEEDING**
5 **AND THE ISSUES THEY ARE ADDRESSING IN DIRECT TESTIMONY.**

6 A ABATE is providing Direct Testimony in this proceeding from three witnesses. They
7 include myself and my colleagues Colin T. Fitzhenry and Christopher C. Walters.

8 I provide an overview of the Direct Testimony of ABATE's witnesses and then
9 address: (i) DTE's use of a projected test year; (ii) DTE's proposed Class Cost of
10 Service study ("CCOS"); (iii) DTE's proposed revenue allocation; and (iv) DTE's
11 proposed gas curtailment tariff language changes.

12 Mr. Fitzhenry addresses DTE's proposed projected test year Operation and
13 Maintenance ("O&M") expense levels and DTE's proposal to include in its revenue
14 requirement expenses for incentive compensation tied to its financial performance. He
15 also addresses several of the capital expenditure amounts that DTE has projected it
16 will incur either during its proposed projected test year or during the bridge period
17 between the end of DTE's proposed historic year and beginning of its proposed
18 projected test year.

19 Mr. Walters addresses DTE's proposed Return on Equity ("ROE") and capital
20 structure.

21 Table JAY-1 summarizes ABATE's recommended downward adjustments to
22 DTE's proposed revenue requirement increase. In total, ABATE's adjustments reduce
23 DTE's proposed revenue requirement increase in this proceeding from \$265.5 million
24 down to \$205.6 million. The Capital Expenditure adjustments in Table JAY-1 assume

the Michigan Public Service Commission ("MPSC" or "Commission") adopts Mr. Walters' rate of return recommendation of an equity ratio of 50% and an authorized ROE of 9.45%. If despite Mr. Walters' recommendation the Commission were to instead adopt an authorized ROE greater than 9.45%, the listed downward revenue requirement adjustment associated with projected capital expenditures would be larger. Mr. Fitzhenry details this in his Direct Testimony.

TABLE JAY-1		
<u>ABATE Revenue Requirement Adjustments</u>		
(\$ Millions)		
Line	Description	Amount
1	DTE Claimed Revenue Deficiency	\$265.5
	<u>Adjustments:</u>	
2	O&M Expenses	\$6.9
3	Financial Performance Portion of Incentive Compensation Expense	\$12.0
4	Projected Capital Expenditures ¹	\$3.4
5	<u>Return on Equity and Equity Ratio</u>	<u>\$37.6</u>
6	Total of ABATE Revenue Requirement Adjustments	\$59.9
7	Adjusted Revenue Deficiency	\$205.6
Notes:		
¹ This is at ABATE's recommended ROE of 9.45% and common equity ratio of 50%. At DTE's proposed ROE of 10.25% and equity ratio of 51.5%, this		

My silence in this testimony, or that of my colleagues in their own testimony, with regard to any issue should not be construed as an endorsement of DTE's position on that issue.

Q PLEASE BRIEFLY SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS IN THIS PROCEEDING.

A My conclusions and recommendations are as follows:

1. DTE is in this proceeding is requesting to increase its natural gas rates (if DTE's proposed Investment Recovery Mechanism ("IRM") is approved) by \$265.5 million despite it reporting a revenue sufficiency of \$35.7 million during its historical test year in this proceeding.
2. As detailed in the Direct Testimony of ABATE witnesses Mr. Fitzhenry and Mr. Walters, at least \$59.9 million (approximately 22.6%) of DTE's proposed \$265.5 million rate increase in this proceeding is unwarranted, unsupported or both. As a minimum, this portion of DTE's proposed rate increase should be denied.
3. DTE's recent rate increases have been driven by the use of projected rather than historical test years for ratemaking and aggressive capital expenditures¹ coupled with the filing of frequent rate cases.
4. In this proceeding, and in four out of five of DTE's most recent previous rate filings, DTE has reported a revenue sufficiency for its filed historical test year indicating recurring instances of DTE earning revenues in excess of its authorized amount due to the continuing use of a projected test year. Given this track record with respect to the use of a projected test year, the Commission should reject DTE's proposed use of a projected test year in this proceeding and require DTE to use its proposed historical test year as the basis of its revenue requirement in this proceeding. Given that DTE is reporting a revenue sufficiency of \$35.7 million for its historical test year in this proceeding, this would limit DTE's revenue requirement increase in this proceeding to no more than \$105.6 million – the revenue requirement amount that DTE has proposed to roll into base rates from its current IRM Surcharge based on DTE's proposed ROE and equity ratio.
5. If, despite my recommendation, the Commission allows DTE to use a projected test year in this proceeding, the Commission should be vigilant to ensure the following: (i) that the projected expenses and investments included in DTE's projected test year are truly necessary to provide reliable service at the lowest reasonable cost; (ii) that DTE is essentially irrevocably committed to incur them or otherwise cannot avoid them; and (iii) they are precisely quantified by DTE with respect to their amount and timing.
6. As was recommended in ABATE's May 14, 2021 and August 11, 2021 filed Comments in Case No. U-18238, the Commission, within the context of the Commission's minimum filing requirements, should generically examine the issue

¹For example, DTE in its summary for its current gas rate filing identified its filing being driven by continued infrastructure investment and increasing operations and maintenance costs. Furthermore, DTE identified \$179 million of its \$265.5 million proposed revenue requirement increase being related to growth in its rate base. (December 28, 2023 Rate Case Summary at page 1-2).

- 1 of projected test years continuing to result in excess revenue being collected from
2 customers.
- 3 7. The Company's proposed CCOS relies on the Peak and Average ("P&A") method
4 for the allocation of transmission and distribution capacity costs. The P&A method
5 does not reflect cost-causation and should be rejected.
- 6 8. The Company's proposed revenue apportionment results in about a 1.6x system
7 average increase for Rate XXLT and a 1.35x system average increase for
8 Rate XLT. These proposed increases are based on the results of a flawed and
9 inaccurate CCOS.
- 10 9. The Company has provided evidence showing that Design Day Demand is the load
11 characteristic that drives investment in transmission and distribution capacity costs.
12 Thus, a Design Day Demand allocation of these costs would produce the most
13 accurate measure of the Company's cost of providing service to each customer
14 class.
- 15 10. The Design Day Demand CCOS shows that a rate decrease would be required for
16 Rate XXLT to reach cost of service, and that a below-system average increase
17 (0.87x) would be required for Rate XLT to reach cost of service.
- 18 11. To the extent that the Commission prefers to continue relying on a partial
19 energy-weighted method of allocating capacity costs, I recommend that the
20 Average and Excess Demand ("AED") approach be used, instead of the P&A
21 method.
- 22 12. Relative to the P&A method, the AED method more accurately assigns the
23 transmission and distribution capacity costs to the lower-load factor, weather
24 sensitive customer classes that drive the need for capacity in excess of the amount
25 needed to provide firm service to the system and each customer class on non-peak
26 days.
- 27 13. I recommend an alternative revenue apportionment reflecting no rate change for
28 Rate XXLT, and I recommend bringing Rate XLT to cost of service based on a
29 Design Day Demand CCOS with a 0.87x system average increase. My proposed
30 revenue allocation mitigates the increase that would be required for the Residential
31 class ("Rate A") to reach cost of service based on the results of a Design Day
32 Demand CCOS.
- 33 14. Alternatively, I recommend a system average increase across all classes, provided
34 the Company commits to provide a properly conducted AED CCOS in its next rate
35 case. My alternative revenue apportionment would reflect a compromise between
36 the P&A and Design Day Demand CCOS until an AED CCOS is conducted.
- 37 15. I recommend certain changes to DTE's proposed Gas Curtailment Service tariff to
38 ensure a similar level of flexibility for customers as provided by Consumers Energy
39 Company ("CEC").

II. Projected Test Year

Q YOU HAVE ALLEGED THAT, ALONG WITH THE PURSUIT OF AGGRESSIVE CAPITAL EXPENDITURES, DTE'S USE OF A PROJECTED TEST YEAR IS A MAJOR DRIVER OF DTE'S PROPOSED RATE INCREASE IN THIS PROCEEDING. PLEASE EXPLAIN WHY THIS IS THE CASE.

A The best starting point for exploring this issue is to compare DTE's own historical and projected test year calculations for this case and its five most recent gas rate cases. I present this comparison below in Table JAY-2.

TABLE JAY-2				
Historical Test Year and Projected Test Year Rate Sufficiency / (Deficiency)				
Line	Case No.	Historical Test Year Sufficiency / (Deficiency)	Projected Test Year Sufficiency / (Deficiency)	Difference Between Historical and Projected
		(1)	(2)	(3)
1	U-16999	\$ 6,551,000	\$ (76,674,000)	\$ (83,225,000)
2	U-17999	56,000	(182,927,000)	(182,983,000)
3	U-18999	61,829,000	(85,105,000)	(146,934,000)
4	U-20642	29,109,000	(203,766,000)	(232,875,000)
5	U-20940	(11,865,000)	(194,817,000)	(182,952,000)
6	U-21291	35,722,000	(265,532,000)	(301,254,000)
7	Total	\$ 121,402,000	\$ (1,008,821,000)	\$ (1,130,223,000)

Sources:

Case No. U-16999, Exhibit A-1 and Exhibit A-8, Schedule A1
Case No. U-17999, Exhibit A-1 and Exhibit A-8, Schedule A1
Case No. U-18999, Exhibit A-1 and Exhibit A-11, Schedule A1
Case No. U-20642, Exhibit A-1 and Exhibit A-11, Schedule A1
Case No. U-20940, Exhibit A-1 and Exhibit A-11, Schedule A1
Case No. U-21291, Exhibit A-1 and Exhibit A-11, Schedule A1

1 What this shows is that even under DTE's own numbers DTE would not have
2 been able to seek the large rate increases it has sought in its last six gas rate cases,
3 and is seeking in this proceeding, but for being permitted to use a projected test year.
4 To put it another way, the use of a projected test year allows DTE to begin recovery of
5 costs before those costs have been verified as being real and prudently incurred. This
6 has had and continues to have several adverse impacts on customers.

7 First, it has caused and continues to cause customers to experience rate
8 increases sooner than they would under the use of a historical test year.

9 Second, it has eliminated and continues to eliminate the incentive for DTE to
10 contain costs that would otherwise exist due to the regulatory lag effect associated with
11 the use of a historical test year.

12 Third, it has allowed and continues to allow DTE to fill its projections with
13 proposed capital expenditures and expenses that either DTE has not irrevocably
14 committed to making or otherwise can avoid if it finds it advantageous to do so to
15 improve its realized rate of return for its shareholders. This can allow DTE to collect
16 revenue from its customers for capital expenditures or expenses it does not ultimately
17 incur or has not yet incurred when rates are placed into effect. This unreasonably
18 benefits DTE's shareholders at the expense of DTE's customers.

19 Finally, the use of a projected test year greatly handicaps the Commission Staff
20 ("Staff") and intervenors in reviewing DTE's rate filings to ensure the projected capital
21 expenditures and expenses are reasonable because they are not actual capital
22 expenditures and expenses reflected on DTE's books, but rather projections developed
23 over many separate cost subaccounts and revenue categories. This requires much
24 more time and greater resources than are necessary in a rate proceeding that utilizes
25 a historical test year all while the rate case timing has been compressed down to a

1 10-month time frame. As a result, while some inappropriate cost projections by DTE
2 may be identified and successfully disallowed as a result of Staff and intervenor review
3 of DTE's projections, many other inappropriate cost projections may be missed and
4 inappropriately included in DTE's rates at the expense of its customers as I have
5 outlined above.

6 **Q ARE DTE'S PROJECTED BRIDGE PERIOD CAPITAL EXPENDITURES AND**
7 **FORECASTED TEST YEAR EXPENSES AND CAPITAL EXPENDITURES KNOWN**
8 **AND MEASURABLE CHANGES TO ITS HISTORICAL TEST YEAR?**

9 A No, they are not. Known and measurable changes are changes to costs that are
10 inescapable and precisely identifiable in amount and timing. Future capital
11 expenditures and projected expenses are often not inescapable, not precisely
12 identifiable in amount and timing, or both. When they are escapable or not precisely
13 identifiable with respect to amount and timing, they are not known and measurable
14 changes from the historical test year. Furthermore, many of the capital expenditures
15 and expenses that DTE has attempted to recover in past general rate cases and is
16 attempting to recover in this current proceeding, as shown by the Direct Testimony of
17 my colleague, Mr. Fitzhenry, are highly speculative. These include capital expenditures
18 and expenses that DTE has not irrevocably committed to make. These too are not
19 known and measurable changes from the historical test year.

1 **Q PLEASE PROVIDE SOME EXAMPLES OF CHANGES FROM A HISTORICAL TEST**
2 **YEAR THAT ARE KNOWN AND MEASURABLE CHANGES.**

3 A Examples of valid known and measurable changes to historical test year amounts
4 include:

- 5 • Normalization to address the effects of volatility, such as those related to economic
6 conditions or weather, and unusual events such as extended forced generation
7 outages that distort the amounts that fall within the historical test year;
- 8 • Annualization to address costs, such as those associated with nuclear generation
9 refueling outages and other types of extended planned generation outages, that
10 regularly occur on a periodic basis, but not in every year;
- 11 • Costs that only occurred during the later months of the historical test year and are
12 expected to continue at that same level on a going forward basis; and
- 13 • Imminent changes in costs that will occur during the period between the end of the
14 historical test period and the date new base rates go into effect and are expected
15 to continue on a going forward basis.

16 **Q IS THERE ANY EVIDENCE THAT SUGGESTS THAT DTE HAS BEEN MORE THAN**
17 **FAIRLY COMPENSATED AS A RESULT OF BEING ALLOWED TO USE A**
18 **PROJECTED TEST YEAR?**

19 A Yes. As my Table JAY-2 shows, in its rate filing in this proceeding, DTE has reported
20 a large revenue sufficiency of approximately \$35.7 million for its historical test year.
21 This means that, in that historical test year (calendar year 2022), DTE received
22 revenues \$35.7 million higher than necessary to earn its authorized rate of return during
23 that historical test year. In addition, in four out of five of DTE's previous gas rate filings,
24 DTE reported a revenue sufficiency for its historical test year and in three of those the
25 sufficiency was large, falling between \$6.5 million to \$61.8 million depending on the
26 filing.

27 It is also important to note that the historical test year values presented in my
28 Table JAY-2 are DTE's reported historical test year values. If these historical test year

1 values were closely examined they might very well reveal costs that are not recoverable
2 in rates. As a result, DTE's actual revenues in excess of its authorized rate of return in
3 its historical test year for this proceeding (calendar year 2022) may very well have been
4 well in excess of the approximately \$35.7 million DTE has reported.

5 **Q DTE'S HISTORIC TEST YEAR IN THIS PROCEEDING IS CALENDAR YEAR 2022.**
6 **IS THERE ANY EVIDENCE IN DTE'S DIRECT CASE THAT IN CALENDAR YEAR**
7 **2023 DTE EXPERIENCED A REVENUE DEFICIENCY?**

8 A No, DTE has provided no such evidence in its direct case. Furthermore, DTE did not
9 make a rate filing in 2022 for new rates to go in effect for a projected test year of
10 Calendar Year 2023. DTE did not make a rate filing after 2021 until its filing in this
11 proceeding on January 8, 2024. This strongly suggests DTE in 2022 was not projecting
12 a revenue deficiency for itself for Calendar Year 2023.

13 **Q IS THE COMMISSION REQUIRED TO SET RATES USING A PROJECTED TEST**
14 **YEAR?**

15 A No. As the Commission discussed in its November 2, 2009 Order in Case
16 No. U-15645, page 8, Section 6a(1) of Act 286, MCL 460.6a(1), provides that a utility
17 "may use projected costs and revenues for a future consecutive 12-month period" to
18 develop its requested rates and charges. The Commission added that the Staff and
19 intervenors should direct their focus "upon the strengths and weaknesses of the
20 evidentiary presentations of the parties regarding specific expense and revenue
21 projections." In a case where a utility decides to base its filing on a fully projected test

1 year, however, the utility bears the burden to substantiate its projections.² Recognizing
2 the statutory time constraints present in a base rate case, the Commission has directed
3 utilities to include all evidence (or sources of evidence) in support of their test year
4 projections in their initial rate case filings.³ If the utility cannot or will not provide
5 sufficient support for a particular revenue or expense item (particularly for an item that
6 substantially deviates from the historical data), “the Commission may choose an
7 alternative method for determining the projection.”⁴ That alternative method should be
8 the use of the historical test year amount for that item adjusted for only known and
9 measurable changes to the amount for that item.

10 **Q WHAT DO YOU RECOMMEND TO THE COMMISSION WITH RESPECT TO THIS**
11 **ISSUE?**

12 A Given DTE’s track record with respect to its use of a projected test year, my primary
13 recommendation is that the Commission reject DTE’s proposed use of a projected test
14 year in this proceeding and reject DTE’s request for a rate increase in this proceeding
15 with the exception of DTE’s proposal to roll \$105.6 million of revenue requirement that
16 it currently collects in its IRM Surcharge into its base rates.

²*In re Detroit Edison Application for Rate Increase*, MPSC Case No. U-15768, January 11, 2010
Order at page 9.

³*Id.*

⁴*Id.*

1 **Q IF, DESPITE YOUR RECOMMENDATION, THE COMMISSION ALLOWS DTE TO**
2 **USE A PROJECTED TEST YEAR IN THIS PROCEEDING, WHAT DO YOU INSTEAD**
3 **RECOMMEND TO THE COMMISSION?**

4 **A**If, despite my recommendation, the Commission decides to allow DTE to use a
5 projected test year for this proceeding, I have a near-term recommendation and one
6 longer-term recommendation, discussed further below, that the Commission should
7 instead adopt.

8 First, I recommend the Commission, be much more vigilant with respect to
9 ensuring the expenses and investments being projected by DTE for its projected test
10 year are truly expenses and investments that are necessary to provide reliable service
11 at lowest reasonable cost. The Commission should also ensure that DTE is irrevocably
12 committed to incur its projected expenses and investments or otherwise cannot avoid
13 them. Finally, the Commission should ensure that DTE's projected investments and
14 expenses are precisely quantified by DTE with respect to both amount and the specific
15 quarter in which DTE will incur these investments and expenses. It is clear from the
16 recent track record of DTE reporting historical test year revenues \$6.5 million to
17 \$61.8 million in excess of its authorized return in four of its six most recent gas rate
18 proceedings (the current one and Case Nos. U-16999, U-18999 and U-20642) ⁵ that it
19 is likely to some extent either questionable projections of DTE are not being caught by
20 intervenors and/or Staff in their review of DTE's proposals given the complexity of
21 verifying those projections, the Commission has provided too great of a benefit of doubt
22 to DTE with respect to the costs found to be questionable by intervenors and/or Staff,
23 DTE is not actually incurring the costs it has projected, or some combination of the
24 three has been occurring. DTE will essentially continue to earn a rate of return higher

⁵Table JAY-2.

1 than authorized by the Commission unless and until this issue is brought under control.
2 It is very important the Commission make progress in this regard in order to ensure
3 DTE does not continue to abuse its use of a projected test year.

4 **Q WHAT IS YOUR LONGER-TERM RECOMMENDATION TO THE COMMISSION?**

5 A ABATE recommended in its May 14, 2021 and August 11, 2021 filed Comments in
6 Case No. U-18238 that, as part of reconvening a collaborative work group to discuss
7 the experience and impact of the rate case filing requirements set forth in its
8 July 31, 2017 Order in Case No. U-18238, the Commission have the collaborative
9 workgroup address the use of projected test years and utility ROE requests continuing
10 to result in excess revenue collection from customers under the Commission's current
11 minimum filing requirements.⁶ As detailed in its May 14, 2021 Comments, the
12 Commission should examine: (i) customer benefits and detriments that have resulted
13 from the use of projected test years; (ii) conditions under which the Commission would
14 reject the use of a projected test year; (iii) categories of expenses/revenues that are
15 uniquely difficult to predict so as to render their inclusion in a projected test year
16 inappropriate; (iv) minimum criteria to reasonably demonstrate a sufficient commitment
17 by the utility to actually incur the expenses it projects; (v) length of time between the
18 end of the historical test year and the beginning of the proposed projected test year;
19 (vi) a method of tracking projections for various costs to determine consistency and
20 extent of over- or under-projection and potential projection guardrails or limits; and
21 (vii) whether the use of a projected test year by a utility should factor into its
22 authorized ROE. Further attention to these issues could help tailor and bolster the
23 Filing Requirements and utility rate case applications to ensure that projected test year

⁶Case No. U-18238, ABATE May 14, 2021 Comments at page 1.

filings more accurately and reasonably align projections with utility revenue requirements.⁷ While the Commission's August 11, 2022 Order in Case No. U-18238 did not adopt ABATE's recommendation, ABATE continues to urge the Commission to pursue resolution of these issues through a collaborative workgroup.

III. Class Cost of Service Study and Revenue Apportionment

Q HAVE YOU REVIEWED THE CLASS COST OF SERVICE STUDIES PROVIDED BY THE COMPANY?

A Yes. The Company has provided two versions of its CCOS in this case, which are sponsored by Mr. T.J. Krynski. DTE's Preferred CCOS relies on a P&A allocation of transmission and distribution capacity costs. The Preferred CCOS is consistent with the allocation methods that have been previously approved by the Commission.

The Alternative CCOS also uses the P&A method to allocate transmission and distribution capacity costs. However, the Alternative CCOS differs from the Preferred CCOS in that it separates the cost of distribution mains between High Pressure ("HP") and Low Pressure ("LP") mains. It is my understanding that the Alternate CCOS has not been endorsed by DTE, or relied upon for revenue distribution or rate design in this proceeding, but was provided pursuant to the Commission's Order in Case No. U-20940.⁸

A comparison of the Company's CCOS results to its proposed revenue apportionment is presented in Table JAY-3.

⁷*Id.* at 5-6.

⁸See the Direct testimony of T.J. Krynski at pages 20-23.

TABLE JAY-3

DTE's Preferred CCOS vs. Proposed Revenue Apportionment (\$000)*

<u>Line</u>	<u>Rate Schedule</u>	<u>Total</u> <u>Revenues</u> <u>at Current</u>	<u>Net Increase / (Decrease)</u> <u>to Reach Cost of Service</u>			<u>DTE Proposed Net</u> <u>Increase / (Decrease)</u>		
		<u>Rates</u> <u>(1)</u>	<u>Amount</u> <u>(2)</u>	<u>Percent</u> <u>(3)</u>	<u>Index</u> <u>(4)</u>	<u>Amount</u> <u>(5)</u>	<u>Percent</u> <u>(6)</u>	<u>Index</u> <u>(7)</u>
1	GS-1/GS-2	\$ 364,227	\$ 28,626	7.9%	0.84	\$ 29,486	8.1%	0.87
2	Rate A	1,154,404	105,609	9.1%	0.98	104,292	9.0%	0.97
3	Rate 2A	36,366	1,480	4.1%	0.44	2,798	7.7%	0.83
4	Rate S	10,898	1,112	10.2%	1.09	252	2.3%	0.25
5	Rate ST	46,063	(7,007)	-15.2%	(1.63)	5,341	11.6%	1.24
6	Rate LT	30,967	1,324	4.3%	0.46	1,704	5.5%	0.59
7	Rate XLT	29,299	14,505	49.5%	5.31	3,696	12.6%	1.35
8	Rate XXLT	31,324	6,629	21.2%	2.27	4,613	14.7%	1.58
9	Exelon	13,145	7,725	58.8%	6.31	7,725	58.8%	6.31
10	Total**	\$ 1,716,694	\$ 160,002	9.3%	1.00	\$ 159,905	9.3%	1.00

Sources and Notes:

* Includes gas cost for bundled service customer classes.

** Difference between CCOS increase and proposed increase is due to rounding.

DTE's workpapers labeled "U-21291 Gas 2023 COS For Filing.xlsx."

Exhibit A-16, Schedule F1.1

Exhibit A-16, Schedule F2.

Exhibit A-16, Schedule F3.

Tab labeled "WP TJK-11 IRM Surch Revenue."

Exhibit A-18, Schedule H-4.

1 As shown in the table, the Company's Preferred CCOS would result in

2 increases well above the system average for Rate XLT, Rate XXLT, and Exelon.

3 However, DTE's proposed revenue apportionment, while generally based on the

4 results of its Preferred CCOS, reflects adjustments in consideration of gradualism.

1 Q IS THE COMPANY'S PROPOSED SPREAD OF THE REVENUE DEFICIENCY
2 REASONABLE?

3 A No. The Company's proposed revenue apportionment is based on the results of an
4 inaccurate CCOS. As discussed below in greater detail, the Company's CCOS does
5 not allocate transmission and distribution main capacity costs in accordance with the
6 load characteristic that drives DTE's investment in transmission and distribution main
7 capacity. An accurate CCOS based on the Design Day Demand method of capacity
8 cost allocation shows that a rate decrease is warranted for certain transportation
9 classes to reach cost of service.

10 Q ARE YOU RECOMMENDING AN ALTERNATIVE REVENUE APPORTIONMENT?

11 A Based on a Design Day Demand allocation of transmission and distribution capacity
12 costs, my recommended revenue apportionment would be as shown in Table JAY-4.

TABLE JAY-4								
<u>Design Day Demand CCOS vs. Proposed Revenue Apportionment (\$000)</u>								
<u>Line</u>	<u>Rate Schedule</u>	<u>Total Revenues at Current Rates</u> (1)	<u>ABATE Modified CCOS¹</u>			<u>Revenue Allocation</u>		
			<u>Net Increase / (Decrease) to Reach Cost of Service</u>			<u>Net Increase / (Decrease) to Reach Cost of Service</u>		
			<u>Amount</u>	<u>Percent</u>	<u>Index</u>	<u>Amount</u>	<u>Percent</u>	<u>Index</u>
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	GS-1/GS-2	\$ 364,227	\$ 36,932	10.1%	1.09	\$ 36,932	10.1%	1.09
2	Rate A	1,154,404	132,259	11.5%	1.23	113,514	9.8%	1.06
3	Rate 2A	36,366	2,042	5.6%	0.60	2,042	5.6%	0.60
4	Rate S	10,898	1,506	13.8%	1.48	1,072	9.8%	1.06
5	Rate ST	46,063	(10,797)	-23.4%	(2.51)	-	0.0%	-
6	Rate LT	30,967	(5,005)	-16.2%	(1.73)	-	0.0%	-
7	Rate XLT	29,299	2,376	8.1%	0.87	2,376	8.1%	0.87
8	Rate XXLT	31,324	(3,377)	-10.8%	(1.16)	-	0.0%	-
9	Exelon	13,145	4,066	30.9%	3.32	4,066	30.9%	3.32
10	Total	\$ 1,716,694	\$ 160,002	9.3%	1.00	\$ 160,002	9.3%	1.00

Notes:

¹ Replaces the P&A allocator in DTE's Preferred CCOS with the Design Day Demand allocator.

1 However, as will be discussed later in this testimony, I would not oppose an
2 equal percent increase across all customer classes for purposes of this case, so long
3 as the Company commits to provide a CCOS using the AED allocation method as an
4 alternative to the P&A CCOS in its next rate case.

5 **Q PLEASE DESCRIBE THE ISSUE YOU TAKE WITH THE COMPANY'S CCOS.**

6 **A** I disagree with the use of the P&A allocator to allocate the cost of transmission and
7 distribution main capacity across rate classes in both the Preferred and Alternate
8 CCOS models. The P&A allocator does not allocate the cost of capacity in line with
9 cost-causation, and distorts the accuracy of the Company's CCOS models. The P&A
10 cost allocation method effectively introduces rate impacts into cost allocation, and,
11 therefore, is not a pure cost allocation method. As described in the National
12 Association of Regulatory Utility Commissioners ("NARUC") Gas Rate Design Manual
13 ("NARUC Manual"), the P&A method tempers costs between high-load factor and
14 low-load factor customers.⁹ In other words, the P&A method artificially produces
15 smaller increases for lower-load factor customer classes than the utility's actual cost of
16 service, relative to a purely demand-based allocation method.

17 I believe cost allocation and rate moderation should be separate steps and
18 accordingly would not characterize the P&A method as a pure cost allocation method.
19 With an accurate CCOS study, the Commission can address any concerns regarding
20 the magnitude of class rate increases in the class revenue allocation and rate design
21 steps.

⁹NARUC Manual, June 1989, at page 28.

1 **III.A. CCOS Allocation of Transmission**
2 **and Distribution Capacity Costs**

3 **Q PLEASE DISCUSS THE ALLOCATION OF COSTS ASSOCIATED WITH**
4 **TRANSMISSION AND DISTRIBUTION MAINS TO CUSTOMER CLASSES IN DTE'S**
5 **PREFERRED AND ALTERNATE CCOS STUDIES.**

6 A The Company uses the P&A cost allocation method to allocate the costs of
7 transmission and distribution main capacity across customer classes.¹⁰

8 The P&A allocation factor consists of a weighting of two system load
9 characteristics: the Design Day Demand allocator (weighted by 1 minus the system
10 load factor) and the Average Demand (or annual volume) allocator (weighted by the
11 system load factor).

12 **Q HAS THE COMMISSION ACCEPTED THE USE OF THE P&A ALLOCATOR FOR**
13 **TRANSMISSION AND DISTRIBUTION MAIN CAPACITY COST IN PAST RATE**
14 **CASES?**

15 A Yes. I will address the factors relied on by the Commission from its past rate cases in
16 support of the P&A allocator. I will also discuss the system and customer load
17 characteristics that drive the Company's need to invest in transmission and distribution
18 capacity, in the amounts necessary to provide firm service to all customer classes every
19 day of the year.

¹⁰DTE's Exhibit A-16, Schedule F1.2 develops the P&A allocator, which is applied to transmission and distribution plant as Factor 3, on Exhibit A-16, Schedule F1.1, page 1.

1 **Q IN PRIOR RATE CASES, WHAT WAS THE COMMISSION'S RATIONALE FOR**
2 **APPROVING THE P&A ALLOCATOR FOR TRANSMISSION AND DISTRIBUTION**
3 **MAIN CAPACITY COSTS IN THE CCOS?**

4 **A In the 1993 DTE rate case, the Commission found that:**

5 A gas distribution system is in some ways similar to a plant that
6 produces two products. One product, peak day service, requires the
7 entire capacity of the 'plant'. The other product, off-peak service,
8 requires only a portion of the 'plant'. The plant has to produce both
9 products to be economically viable; peak day load alone insufficient to
10 pay for the cost of building the plant, and off-peak service alone is not
11 sufficiently desirable to many customers to allow for rates sufficient to
12 recover the costs of building the plant. ABATE would have the
13 Commission allocate the entire cost of the 'plant' to users of the peak
14 day service product, because the whole plant is needed to produce that
15 product. ABATE ignores the original cost causation question, i.e. would
16 the plant have ever been built to produce only peak day service? The
17 answer to that question is a resounding no.¹¹

18 In the 2021 rate case, Docket No. U-20940, the Commission agreed with Staff's
19 explanation, and also referenced the 1993 rate case Order. The Commission stated:

20 Staff proposed using the A&P allocation method because of its nature
21 as a compromise between the interests of high and low load factor
22 customers. High and low load factor customers use the distribution
23 system differently, so it is not fair to allocate the costs for using that
24 system as if it were used for a single purpose; to meet designed peak
25 demand. Because customer classes use the distribution system
26 differently, it is reasonable to use an allocation method that combines
27 how those disparate classes cause costs. Staff maintains that the
28 reasonable method is A&P allocation.¹²

¹¹Docket No. U-10149/U-10150. Final Order dated October 28, 1993 at page 96.

¹²Docket No. U-20940, Final Order at page 193.

1 **Q ARE YOU REQUESTING THAT THE COMMISSION RECONSIDER THE MERITS OF**
2 **USING THE P&A ALLOCATION FACTOR TO ALLOCATE TRANSMISSION AND**
3 **DISTRIBUTION MAIN CAPACITY COSTS ACROSS RATE CLASSES?**

4 A Respectfully, yes. I believe the Commission is supportive of setting rates based on
5 cost-causation principles. Thus, I address the substantive points cited by the
6 Commission in its previous decisions to continue to rely on the P&A allocation factor
7 for transmission and distribution main capacity costs. I will show that the cost-causation
8 facts in this case demonstrate that the P&A allocator for transmission and distribution
9 main capacity costs does not accurately allocate capacity costs across rate classes.
10 To the contrary, the P&A allocation factor over allocates transmission and distribution
11 main capacity costs to high-load factor customer classes and under allocates these
12 main capacity costs to low-load factor customers. The P&A allocator does not align
13 with how DTE incurs the cost of transmission and distribution main capacity to provide
14 firm service to its customer classes.

15 **Q DO YOU HAVE ANY OTHER COMMENTS ON WHY YOU RECOMMEND THE**
16 **COMMISSION RECONSIDER ITS PRIOR POSITIONS ON THE P&A METHOD?**

17 A Yes. Large energy intensive customers, such as ABATE members, are aware of the
18 cost allocation methods used in Michigan as compared to other jurisdictions. In order
19 to remain competitive within their industries and across the jurisdictions in which they
20 operate, these customers make investment decisions based on that knowledge. Thus,
21 it is important to note that other jurisdictions have adopted cost allocation methods that
22 more accurately measure each class's cost of service than the P&A method. Examples
23 include Manitoba, Missouri, and Pennsylvania, which are discussed in greater detail
24 later in this testimony.

**III.B. The P&A Cost Allocation Method
Does Not Reflect Cost-Causation**

**Q PLEASE EXPLAIN WHY DESIGNING THE DELIVERY CAPACITY OF THE UTILITY
BASED ON PEAK DAY DEMANDS ALLOWS THE UTILITY TO JUSTIFY ITS
DELIVERY MAIN INVESTMENT BASED ON DEMANDS FOR A SINGLE PEAK DAY.**

A Transmission and distribution mains are used to provide service every day of the year including the peak day, as well as the daily demand on non-peak days throughout the year. This is not in dispute. In order to achieve this year round service objective, the capacity of the delivery mains must be able to meet the system Design Day Demand and each rate class's daily demands. Hence, this system's main capacity is designed to serve the system's Peak Day, or Design Day Demand. As a result, measures of utilization (e.g., Average Demand, or annual throughput) have no bearing on the delivery capacity cost that customers are causing the utility to incur.

**Q DO YEAR-ROUND DEMANDS PLAY A ROLE IN SHAPING INVESTMENT IN
TRANSMISSION AND DISTRIBUTION MAIN CAPACITY?**

A No. As explained by DTE, while transmission and distribution main capacity is designed to meet Peak Day demand, the Company varies the pressure and amount of gas in the mains to meet the demands of all rate classes, and the system, every day of the year.¹³ Thus, the fixed cost of transmission and distribution main capacity designed to meet the system peak demand remains the same every day of the year, irrespective of operating pressure and capacity utilization of the mains. Therefore, there is no causal link between the cost of transmission and distribution main capacity and annual throughput.

¹³DTE's Response to Discovery Request ABDG-1.21d, 1.21f, 1.21gi and 1.21gii. Attached as Exhibit AB-1 at pages 1-4.

1 **Q ON A NON-PEAK DAY, IS THE EXCESS AVAILABLE MAIN CAPACITY USED TO**
2 **MEET THE DEMAND OF HIGH-LOAD FACTOR CUSTOMERS?**

3 A No. Relative to lower-load factor weather-sensitive customers, higher-load factor
4 customers more efficiently and consistently utilize the main capacity installed to meet
5 their coincident peak Design Day Demand. The excess available main capacity on
6 non-peak days exists due to weather-sensitive demand which is not driven by larger
7 users. This excess capacity is held in reserve for weather-sensitive customers for when
8 their demands spike on peak days. This was confirmed by the Company in response
9 to Discovery Request ABDG-1.21f, where it stated that during normal non-peak day
10 operations, customer load demands are less, therefore, the full capacity of a distribution
11 main is not utilized with the exception of pipelines that have been sized specifically for
12 customers with firm process loads.¹⁴

13 Thus, the excess main capacity that is available on a non-peak day is not used
14 to meet the demands of higher-load factor, non-weather-sensitive customers
15 throughout the year when it is not needed to serve weather-sensitive customers.
16 Rather, as noted above, the capacity installed to serve all rate classes' demands on
17 the peak day, is also used to serve their daily demands, but at a lower operating
18 pressure than what is required on a peak day.

¹⁴Attached as Exhibit AB-1 at page 2.

1 **Q SHOULD HIGHER-LOAD FACTOR CUSTOMER CLASSES, SUCH AS THE**
2 **RATE XLT AND XXLT CLASSES IN THIS CASE, BE ALLOCATED CAPACITY**
3 **COSTS INCURRED TO MEET THE DESIGN DAY DEMAND OF LOWER-LOAD**
4 **FACTOR, WEATHER-SENSITIVE CUSTOMER CLASSES?**

5 **A No.** Costs should be allocated based on how they are incurred. The Company's cost
6 of mains is not driven by Average Demand, or annual volume. As a result, a purely
7 cost-causation-based allocation of transmission and distribution mains should not
8 include a volumetric component. The volumetric component of the P&A allocator (the
9 Average component) results in higher-load factor customer classes, such as the
10 Rate XLT and Rate XXLT classes in this case, being allocated main capacity cost which
11 they do not cause; i.e., that is not incurred to provide service to them.

12 **Q DOES THE DESIGN DAY DEMAND METHOD FOR ALLOCATING MAIN COSTS TO**
13 **CLASSES BETTER REFLECT COST-CAUSATION ON DTE'S SYSTEM?**

14 **A Yes.** The cost of transmission and distribution main capacity should be allocated based
15 on Design Day Demand, which better reflects cost-causation on the Company's
16 system. The Company has produced numerous discovery responses confirming that
17 Design Day Demand is the most appropriate allocation factor to reflect cost-causation.
18 Specifically, the Company has confirmed the following:

- 19 • The system is designed to provide service at design day peak volumes.¹⁵
- 20 • The Company does not use load factor when determining transmission facilities
21 required by any DTE customer.¹⁶

¹⁵DTE's Response to Discovery Request ABDG-1.3, 1.4, 1.7a, 1.7b, 1.7d, 1.8a, 1.8b, and 1.8d. Attached as Exhibit AB-1 at pages 5-12.

¹⁶DTE's Response to Discovery Request ABDG-1.9. Attached as Exhibit AB-1 at page 13.

- 1 • The cost to construct distribution mains is not related to annual volume delivered.¹⁷
- 2 • The cost to construct transmission mains is not related to annual volume
- 3 delivered.¹⁸

4 **Q HAS THE ISSUE OF HOW TO ALLOCATE MAIN COSTS BASED ON**
 5 **COST-CAUSATION COME UP IN OTHER RECENT REGULATORY**
 6 **PROCEEDINGS?**

7 **A** Yes. To provide one example, in a rate case filed by Centra Gas Manitoba Inc. before
 8 the Public Utilities Board of Manitoba, Canada (the “Manitoba Board”)The Manitoba
 9 Board’s Final Order in the case was issued on October 12, 2022 and found that the
 10 P&A methodology is not reflective of cost causation.¹⁹ Specifically, the order states:

11 “The Board accepts Atrium’s evidence that Centra must rely on design
 12 day demand in planning and constructing downstream transmission and
 13 distribution facilities.”²⁰

14 “The Board accepts the evidence of Koch’s expert that the peak and
 15 average methodology is not reflective of cost-causation, as Centra’s
 16 system must be sized to meet its Design Day Peak Demand.”²¹

¹⁷DTE’s Response to Discovery Request ABDG-1.10 and 1.11. Attached as Exhibit AB-1 at pages 14-15.

¹⁸DTE’s Response to Discovery Request ABDG-1.12. Attached as Exhibit AB-1 at page 16.

¹⁹Manitoba Board Final Order, available at: <http://www.pubmanitoba.ca/v1/proceedings-decisions/orders/pubs/22-orders/109-22.pdf> (last visited May 6, 2024); see also *Centra Gas Manitoba Inc. - 2021 Cost of Service Study*, Public Utilities Board of Manitoba, docket available at: <http://www.pubmanitoba.ca/v1/proceedings-decisions/appl-current/centra-2021-coss.html> (last visited May 6, 2024).

²⁰*Ibid.* at page 46.

²¹*Ibid.* at page 47.

1 **Q ARE YOU AWARE OF ANY OTHER JURISDICTIONS THAT HAVE FOUND THAT**
2 **THE P&A METHOD DOES NOT ACCURATELY REFLECT COST-CAUSATION FOR**
3 **DISTRIBUTION AND TRANSMISSION MAIN CAPACITY COSTS?**

4 A Yes. In PECO Energy Gas's 2020 base rate case, the Pennsylvania Public Utility
5 Commission ("Pennsylvania Commission") approved the utility's proposed Average
6 and Excess ("A&E") cost allocation method, and cited the issue of double counting as
7 evidence for support of the A&E methodology. Specifically, the Pennsylvania
8 Commission stated the following:

9 "Moreover, we are also persuaded by PECO's argument regarding the
10 implicit double counting of Average Demand in the P&A methodology.
11 Again, the A&E methodology allocates mains costs based, in part, on
12 Average Demand, and, in part, on the portion of Peak Demand that
13 exceeds Average Demand. Alternatively, mains costs are allocated
14 under the P&A methodology based, in part, on Average Demand, and,
15 in part, on the total Peak Demand. Consequently, Average Demand is
16 included in the Average Demand component and in the Peak Demand
17 component, which includes Average Demand. Accordingly, due to
18 residential customers having temperature sensitive demand and
19 corresponding low-load factors, double-counting Average Demand
20 understates the residential cost of service while overstating the cost of
21 service of more efficient gas users."²²

22 In addition, the Missouri Public Service Commission on several occasions has
23 found that the double counting of Average Demand in the P&A method is a flaw. The
24 Missouri Public Service Commission in its May 28, 2010 Order, at page 85 for Case
25 No. ER-2010-0036, an AmerenUE electric rate case, found that:

26 "The Peak and Average method, in contrast, initially allocates average
27 costs to each class, but then, instead of allocating just the excess of the
28 peak usage period to the various classes to the cost causing classes,
29 the method reallocates the entire peak usage to the classes that
30 contribute to the peak. Thus, the classes that contribute a large amount
31 to the average usage of the system but add little to the peak, have their
32 average usage allocated to them a second time. Thus, the Peak and

²²Case No. R-2020-3018929, June 22, 2021 Opinion and Order, at pages 229-230.

1 Average method double counts the average system usage, and for that
2 reason is unreliable."²³

3 In 2011, the Missouri Public Service Commission again found the P&A method
4 to be unreliable in Case No. ER-2011-0028,²⁴ and rejected the use of the P&A method
5 in Case No. ER-2014-0258²⁵ because of the double counting of Average Demand.

6 **Q SHOULD AN ALLOCATION METHOD REFLECT A COMPROMISE BETWEEN**
7 **HIGH- AND LOW-LOAD FACTOR CUSTOMER CLASSES?**

8 A No. Concern regarding the rate impact that would result if lower-load factor classes
9 were brought to cost of service are misplaced considering cost of service principles.

10 **Q HOW DO YOU RESPOND TO THE CONCERN ABOUT THE EFFECT OF COST**
11 **ALLOCATION METHODS ON CUSTOMER CLASS RATE IMPACTS?**

12 A The transmission and distribution main capacity costs allocated to each class using the
13 P&A allocation method do not align with how customers cause the capacity needed by
14 DTE to provide firm service to the lower-load factor customer classes every day of the
15 year, including the peak day. Rather, the Commission's prior adoption of this method
16 simply reflects the fact that the P&A allocator assigns less transmission and distribution
17 main capacity cost to the lower-load factor classes than a purely demand-based
18 approach. In other words, the "compromise" that the P&A allocation method strikes
19 between high- and low-load factor customer classes does not reflect cost of service.

²³Missouri Public Service Commission Report and Order available at:
<https://efis.psc.mo.gov/Document/Display/81315> (last visited May 6, 2024).

²⁴Missouri Public Service Commission Report and Order dated July 23, 2011 at pages 114-115.
<https://efis.psc.mo.gov/Document/Display/76964> (last visited May 6, 2024).

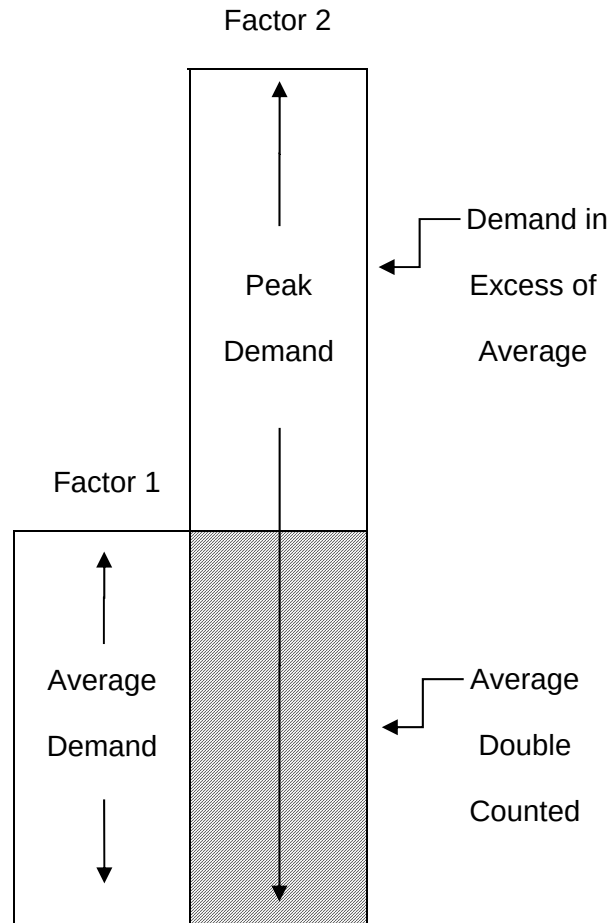
²⁵Missouri Public Service Commission Report and Order dated April 29, 2015 at pages 70-71.
<https://efis.psc.mo.gov/Document/Display/101982> (last visited May 6, 2024).

1 I recommend the Commission seek an answer to the question of whether the
2 P&A allocator accurately assigns DTE's transmission and distribution main capacity
3 cost across all rate classes in a manner that reflects how the Company has invested in
4 transmission and distribution main capacity to provide firm service to the system and
5 each rate class; i.e., does the P&A allocator ensure the establishment of rates equal to
6 the cost of providing service to each customer class?

7 With the most accurate cost of service study, the Commission can set rates to
8 all classes and have a more accurate assessment of whether the class is paying a
9 subsidy to other classes or receiving a subsidy from other rate classes. This will give
10 the Commission important information to ensure that all rate classes are treated fairly,
11 and that rate adjustments move rates toward cost of service.

12 **Q DOES THE P&A ALLOCATOR PRIMARILY ALLOCATE CAPACITY COSTS ON**
13 **VOLUME RATHER THAN PEAK DEMAND?**

14 **A** Yes. The P&A method is largely a volumetric allocation factor because it counts
15 Average Demand twice in the cost allocation: once in the Average Demand component
16 and again in the Peak Demand component. The impact of using the P&A method to
17 allocate distribution main and regulator station equipment costs is the over-allocation
18 of capacity costs to high-load factor customers. This is represented graphically in
19 Diagram 1. The Average Demand (Factor 1) is weighted by the system load
20 factor ("LF"). Peak demand (Factor 2) is weighted by $(1 - LF)$. The two weighted
21 demands are added together to arrive at the P&A allocation factor. As a result,
22 arithmetically, Average Demand receives a full weight of 1, while demand in excess of
23 the average is weighted less than 1 (i.e., by $(1 - LF)$).

Peak and Average Method

Peak and Average =

$$(LF \times \text{Factor 1}) + (1 - LF) \times \text{Factor 2}$$

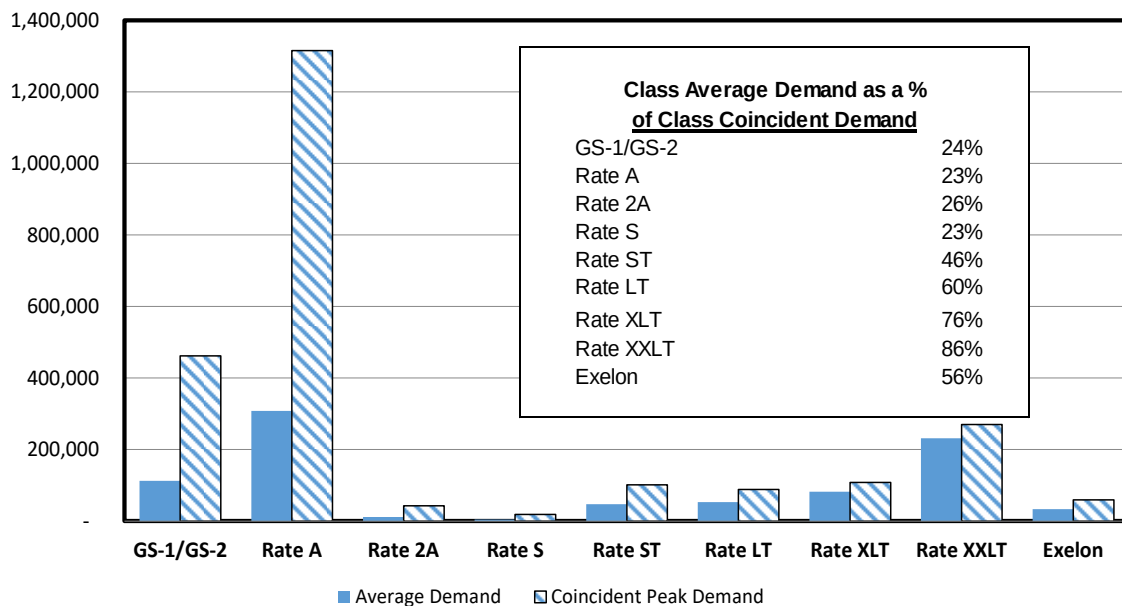
Diagram 1

- 1 Diagram 1 illustrates the two steps in the process of calculating the P&A factors,
- 2 the first of which is to determine the Average Demand component. The double counting
- 3 of Average Demand occurs in the next step of the process where each class's
- 4 contribution to the system's Peak Demand is determined. In this second step, the P&A

method considers the entire Peak Demand, including the Average Demand. As shown in Diagram 2, the double counting of Average Demand particularly affects the Rate XLT and Rate XXLT classes adversely, because class Average Demand constitutes a larger percentage of coincident demand for these classes as compared to the other rate classes. For example, class Average Demand constitutes 86% of coincident demand for the Rate XXLT class, versus 23% for the Rate A class.²⁶

In total, the Average Demand (throughput) component for Rate XXLT represents about 91% of the P&A allocation factor.²⁷ The Average Demand component for Rate XLT represents 84.4% of the P&A allocation factor.²⁸ Thus, the P&A allocation factor largely allocates fixed capacity costs on the basis of Average Demand (i.e., annual throughput or volume).

DTE Gas Peak and Average Allocators



²⁶DTE's Exhibit A-16, Schedule F1.2, page 3. Average daily demand divided by peak day demand for Rate A is 308,121 / 1,315,899 = 23%. For Rate XXLT, 231,925 / 269,937 = 86%.

²⁷System load factor of 35.8% + (86% x (1 - 35.8%)) = 90.95%. Derived from Exhibit A-16, Schedule F1.2, page 3.

²⁸35.8% + (76% x (1 - 35.8%)) = 84.38%. Derived from Exhibit A-16, Schedule F1.2, page 3.

1 **Q ARE YOU AWARE OF ANY OTHER JURISDICTIONS THAT HAVE FOUND THAT**
2 **THE P&A METHOD DOUBLE COUNTS AVERAGE DEMAND?**

3 A Yes. As described above, the Pennsylvania Commission and the Missouri Public
4 Service Commission have both found that the P&A method double counts average
5 demand.

6 **Q DOES THE COMPANY INCUR DIFFERENT UNIT COSTS OF CAPACITY FOR**
7 **DIFFERENT CUSTOMER CLASSES?**

8 A No. The utility incurs capacity cost to meet the total Design Day Demand of all
9 customers on its system. Thus, in order to accurately reflect cost-causation, every
10 class should be assigned the same system average unit cost of capacity. However,
11 the P&A allocation method does not accomplish this objective. Instead, the P&A
12 method allocates an above-system average unit cost of capacity to higher-load factor
13 classes, and allocates a below-system average unit cost of capacity to lower-load factor
14 classes.

15 **Q HAVE YOU PREPARED AN EXAMPLE TO ILLUSTRATE THE IMPACT ON THE**
16 **CCOS DUE TO THE ALLOCATION OF DELIVERY MAIN CAPACITY DESCRIBED**
17 **ABOVE?**

18 A Yes. As an example, Table JAY-5 below shows a comparison of the allocation of
19 investment in transmission plant in-service across customer classes using both the
20 P&A allocator and the Design Day Demand allocator.

TABLE JAY-5						
<u>Allocation of Transmission Plant in Service</u>						
<u>Line</u>	<u>Rate Schedule</u>	<u>Design Day Demand Units</u> (1)	<u>P&A</u>		<u>Design Day</u>	
			<u>Allocation of Costs (\$000)</u> (2)	<u>Capacity Unit Cost</u> (3)	<u>Allocation of Costs (\$000)</u> (4)	<u>Capacity Unit Cost</u> (5)
1	GS-1/GS-2	461,804	\$ 184,281	\$ 399	\$ 208,106	\$ 451
2	Rate A	1,315,899	519,767	395	592,994	451
3	Rate 2A	42,192	17,186	407	19,013	451
4	Rate S	18,882	7,441	394	8,509	451
5	Rate ST	101,303	50,388	497	45,651	451
6	Rate LT	88,602	49,412	558	39,927	451
7	Rate XLT	107,783	67,958	631	48,571	451
8	Rate XXLT	269,937	182,653	677	121,644	451
9	Exelon	59,141	31,980	541	26,651	451
10	Total	2,465,544	\$ 1,111,067	451	\$ 1,111,067	451
Sources and Notes:						
DTE's workpapers labeled "U-21291 Gas 2023 COS For Filing.xlsx."						

As shown in Table JAY-5, the P&A method allocates a below-system average cost of transmission plant in-service capacity to the lower-load factor, weather-sensitive Rate A and Rate 2A classes, and a 1.4x to 1.5x system average cost of transmission plant in-service capacity to the higher-load factor classes like Rate XLT and Rate XXLT. In contrast, the Design Day Demand method assigns the system average cost of transmission plant in-service capacity to all classes, consistent with cost-causation.

Q WHY DOES DTE USE THE P&A METHOD WHEN THE EVIDENCE SHOWS THAT DESIGN DAY DEMAND IS THE DRIVER OF TRANSMISSION AND DISTRIBUTION CAPACITY COST?

A It appears that DTE used the P&A method in part due to the Commission's prior acceptance of the method. The Company stated in response to Discovery

1 Request ABDG-1.21e that the allocation schedules used in DTE's proposed CCOS are
2 the result of long-standing practices that have evolved over decades of litigated rate
3 cases.²⁹ In addition, the Company stated that it believes the P&A method is suitable
4 because it is referenced in the NARUC Manual as one of the methods appropriate for
5 the allocation of demand or capacity costs in a CCOS.³⁰ However, as explained above,
6 and based on the evidence provided by DTE through discovery responses, continued
7 reliance on the P&A CCOS is not justified based on cost-causation principles.

8 **Q DOES NARUC COMMENT ON THE USE OF THE P&A CAPACITY ALLOCATOR?**

9 A Yes. The NARUC Manual indicates that the P&A method reflects a compromise
10 between the coincident and non-coincident demand allocation methods.³¹ In addition,
11 the NARUC Manual states in a results-oriented conclusion that the P&A method
12 tempers the apportionment of costs between high- and low-load factor customers.³²
13 The manual suggesting limited guidance is not a substitute for a CCOS based on record
14 evidence.

15 **Q SHOULD THE SELECTION OF A COST ALLOCATION METHOD BE INFLUENCED**
16 **BY THE RESULTING RATE INCREASES OR DECREASES THAT WOULD BE**
17 **REQUIRED FOR EACH CUSTOMER CLASS TO REACH COST OF SERVICE?**

18 A No. The selection of a cost allocation method should not be influenced by the results
19 that would occur. Any rate impacts that would result if certain customer classes were

²⁹DTE's Response to Discovery Request ABDG-1.21e. Attached as Exhibit AB-1 at page 17.

³⁰DTE's Response to Discovery Request ABDG-1.21b. Attached as Exhibit AB-1 at page 18.

³¹NARUC Manual, June 1989, page 27.

³²*Ibid.* at 28.

1 moved to cost of service can be mitigated through the revenue allocation step of the
2 overall rate design process.

3 Instead, the selection of a cost allocation method to be used in the Company's
4 CCOS should be influenced by cost-causation, and the way DTE designs its system to
5 safely provide firm service to its firm customers every day of the year. In this case,
6 DTE has provided evidence in its discovery responses showing that it designs its
7 system capacity to meet the Design Day and Design Hour Demands of its customers.
8 Therefore, the Design Day Demand allocation method would be the most appropriate
9 from a cost-causation standpoint to allocate capacity costs to DTE's customer classes.

10 **Q HAVE YOU MODIFIED THE COMPANY'S PREFERRED CCOS TO REFLECT THE**
11 **DESIGN DAY DEMAND ALLOCATION OF CAPACITY COSTS?**

12 **A** Yes. Exhibit AB-2 contains the detailed Design Day Demand CCOS, but the results
13 are summarized in Table JAY-6.

TABLE JAY-6								
<u>P&A CCOS vs. Design Day Demand CCOS</u>								
<u>Line</u>	<u>Rate Schedule</u>	<u>Total Revenues at Current Rates</u> (1)	<u>P&A CCOS</u>			<u>Design Day CCOS¹</u>		
			<u>Net Increase / (Decrease) to Reach Cost of Service</u>			<u>Net Increase / (Decrease) to Reach Cost of Service</u>		
			<u>Amount</u>	<u>Percent</u>	<u>Index</u>	<u>Amount</u>	<u>Percent</u>	<u>Index</u>
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	GS-1/GS-2	\$ 364,227	\$ 28,626	7.9%	0.84	\$ 36,932	10.1%	1.09
2	Rate A	1,154,404	105,609	9.1%	0.98	132,259	11.5%	1.23
3	Rate 2A	36,366	1,480	4.1%	0.44	2,042	5.6%	0.60
4	Rate S	10,898	1,112	10.2%	1.09	1,506	13.8%	1.48
5	Rate ST	46,063	(7,007)	-15.2%	(1.63)	(10,797)	-23.4%	(2.51)
6	Rate LT	30,967	1,324	4.3%	0.46	(5,005)	-16.2%	(1.73)
7	Rate XLT	29,299	14,505	49.5%	5.31	2,376	8.1%	0.87
8	Rate XXLT	31,324	6,629	21.2%	2.27	(3,377)	-10.8%	(1.16)
9	Exelon	13,145	7,725	58.8%	6.31	4,066	30.9%	3.32
10	Total	\$ 1,716,694	\$ 160,002	9.3%	1.00	\$ 160,002	9.3%	1.00

Notes:

¹ Replaces the P&A allocator in DTE's Preferred CCOS with the Design Day Demand allocator.

As shown in the table, at the Company's claimed revenue deficiency, the Design Day Demand allocation method shows that a rate decrease of 10.8% would be needed to move Rate XXLT to cost of service, rather than an increase of 2.27x system average and a below-system average increase of 8.1% would be needed to move Rate XLT to cost of service.

Q DO YOU HAVE AN ALTERNATIVE RECOMMENDATION, IF THE DESIGN DAY DEMAND METHOD IS NOT ADOPTED?

A Yes. To the extent that the Commission does not support a purely demand-based allocation of capacity costs, the AED method is more reasonable and more accurate than the P&A method.

Q PLEASE DESCRIBE THE AED METHOD.

A The AED method is similar to the P&A method, in that they both include a component based on average demand that is weighted by the utility's system load factor. Both methods also provide a measure of each class's peak demand. However, the two methods differ in the approach to determining the demand component, which results in the AED method being superior.

The demand component of the P&A allocator reflects each class's contribution to system peak day demand (i.e., coincident peak demand), which also includes the average demand. On the other hand, the AED allocator reflects the difference between each class's non-coincident peak demand and average demand (i.e., demand in excess of average demand), and as such does not suffer from the inherent flaw of double counting the average demand like the P&A method does.

1 Thus, the AED method assigns greater cost responsibility to gas deliveries that
2 are more variable due to weather sensitivity or other factors.

3 **Q IS THE AED METHOD MATHEMATICALLY EQUIVALENT TO THE DESIGN DAY**
4 **DEMAND METHOD?**

5 A The AED method is not equivalent to the design day demand method, as long as each
6 class's non-coincident peak demand is used to develop the demand component of the
7 allocation factor, rather than each class's contribution to system peak day demand.

8 **Q HAS DTE PROVIDED NON-COINCIDENT PEAK DEMAND DATA FOR EACH**
9 **CLASS IN THIS CASE?**

10 A No. DTE indicated that it does not have projected non-coincident peak demand data
11 available for its customer classes.³³ As such, I have not calculated the AED allocator
12 at this time. However, each class's AED allocation percentage would fall somewhere
13 in the range between the P&A and Design Day Demand allocation percentages.

14 **Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS WITH RESPECT TO**
15 **CAPACITY COST ALLOCATION IN THE COMPANY'S CCOS.**

16 A Based on the evidence provided by DTE, it is clear that Design Day Demand is the load
17 characteristic that drives investment in capacity to provide safe, reliable firm service to
18 customers on the peak day and all other days throughout the year. Thus, from a
19 cost-causation standpoint, Design Day Demand would produce the most accurate
20 measure of the Company's cost of providing service to each class.

³³DTE's Response to Discovery Request ABDG-1.5. Attached as Exhibit AB-1 at page 19.

1 However, to the extent that the Commission prefers to continue relying on a
2 partial energy-weighted method, then the AED approach would be more accurate and
3 reasonable than the P&A method. In that case, I recommend the Commission direct
4 DTE to provide such CCOS for consideration in the next rate case as CEC did in its
5 most recent rate case, Case No. U-21490.

6 **IV. Gas Curtailment Service Tariff**

7 **Q HAS THE COMPANY PROPOSED CHANGES TO ITS GAS CURTAILMENT**
8 **SERVICE TARIFF?**

9 A Yes. As discussed in the Direct Testimony of DTE witness Mr. Decker, the Company
10 proposes several changes to the Curtailment section of its tariff, in order to consolidate
11 common information and make changes based upon learnings from Case No. U-20632
12 Curtailment Workgroup.³⁴

13 **Q DO YOU HAVE ANY RECOMMENDED MODIFICATIONS TO THE COMPANY'S**
14 **PROPOSED CHANGES TO THE CURTAILMENT SECTION OF ITS TARIFF?**

15 A Yes. Regarding base period volumes, the Company's proposed tariff states the
16 following:

17 For the purpose of determining the customer's volumes within each
18 Curtailment Priority Category, a twelve month base period shall be
19 established. Such base period shall be fixed for the term of the
20 curtailment. The base period volumes shall consist of the twelve
21 consecutive monthly consumptions ending June of each year. In those
22 instances where the customer has encountered strikes, interruption of
23 gas service or unavoidable operational abnormalities, the Company
24 may make reasonable adjustments to normalize the customer's
25 requirements. Base period volumes may be adjusted for equipment
26 added or deleted.³⁵

³⁴See the Direct Testimony of H.J. Decker at page 71.

³⁵DTE's Exhibit A-16, Schedule F5.1, page 7.

1 To ensure that DTE's customers have the same level of flexibility with respect
2 to adjustments to base period volumes as CEC's customers, I recommend adding the
3 following language to the end of the paragraph cited above:

4 The customer shall notify the Company of any adjustment to base period
5 volumes using any reasonable method of the customer's choice,
6 including but not limited to written request, phone call, or email. The
7 Company shall notify the customer if the base period adjustment is
8 accepted or rejected within 60 days of the request. A failure to
9 affirmatively notify the customer shall be treated as an acceptance. If
10 the requested adjustment is rejected, the Company shall provide the
11 customer a written explanation detailing the reasons for the rejection. A
12 customer may request an adjustment to its base period volumes two (2)
13 times during a calendar year.³⁶

14 **Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

15 **A** Yes, it does.

³⁶CEC's gas tariff (MPSC No. 3), Second Revised Sheet No. C-11.00. Effective October 1, 2022.

Qualifications of Jessica A. York

1 **Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A Jessica A. York. My business address is 16690 Swingley Ridge Road, Suite 140,
3 Chesterfield, MO 63017.

4 **Q PLEASE STATE YOUR OCCUPATION.**

5 A I am a consultant in the field of public utility regulation and a Principal with the firm of
6 Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

7 **Q PLEASE IDENTIFY THE JURISDICTIONS IN WHICH YOU HAVE PREVIOUSLY**
8 **SPONSORED TESTIMONY.**

9 A I have sponsored expert testimony in front of the Idaho Public Utilities Commission, the
10 Illinois Commerce Commission, Indiana Utility Regulatory Commission, the Michigan
11 Public Service Commission, the Minnesota Public Utilities Commission, the Missouri
12 Public Service Commission, the Public Utilities Commission of Nevada, the Oklahoma
13 Corporation Commission and the Public Service Commission of Wisconsin.

14 **Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL**
15 **EMPLOYMENT EXPERIENCE.**

16 A I graduated from Truman State University in 2008 where I received my Bachelor of
17 Science Degree in Mathematics with minors in Statistics and Actuarial Science. I
18 earned my Master of Business Administration Degree with a concentration in Finance
19 from the University of Missouri-St. Louis in 2014.

20 I joined BAI in 2011 as an analyst. Then, in March 2015, I joined the consulting
21 team of BAI.

1 I have worked in various electric, natural gas and water and wastewater
2 regulatory proceedings addressing cost of capital, sales revenue forecasts, revenue
3 requirement assessments, class cost of service studies, rate design, and various policy
4 issues. I have also conducted competitive power and natural gas solicitations on behalf
5 of large electric and natural gas users, have assisted those large power and natural
6 gas users in developing procurement plans and strategies, assisted in competitive
7 contract negotiations, and power and natural gas contract supply administration. In the
8 regulated arena, I have evaluated cost of service studies and rate designs proffered by
9 other parties in cases for various utilities, including in Idaho, Illinois, Indiana, Kansas,
10 Wisconsin and others. I have conducted bill audits, rate forecasts and tariff rate
11 optimization studies.

12 I have also provided support to clients with facilities in deregulated markets,
13 including drafting supply requests for proposals, evaluating supply bids, and auditing
14 competitive supply bills. I have also prepared and presented to clients reports that
15 monitor the electric market and recommend strategic hedging transactions.

16 BAI was formed in April 1995. BAI and its predecessor firm have participated
17 in more than 700 regulatory proceedings in forty states and Canada.

18 BAI provides consulting services in the economic, technical, accounting, and
19 financial aspects of public utility rates and in the acquisition of utility and energy
20 services through RFPs and negotiations, in both regulated and unregulated markets.
21 Our clients include large industrial and institutional customers, some utilities and, on
22 occasion, state regulatory agencies. We also prepare special studies and reports,
23 forecasts, surveys and siting studies, and present seminars on utility-related issues.

24 In general, we are engaged in energy and regulatory consulting, economic
25 analysis and contract negotiation.

- 1 In addition to our main office in St. Louis, the firm also has branch offices in
- 2 Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

495645

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

**In the matter of the Application of DTE GAS
COMPANY for authority to increase its
rates, amend its rate schedules and rules
governing the distribution and supply of
natural gas, and for miscellaneous
accounting authority**

Case No. U-21291

Rebuttal Testimony and Exhibit of

Jessica A. York

On behalf of

Association of Businesses Advocating Tariff Equity

May 29, 2024



STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of DTE GAS	)	
COMPANY for authority to increase its	)	
rates, amend its rate schedules and rules	)	
governing the distribution and supply of	)	
natural gas, and for miscellaneous	)	Case No. U-21291
accounting authority	)	

Table of Contents for the
Rebuttal Testimony of Jessica A. York

I. Introduction	1
II. Staff’s CCOSS and Revenue Distribution.....	2
III. Staff’s Proposed Transportation Rate Design.....	8
Exhibit AB-19: Referenced Response to Discovery Request	

A Yes. I filed Direct Testimony on behalf of the Association of Businesses Advocating Tariff Equity (“ABATE”). ABATE consists of large customers that purchase substantial amounts of natural gas and/or delivery service from DTE Gas Company (“DTE” or “Company”). They primarily take service under DTE’s Extra Large Transportation (“Rate XLT”) service tariff and Extra-Extra Large Transportation (“Rate XXLT”) service tariff.

1 **Q WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

2 A My Rebuttal Testimony will address the Michigan Public Service Commission ("MPSC"
3 or "Commission") Staff's ("Staff") recommendations regarding Class Cost of Service
4 Study ("CCOSS"), revenue apportionment and rate design. Specifically, I will respond
5 to the Direct Testimonies of Staff witnesses Kevin S. Krause, Nicholas M. Revere, and
6 Madison S. Todd.

7 My silence with regard to any issue should not be construed as an endorsement
8 of positions taken by other parties on that issue.

9 **II. Staff's CCOSS and Revenue Distribution**

10 **Q WHAT ARE STAFF'S RECOMMENDATIONS WITH RESPECT TO THE**
11 **COMPANY'S CCOSS?**

12 A Staff witness Mr. Revere recognizes that DTE's alternate CCOSS reflecting increased
13 granularity with respect to the allocation of costs associated with distribution mains
14 complies with the Commission's directive in its Order in the prior rate case.¹ However,
15 he goes on to say that for purposes of this case, it would be inappropriate to utilize the
16 additional CCOSS directly, as recognizing the difference in costs in rates should be
17 accompanied by a reexamination of the structure of rates.² Further, he argues that the
18 scope of rate redesign, as well as determining the best way to approach it, is too large
19 for the context of a 10-month rate case.³ Despite these comments, Staff has used the
20 additional CCOSS as a guide to how revenue responsibility should be shifted between

¹See the Direct Testimony of Nicholas Revere at page 6.

²*Id.* at 7.

³*Id.*

transportation schedules when adjustments must be made to maintain the current breakeven points.⁴

Lastly, Mr. Revere recommends the Company continue to provide the Alternate CCROSS in future rate cases, and continue to explore the best way to modify rate design to directly utilize this alternate CCROSS.⁵

Q HAVE YOU COMPARED STAFF'S PROPOSED REVENUE APPORTIONMENT TO THE RESULTS OF BOTH DTE'S PREFERRED CCROSS AND ITS ALTERNATE CCROSS, BASED ON STAFF'S ADJUSTMENTS?

A Yes. A comparison of the results of the two CCROSS models with Staff's adjustments, to Staff's proposed revenue apportionment is presented in Table JAY-1-RT.

TABLE JAY-1-RT											
Staff's CCROSS Results vs. Proposed Revenue Apportionment (\$000)*											
Line	Rate Schedule	Total Revenues at Current Rates (1)	Preferred CCROSS Net Increase / (Decrease) to Reach Cost of Service			Alternate CCROSS Net Increase / (Decrease) to Reach Cost of Service			Staff Proposed Net Increase / (Decrease)		
			Amount	Percent	Index	Amount	Percent	Index	Amount	Percent	Index
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	GS-1/GS-2	\$ 355,402	\$ 11,083	3.1%	0.75	\$ 14,009	3.9%	0.94	\$ 5,329	1.5%	0.36
2	Rate A	1,125,079	47,674	4.2%	1.01	59,668	5.3%	1.27	55,787	5.0%	1.19
3	Rate 2A	35,363	(36)	-0.1%	(0.02)	337	1.0%	0.23	1,576	4.5%	1.07
4	Rate S	10,575	583	5.5%	1.32	729	6.9%	1.65	(492)	-4.6%	(1.11)
5	Rate ST	46,063	(9,169)	-19.9%	(4.76)	(10,295)	-22.3%	(5.34)	(5,205)	-11.3%	(2.70)
6	Rate LT	30,967	(934)	-3.0%	(0.72)	(7,812)	-25.2%	(6.03)	(3,486)	-11.3%	(2.69)
7	Rate XLT	29,299	11,137	38.0%	9.08	(3,646)	-12.4%	(2.97)	1,568	5.4%	1.28
8	Rate XXLT	31,324	3,671	11.7%	2.80	11,903	38.0%	9.08	9,164	29.3%	7.00
9	Exelon	13,145	6,179	47.0%	11.23	5,294	40.3%	9.62	5,849	44.5%	10.65
10	Total**	\$ 1,677,217	\$ 70,189	4.2%	1.00	\$ 70,189	4.2%	1.00	\$ 70,092	4.2%	1.00

Sources and Notes:

* Includes gas cost for bundled service customer classes.

** Difference between CCOS increase and proposed increase is due to rounding.

Exhibit S-6.0, Schedule F1

Exhibit S-6.0, Schedule F2.

Exhibit S-6.0, Schedule F3.

⁴Id.

⁵Id. at 8.

1 As shown in the table, Staff's adjusted version of DTE's Preferred CCOSS
2 shows that an increase of about \$3.7 million, or 11.7%, would be needed for the
3 XXLT class to reach cost of service. However, Staff proposes an increase of
4 \$9.2 million, or 29.3%, or 7x the system average, based on the results of the Alternate
5 CCOSS. Thus, despite Staff's proposed revenue deficiency being about 34% less than
6 DTE's,⁶ Staff's revenue spread assigns approximately \$5.5 million more (\$9.164 million
7 – \$3.671 million) to the XXLT class than indicated by the Company's Preferred CCOSS
8 model, and about \$4.5 million more (\$9.164 million - \$4.613 million) than proposed by
9 the Company in its recommended revenue apportionment.

10 **Q IS STAFF'S PROPOSED REVENUE SPREAD FOR THE TRANSPORTATION**
11 **CLASSES REASONABLE?**

12 A No. Staff's proposed revenue apportionment for the transportation classes should be
13 rejected, as it is based on the results of two flawed CCOSS models.

14 Both CCOSS models rely on the Peak and Average ("P&A") cost allocation
15 method for transmission and distribution capacity costs. For the reasons explained in
16 detail in my Direct Testimony, the P&A method does not accurately assign costs to
17 cost-causers based on the load characteristic that drives DTE's investment in
18 transmission and distribution main capacity. Indeed, the P&A method effectively
19 penalizes higher load factor customers for efficiently utilizing the system capacity that
20 was installed to serve them.

21 In addition, setting aside the use of the P&A method, there are other
22 deficiencies with the Alternate CCOSS that would need to be addressed before it can
23 be relied upon for revenue apportionment and rate design purposes.

⁶\$175.7 million / \$265.5 million – 1 = -33.8%.

Furthermore, regardless of which CCOSS is used to guide revenue apportionment and rate design, refinements to the transportation rate structures are warranted to ensure that customers served at different service levels (e.g., transmission, high-pressure distribution, or low-pressure distribution) are responsible for the costs associated with the infrastructure used to serve them. Staff's proposed rates do not address this significant issue. As a result, within the XXLT class for example, customers served directly from transmission mains or high-pressure distribution mains are required to pay for portions of the low-pressure distribution system that are not and cannot be used to provide service to them.

Q PLEASE DISCUSS THE SHORTCOMINGS OF THE ALTERNATE CCOSS.

A First, I would note that in theory, the more granular approach to distribution cost allocation used in the Alternate CCOSS would better reflect cost-causation given the differences in the infrastructure used to provide service to the handful of customers within that class. However, there are significant concerns related to the Alternate CCOSS and refinements to the study would be required in order to ensure that distribution main costs are accurately assigned to the XXLT class. Areas of concern are as follows:

- The Alternate CCOSS relies on the P&A method, which results in an inaccurate measure of the cost of providing service to each class, as described in my Direct Testimony.
- The Alternate CCOSS reflects a significant change in the allocation of distribution mains costs relative to prior cases.
- Reliance on the Alternate CCOSS produces significant, unjust, and unreasonable rate impacts for certain classes like Rate XXLT.
- Peak day demand data is not available by service level within each class. As a result, the Company has assumed that the portion of each class's peak day demand served from transmission and high-pressure distribution mains is equal to the

1 portion of each class's annual throughput served by each type of main.⁷ This calls
2 into question the accuracy of the allocation of costs that rely on customer class
3 contributions to peak demand.

- 4 • DTE needs to review the infrastructure used to provide service to the customers in
5 the XXLT class. It may be the case that a very limited portion of system distribution
6 mains are used to serve customers in this class, such that an allocated slice of total
7 system distribution mains is not appropriate.
- 8 • Rate design improvements are needed to ensure that the cost of distribution mains
9 assigned to Rate XXLT are paid for by the customers in the class who use the
10 distribution infrastructure.

11 **Q WERE SOME OF THESE CONCERNS REGARDING THE ALTERNATE CCROSS**
12 **RAISED BY PARTIES IN THE LAST CASE?**

13 A Yes, and despite the fact that these concerns have not been addressed in this case,
14 Staff has relied, in part, upon the Alternate CCROSS to inform revenue apportionment.
15 As described by Mr. Revere, Staff witness Mr. Todd was instructed to keep each
16 transportation schedule's share of the total transportation revenue requirement
17 between the results of the CCROSS using the current methods of allocation and Staff's
18 Alternate CCROSS to the extent possible while conducting rate design.⁸

19 **Q HAVE YOU REVISED STAFF'S CCROSS MODELS TO REFLECT YOUR**
20 **RECOMMENDED DESIGN DAY DEMAND ALLOCATION OF CAPACITY COSTS?**

21 A Yes. The results are shown in Table JAY-2-RT. In addition, my recommended revenue
22 apportionment using Staff's proposed revenue deficiency is shown in the table.

⁷DTE's response to Discovery Request ABDG-1.22a. Attached as Exhibit AB-19.

⁸See the Direct Testimony of Nicholas Revere at pages 7-8.

TABLE JAY-2-RT											
<u>Design Day Demand CCROSS vs. Proposed Revenue Apportionment (\$000)</u>											
<u>Line</u>	<u>Rate Schedule</u>	<u>Total Revenues at Current Rates</u> (1)	<u>Preferred CCROSS*</u> <u>Net Increase / (Decrease)</u> <u>to Reach Cost of Service</u>			<u>Alternate CCROSS*</u> <u>Net Increase / (Decrease)</u> <u>to Reach Cost of Service</u>			<u>ABATE Proposed Net Increase / (Decrease)</u>		
			<u>Amount</u>	<u>Percent</u>	<u>Index</u>	<u>Amount</u>	<u>Percent</u>	<u>Index</u>	<u>Amount</u>	<u>Percent</u>	<u>Index</u>
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	GS-1/GS-2	\$ 355,402	\$18,511	5.2%	1.24	\$17,562	4.9%	1.18	\$18,511	5.2%	1.24
2	Rate A	1,125,079	71,518	6.4%	1.52	72,139	6.4%	1.53	47,633	4.2%	1.01
3	Rate 2A	35,363	466	1.3%	0.32	539	1.5%	0.36	466	1.3%	0.32
4	Rate S	10,575	936	8.9%	2.12	912	8.6%	2.06	448	4.2%	1.01
5	Rate ST	46,063	(12,579)	-27.3%	(6.53)	(13,043)	-28.3%	(6.77)	-	0.0%	-
6	Rate LT	30,967	(6,622)	-21.4%	(5.11)	(10,908)	-35.2%	(8.42)	-	0.0%	-
7	Rate XLT	29,299	241	0.8%	0.20	(7,721)	-26.4%	(6.30)	241	0.8%	0.20
8	Rate XXL	31,324	(5,173)	-16.5%	(3.95)	7,875	25.1%	6.01	-	0.0%	-
9	Exelon	13,145	2,890	22.0%	5.25	2,835	21.6%	5.15	2,890	22.0%	5.25
10	Total	\$1,677,217	\$70,189	4.2%	1.00	\$70,189	4.2%	1.00	\$70,189	4.2%	1.00

Sources and Notes:
* Uses Staff's CCROSS models and replaces the P&A allocator with Design Day (i.e. Peak Day) Demand.

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE CCROSS AND REVENUE APPORTIONMENT?

A I continue to support the recommendations made in my Direct Testimony. That is, I recommend an alternative revenue apportionment reflecting no rate change for Rate XXL, and I recommend bringing Rate XLT to cost of service based on a Design Day Demand CCROSS with a below-system average increase (0.20x the system average based on Staff's proposed revenue deficiency, as shown above in Table JAY-2-RT).

Alternatively, I recommend a system average increase across all classes, provided the Company commits to provide a properly conducted Average and Excess Demand ("AED") CCROSS in its next rate case. As explained in my Direct Testimony, my alternative revenue apportionment would reflect a compromise between the P&A

and Design Day Demand CCOSS until an AED CCOSS is conducted, and until such time as concerns regarding the Alternate CCOSS have been addressed.

III. Staff's Proposed Transportation Rate Design

Q PLEASE DISCUSS THE RATE DESIGN FOR TRANSPORTATION CUSTOMERS.

A Transportation customers take service under Rate ST (Small Transportation), Rate LT (Large Transportation), Rate XLT and Rate XXL. While these rates are treated as separate classes in the CCOSS, they are all included in a single tariff rate schedule which uses economic breakeven points based on usage to develop target rate levels.⁹

Q WHAT IS THE PURPOSE OF RATE XXL?

A As noted by DTE, Rate XXL is designed to retain the very largest End Use Transportation ("EUT") customers that would otherwise bypass DTE's system and take service directly from interstate transmission pipelines.¹⁰ Their size, energy consumption, and location near interstate pipelines afford these customers the opportunity and means to make an investment to bypass DTE's system.¹¹

Q PLEASE DISCUSS STAFF'S PROPOSED RATE DESIGN FOR THE TRANSPORTATION RATE SCHEDULES.

A Staff's proposed rate design for the transportation customers is based on its proposed revenue apportionment identified in Table JAY-1-RT, as well as the preservation of existing break-even points between rate schedules.¹² In addition, Mr. Todd

⁹See the Direct Testimony of H.J. Decker at pages 10-11.

¹⁰See the Direct Testimony of H.J. Decker at page 12.

¹¹See the Direct Testimony of H.J. Decker at pages 12-13.

¹²See the Direct Testimony of Madison Todd at page 4.

acknowledges that Staff's rate design considers the percentage share of the revenue requirement to be collected from each transportation schedule based on the Alternate CCOSS.¹³

For Rate XXLT, Staff's CCOSS contained in Exhibit S-6 results in a cost based increase (including over-allocations resulting from the P&A method) of about \$3.7 million, or 11.7%. Using the Alternate CCOSS to justify assigning an additional \$5.5 million to Rate XXLT for a total proposed increase of \$9.2 million, or 29.3%, is unjust and unreasonable, and should be rejected.

In addition, for the Large Transportation ("LT") and XLT rate schedules, Staff proposes to reduce the customer charges from their current levels. This is inappropriate given the Company's cost of service is largely comprised of fixed costs, and that the transportation rate structure does not include a demand charge for fixed cost recovery.

Further, Staff does not propose modifications to the transportation rate structure to address the intra-class allocations of distribution main costs that would be necessary to properly recover the costs of distribution mains from the customers within the various transportation schedules who use that part of the system.

Q DOES STAFF'S PROPOSED RATE DESIGN SUPPORT THE PURPOSE OF RATE XXLT?

A No. For the reasons I have discussed, Staff's proposal to assign an additional \$5.5 million to the XXLT class based on its Alternate CCOSS does not reflect cost-causation and is inconsistent with the objective of providing competitive,

¹³*Id.* at 7.

1 cost-based rates to customers that have the potential to bypass the Company's
2 distribution system altogether.

3 **Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO RATE DESIGN?**

4 A I recommend maintaining the existing transportation rate structures, but designing rates
5 to reflect the revenue apportionment outlined in Table JAY-2-RT. Further, I recommend
6 maintaining the transportation customer charges recommended by DTE, and modifying
7 the volumetric distribution charges accordingly.

8 **Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

9 A Yes, it does

1 MR. CAMPBELL: Thank you, your Honor.

2 Mr. Fitzhenry's direct testimony consists of a cover
3 page, a table of contents, 17 pages of questions and
4 answers, and an Appendix A setting out his
5 qualifications; and along with his direct testimony,
6 Mr. Fitzhenry sponsored Exhibit AB-3; and Mr. Fitzhenry
7 did not submit rebuttal testimony.

8 JUDGE THOITS: All right. Are there any
9 objections to the admission of this testimony or these
10 exhibits? (No response.)

11 Hearing none, the Direct Testimony of
12 Colin Fitzhenry is bound into the record, and Exhibit
13 AB-3 is admitted.

14 (Testimony bound in.)

15 - - -
16
17
18
19
20
21
22
23
24
25

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

	)	
In the matter of the Application of DTE GAS	)	
COMPANY for authority to increase its	)	
rates, amend its rate schedules and rules	)	
governing the distribution and supply of	)	Case No. U-21291
natural gas, and for miscellaneous	)	
accounting authority	)	
	)	

Direct Testimony and Exhibit of
Colin T. Fitzhenry

On behalf of
Association of Businesses Advocating Tariff Equity

May 7, 2024



STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of DTE GAS	)	
COMPANY for authority to increase its	)	
rates, amend its rate schedules and rules	)	
governing the distribution and supply of	)	
natural gas, and for miscellaneous	)	Case No. U-21291
accounting authority	)	

Table of Contents for the
Direct Testimony of Colin T. Fitzhenry

I.	Introduction.....	1
II.	Capital Expenditures	3
	II.A. Main Replacement Program	4
	II.B. Large Capital Projects.....	7
III.	O&M Expense	10
	III.A. Inflation Factor	11
	III.B. Incentive Compensation.....	14
IV.	Conclusion.....	16
	Qualifications of Colin T. Fitzhenry.....	Appendix A
	Exhibit AB-3: Referenced Responses to Discovery Requests	

“Company”). They primarily take service under DTE’s Extra Large Transportation (“Rate XLT”) service tariff and Extra-Extra Large Transportation (“Rate XXLT”) service tariff.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A My testimony will address DTE’s Capital and Operation and Maintenance (“O&M”) expenditures.

My silence with regard to any position taken by DTE in its application or direct testimony in this proceeding does not indicate my endorsement of that position.

Q PLEASE SUMMARIZE YOUR TESTIMONY.

A My testimony can be summarized as follows:

- DTE has demonstrated that it is able to improve safety and reliability by replacing Legacy Mains at recent historical levels. The Company can reduce the proposed rate of main replacement and still accomplish its long term gas planning goals. I recommend a slight reduction in the miles of main replaced per year in the Main Replacement Program to reduce the impact to customer rates.
- Project delays can have significant impacts on rate case capital expenditures and the rate base when a future test year is utilized. If the large capital projects in this proceeding experience project delays, then all or portions of the projects may not be placed into service prior to the end of the future test year period. There is historical evidence to suggest that DTE has not always completed its large capital projects according to the proposed project schedules. I recommend a reduction in the proposed capital expenditures in the future test year period to ensure customers will not have capital investment included in rates for project work that was not completed.
- I recommend DTE use the Blue Chip GDP Chained Price Index for the O&M inflation factors. The wage inflation rate used by the Company is not well supported, and the Consumer Price Index for Urban Customers (“CPI-U”) non-labor inflation rate is well above the consensus industry experts’ opinion of the GDP Chained Price Index.
- DTE proposes to include in its revenue requirement incentive compensation tied to financial performance measures. The Michigan Public Service Commission (“MPSC” or “Commission”) has historically disallowed incentive compensation tied

1 to financial measures because it has not been shown to benefit customers, and
2 should do so again here.

3 **II. Capital Expenditures**

4 **Q HAVE YOU REVIEWED THE COMPANY'S PROPOSED CAPITAL**
5 **EXPENDITURES?**

6 A Yes. Company witness Kelly M. Fedele supports the need for the Company's proposed
7 capital expenditures. The capital expenditures fall into four categories: (1) Routine;
8 (2) Large Capital Projects; (3) Infrastructure Recovery Mechanism; and (4) Gas
9 Information Technology. I have provided an overview of the Company's proposed
10 capital expenditures in Table CTF-1 below.

Table CTF-1				
<u>Summary of Proposed Capital Expenditures</u>				
(\$1,000s)				
<u>Description</u>	Historical 12 mos. ended <u>12/31/2022</u>	Bridge Period 21 mos. ending <u>9/30/2024</u>	Test Year 12 mos. ending <u>9/30/2025</u>	<u>Total</u>
Routine	\$284,399	\$527,645	\$289,498	\$1,101,542
Large Capital Projects	73,471	108,277	75,977	257,725
Infrastructure Recovery Mechanism	347,686	630,945	89,584	1,068,215
Gas Information Technology	23,025	22,839	10,240	56,104
Total	<u>\$728,580</u>	<u>\$1,289,707</u>	<u>\$465,299</u>	<u>\$2,483,586</u>
Source: Exhibit A-12, Schedule B5.1				

11 As can be seen from Table CTF-1, the Company is proposing to add
12 approximately \$2.5 billion in capital investments over the rate case period. The two
13 largest capital expenditure categories, Routine Distribution Plant and Infrastructure
14 Recovery Mechanism, make up the vast majority of the Company's proposed capital
15 expenditures. A large portion of the Infrastructure Recovery Mechanism investment is
16 related to the Main Replacement Program, which I will address in greater detail below.

II.A. Main Replacement Program

Q PLEASE DESCRIBE THE COMPANY'S MAIN REPLACEMENT PROGRAM.

A The Company's Main Replacement Program is focused on the replacement of legacy mains in DTE's gas distribution system. Legacy mains refers to mains constructed of cast iron or steel that does not have cathodic protection from corrosion.¹ Historically, the Main Replacement Program was referred to as the Main Renewal Program, but now the program is referred to as the Gas Renewal Program.² Regardless of the name of the program, both programs have targeted the replacement of legacy mains that are more prone to gas leaks.

DTE is requesting capital expenditures for the Main Replacement Program of \$265 million in the historical test year, \$468 million in the projected bridge period and \$68 million in the projected test year period, for a total of \$801 million.³ The projected capital investments in the test year period are less than previous years because the Investment Recovery Mechanism ("IRM") capital investments are only included through December 31, 2024, in base rates. DTE is requesting \$274 million per year in main replacement capital expenditures to be recovered in its IRM surcharge for the calendar years beyond the rate case period, 2025 through 2029.

Q PLEASE DESCRIBE THE COMPANY'S HISTORICAL INVESTMENT IN ITS MAIN REPLACEMENT PROGRAM.

A DTE has made significant investments in the replacement of its distribution mains in recent years. I have shown the actual capital expenditures for the Company's Main Replacement Program in Table CTF-2.

¹See the Direct Testimony of Eric D. Janness at page 6, lines 17-21.

²See the Direct Testimony of Eric D. Janness at page 5, lines 6-7.

³Exhibit A-12, Schedule B5.3.

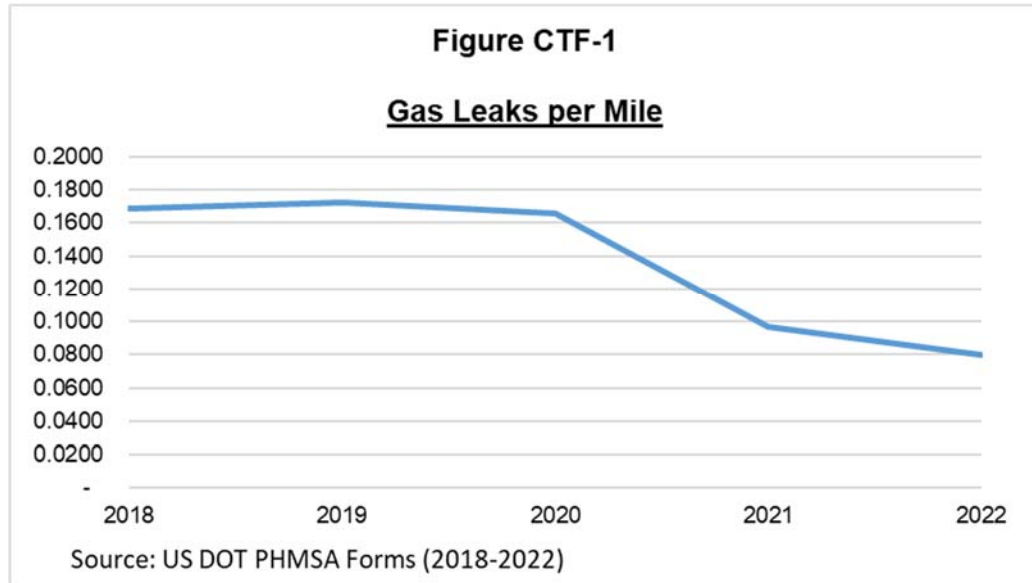
Table CTF-2	
<u>Historical Main Replacement Program Capital Expenditures</u> (\$1,000s)	
<u>Year</u>	<u>2018</u>
2018	\$143,109
2019	\$200,229
2020	\$228,638
2021	\$241,969
2022	<u>\$263,105</u>
Total	\$1,077,050
Source: Exhibit A-12, Schedule B6.1	

As can be seen from Table CTF-2 above, in recent years, the rate of investment in distribution mains has accelerated. In 2022 the Company invested approximately \$263 million in distribution main replacement, approximately \$120 million greater than in 2018, or an 84% increase. The Main Replacement Program capital expenditures made up a significant portion of DTE's historical distribution plant investment, and as a result, caused significant increases in the Company's rate base.

Q HAVE THE HISTORICAL INVESTMENTS IN DTE'S MAIN REPLACEMENT PROGRAM IMPACTED THE COMPANY'S SAFETY AND RELIABILITY METRICS?

A Yes. According to the data reported in the U.S. Department of Transportation's ("DOT") Pipeline and Hazardous Materials Safety Administration's ("PHMSA") annual reports for 2018 and 2022, DTE reported 3,385 gas leaks in 2018 and only 1,693 in 2022, an approximate 50% reduction.⁴ In order to account for the changes to the number of miles of main in-service and the number of gas leaks, I have shown the number of gas leaks per mile of main over the past five years in Figure CTF-1.

⁴<https://www.phmsa.dot.gov/forms/gas-distribution-annual-report-form-f71001-1>.



As can be seen from Figure CTF-1, the replacement of legacy gas mains has significantly reduced the average number of gas leaks per mile. Over this time period, DTE has targeted high risk mains and removed 267 miles of unprotected steel and 632 miles of Cast/Wrought Iron.⁵

Q DO YOU AGREE THAT THE COMPANY REQUIRES ITS PROPOSED LEVEL OF CAPITAL EXPENDITURES FOR ITS MAIN REPLACEMENT PROGRAM TO ENSURE SAFETY AND RELIABILITY?

A No. The Company was able to demonstrate it could make system improvements through its Main Replacement Program prior to the elevated level of investment incurred in 2022. In addition, the Company only needs to retire an average of 190 miles of main each year to meet the 18-year pace approved in Case No. U-18999.⁶ This is less than the 206 miles being proposed by the Company.

⁵US DOT, PHMSA Form 7100, 2018 and 2022.

⁶See the Direct Testimony of Eric D. Janness at page 26, lines 11-13.

Q WHAT DO YOU RECOMMEND?

A I recommend that DTE adjust the rate of main replacements in order to reduce the impact of capital expenditures on customers' rates. The Company can still remain on pace with the approved target miles in Case No. U-18999 by replacing 16 less miles of main per year. This would reduce the Main Replacement Program capital expenditures by approximately 8% per year. I have shown the impact of my proposed adjustment to the Main Replacement Program capital expenditures in Table CTF-3 below.

Table CTF-3				
<u>Main Replacement Program Capital Expenditures</u>				
(\$1,000s)				
<u>Description</u>	Historical 12 mos. ended <u>12/31/2022</u>	Bridge Period 21 mos. ending <u>9/30/2024</u>	Test Year 12 mos. ending <u>9/30/2025</u>	<u>Total</u>
Company Proposed	\$264,780	\$467,768	\$68,043	\$800,591
Adjustment	<u>(20,547)</u>	<u>(36,299)</u>	<u>(5,280)</u>	<u>(62,126)</u>
Adjusted Capital Expenditures	244,233	431,469	62,763	738,465
Source: Exhibit A-12, Schedule B5.3				

As shown in Table CTF-3, the adjustment to the rate of main replacements would reduce the Main Replacement Program capital expenditures by approximately \$62 million.

II.B. Large Capital Projects**Q HAVE YOU REVIEWED THE COMPANY'S LARGE CAPITAL PROJECTS?**

A Yes. These projects, for the most part, have large capital expenditures that are not considered routine in nature and are not part of IRM programs. Many of these projects have long project schedules extending multiple years and will not be completed prior to the end of the projected test year. The Company is proposing to include capital expenditures related to 12 large capital projects in the proposed rate base. From the

1 end of the historical test year through the end of the projected test year, DTE will have
2 incurred \$184.3 million of large project capital expenditures.⁷

3 **Q DO YOU HAVE ANY CONCERNS ABOUT THE PROJECTED TIMELINES FOR THE**
4 **PROPOSED CAPITAL PROJECTS?**

5 A Yes. I have reviewed the projected In-Service dates for the 25 largest capital projects
6 and several of these projects are not expected to be In-Service until after
7 September 30, 2025, the end of the projected test year. If any of these projects
8 experience unforeseen delays due to permitting, labor shortages, material delays, or
9 unforeseen site conditions, it is unlikely that the capital investment being requested by
10 DTE will be realized prior to the end of the projected test year.

11 **Q HAS DTE HISTORICALLY EXPERIENCED ISSUES WITH LARGE CAPITAL**
12 **PROJECT DELAYS?**

13 A Yes. Phase 3 of the Traverse City Alpena Reinforcement Project was completed in
14 2022 rather than 2021 as was proposed in the project Schedule in MPSC Case
15 No. U-20940. This resulted in an actual spend of \$40,667,000 in 2022 as opposed to
16 the proposed spend of \$640,000, a variance of approximately \$40 million. The variance
17 is due to work that was originally planned to be completed in 2021 actually being
18 completed in 2022.⁸

⁷See the Direct Testimony of Kelly M. Fedele at page 25, lines 13-16.

⁸See Data Request ABDG-1.37, subpart e, included in Exhibit AB-3.

**Q HOW DO PROJECT DELAYS IMPACT THE COMPANY'S PROPOSED RATE CASE
CAPITAL EXPENDITURES?**

A Project delays impact the rate case capital expenditures in two ways. First, projects with capital investment included in prior rate cases could have additional capital expenditures spill over into the current rate case if the project experiences delays and the work approved in prior rate cases is not completed according to the Company's original project schedules. Second, a similar issue can occur in the projected test year of the current rate case. If the large capital projects in this proceeding experience project delays the proposed level of capital investment will not be realized by the end of the projected test year. The combination of these two issues can create a squeezing effect on the rate case historical and future test year periods, where both historical and future capital expenditures are included in customer rates despite the fact that not all of the proposed capital investments have been placed into service.

**Q HOW DO YOU RECOMMEND ADJUSTING FOR THE IMPACT OF PROJECT
DELAYS?**

A I recommend a reduction in the proposed capital expenditures in the future test year period to ensure customers will not have capital investment included in rates for work that was not completed. In Table CTF-4, I removed the last six months of the Company's proposed capital investment for the projects shown from the projected test year to adjust the level of capital investment. Based on the Gantt Charts and projected In-Service dates provided in response to Data Request ABDG-1.30,⁹ I determined that six months was most appropriate period of time to exclude from the projected test year.

⁹See Exhibit AB-3.

Table CTF-4				
<u>Capital Projects with Expenditures Impacted by Project Delays</u>				
(\$1,000s)				
Project Description	In-Service Date ¹	Projected Test Year		Adjusted CapEx
		Company Proposed ²	Adjustment	
Fort Street Main Replacement	12/31/2027	\$32,753	(\$16,799)	\$15,954
Austin-Detroit A/B Lines	12/31/2028	\$16,181	(\$9,778)	\$6,404
Belle River - Detroit Interconnect and Loop Project	1/31/2027	\$7,378	(\$4,750)	\$2,628
E-line Interconnect (CMS Line 2700)	11/30/2025	\$4,694	(\$2,937)	\$1,758
ILI Expansion - Muskegon - Ludington (10) - Scottville Tie In	10/31/2025	\$4,101	(\$2,051)	\$2,051
Taggart Compressor Replacement	12/31/2027	\$2,859	(\$2,000)	\$859
ILI Expansion – Belle River Field Headers (24" Traps)	10/30/2025	\$3,263	(\$1,632)	\$1,632
Total	Total	\$71,230	(\$39,945)	\$31,285
Sources:				
¹ Attachment: U-21291 ABDG-1.30 - Top 25 Gantt Chart provided in Response to Data Request ABDG-1.30.				
² Exhibit A-12, Schedule B5.3.				

As can be seen from Table CTF-4 above, my proposed adjustment removes approximately \$40 million of proposed capital expenditures from the projected test year. To calculate the adjustment, I reviewed the proposed capital investment by month, and removed the last six months (April 2025 through September 2025) of the proposed investment. This adjustment will ensure that customers will not be subject to the impact of capital expenditures related to project work that was not completed during the rate case period.

III. O&M Expense

Q HAVE YOU REVIEWED THE COMPANY'S PROPOSED O&M EXPENSE?

A Yes. The Company's Summary of its Projected O&M Expense is included in Exhibit A-13, Schedule C5, and sponsored by Company witness Theresa M. Uzenski. DTE utilizes a multi-step process to develop the projected test period O&M expense. First, the historical test period is adjusted to account for eliminations, reclasses, and normalization. Then, the adjusted historical test period is adjusted for future inflation

and other adjustments identified by the Company. The sum of the adjusted historical test period and the projected adjustments result in the Company's projected test period O&M expense. I have illustrated this process in Table CTF-5 below.

Table CTF-5	
<u>Summary of O&M Expense</u>	
(\$1,000s)	
<u>Description</u>	<u>O&M Expense</u>
Historical Test Period	\$527,617
Eliminations and Reclasses	(71,626)
Normalization Adjustment	7,093
Adjusted Historical Test Period	\$463,084
Inflation 1/1/23-12/31/23	\$11,449
Inflation 1/1/23-12/31/24	10,708
Inflation 1/1/23-12/31/25	8,264
Other Adjustments	44,746
Projected Test Period	\$538,251
Source: Exhibit A-12, Schedule B6.1	

As can be seen from Table CTF-5, DTE is requesting a projected test period O&M expense of approximately \$538 million, a net increase of \$11 million over the historical test period. I will discuss the inflation factor used to adjust the O&M expense in greater detail below.

III.A. Inflation Factor

Q PLEASE DESCRIBE THE INFLATION ADJUSTMENT DTE USED TO DEVELOP THE PROJECTED TEST PERIOD O&M EXPENSE.

A The Company proposes an upward adjustment of \$30.5 million in O&M expense related to inflation. DTE uses labor inflation rates of 3.2% for 2023, 2.9% for 2024, and

1 2.9% for 2025.¹⁰ The labor inflation rates are based on a weighted average of the labor
2 inflation, contractor inflation, and non-labor inflation rates each year. Both the labor
3 and contractor inflation rates are based on the same wage inflation rate of 3.0%
4 sponsored by Company witness Michael S. Cooper. The labor inflation rates are used
5 for all O&M expense categories regardless of the function.

6 **Q HOW DOES THE COMPANY SUPPORT THE USE OF A 3.0% WAGE INFLATION**
7 **FACTOR?**

8 A The Company did not produce any supporting workpapers to support the 3.0%
9 assumption for the expected labor cost escalation assumption. Company witness
10 Mr. Cooper supports the wage inflation factor by relying on historical practices for the
11 non-represented workforce and existing collective bargaining agreements for
12 represented employees.¹¹

13 **Q DO YOU AGREE WITH THE COMPANY'S USE OF A 3.0% WAGE INFLATION**
14 **FACTOR?**

15 A No. If the Company is experiencing increased labor cost, they could have supported
16 the 3.0% wage inflation rate with supporting workpapers, but absence any direct
17 evidence demonstrating increased Company labor cost, the 3.0% wage inflation rate
18 should not be relied on to escalate O&M expense.

¹⁰Exhibit A-13, Schedule C12.

¹¹See the Response to Data Request No. ABDG-1.38 included in Exhibit AB-3.

1 **Q DO YOU HAVE ANY CONCERNS WITH THE NON-LABOR INFLATION RATE USED**
2 **BY THE COMPANY?**

3 A Yes. The Company uses the CPI-U (Consumer Price Index for Urban Customers) to
4 determine the appropriate non-labor inflation rate. The Company's proposed non-labor
5 inflation rate is 4.1% for 2023, 2.9% for 2024, and 2.2% for 2025.¹²

6 I compared these proposed rates to the Blue Chip Economic Indicators industry
7 expert consensus GDP Chained Price Index over the same time period. The GDP
8 chained price index uses a "chained" methodology. Each year, the basket of goods
9 and services is updated to reflect what people are actually buying. This is unlike the
10 CPI, which uses a fixed basket for a set period. This makes the GDP deflator more
11 responsive to consumer substitution – if prices of certain goods rise, people might
12 switch to cheaper alternatives, and the index will reflect that change. In addition, CPI
13 can be heavily weighted by the cost of medical expenses, which is not reflective of the
14 cost of utility expenses. The Blue GDP Chained Price Index is 2.6% for 2023, 2.2%
15 for 2024, and 2.2% for 2025.¹³

16 **Q HOW DO YOU RECOMMEND THE COMPANY UPDATE ITS O&M INFLATION**
17 **FACTORS?**

18 A I recommend DTE use the Blue Chip GDP Chained Price Index for the O&M inflation
19 factors. The wage inflation rate used by the Company is not well supported, and the
20 CPI-U non-labor inflation rate is well above the consensus industry experts' opinion of
21 the GDP Chained Price Index. I have shown the impact of the revised inflation rate on
22 O&M expense in Table CTF-6.

¹²Exhibit A-13, Schedule C12.

¹³Blue Chip Economic Indicators, March 11, 2024, page 5.

Table CTF-6				
<u>O&M Expense Inflation Factor Adjustment</u>				
(\$1,000s)				
<u>Description</u>	1/1/23 - 12/31/23 <u>Inflation</u>	1/1/24 - 12/31/24 <u>Inflation</u>	1/1/25 - 9/30/25 <u>Inflation</u>	<u>Total</u>
Company Proposed	\$11,449	\$10,708	\$8,264	\$30,421
Revised O&M Inflation Adjustment	<u>9,303</u>	<u>8,076</u>	<u>6,190</u>	<u>23,569</u>
O&M Expense Adjustment	(\$2,147)	(\$2,632)	(\$2,074)	(\$6,852)
Source: Exhibit A-13, Schedule C5				

As can be seen from Table CTF-6 above, the adjustment to the inflation factor reduced the Company's proposed O&M expense by approximately \$6.9 million.

III.B. Incentive Compensation

Q PLEASE DISCUSS THE AMOUNT OF INCENTIVE COMPENSATION INCLUDED IN THE COMPANY'S REVENUE REQUIREMENT.

A The Company proposes to include \$18.2 million of incentive compensation expense in the revenue requirement adopted by the Commission in this case.¹⁴ This represents the non-capitalized portion of incentive compensation related to operating measures associated with the Annual Incentive Plan ("AIP") and Rewarding Employees ("REP"), and the total cost (non-capitalized) associated with the Long-Term Incentive Plan ("LTIP").¹⁵

¹⁴See the Direct Testimony of Michael Cooper at page 44, lines 10-11.

¹⁵*Ibid.* at page 48, lines 15-21.

1 **Q OF THE \$18.2 MILLION INCENTIVE COMPENSATION EXPENSE, WHAT PORTION**
2 **IS ASSOCIATED WITH FINANCIAL PERFORMANCE?**

3 A All three incentive compensation programs contain measures that are impacted by
4 financial performance. These include goals such as realizing the Company's operating
5 earnings objectives, cash from operations, and operating earnings per share.¹⁶ As
6 shown in Table 3 of Mr. Cooper's Direct Testimony, the amount associated with
7 financial performance is \$12.0 million.¹⁷

8 **Q IS IT REASONABLE TO INCLUDE ALL INCENTIVE COMPENSATION COSTS IN A**
9 **COMPANY'S RATEMAKING COST OF SERVICE?**

10 A No. Incentive Compensation Programs that are designed to align the interests of
11 employees with shareholders should be paid for by shareholders. To the extent
12 incentive compensation reflects customer-directed goals such as service reliability,
13 and/or employee safety, only then is it fair and reasonable to recover the costs of those
14 programs from ratepayers if the operational performance metrics are actually achieved.

15 **Q HAS THE COMMISSION PREVIOUSLY REJECTED THE INCLUSION OF**
16 **INCENTIVE COMPENSATION RELATED TO FINANCIAL PERFORMANCE IN THE**
17 **REVENUE REQUIREMENT?**

18 A Yes. As noted in its May 8, 2020 Final Order in DTE's last rate case, Case
19 No. U-20561, for over a decade the Commission has unequivocally and consistently
20 disallowed incentive compensation costs tied to financial measures.¹⁸ In addition, the
21 Commission indicated that it, "has been unwaveringly clear that incentive

¹⁶*Ibid.* at page 50.

¹⁷*Ibid.* at page 56, lines 6-16.

¹⁸Case No. U-20561, May 8, 2020 Final Order at page 17.

1 compensation tied to financial performance measures has not been shown to benefit
2 ratepayers.”¹⁹ Similarly, in Case No. U-20836, the Commission found that, “incentive
3 compensation tied to financial performance measures has not been shown to benefit
4 ratepayers and, thus, should not be recovered through rates.”²⁰

5 **Q HAS DTE PROVIDED EVIDENCE SHOWING THAT CUSTOMERS BENEFIT FROM**
6 **INCENTIVE COMPENSATION TIED TO FINANCIAL PERFORMANCE METRICS?**

7 A No. As shown on DTE’s Exhibit A-19, Schedule I-5, the costs associated with financial
8 performance outweigh the benefits to customers in five out of six metrics, and cost
9 \$12.0 million but only ostensibly provide \$6.1 million in benefits to customers.²¹

10 **Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE INCENTIVE**
11 **COMPENSATION RELATED TO FINANCIAL PERFORMANCE?**

12 A I recommend the Commission reject DTE’s proposal to include \$12.0 million of
13 incentive compensation expense that is associated with financial performance in the
14 revenue requirement adopted in this case, consistent with its findings in prior cases.

15 **IV. Conclusion**

16 **Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.**

17 A I have four recommendations for the Commission: (1) Reduce the Main Replacement
18 Program capital expenditures to recent historical levels; (2) Remove the portions of
19 Large Capital Project capital expenditures that are unlikely to be in-service prior to the
20 end of the projected test period; (3) Revise the O&M inflation adjustment factor; and

¹⁹*Ibid.* at 19.

²⁰Case No. U-20836, November 18, 2022 Final Order at page 301.

²¹Exhibit A-29, Schedule I5, line 14, columns (k) and (l).

(4) Remove the portions of Incentive Compensation related to financial performance. I have summarized the impact of my recommendations in Table CTF-7 below.

Table CTF-7			
<u>Summary of Adjustments</u>			
(\$Millions)			
<u>Description</u>	<u>Plant Expense</u>	<u>Rev. Req. Impact</u>	
		<u>At Company Proposed ROR</u>	<u>At ABATE Proposed ROR</u>
Capital Expenditures			
Main Replacement Program	\$62.1	\$2.37	\$2.05
Large Capital Projects	<u>\$39.9</u>	<u>\$1.53</u>	<u>\$1.32</u>
Subtotal	\$102.0	\$3.90	\$3.37
O&M Expenditures			
Inflation Factor Adjustment		\$6.9	\$6.9
Incentive Compensation		<u>\$12.0</u>	<u>\$12.0</u>
Subtotal		\$18.9	\$18.9
Total		\$22.8	\$22.3

As shown in Table CTF-7, the total impact of my proposed adjustments is a \$22.8 million reduction in revenue requirement at the Company's proposed ROR and \$22.3 million at ABATE's proposed ROR.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does

Qualifications of Colin T. Fitzhenry

1 **Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A Colin Fitzhenry. My business address is 16690 Swingley Ridge Road, Suite 140,
3 Chesterfield, MO 63017.

4 **Q PLEASE STATE YOUR OCCUPATION.**

5 A I am a Senior Consultant in the field of public utility regulation with the firm of Brubaker
6 & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

7 **Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

8 A I received a Bachelor of Science in General Engineering from the University of Illinois
9 Urbana-Champaign, which provided a broad background in mechanics and control
10 systems. Prior to joining BAI, I served as an Engineer Intern for Dynegy Inc., where I
11 was involved with generation operation at both Vermilion Power Station and Tilton
12 Power Station.

13 Since joining BAI in January 2013, I have provided assistance in several
14 regulated utility matters. Some of these include resource planning, transmission
15 planning, fuel cost recovery, environmental compliance plans, mergers, asset transfers,
16 electrical and commodity price forecasting, and power procurement. I have provided
17 testimony in regulatory proceedings before Commissions in Illinois, Maryland,
18 Wyoming, and Georgia.

19 The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and
20 assumed the utility rate and economic consulting activities of Drazen Associates, Inc.,
21 founded in 1937. In April, 1995 the firm of Brubaker & Associates, Inc. was formed. It
22 includes most of the former DBA principals and staff. Our staff includes consultants

1 with backgrounds in accounting, engineering, economics, finance, mathematics,
2 computer science and business.

3 Brubaker & Associates, Inc. and its predecessor firm have participated in over
4 700 major utility rate and other cases and statewide generic investigations before utility
5 regulatory commissions in 40 states, involving electric, gas, water, and steam rates and
6 other issues. Cases in which the firm has been involved have included more than 80
7 of the 100 largest electric utilities and over 30 gas distribution companies and pipelines.

8 While the firm has always assisted its clients in negotiating contracts for utility
9 services in the regulated environment, increasingly there are opportunities for certain
10 customers to acquire power on a competitive basis from a supplier other than its
11 traditional electric utility. The firm assists clients in identifying and evaluating purchased
12 power options, conducts RFPs and negotiates with suppliers for the acquisition and
13 delivery of supplies. We have prepared option studies and/or conducted RFPs for
14 competitive acquisition of power supply for industrial and other end-use customers
15 throughout the United States and in Canada, involving total needs in excess of 3,000
16 megawatts. The firm is also an associate member of the Electric Reliability Council of
17 Texas.

18 In addition to our main office in St. Louis, the firm also has branch offices in
19 Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

495643

1 MR. CAMPBELL: Thank you, your Honor.

2 Mr. Walters' direct testimony consists of a cover page, a
3 table of contents, 71 pages of questions and answers, and
4 an Appendix A setting out his qualifications; and along
5 with his direct testimony, Mr. Walters sponsored Exhibits
6 AB-4 through AB-18. Mr. Walters' rebuttal testimony
7 consists of a cover page and eight pages of questions and
8 answers.

9 JUDGE THOITS: All right. Are there any
10 objections to the admission of this testimony or these
11 exhibits? (No response.)

12 Hearing none, the Direct and Rebuttal
13 Testimony of Christopher Walters is bound into the
14 record, and Exhibits AB-4 through AB-18 are admitted.

15 (Testimony bound in.)

16 - - -
17
18
19
20
21
22
23
24
25

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

**In the matter of the Application of DTE
GAS COMPANY for authority to increase
its rates, amend its rate schedules and
rules governing the distribution and
supply of natural gas, and for
miscellaneous accounting authority.**

Case No. U-21291

Direct Testimony and Exhibits of

Christopher C. Walters

On behalf of

Association of Businesses Advocating Tariff Equity

May 7, 2024



Project 11589

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

Case No. U-21291

Table of Contents for the Direct Testimony of Christopher C. Walters

I.	INTRODUCTION.....	1
II.	SUMMARY	2
III.	ACCESS TO CAPITAL	3
	AND ECONOMIC ENVIRONMENT	3
III.A.	Regulated Utility Industry Authorized	3
	ROEs, Access to Capital, and Credit Strength	3
III.B.	Federal Reserve Monetary Policy	10
III.C.	Market Sentiments and Utility Industry Outlook.....	16
III.D.	Additional Remarks	19
IV.	RETURN ON EQUITY	21
IV.A	DTE’s Investment Risk	23
IV.B.	DTE’s Proposed Capital Structure.....	25
IV.C.	Development of Proxy Group	27
IV.D.	DCF Model	30
IV.E.	Sustainable Growth DCF	34
IV.F.	Multi-Stage Growth DCF Model.....	35
IV.G.	Risk Premium Model	42
IV.H.	Capital Asset Pricing Model (“CAPM”)	46
IV.I.	Return on Equity Summary	56
V.	RESPONSE TO DR. BENTE VILLADSEN	58

V.A.	Summary of Response	58
V.B.	ATWACC	61
V.C.	Dr. Villadsen's DCF Analysis.....	64
V.D.	Dr. Villadsen's CAPM Analysis.....	65
V.E.	Dr. Villadsen's Risk Premium Analysis.....	69
Qualifications of Christopher C. Walters.....		1

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

**In the matter of the Application of DTE GAS
COMPANY for authority to increase its
rates, amend its rate schedules and rules
governing the distribution and supply of
natural gas, and for miscellaneous
accounting authority.**

Case No. U-21291

Direct Testimony of Christopher C. Walters

I. INTRODUCTION

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Christopher C. Walters. My business address is 16690 Swingley Ridge Road,
Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Principal with the firm of
Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Association of Businesses Advocating Tariff Equity
("ABATE"). ABATE consists of large usage customers that purchase substantial

1 amounts of electric power and/or delivery service from DTE Gas Company ("DTE" or
2 "Company").

3 **Q HAVE YOU PRESENTED TESTIMONY IN PRIOR REGULATORY PROCEEDINGS**
4 **BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION ("COMMISSION")?**

5 **A** Yes.

6 **II. SUMMARY**

7 **Q PLEASE SUMMARIZE YOUR TESTIMONY.**

8 **A** In Section III of my testimony, I review and analyze the regulated utility industry's
9 access to capital, credit rating trends, and outlooks, as well as the overall trend in the
10 authorized ROE for utilities throughout the country. I conclude that the trend in
11 authorized ROEs for utilities has declined over the last several years and has remained
12 below 10.0% in more recent history. I also review the impact that the Federal Reserve's
13 (the "Fed") monetary policy actions have had on the cost of capital.

14 In Section IV of my testimony, I outline how a fair ROE should be established,
15 provide an overview of the market's perception of the Company's investment risk,
16 comment on the Company's proposed capital structure, and present the analyses I
17 relied on to estimate an appropriate ROE for DTE. Based on the results of several cost
18 of equity estimation methods performed on publicly traded utility companies, I estimate
19 the current fair market ROE for the Company to fall within the range of 9.10% to 9.80%.
20 Based on my assessment of the Company's overall risk profile and the results of the
21 analytical methods, I recommend DTE be awarded an ROE of 9.45%, which is the
22 mid-point of my estimated range.

1 In Section V of my testimony, I respond to Company witness Dr. Villadsen's
2 estimate of the current market cost of equity for DTE. Dr. Villadsen recommends the
3 Company be authorized an ROE of 10.25%. I demonstrate that her ROE
4 recommendations are excessive and should be rejected.

5 Based on all of the foregoing, I request this Commission adopt the following
6 recommendations:

- 7 1. Reject DTE's proposed ROE of 10.25% and instead adopt my recommended ROE
8 of 9.45%, which is based on my assessment of the current and expected capital
9 market environment, the Company's overall risk profile, and the results of several
10 analytical methods which I have used, to determine a fair and reasonable ROE to
11 be authorized for DTE.
- 12 2. I recommend the Commission reject DTE's proposed equity ratio of 51.5% and
13 instead authorize DTE an equity ratio of 50.0%, consistent with the Commission's
14 stated preference for a more balanced capital structure. DTE's requested equity
15 ratio of 51.5% defies at least three separate directives by this Commission in Orders
16 issued in previous rate cases.
- 17 3. My recommended ROE and capital structure along with the Company's proposed
18 embedded cost of debt produce an overall ratemaking ROR of 5.66%.
- 19 4. My recommendations would reduce DTE's retail natural gas delivery service
20 revenue requirements by approximately \$37.6 million.
- 21

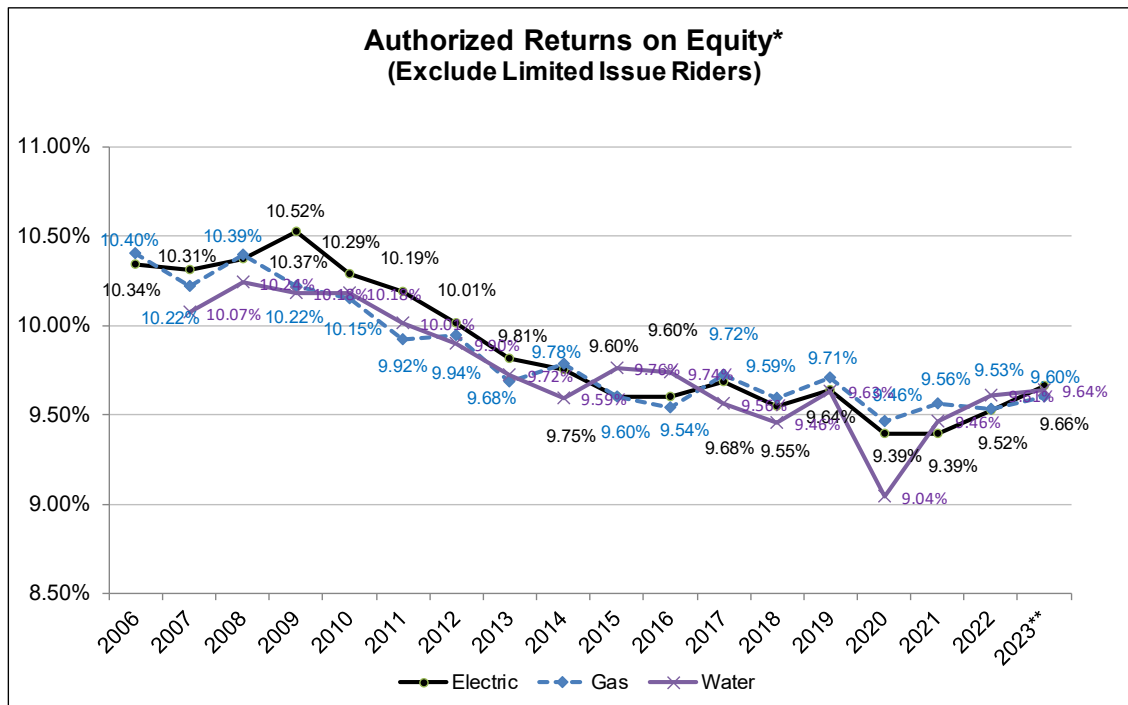
22 **III. ACCESS TO CAPITAL** 23 **AND ECONOMIC ENVIRONMENT**

24 **III.A. Regulated Utility Industry Authorized** 25 **ROEs, Access to Capital, and Credit Strength**

26 **Q PLEASE DESCRIBE THE OBSERVABLE EVIDENCE ON TRENDS IN**
27 **AUTHORIZED ROEs FOR REGULATED UTILITIES.**

28 **A** Authorized ROEs for regulated utilities have generally declined over the last 10 years,
29 as illustrated in Figure CCW-1, and have been below 10.0% for about the last nine
30 years.

FIGURE CCW-1



Source and Notes:

* Electric Returns exclude Limited Issue Riders.

** S&P Global Market Intelligence, RRA Regulatory Focus, Major Rate Case Decisions -- January - December 2023, February 6, 2024 at page 4.

1 **Q PLEASE DESCRIBE THE DISTRIBUTION OF AUTHORIZED ROEs FOR UTILITIES**
2 **FOR THE LAST FEW YEARS.**

3 **A The distribution of authorized returns, annually, since 2016 is summarized in Table**
4 **CCW-1.**

TABLE CCW-1									
<u>Distribution of Authorized ROEs</u>									
<u>Line</u>	<u>Year</u> (1)	<u>Natural Gas</u> ¹				<u>Water</u>			
		<u>Average</u> (2)	<u>Median</u> (3)	<u>Share of</u> <u>Decisions</u> <u>≤ 9.5%</u> (4)	<u>Share of</u> <u>Decisions</u> <u>≤ 9.7%</u> (5)	<u>Average</u> (6)	<u>Median</u> (7)	<u>Share of</u> <u>Decisions</u> <u>≤ 9.5%</u> (8)	<u>Share of</u> <u>Decisions</u> <u>≤ 9.7%</u> (9)
1	2016	9.52%	9.50%	52%	74%	9.74%	9.75%	12.50%	12.50%
2	2017	9.71%	9.60%	43%	74%	9.56%	9.63%	44.44%	44.44%
3	2018	9.73%	9.80%	53%	72%	9.46%	9.20%	53.33%	53.33%
4	2019	9.70%	10.23%	23%	57%	9.63%	9.73%	16.67%	16.67%
5	2020	9.42%	9.40%	68%	87%	9.04%	9.15%	83.33%	83.33%
6	2021	9.53%	9.52%	50%	74%	9.46%	9.60%	20.00%	20.00%
7	2022	9.50%	9.40%	53%	80%	9.61%	9.75%	37.50%	62.50%
8	2023	9.60%	9.38%	27%	43%	9.64%	9.57%	40.00%	60.00%

Source and Notes:
¹ S&P Global Market Intelligence, data through 12/31/23.
 - Excludes limited issue rider cases.

The distribution shows that the majority of authorized ROEs since 2016 have generally been below 9.7%, with many of those being below 9.5%.

Q HOW HAS THE AUTHORIZED COMMON EQUITY RATIO FLUCTUATED OVER THE SAME TIME PERIOD FOR UTILITIES?

A In general, the utility industry's common equity ratios have not deviated too much from the range of 50.0% to 52.0%. As shown in Table CCW-2 below, I have provided the authorized common equity ratios for utilities around the country, excluding the reported common equity ratios for Arkansas, Florida, Indiana, and Michigan. For my overall market analysis, I have excluded the reported authorized common equity ratios for these states because these jurisdictions include sources of capital outside of investor-supplied capital such as accumulated deferred income taxes. As such, the reported common equity ratios in these states would result in a downward bias in the reported permanent common equity ratios authorized for ratemaking purposes within my trend analysis.

TABLE CCW-2

Trends in State Authorized Common Equity Ratios
(Industry)

<u>Line</u>	<u>Year</u> (1)	<u>Electric</u> ¹		<u>Natural Gas</u> ¹		<u>Water</u> ¹	
		<u>Average</u> (2)	<u>Median</u> (3)	<u>Average</u> (4)	<u>Median</u> (5)	<u>Average</u> (6)	<u>Median</u> (7)
1	2013	50.12%	51.03%	51.16%	50.43%	48.34%	45.79%
2	2014	50.28%	50.00%	51.90%	51.99%	49.69%	50.27%
3	2015	50.24%	50.48%	49.79%	50.33%	51.52%	51.36%
4	2016	49.70%	49.99%	51.85%	51.35%	50.65%	50.77%
5	2017	50.02%	49.85%	51.13%	51.76%	48.43%	46.09%
6	2018	50.60%	50.23%	52.58%	53.08%	52.41%	53.22%
7	2019	51.55%	51.37%	52.72%	52.22%	50.75%	50.35%
8	2020	50.94%	51.17%	52.34%	52.00%	49.75%	48.55%
9	2021	51.01%	52.00%	51.63%	52.00%	51.96%	52.73%
10	2022	51.50%	51.92%	51.84%	52.00%	51.53%	51.15%
11	2023	51.59%	52.27%	52.45%	52.00%	52.53%	53.40%
11	Min	49.70%	49.85%	49.79%	50.33%	48.34%	45.79%
12	Max	51.59%	52.27%	52.72%	53.08%	52.53%	53.40%
12	Average	50.69%	50.94%	51.76%	51.74%	50.69%	50.33%
13	Median	50.60%	51.03%	51.85%	52.00%	50.75%	50.77%

Source and Notes:

¹ S&P Global Market Intelligence; data through December 31, 2023.

- Excludes Arkansas, Florida, Indiana and Michigan
because they include non-investor capital.

1 Q HAVE REGULATED UTILITY COMPANIES BEEN ABLE TO MAINTAIN
2 RELATIVELY STRONG CREDIT RATINGS DURING PERIODS OF DECLINING
3 AUTHORIZED ROEs?

4 A Yes. As shown below in Table CCW-3, the credit ratings of the industry have improved
5 since 2009. In 2009, approximately 75% of natural gas utilities were rated BBB+ or
6 higher. Currently, 85% of the industry has a rating of BBB+ or higher.

TABLE CCW-3																
S&P Ratings by Category																
Natural Gas Utility Subsidiaries																
(Year End)																
Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
A or higher	50%	50%	50%	50%	38%	33%	33%	44%	56%	33%	38%	38%	13%	15%	17%	17%
A-	0%	0%	0%	0%	38%	33%	33%	22%	11%	11%	38%	38%	38%	38%	38%	34%
BBB+	25%	25%	38%	38%	13%	22%	33%	33%	33%	44%	13%	13%	25%	30%	29%	34%
BBB	13%	13%	0%	0%	0%	0%	0%	0%	0%	11%	13%	13%	25%	18%	16%	15%
BBB-	13%	13%	13%	13%	13%	11%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Below BBB-	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Source: S&P CAPITAL IQ and Market Intelligence, data retrieved 4/17/24.
Note: Subsidiary ratings used.

Q HAVE UTILITIES BEEN ABLE TO ACCESS EXTERNAL CAPITAL TO SUPPORT CAPITAL EXPENDITURE PROGRAMS?

A Yes. In Regulatory Research Associates' ("RRA") November 8, 2023 Utility Capital Expenditures report, *RRA Financial Focus*, a division of S&P Global Market Intelligence, made several relevant comments about utility investments generally:

- Projected 2023 capital expenditures for the 46 energy utilities included in the Regulatory Research Associates representative sample of publicly traded, US-based utilities is nearly \$171 billion — a more than 18% jump from the group's \$144 billion of actual spending in 2022. The increase is being driven in large part by federal legislation enacted in 2021 and 2022 supporting infrastructure investment.

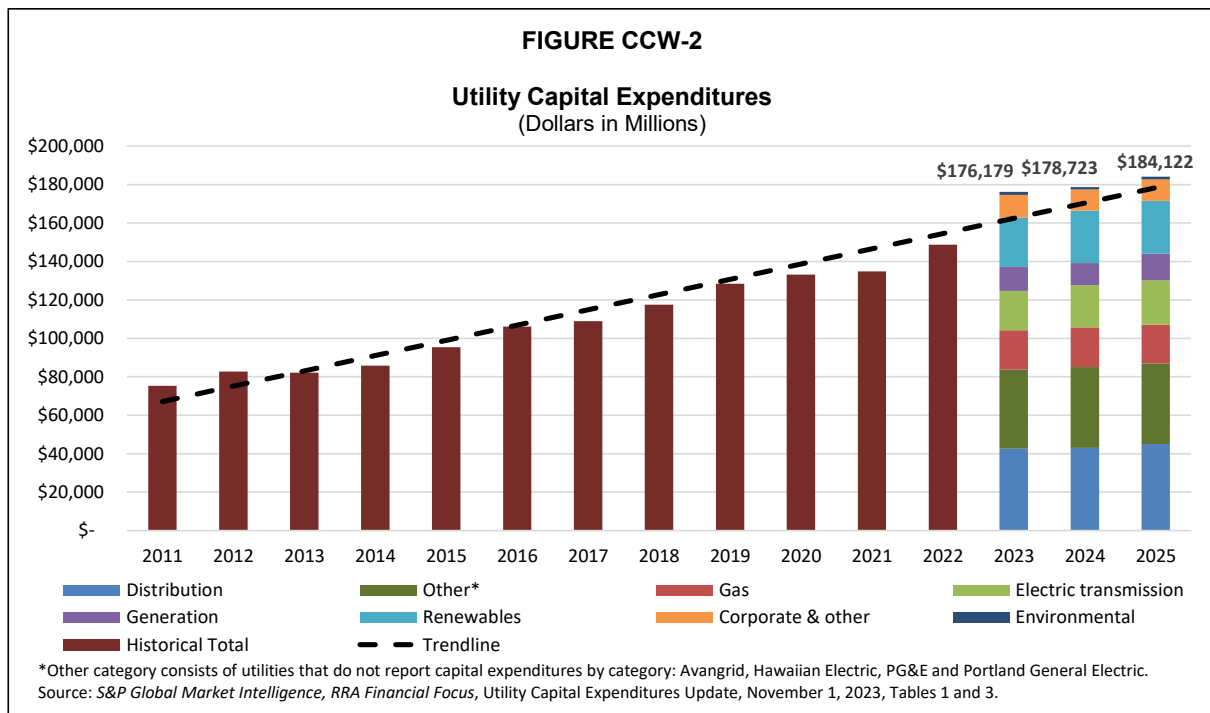
* * *

- Aggregated capex estimates for both 2024 and 2025 indicate successively higher spending levels, reaching \$173.5 billion and \$179.4 billion, respectively. Spending expectations for 2024 and beyond are likely to increase as the companies' plans for future projects continue to get around multiple new pieces of federal legislation supporting infrastructure investment.

The nation's electric, gas, and water utilities are investing in infrastructure to upgrade aging transmission and distribution systems, build new natural gas, solar and wind generation, and implement new technologies, including smart meter deployment, smart grid systems, cybersecurity measures, electric vehicles and battery storage. These considerable levels of spending are expected to serve as the basis for solid profit expansion in the utility industry for the foreseeable future.

Multiple drivers are expected to impel elevated spending over the next several years, including pent-up demand to replace and modernize aging infrastructure, renewable portfolio standards of multiple states — that include large expansions in low-carbon energy generation capacity — continue to ramp up, and federal infrastructure investment plans that are intended to steer conversion of the nation's power generation network to zero-carbon sources by 2035 come to fruition.¹

As shown in Figure CCW-2 below, capital expenditures for the regulated electric and natural gas delivery utilities have increased considerably over the period 2023 into 2024, and the forecasted capital expenditures remain elevated through the end of 2025. The outlooks for electric and natural gas industries reasonably align with capital expenditure outlooks for water utilities as noted by RRA above.



As demonstrated in Figure CCW-2 above, and in the comments made by RRA S&P Global Market Intelligence, capital investments for the utility industry continue to stay at elevated levels, and these capital expenditures are expected to fuel utilities'

¹S&P Global Market Intelligence, RRA Financial Focus: "Utility Capital Expenditures Update: H2 2023, Energy, water utility capex plans on track to record-breaking year," November 8, 2023, pages 4-5 (emphasis added).

1 profit growth into the foreseeable future. This is clear evidence that the capital
2 investments are enhancing shareholder value and are attracting both equity and debt
3 capital to the utility industry in a manner that allows for funding these elevated capital
4 investments. While capital markets embrace these profit-driven capital investments,
5 regulatory commissions also must be careful to maintain reasonable prices and tariff
6 terms and conditions to protect customers' need for reliable utility service at reasonable
7 rates. If this is not done, utility rates will expand beyond the ability of customers to pay,
8 resulting in revenue constraints for utilities, which will impact their financial integrity.

9 **Q WHAT IS THE SIGNIFICANCE OF THESE FINDINGS?**

10 A This is clear evidence that the capital investments are enhancing shareholder value,
11 and are attracting both equity and debt capital to the utility industry in a manner that
12 allows for these elevated capital investments.

13 **Q IS THERE EVIDENCE OF ROBUST VALUATIONS OF REGULATED UTILITY**
14 **EQUITY SECURITIES?**

15 A Yes. Robust valuations are an indication that utilities can sell securities at high prices,
16 which is a strong signal that they can access equity capital under reasonable terms and
17 conditions, and at relatively low cost. As shown on Exhibit AB-4, the historical valuation
18 of utilities followed by *The Value Line Investment Survey* ("Value Line"), based on a
19 price-to-earnings ("P/E") ratio, price-to-cash flow ("P/CF") ratio, and market
20 price-to-book value ("M/B") ratio, indicates utility security valuations today are very
21 strong and robust relative to the last several years. These strong valuations of utility
22 stocks indicate that utilities have access to equity capital under reasonable terms and
23 at lower costs.

**Q WHAT CONCLUSION DO YOU DRAW FROM THIS OBSERVABLE MARKET DATA
IN FORMING YOUR RECOMMENDED ROE AND OVERALL ROR?**

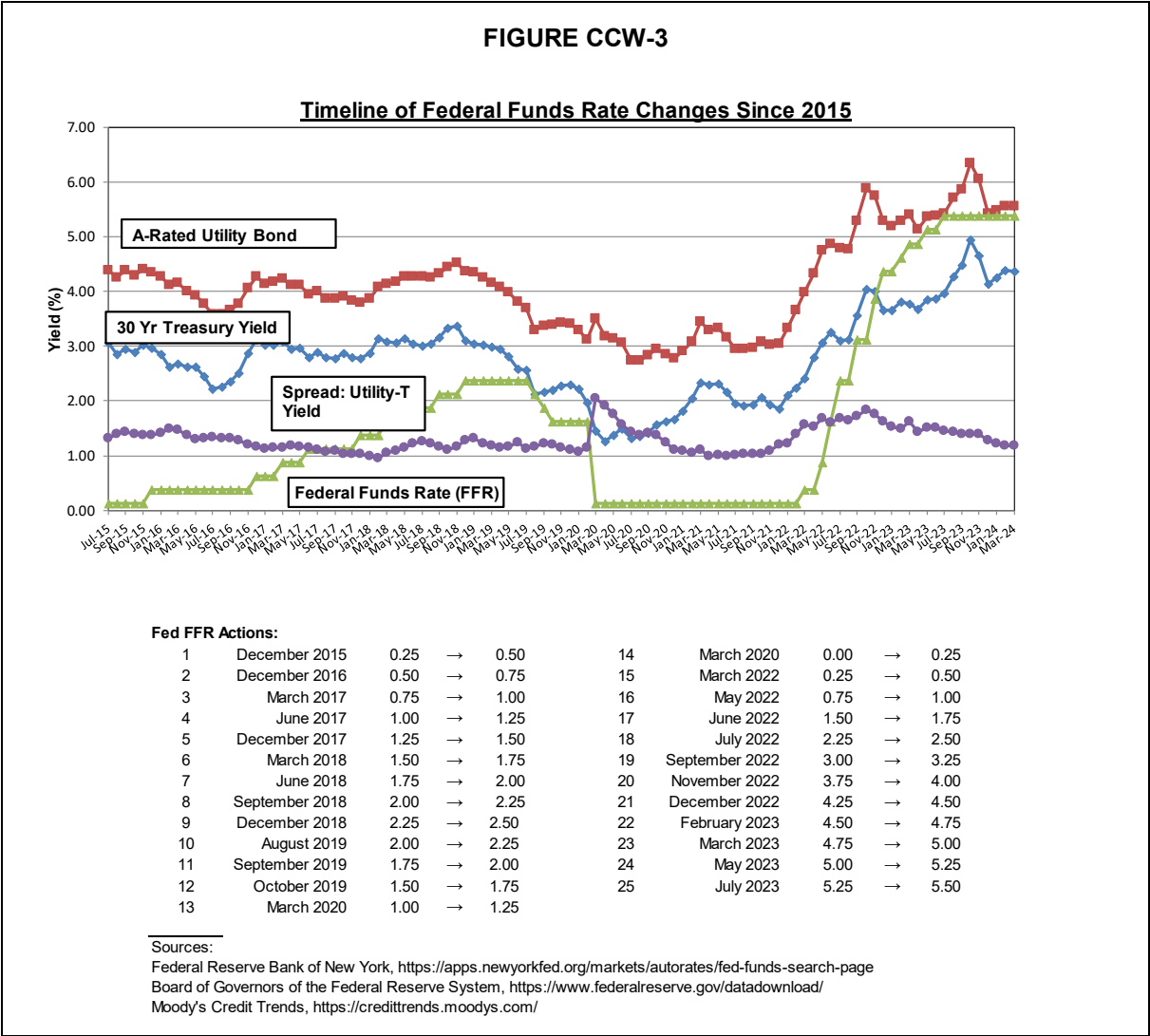
A Generally, authorized ROEs, credit standing, and access to capital have been quite robust for utilities over the last several years, even throughout the duration of the global pandemic. It is critical that this Commission ensure that utility rates are increased no more than necessary to provide fair compensation and maintain financial integrity.

III.B. Federal Reserve Monetary Policy

**Q ARE THE FEDERAL OPEN MARKET COMMITTEE'S ("FOMC") ACTIONS KNOWN
TO THE MARKET PARTICIPANTS, AND IS IT REASONABLE TO BELIEVE THEY
ARE REFLECTED IN THE MARKET'S VALUATION OF BOTH DEBT AND EQUITY
SECURITIES?**

A Yes to both questions. The Fed has been transparent about its efforts to support the economy to achieve maximum employment, and to manage long-term inflation to around a 2% level. The Fed has implemented procedures to support the economy's efforts to achieve these policy objectives. Specifically, the Fed had previously lowered the Federal Overnight Rate for securities and had engaged in a Quantitative Easing program where the Fed was buying, on a monthly basis, Treasury and mortgage-backed securities in order to moderate the demand in the marketplaces and support the economy. Currently, the Fed is unwinding its Quantitative Easing program and taking actions towards monetary policy normalization. Such monetary policy actions include raising the target federal funds rate and allowing maturing bonds to roll off its balance sheet.

A visualization of the market's reaction to the Fed's actions on the federal funds rate is shown below in Figure CCW-3.



1 As shown in Figure CCW-3 above, the rise in the Federal Funds Rate has far

2 outpaced the rise in Utility and Treasury yields while the spread of Utility bonds over

3 Treasury bond yields have stabilized recently.

4 **Q HAS THE FED MADE RECENT COMMENTS CONCERNING MONETARY POLICY**

5 **AND THE POTENTIAL IMPACT ON INTEREST RATES?**

6 **A** Yes. In its recent press release, the FOMC stated the following:

7 Recent indicators suggest that growth of economic activity has slowed

8 from its strong pace in the third quarter. Job gains have moderated since

9 earlier in the year but remain strong, and the unemployment rate has

1 remained low. Inflation has eased over the past year but remains
2 elevated.

3 The U.S. banking system is sound and resilient. Tighter financial and
4 credit conditions for households and businesses are likely to weigh on
5 economic activity, hiring, and inflation. The extent of these effects
6 remains uncertain. The Committee remains highly attentive to inflation
7 risks.

8 The Committee seeks to achieve maximum employment and inflation at
9 the rate of 2 percent over the longer run. In support of these goals, the
10 Committee decided to maintain the target range for the federal funds
11 rate at 5-1/4 to 5-1/2 percent. The Committee will continue to assess
12 additional information and its implications for monetary policy. In
13 determining the extent of any additional policy firming that may be
14 appropriate to return inflation to 2 percent over time, the Committee will
15 take into account the cumulative tightening of monetary policy, the lags
16 with which monetary policy affects economic activity and inflation, and
17 economic and financial developments. In addition, the Committee will
18 continue reducing its holdings of Treasury securities and agency debt
19 and agency mortgage-backed securities, as described in its previously
20 announced plans. The Committee is strongly committed to returning
21 inflation to its 2 percent objective.

22 In assessing the appropriate stance of monetary policy, the Committee
23 will continue to monitor the implications of incoming information for the
24 economic outlook. The Committee would be prepared to adjust the
25 stance of monetary policy as appropriate if risks emerge that could
26 impede the attainment of the Committee's goals. The Committee's
27 assessments will take into account a wide range of information,
28 including readings on labor market conditions, inflation pressures and
29 inflation expectations, and financial and international developments.²

30 The above quotes suggest to me that the FOMC has recently shown signs of
31 success in, and remains committed to, stabilizing consumer prices and promoting
32 maximum employment through its monetary policy tools.

²Found here:
<https://www.federalreserve.gov/newsevents/pressreleases/monetary20231213a.htm>, December 13,
2023.

**Q WHAT DO INDEPENDENT ECONOMISTS' OUTLOOKS FOR FUTURE INTEREST
RATES INDICATE?**

A Independent economists, surveyed by *Blue Chip Financial Forecasts*, expect current capital costs to increase at mixed rates over the near term, while maintaining levels that are still low by historical standards. For example, independent projections show that the consensus is the federal funds rate will increase at a rate much faster than that of long-term interest rates as measured by the 30-year Treasury bond. Inflation, as measured through the Gross Domestic Product ("GDP") price index, is expected to cool off in the near to intermediate term.

 The consensus projections for the next several quarters are provided in Table CCW-4 below.

TABLE CCW-4												
Blue Chip Financial Forecasts												
Projected Federal Funds Rate, 30-Year Treasury Bond Yields, and GDP Price Index												
Publication Date	4Q 2022	1Q 2023	2Q 2023	3Q 2023	4Q 2023	1Q 2024	2Q 2024	3Q 2024	4Q 2024	1Q 2025	2Q 2025	3Q 2025
<u>Federal Funds Rate</u>												
Jan-23	3.6	4.7	5.0	4.9	4.7	4.4	4.0					
Feb-23	3.7	4.7	5.0	4.9	4.7	4.3	4.0					
Mar-23	3.7	4.7	5.1	5.1	5.0	4.7	4.2					
Apr-23		4.5	5.0	5.1	4.9	4.6	4.2	3.8				
May-23		4.5	5.0	5.1	5.0	4.7	4.2	3.8				
Jun-23		4.5	5.0	5.1	5.0	4.6	4.2	3.9				
Jul-23			5.0	5.3	5.2	5.0	4.6	4.3	3.9			
Aug-23			5.0	5.4	5.4	5.2	4.9	4.4	4.0			
Sep-23			5.0	5.3	5.4	5.3	5.0	4.6	4.2			
Oct-23				5.3	5.4	5.4	5.1	4.7	4.3	4.0		
Nov-23				5.3	5.4	5.4	5.2	4.9	4.5	4.1		
Dec-23				5.3	5.4	5.4	5.2	4.9	4.6	4.2		
Jan-24					5.3	5.3	5.1	4.8	4.4	4.1	3.8	
Feb-24					5.3	5.3	5.1	4.7	4.4	4.1	3.8	
Mar-24					5.3	5.4	5.2	4.9	4.5	4.2	3.8	
Apr-24						5.3	5.2	5.0	4.6	4.2	3.9	3.7
<u>T-Bond, 30 yr.</u>												
Jan-23	3.9	4.0	4.0	3.9	3.9	3.8	3.8					
Feb-23	3.9	3.8	3.9	3.9	3.8	3.8	3.7					
Mar-23	3.9	3.9	4.0	3.9	3.9	3.8	3.8					
Apr-23		3.8	3.9	3.8	3.8	3.8	3.8	3.7				
May-23		3.7	3.8	3.8	3.8	3.8	3.7	3.7				
Jun-23		3.7	3.8	3.8	3.8	3.8	3.8	3.7				
Jul-23			3.8	3.9	3.9	3.9	3.8	3.8	3.8			
Aug-23			3.8	4.0	3.9	4.0	3.9	3.9	3.8			
Sep-23			3.8	4.1	4.2	4.1	4.0	4.0	3.9			
Oct-23				4.2	4.4	4.3	4.2	4.2	4.1	4.0		
Nov-23				4.2	4.8	4.7	4.5	4.5	4.3	4.2		
Dec-23				4.2	4.8	4.7	4.5	4.5	4.4	4.3		
Jan-24					4.6	4.3	4.3	4.2	4.1	4.0	4.0	
Feb-24					4.6	4.3	4.2	4.2	4.1	4.0	4.0	
Mar-24					4.6	4.4	4.3	4.2	4.2	4.1	4.1	
Apr-24						4.3	4.3	4.2	4.2	4.1	4.1	4.0
<u>GDP Price Index</u>												
Jan-23	4.3	3.6	3.0	2.7	2.5	2.3	2.2					
Feb-23	3.5	3.3	3.0	2.7	2.6	2.4	2.3					
Mar-23	3.9	3.2	2.8	2.6	2.5	2.5	2.3					
Apr-23		3.2	3.2	2.9	2.7	2.5	2.3	2.2				
May-23		4.0	3.2	2.9	2.7	2.5	2.3	2.2				
Jun-23		4.2	3.3	2.8	2.7	2.5	2.5	2.2				
Jul-23			3.3	2.9	2.8	2.5	2.4	2.2	2.2			
Aug-23			2.2	2.7	2.6	2.5	2.3	2.3	2.3			
Sep-23			2.0	2.7	2.6	2.4	2.3	2.2	2.2			
Oct-23				2.7	2.7	2.4	2.2	2.2	2.2	2.2		
Nov-23				3.5	2.7	2.4	2.3	2.2	2.2	2.3		
Dec-23				3.6	2.7	2.4	2.3	2.2	2.2	2.2		
Jan-24					2.7	2.3	2.3	2.3	2.2	2.2	2.1	
Feb-24					1.5	2.2	2.2	2.3	2.2	2.2	2.1	
Mar-24					1.6	2.2	2.3	2.2	2.2	2.1	2.1	
Apr-24						2.2	2.4	2.3	2.2	2.2	2.1	2.2
Source and Note:												
Blue Chip Financial Forecasts, Jan 2022 through April 2024.												
Actual Yields in Bold.												

- Further, the outlook for long-term interest rates in the intermediate to long term
- are also impacted by the current Fed actions and the expectation that eventually the

- 1 Fed's monetary actions will return to more-normal levels. Long-term interest rate
2 projections are illustrated in Table CCW-5 below.

TABLE CCW-5			
<u>30-Year Treasury Bond Yield Actual Vs. Projection</u>			
<u>Description</u>	<u>Actual</u>	<u>Near-Term Projected*</u>	<u>5- to 10-Year Projected</u>
<u>2019</u>			
Q1	3.01%	3.50%	
Q2	2.78%	3.17%	3.6% - 3.8%
Q3	2.30%	2.70%	
Q4	2.30%	2.50%	3.2% - 3.7%
<u>2020</u>			
Q1	1.88%	2.57%	
Q2	1.38%	1.90%	3.0% - 3.8%
Q3	1.36%	1.87%	
Q4	1.62%	1.97%	2.8% - 3.6%
<u>2021</u>			
Q1	2.07%	2.23%	
Q2	2.26%	2.77%	3.5% - 3.9%
Q3	1.93%	2.63%	
Q4	1.95%	2.70%	3.4% - 3.8%
<u>2022</u>			
Q1	2.25%	2.87%	
Q2	3.04%	3.47%	3.8% - 3.9%
Q3	3.26%	3.63%	
Q4	3.90%	3.87%	3.9% - 4.0%
<u>2023</u>			
Q1	3.74%	3.77%	
Q2	3.80%	3.70%	3.8% - 3.9%
Q3	4.24%	3.83%	
Q4	4.58%	4.17%	4.1% - 4.2%
Source and Note:			
<i>Blue Chip Financial Forecasts</i> , January 2019 through March 2024.			
*Average of all 3 reports in Quarter.			

As outlined in Table CCW-5 above, the outlook for increases in interest rates has jumped more recently relative to 2020 and part of 2021, but is still relatively modest compared to time periods prior to the beginning of the worldwide pandemic. Indeed, relatively low capital market costs are expected to prevail at least in the near-term and out over the next five to ten years. While there is potential for some upward movement in the cost of capital, that upward movement is uncertain. In fact, as shown on Figure CCW-3 above, increases in the federal funds rate do not necessarily translate into increases in longer-term yields.

III.C. Market Sentiments and Utility Industry Outlook

Q PLEASE DESCRIBE THE CREDIT RATING OUTLOOK FOR REGULATED UTILITIES.

A All credit rating agencies see rate affordability as an important consideration in assessing utility credit, including Standard & Poor's ("S&P") and Moody's Investors Service ("Moody's") as discussed below.

In 2024, S&P updated its industry outlook to "Negative," stating the following:

Key Takeaways

- We are updating our 2024 outlook on the investor-owned North American regulated utility industry to negative.

- Given the relatively high percentage of companies with negative outlooks, we expect that 2024 will likely be the fifth consecutive year that downgrades outpace upgrades.

- The industry faces rising physical risks and high cash flow deficits that may not be sufficiently funded in a credit-supportive manner.

- Still, we expect that the utility industry will maintain a median investment-grade rating of 'BBB+'.

1 - We also expect that a smaller percentage of companies rated 'BBB' or
2 lower are more likely to implement measures to maintain or even
3 improve credit quality.³

4 Specifically, in S&P's utility report, it notes that the credit quality of the industry
5 has changed to BBB+ from an A- rating over the last few years. It notes the recently
6 increased interest rates, which are expected to stabilize and ease the pressure on
7 utilities financial performance. S&P also comments on the narrowing spread between
8 utilities authorized returns and the 10-year Treasury yield, which hinders the financial
9 performance of the industry. The credit rating agency expects continued robust capital
10 spending for utilities, projecting over \$200 billion investment in 2025. S&P believes
11 that the risks around the industry outlook include regulatory risks in responding to
12 capital spending and the practice of many companies operating with minimal financial
13 cushion from their downgrade thresholds.⁴

14 A concern for all utilities' financial health is rate affordability, which requires a
15 careful measurement of the ratemaking overall ROR to ensure that is fair to both
16 customers, and shareholders.

17 **Q HAVE CREDIT AGENCIES NOTED CONCERN ABOUT RATE AFFORDABILITY AS**
18 **A CREDIT RISK TO UTILITIES?**

19 A Yes. Credit rating agencies have been emphasizing rate affordability, maintaining
20 adequate financial coverages of debt obligations, and supporting utilities' overall
21 investment grade bond ratings.

³*S&P Global Ratings*: "Rising Risks: Outlook For North American Investor-Owned Regulated Utilities Weakens," February 14, 2024 at 1.

⁴*Id.*

1 In a recent industry report, Moody's explained that the regulated utilities' outlook
2 remains "Negative" largely due to increased pricing pressures on customers. Moody's
3 stated that it changed its outlook from "Positive" to "Negative" due to the following:

4 We have revised our outlook on the US regulated utilities sector to
5 negative from stable. We changed the outlook because of increasingly
6 challenging business and financial conditions stemming from higher
7 natural gas prices, inflation and rising interest rates. These
8 developments raise residential customer affordability issues, increasing
9 the level of uncertainty with regard to the timely recovery of costs for fuel
10 and purchased power, as well as for rate cases more broadly.⁵

11 Also, in a report published in January of 2024, S&P specifically mentioned
12 commodity price volatility, in combination with significant increases in capital
13 investments, driving utility rate increases which may strain affordability concerns.⁶

14 Finally, Fitch opined that the regulated utilities' outlook is deteriorating due to
15 elevated capital expenditures that put pressure on credit metrics. Fitch also notes the
16 bill affordability concerns for ratepayers, and regulators' ability to balance the rate
17 requests with increasing customer bills.

18 Specifically, Fitch states:

19 Fitch Ratings' deteriorating outlook for the North American Utilities,
20 Power & Gas sector reflects continuing macroeconomic headwinds and
21 elevated capex that are putting pressure on credit metrics in the high-
22 cost funding environment. Bill affordability concerns for ratepayers
23 continue to persist despite the pull back in natural gas prices and
24 inflationary pressures. Fitch expects utility capex to grow by double
25 digits in 2024, underpinned by investments needed to make the electric
26 infrastructure more resilient against extreme weather events and to
27 accommodate renewable generation, including distributed sources.
28 Rate case outcomes are key to watch as regulators balance more rate
29 requests with increases in customer bills. Authorized ROEs could prove
30 to be sticky despite an increase in cost of capital. Higher weather-
31 normalized retail electricity sales, driven by datacenter growth and
32 onshoring of manufacturing activities, and tax transferability provisions
33 of the Inflation Reduction Act could somewhat offset headwinds to

⁵Moody's *Investors Service Outlook*: "Regulated Electric and Gas Utilities – US 2023 outlook negative due to higher natural gas prices, inflation and rising interest rates," November 10, 2022 at 1. (emphasis added).

⁶S&P *Global Ratings*: "Industry Credit Outlook 2024: North America Regulated Utilities," January 9, 2024, at 8.

1 utilities. Ongoing management actions to sell assets and issue equity,
2 in some cases, is supportive of parent companies' ratings. Within Fitch's
3 coverage, 90% of ratings hold Stable Rating Outlooks. We expect
4 limited rating movement in 2024. The number of upgrades in 2023 so
5 far exceeds the number of downgrades, and is driven by positive rating
6 actions on several parent holding companies and their regulated
7 subsidiaries.⁷

8 As outlined by Moody's, S&P and Fitch above, credit analysts are focusing on
9 rate affordability as an important factor needed to support strong credit standing.
10 Customers must be able to afford to pay their utility bills in order for utilities to maintain
11 their financial integrity and strong investment grade credit standing. For this reason,
12 this Commission should carefully assess the reasonableness of cost of service in this
13 proceeding, including an appropriate overall ROR necessitated by a reasonably
14 cost-effective balanced ratemaking capital structure, and a return on equity that
15 represents fair compensation but also maintains competitive, just and reasonable rates.

16 **III.D. Additional Remarks**

17 **Q IN LIGHT OF HIGHER LEVELS OF INFLATION, AND EXPECTATIONS OF HIGHER**
18 **INTEREST RATES, HOW HAS THE MARKET PERCEIVED UTILITIES AS**
19 **INVESTMENT OPTIONS?**

20 **A** In 2023, the utility sector underperformed the S&P 500 and has continued to do so in
21 2024. This is presented below in Figure CCW-4. However, it should be noted that the
22 performance of the S&P 500 has largely been driven by a handful of "mega cap"
23 companies because the S&P 500 is a market capitalization weighted index (meaning
24 the higher the market capitalization a company has, the more influence it has on the

⁷*FitchRatings*. "North American Utilities, Power & Gas Outlook 2024," December 6, 2023 at 1.
(emphasis added)

index's performance). For example, in the S&P Dow Jones Indices report "U.S. Equity Market Attributes June 2023," it is noted that:

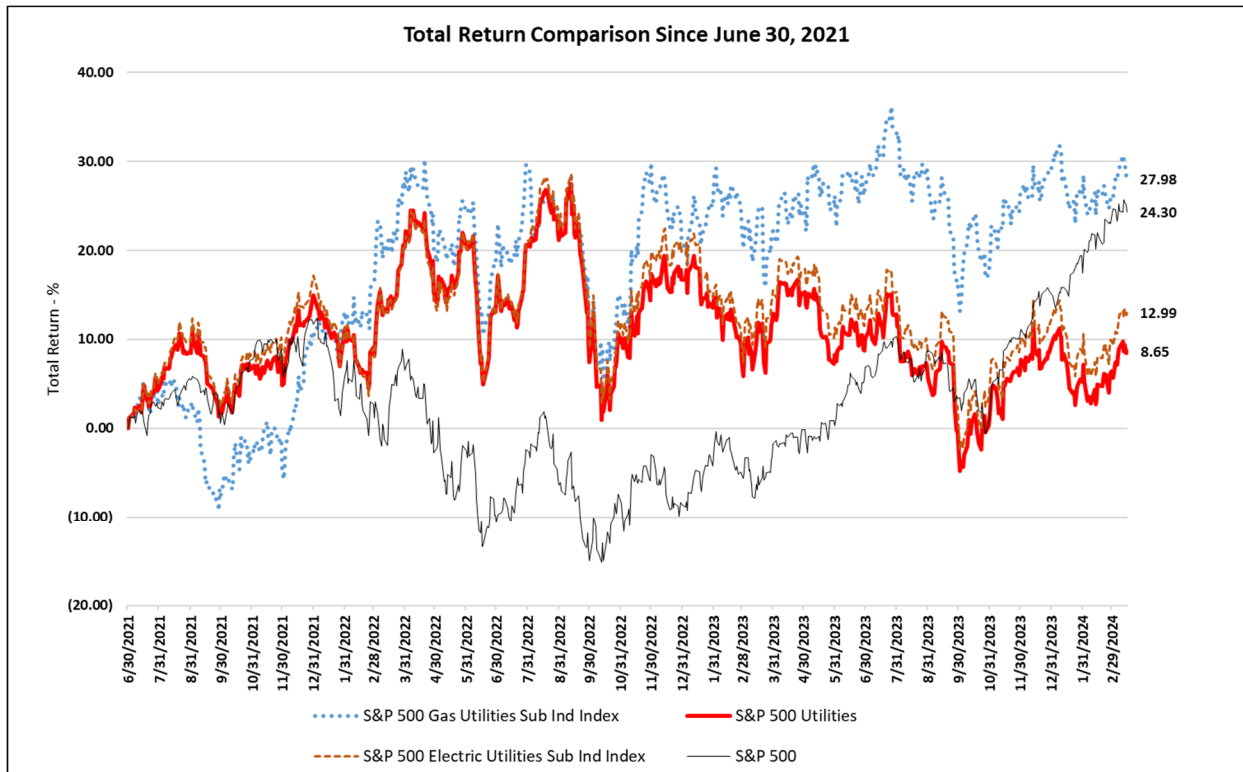
For June, the S&P 500 total return was up 6.61%, with broad contributions across issues, compared to previous months when high-market-value issues dominated the market; underlying breadth (and contributions) remained negative. That dominance still exists, as the index's total return was up 16.89% YTD, but without the top 44 issues, the index would be negative YTD, though that 44 was 8 in May. Apple (AAPL) and Tesla (TSLA) were still on top for the month, with Alphabet (GOOG/L) (then Salesforce [CRM]) the largest negative contributor for the month.

Meanwhile, the positive contributions were broad for June, even though they remain highly concentrated YTD. The index is still top heavy, with the top 10 issues accounting for 30.5% of the market value (below 20% is more typical). Of note to the top of the market, semiconductor issue NVIDIA (NVDA) joined the USD 1 trillion in market value club this month, as Apple (which set a record at 7.72% of the index) became the first public issue to trade above USD 3 trillion in market value; the other three members of the club are Microsoft (MSFT), Alphabet and Amazon (AMZN).⁸

Notwithstanding its recent underperformance relative to the S&P 500, the utility industry has been able to deliver generally positive and relatively stable returns during a period of elevated inflation, rising interest rates, and uncertainty because of geopolitical events around the world.

⁸<https://www.spglobal.com/spdji/en/documents/commentary/market-attributes-us-equities-202306.pdf>

Figure CCW-4



IV. RETURN ON EQUITY

Q PLEASE DESCRIBE WHAT IS MEANT BY A “UTILITY’S COST OF COMMON EQUITY.”

A A utility’s cost of common equity is the expected return that investors require on an investment in the utility. Investors expect to earn their required return from receiving dividends and through stock price appreciation.

Q PLEASE DESCRIBE THE FRAMEWORK FOR DETERMINING A REGULATED UTILITY’S COST OF COMMON EQUITY.

A In general, determining a fair cost of common equity for a regulated utility has been framed by two hallmark decisions of the U.S. Supreme Court: Bluefield Water Works

1 & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) and Fed.
2 Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944). In these decisions, the
3 Supreme Court found that just compensation depends on many circumstances and
4 must be determined by fair and enlightened judgments based on relevant facts. The
5 Court also found that a utility is entitled to such rates as would permit it to earn a return
6 on a property devoted to the convenience of the public that is generally consistent with
7 the same returns available in other investments of corresponding risk. The Court
8 continued that the utility has "no constitutional rights to profits" such as those "realized
9 or anticipated in highly profitable enterprises or speculative ventures,"⁹ and defined the
10 ratepayer/investor balance as follows:

11 The return should be reasonably sufficient to assure confidence in the
12 financial soundness of the utility and should be adequate, under efficient
13 and economical management, to maintain and support its credit and
14 enable it to raise the money necessary for the proper discharge of its
15 public duties.¹⁰

16 As such, a fair ROR is based on the expectation that the utility costs reflect
17 efficient and economical management, and the return will support its credit standing
18 and access to capital, but the return will not be in excess of this level. Utility rates that
19 are consistent with these standards will be just and reasonable, and compensation to
20 the utility will be fair and support financial integrity and credit-standing, under economic
21 management of the utility.

22 **Q PLEASE DESCRIBE THE PROCESS YOU HAVE USED TO ESTIMATE DTE'S**
23 **COST OF COMMON EQUITY.**

24 **A**First, I assessed the market's assessment of DTE's risk. Then, I developed a proxy
25 group of publicly-traded utility companies that have similar risks and characteristics to

⁹*Bluefield*, 262 U.S. at 692-93.

¹⁰*Id.* at 693 (emphasis added).

DTE and compared potential differences in risks. I then performed several models based on financial theory to estimate DTE's cost of common equity. These models are: (1) a constant growth Discounted Cash Flow ("DCF") model using consensus analysts' growth rate projections; (2) a constant growth DCF model using sustainable growth rate estimates; (3) a multi-stage growth DCF model; and (4) a Capital Asset Pricing Model ("CAPM").

IV.A DTE's Investment Risk

Q PLEASE DESCRIBE THE MARKET'S ASSESSMENT OF DTE'S INVESTMENT RISK.

A The market's assessment of a company's investment risk is generally described by credit rating analysts' reports. DTE's current credit ratings are A- and A3 from S&P and Moody's, respectively.¹¹ DTE currently has a "stable" outlook from S&P and Moody's. In its September 2023 report covering DTE, S&P stated as follows:

Business Risk

Our assessment of DTEG's business risk profile primarily reflects its very low-risk, regulated gas utility operations, very large customer base, and effective regulatory risk management. DTEG's utility operations provide indispensable services that are strategically important to economies, feature material barriers to entry, and essentially operate as a monopoly insulated from market challenges. The company benefits from the strength of the regulatory support in Michigan by managing its costs, filing forward-looking rate cases, and using various riders that enhance its cash flow predictability. DTEG also operates under a revenue decoupling mechanism that supports cash flow stability. Somewhat offsetting these benefits is DTEG's limited geographic and regulatory diversity, given that it only operates in Michigan. However, we believe this is mitigated by the utility's large, diverse base of 1.3 million customers and constructive regulation; the predominance of residential and commercial customers limits its susceptibility to economic cyclicalities, further supporting our expectation for stable cash flows. Overall, we assess DTEG in the upper-half of its business risk profile category compared to peers.

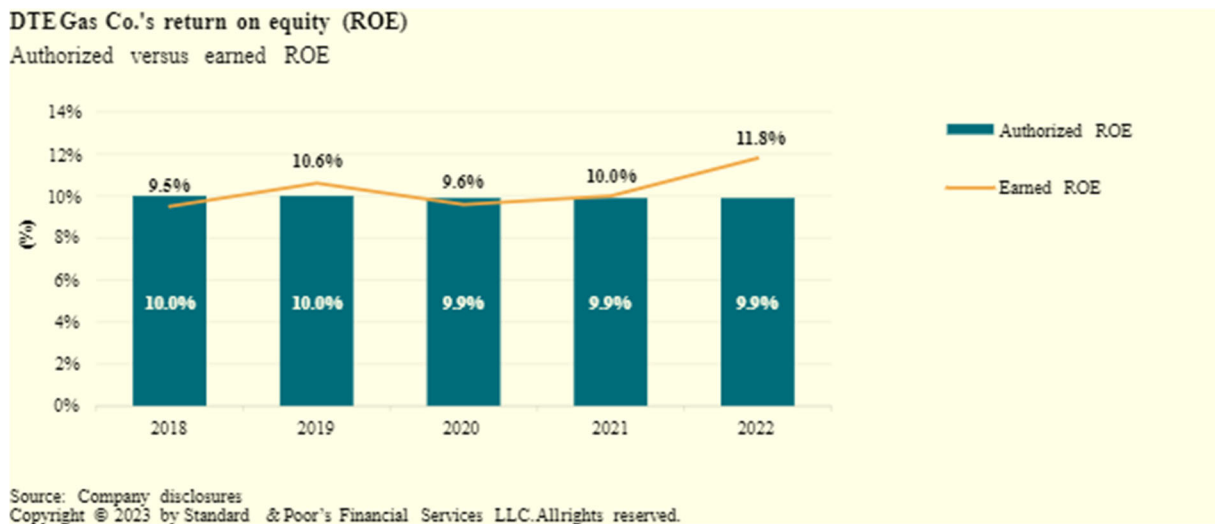
¹¹S&P Capital IQ, accessed on April 5, 2024.

Financial Risk

We assess DTEG's financial risk profile using our low volatility table rather than the benchmark tables we use for typical corporate issuers. This is due to its low-risk, regulated utility business model and effective management of regulatory risk compared with its peers. Our assessment also reflects our stand-alone base case, which includes S&P Global Ratings-adjusted FFO to debt of about 17%-20% through our forecast period and a need for external funding due to consistently negative discretionary cash flow (after accounting for the utility's capital spending and dividend payments). Overall, our base case assumes that DTEG will continue to effectively manage regulatory risk, with consistent and timely recovery of its capital expenditure and costs such that its financial risk profile does not materially deviate from our base case expectations.¹²

Q DOES S&P ACKNOWLEDGE DTE'S ABILITY TO EARN AT OR ABOVE ITS AUTHORIZED ROE?

A Yes, in the same September 2023 report cited above, S&P includes the following chart:



This chart indicates that the Company has, on balance, over-earned its allowed ROE over the last several years. This is consistent with the Company's historical test year figures showing that it has over-earned its allowed rate of return by a figure of

¹²S&P Global Ratings, RatingsDirect, DTE Gas Co., September 25, 2023.

approximately \$35.7 million on a revenue requirement basis.¹³ The Commission should carefully consider these data when determining a fair and reasonable ROE for DTE.

IV.B. DTE's Proposed Capital Structure

Q WHAT IS DTE'S PROPOSED CAPITAL STRUCTURE?

A DTE's proposed capital structure is summarized in Table CCW-6 below:

Table CCW-6	
<u>Investor-Supplied Capital Structure</u>	
<u>Description</u>	<u>Weight</u>
Debt	48.50%
Common Equity	<u>51.50%</u>
Total	100.00%

Q DO YOU HAVE ANY COMMENTS ON DTE'S PROPOSED CAPITAL STRUCTURE?

A Yes. As I will discuss later, DTE's proposed equity ratio of 51.50% significantly exceeds the equity ratio for the proxy group used to estimate the cost of equity for DTE. As shown on Exhibit AB-5, the proxy group has an average common equity ratio of 44.4% (including short-term debt) and 50.0% (excluding short-term debt).

Further, the Company's request flies in the face of this Commission's previous Order in U-20940 where it authorized an equity ratio of 51.0%. In that same Order, the Commission stated that authorizing an equity ratio of 51%, instead of the Company's requested 52%, represented "a reasonable transition to a more balanced capital structure". The Company's requested equity ratio of 51.5% moves in the opposite direction of the Commission's explicit directive to move toward a capital structure

¹³Exhibit A-1 Schedule A1.

1 consisting of 50% equity.¹⁴ Further, the Commission's Order in U-20940 makes
2 reference to explicit directives it provided in the August 20, 2020 Order in U-20642 as
3 well as the September 13, 2018 Order in U-18999, directing the Company to move
4 towards a more balanced capital structure.¹⁵

5 This Commission has recognized the need for DTE to move toward a balanced
6 capital structure, and has provided the Company several directives to do so.
7 Nevertheless, DTE ignores these explicit directives and requests an equity ratio
8 exceeding what the Commission has directed it to do.

9 **Q ARE YOU AWARE OF OTHER REGULATORY COMMISSIONS RECOGNIZING THE**
10 **NEED TO ALIGN THE COST OF EQUITY WITH THE CAPITAL STRUCTURE?**

11 A Yes. In a recent Order, the Arkansas Public Service Commission imputed the capital
12 structure of Southwestern Electric Power Company ("SWEPCO") to be more in-line
13 with the comparable companies used to estimate the cost of equity.¹⁶ The adjustment
14 was to recognize that there must be *congruence* between the cost of equity and the
15 capital structure. Specifically, the Order states as follows:

16 Consistent with our ruling in Order No. 10 of Docket No. 06-101-U, the
17 Commission holds that there should be congruence between the
18 estimated cost of equity and the [debt-to-equity] ratio, whereby a lower
19 [debt-to-equity] ratio decreases financial risk and decreases the cost of
20 equity. The evidence of record supports imputing the average capital
21 structure of companies with comparable risk to SWEPCO for the
22 purposes of determining SWEPCO's overall cost of capital.¹⁷

23 As I described above, and in more detail below, my proxy group in this case
24 has an average common equity ratio of 44.4% (including short-term debt) and 50.0%
25 (excluding short-term debt) as calculated by S&P Global Market Intelligence and *Value*

¹⁴MPSC Case No. U-20940, Order at 77.

¹⁵*Id.* at 76.

¹⁶APSC Docket No. 21-170-U, Doc. No. 323, May 23, 2022, Order No. 14.

¹⁷*Id.* at 25.

1 *Line*, respectively. In this case the Company's proposed ratemaking equity ratio of
2 51.50% (excluding short-term debt) exceeds that of the proxy group's equity ratio and
3 is not reasonable for ratemaking purposes.

4 **Q ARE YOU RECOMMENDING AN ADJUSTMENT BE MADE TO DTE'S PROPOSED**
5 **CAPITAL STRUCTURE?**

6 A Yes. The Company has not reasonably demonstrated a need to be awarded a common
7 equity ratio well in excess of 50.0%. A common equity ratio of 50.0% is consistent with
8 this Commission's stated preference for a balanced capital structure consisting of
9 permanent equity ratios of 50% in previous rate cases. As such, I recommend this
10 Commission authorize DTE an equity ratio of 50.0%. Should this Commission
11 authorize DTE its requested equity ratio of 51.50%, an ROE in the lower half of my
12 recommended range (i.e. 9.1% to 9.45%) would be warranted.

13 **IV.C. Development of Proxy Group**

14 **Q PLEASE BRIEFLY DESCRIBE WHY A PROXY GROUP IS NEEDED IN**
15 **ESTIMATING THE COST OF EQUITY.**

16 A There are a few reasons why a proxy group is needed to estimate the cost of equity.
17 As an initial matter, to be consistent with the *Hope* and *Bluefield* standards, as
18 described above, the allowed return should be commensurate with returns on
19 investments in other firms of comparable risk. A proxy group of similarly situated
20 companies of comparable risk is needed to assess the Company's proposal under this
21 standard.

22 Even if DTE were a publicly-traded company whose securities could be used to
23 estimate its cost of equity, there exists the potential for certain errors and biases which

1 would make the reliance on a single estimate undesirable and potentially less accurate.
2 A proxy group of comparable risk companies adds reliability to the estimates by
3 mitigating the potential for bias that may be introduced by measurement errors of model
4 inputs.

5 **Q PLEASE DESCRIBE HOW YOU IDENTIFIED A PROXY UTILITY GROUP THAT**
6 **COULD BE USED TO ESTIMATE DTE'S CURRENT MARKET COST OF EQUITY.**

7 A I relied on the same proxy group developed by DTE's witness, Dr. Villadsen, with six
8 exceptions. First, I removed Chesapeake Utilities for not being a rated entity by S&P or
9 Moody's. Not only is Chesapeake Utilities not a rated entity, neither are any of its utility
10 subsidiaries. Credit ratings are a critical, independent assessment of total risk, and
11 one of the most cited screening criteria used by rate of return analysts around the
12 country.

13 Second, I removed NiSource Inc. and Southwest Gas Holdings for being parties
14 to significant merger and acquisition ("M&A") activities. On June 20, 2023, NiSource
15 announced a deal to sell Northern Indiana Public Service Company, a vertically
16 integrated electric utility in Indiana, for \$2.15 billion, which represents more than 10%
17 of its market capitalization. The deal closed on January 2, 2024. Similarly, Southwest
18 Gas Holdings closed a deal to sell MountainWest Pipelines for \$1.5 billion on February
19 14, 2023. That deal represents about 37% of Southwest Gas' market capitalization.
20 Importantly, Dr. Villadsen kept NiSource and Southwest Gas in her proxy group even
21 though they were parties to significant M&A transactions during the study period of her
22 analysis even though M&A activity was a screening criterion she employed to develop
23 her proxy group.¹⁸ She makes note that Chesapeake Utilities entered into an M&A

¹⁸Villadsen Direct at 29.

1 transaction after her study period, however, she makes no mention of the M&A
2 transactions of NiSource or Southwest Gas.

3 Finally, I removed Artesian Resources Corp., Global Water Resources, and
4 York Water Company from the proxy group as they are not listed entities of the Water
5 Utility Industry in the *Value Line Investment Survey*. Companies not in the *Value Line*
6 *Investment Survey* are not covered by a Value Line analyst. Any reported growth rates
7 for Companies no longer in the *Value Line Investment Survey* are the most recently
8 reported growth rates from when that Company was in the *Value Line Investment*
9 *Survey*.

10 **Q HOW DOES THE INVESTMENT RISK OF DTE COMPARE TO THAT OF THE**
11 **PROXY GROUP?**

12 A As shown on my Exhibit AB-5, the full proxy group has average credit ratings of A and
13 A3 from S&P and Moody's, respectively. The full proxy group's average rating of A
14 from S&P is one notch higher than rating of A- from S&P. The full proxy group's
15 average rating of A3 from Moody's is identical to DTE's rating of A3. The Gas group
16 has average ratings of A and A3 from S&P and Moody's, respectively. The Gas group's
17 rating of A from S&P is one notch higher than DTE's, while the Gas group's rating of
18 A3 from Moody's is identical to the rating assigned to DTE. The Water group has
19 average ratings of A and Baa1 from S&P and Moody's, respectively. The Water group's
20 rating of A from S&P is one notch higher than DTE's, while the Water group's rating of
21 Baa1 is one notch lower than DTE's rating of A3. On balance, DTE's ratings are
22 comparable to those of the proxy companies.

23 As shown on the same exhibit, the proxy group has an average common equity
24 ratio of 44.4% (including short-term debt) and 50.0% (excluding short-term debt) as

calculated by S&P Global Market Intelligence and *Value Line*, respectively. DTE's requested common equity ratio of 51.50% significantly exceeds the proxy group's equity ratio as described above. While my recommended ratemaking equity ratio of 50.0% is still higher than that of the proxy group, it provides a more comparable basis to estimate the cost of equity with than the equity ratio requested by DTE. As such, I believe my proxy group is reasonably comparable to DTE.

IV.D. DCF Model

Q PLEASE DESCRIBE THE DCF MODEL.

A The DCF model posits that a stock price equals the sum of the present value of expected future cash flows discounted at the investor's required ROR or cost of capital. This model is expressed mathematically as follows:

$$P_0 = \frac{D_1}{(1+K)^1} + \frac{D_2}{(1+K)^2} + \dots + \frac{D_\infty}{(1+K)^\infty} \quad (\text{Equation 1})$$

P_0 = Current stock price
 D = Dividends in periods 1 - ∞
 K = Investor's required return

This model can be rearranged in order to estimate the discount rate or investor-required return, known as "K." If it is reasonable to assume that earnings and dividends will grow at a constant rate, then Equation 1 can be rearranged as follows:

$$K = D_1/P_0 + G \quad (\text{Equation 2})$$

K = Investor's required return
 D_1 = Dividend in first year
 P_0 = Current stock price
 G = Expected constant dividend growth rate

Equation 2 is referred to as the annual "constant growth" DCF model.

1 **Q PLEASE DESCRIBE THE INPUTS TO YOUR CONSTANT GROWTH DCF MODEL.**

2 A As shown in Equation 2 above, the DCF model requires a current stock price, the
3 expected dividend, and the expected growth rate in dividends.

4 **Q WHAT STOCK PRICE HAVE YOU RELIED ON IN YOUR CONSTANT GROWTH**
5 **DCF MODEL?**

6 A I relied on the average of the weekly high and low stock prices of the utilities in the
7 proxy group over a 13-week period ending on April 5, 2024. An average stock price is
8 less susceptible to market price variations than a price at a single point in time.
9 Therefore, an average stock price is less susceptible to aberrant market price
10 movements, which may not reflect the stock's long-term value.

11 **Q WHAT DIVIDEND DID YOU USE IN YOUR CONSTANT GROWTH DCF MODEL?**

12 A I used each proxy company's most recently paid quarterly dividend as reported in *Value*
13 *Line*.¹⁹ This dividend was annualized (multiplied by 4) and adjusted for next year's
14 growth to produce the D_1 factor for use in Equation 2 above. In other words, I calculate
15 D_1 by multiplying the annualized dividend (D_0) by $(1+G)$.

16 **Q WHAT DIVIDEND GROWTH RATES HAVE YOU USED IN YOUR CONSTANT**
17 **GROWTH DCF MODEL?**

18 A There are several methods that can be used to estimate the expected growth in
19 dividends. However, regardless of the method, for purposes of determining the
20 market-required return on common equity, one must attempt to estimate investors'

¹⁹*The Value Line Investment Survey.*

1 expectations about what the dividend, or earnings growth rate, will be, and not what an
2 individual investor or analyst may use to make individual investment decisions.

3 As predictors of future returns, securities analysts' growth estimates have been
4 shown to be more accurate than growth rates derived from historical data.²⁰ That is,
5 assuming the market generally makes rational investment decisions, analysts' growth
6 projections are more likely to influence investors' decisions, which are captured in
7 observable stock prices, than growth rates derived only from historical data.

8 For my constant growth DCF analysis, I have relied on a consensus, or mean,
9 of professional securities analysts' earnings growth estimates as a proxy for investors'
10 dividend growth rate expectations. I used the average of analysts' growth rate
11 estimates from three sources: Zacks, S&P Capital IQ Market Intelligence ("MI"), and
12 Yahoo! Finance. All such projections were available on April 5, 2024, and all were
13 reported online.²¹

14 Each growth rate projection is based on a survey of independent securities
15 analysts. There is no clear evidence whether a particular analyst is most influential on
16 general market investors. Therefore, a single analyst's projection does not predict
17 investor outlooks as reliably as does a consensus of market analysts' projections. The
18 consensus of estimates is a simple arithmetic average, or mean, of surveyed analysts'
19 earnings growth forecasts. A simple average of the growth forecasts gives equal
20 weight to all surveyed analysts' projections. Therefore, a simple average, or arithmetic
21 mean, of analysts' forecasts is a good proxy for investor expectations.

22 The growth rates I used in my DCF analysis are shown in Exhibit AB-6. The
23 average growth rate for my proxy group is 6.27% and a median growth rate of 6.43%.

²⁰See, e.g., David Gordon, Myron Gordon, and Lawrence Gould, Choice Among Methods of Estimating Share Yield, The Journal of Portfolio Management, Spring 1989.

²¹www.zacks.com; <https://finance.yahoo.com>; and <https://www.capitaliq.spglobal.com/>.

1 **Q WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF MODEL?**

2 A As shown in Exhibit AB-7, page 1, the average and median constant growth DCF
3 returns for my proxy group for the 13-week analysis are 9.84% and 10.26%,
4 respectively.

5 **Q ARE THERE LIMITATIONS OF THE CONSTANT GROWTH DCF ANALYSIS?**

6 A Yes. The constant growth DCF analysis for my proxy group is based on a group
7 average long-term growth rate of 6.27%. The three- to five-year growth rates are more
8 than 50% higher than the long-term projected GDP growth rate of 4.14%, described
9 below. In my professional opinion, I do not consider a 6.27% growth rate to be a
10 realistic forward-looking projection. As I explain in detail below, the consensus of
11 research on the subject finds a utility's growth rate cannot exceed the growth rate of
12 the economy in which it provides services in perpetuity, which is the time period
13 assumed by the DCF model.

14 **Q HOW DID YOU IDENTIFY THE LONG-TERM PROJECTED GDP GROWTH RATE?**

15 A Although there may be short-term peaks, the long-term sustainable growth rate for a
16 utility stock cannot exceed the growth rate of the economy in which it sells its goods
17 and services. The long-term maximum sustainable growth rate for a utility investment
18 is limited by the projected long-term GDP growth rate, as that reflects the projected
19 long-term growth rate of the economy as a whole. *Blue Chip Financial Forecasts*
20 projects that over the next 5 and 10 years, the U.S. nominal GDP will grow at an annual

1 rate of approximately 4.14%.²² As such, the average nominal growth rate over the next
2 10 years is around 4.14%, which I believe is a reasonable proxy of long-term growth.

3 Later in this testimony, I discuss academic and investment-practitioner support
4 for using the projected long-term GDP growth outlook as a maximum long-term growth
5 rate projection. Using the long-term GDP growth rate as a conservative projection for
6 the maximum growth rate is logical, and is generally consistent with academic and
7 economic-practitioner accepted practices.

8 **IV.E. Sustainable Growth DCF**

9 **Q PLEASE DESCRIBE WHAT THE SUSTAINABLE GROWTH DCF METHOD IS AND**
10 **HOW YOU ESTIMATED A SUSTAINABLE GROWTH RATE FOR YOUR**
11 **SUSTAINABLE GROWTH DCF MODEL.**

12 A The sustainable growth rate, also referred to as the internal growth rate, is determined
13 by the proportion of the utility's earnings that is retained and reinvested in its plant and
14 equipment. These reinvested earnings enhance the earnings base, also known as the
15 rate base. The earnings grow as the plant, funded by the reinvested earnings, is put
16 into operation, allowing the utility to receive its authorized return on the additional rate
17 base investment.

18 The internal growth approach is linked to the percentage of earnings retained
19 within the company, as opposed to being paid out as dividends. The earnings retention
20 ratio is calculated as 1 minus the dividend payout ratio. As the payout ratio decreases,
21 the retention ratio increases, leading to stronger growth as the company funds more
22 investments using retained earnings.

²²Blue Chip Economic Indicators, March 11, 2024 at page 14.

1 The payout ratios of the proxy group are shown in my Exhibit AB-8. These
2 dividend-payout ratios and earnings-retention ratios can then be used to develop a
3 long-term growth rate driven by earnings retention.

4 The data used to estimate the long-term sustainable growth rate is based on
5 the Company's current market-to-book ratio and on *Value Line's* three- to five-year
6 projections of earnings, dividends, earned returns on book equity, and stock issuances.

7 As shown in Exhibit AB-9, the average and median sustainable growth rates for
8 the proxy group using this internal growth rate model are 5.27% and 4.53%,
9 respectively.

10 **Q WHAT IS THE DCF ESTIMATE USING THESE SUSTAINABLE GROWTH RATES?**

11 A A DCF estimate based on these sustainable growth rates is developed in Exhibit AB-10.
12 As shown there, and using the same formula in Equation 2 above, a sustainable growth
13 DCF analysis produces proxy group average and median DCF results for the 13-week
14 period of 8.80% and 8.80%, respectively.

15 **IV.F. Multi-Stage Growth DCF Model**

16 **Q HAVE YOU CONDUCTED ANY OTHER DCF STUDIES?**

17 A Yes. As previously noted, the DCF model is intended to represent the present value
18 of an endless series of future cash flows. Nevertheless, the initial constant growth DCF
19 that I created is based on analyst growth-rate projections, providing a plausible
20 representation of rational investment expectations over the next three-to-five years.
21 The limitation of this constant growth DCF model is that it cannot reflect a reasonable
22 expectation of a shift in growth from a high or low short-term rate to a rate that aligns
23 more with long-term sustainable growth. To accommodate changing growth

1 expectations, I conducted a multi-stage DCF analysis that reflects growth rate change
2 over time.

3 **Q WHY DO YOU BELIEVE GROWTH RATES CAN CHANGE OVER TIME?**

4 A The growth rate projections by analysts for the next three-to-five years are subject to
5 change as the outlook for utility earnings-growth evolves. Utility companies experience
6 fluctuations in their investment cycles. When these companies are undertaking
7 substantial investments, the growth of their rate base accelerates, leading to an
8 increase in earnings growth. However, once a major construction cycle reaches
9 completion or plateaus, the growth in the utility rate base slows down, and its earnings
10 growth rate declines, from an abnormally high three-to-five-year rate, to a lower,
11 sustainable growth rate.

12 As construction cycles become longer in duration, even with an aggressive
13 construction plan, the growth rate of the utility will naturally slow due to a decrease in
14 rate base growth, as the utility has limited human and capital resources to expand its
15 construction activities. Therefore, the three-to-five-year growth rate projection should
16 be viewed as a long-term sustainable growth rate, but not without considering the
17 current market conditions, industry trends, and determining whether the
18 three-to-five-year growth outlook is feasible and sustainable.

19 **Q PLEASE DESCRIBE YOUR MULTI-STAGE DCF MODEL.**

20 A The multi-stage DCF model reflects the possibility of non-constant growth for a
21 company over time. The multi-stage DCF model reflects three growth periods: (1) a
22 short-term growth period consisting of the first five years; (2) a transition period,

1 consisting of the next five years (6 through 10); and (3) a long-term growth period
2 starting in year 11 and extending into perpetuity.

3 For the short-term growth period, I relied on the consensus of analysts' growth
4 projections described above in relationship to my constant growth DCF model. For the
5 transition period, the growth rates were reduced or increased by an equal factor
6 reflecting the difference between the analysts' growth rates and the long-term
7 sustainable growth rate. For the long-term growth period, I assumed each company's
8 growth would converge to the maximum sustainable long-term growth rate.

9 **Q WHY IS THE GDP GROWTH PROJECTION A REASONABLE PROXY FOR THE**
10 **MAXIMUM SUSTAINABLE LONG-TERM GROWTH RATE?**

11 A Utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the
12 economy in which they sell services. A utilities' earnings and dividend growth is created
13 by increased utility investment in its rate base. Examples of what can drive such
14 investment are: service area economic growth, system reliability upgrades, or state and
15 federal green energy initiatives. As such, nominal GDP growth is a reasonable upper
16 limit for utility sales growth, rate base growth, and earnings growth in the long-run.
17 Therefore, the U.S. GDP nominal growth rate is a conservative proxy for the highest
18 sustainable long-term growth rate of a utility.

Q IS THERE RESEARCH THAT SUPPORTS YOUR POSITION THAT, OVER THE LONG TERM, A COMPANY’S EARNINGS AND DIVIDENDS CANNOT GROW AT A RATE GREATER THAN THE RATE OF GROWTH OF THE U.S. GDP?

A Yes. This concept is supported in published analyst literature and academic work. Specifically, in a textbook titled “Fundamentals of Financial Management,” published by Eugene Brigham and Joel F. Houston, the authors state as follows:

The constant growth model is most appropriate for mature companies with a stable history of growth and stable future expectations. Expected growth rates vary somewhat among companies, but dividends for mature firms are often expected to grow in the future at about the same rate as nominal gross domestic product (real GDP plus inflation).²³

The use of the economic growth rate is also supported by investment practitioners as outlined as follows:

Estimating Growth Rates

One of the advantages of a three-stage discounted cash flow model is that it fits with life cycle theories in regards to company growth. In these theories, companies are assumed to have a life cycle with varying growth characteristics. Typically, the potential for extraordinary growth in the near term eases over time and eventually growth slows to a more stable level.

* * *

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.²⁴

²³*Fundamentals of Financial Management*, Eugene F. Brigham and Joel F. Houston, Eleventh Edition 2007, Thomson South-Western, a Division of Thomson Corporation at 298 (emphasis added).

²⁴Morningstar, Inc., Ibbotson SBBI 2013 Valuation Yearbook at 51 and 52.

1 **Q HOW DID YOU DETERMINE A LONG-TERM GROWTH RATE THAT REFLECTS**
2 **THE CURRENT CONSENSUS OF INDEPENDENT MARKET PARTICIPANTS?**

3 A I relied on the consensus of long-term GDP growth projections as projected by
4 independent economists. *Blue Chip Financial Forecasts* publishes the consensus for
5 GDP growth projections twice a year. These projections reflect current outlooks for
6 GDP and are likely to be influential on investors' expectations of future growth outlooks.
7 The consensus of projected GDP growth is about 4.14% over the next 10 years.²⁵

8 **Q DO YOU CONSIDER OTHER SOURCES OF PROJECTED LONG-TERM GDP**
9 **GROWTH?**

10 A Yes, and these alternative sources corroborate the consensus analysts' projections I
11 relied on. Several projections are shown in Table CCW-7 below.

²⁵Blue Chip Economic Indicators, March 11, 2024 at page 14.

TABLE CCW-7

GDP Forecasts

<u>Source</u>	<u>Projected Period</u>	<u>Real GDP</u>	<u>Inflation</u>	<u>Nominal GDP</u>
Blue Chip Economic Indicators ¹	5-10 Yrs	1.9%	2.2%	4.1%
EIA - Annual Energy Outlook ²	27 Yrs	1.9%	2.3%	4.3%
Congressional Budget Office ³	30 Yrs	1.7%	2.0%	3.8%
Moody's Analytics ⁴	31 Yrs	2.0%	2.1%	4.1%
Social Security Administration ⁵	77 Yrs	1.6%	2.4%	4.1%
Economist Intelligence Unit ⁶	31 Yrs	1.7%	2.2%	3.9%

Sources:

¹Blue Chip Economic Indicators, March 11, 2024 at 14.

²U.S. Energy Information Administration (EIA),
Annual Energy Outlook 2023, September, 2022.

³Congressional Budget Office, Long-Term Budget Outlook, June 28, 2023.

⁴Moody's Analytics Forecast, last updated January 8, 2024.

⁵Social Security Administration, "2023 OASDI Trustees Report,"
Table VI.G6. March 31, 2023.

⁶S&P MI, Economist Intelligence Unit, downloaded on January 18, 2024.

As shown in the table above, the real GDP and the inflation fall in the range of 1.6% to 2.0% and 2.0% to 2.4%, respectively. This results in a nominal GDP in the range of 3.8% to 4.3%. Therefore, the nominal GDP growth projections made by these independent sources support my use of 4.14% as a reasonable estimate of market participants' expectations for long-term GDP growth. The real GDP and nominal GDP growth projections made by these independent sources support my use of 4.14% as a reasonable estimate of market participants' expectations for long-term GDP growth.

Q WHAT STOCK PRICE, DIVIDEND, AND GROWTH RATES DID YOU USE IN YOUR MULTI-STAGE DCF ANALYSIS?

A I relied on the same 13-week average stock prices and the most recent quarterly dividend payment data discussed above. For the first stage, I used the consensus of analysts' growth rate projections discussed above in my constant growth DCF model. The first stage covers the first five years, consistent with the time horizon of the securities analysts' growth rate projections. The second stage, or transition stage, begins in year 6 and extends through year 10. The second stage growth transitions the growth rate from the first stage to the third stage using a straight linear trend. For the third stage, or long-term sustainable growth stage, starting in year 11, I used a 4.14% long-term sustainable growth rate based on the consensus of economists' long-term projected nominal GDP growth rate.

Q WHAT ARE THE RESULTS OF YOUR MULTI-STAGE DCF MODEL?

A As shown in Exhibit AB-11, the average and median DCF ROEs for my proxy group using the 13-week average stock price are 8.09% and 7.69%, respectively.

Q PLEASE SUMMARIZE THE RESULTS FROM YOUR DCF ANALYSES.

A The DCF results are summarized in Table CCW-8 below. As described above, the results of the constant growth DCF using analysts' growth rates assume an average long-term growth rate of 6.27%, which is approximately 54% higher than the long-term projected GDP growth rate of 4.14%. This is an unsustainable assumption, and likely leads to an overstatement in the cost of equity for a low-risk regulated utility. As such, it is my opinion that more weight should be given to the sustainable growth and multi-stage models of the DCF.

Table CCW-8		
<u>Summary of DCF Results</u>		
<u>Description</u>	<u>Proxy Group</u>	
	<u>Mean</u>	<u>Median</u>
Constant Growth DCF Model (Analysts' Growth)	9.84%	10.26%
Constant Growth DCF Model (Sustainable Growth)	8.80%	8.80%
Multi-Stage DCF Model	<u>8.09%</u>	<u>7.69%</u>
Average of Full Group Results	9.02%	9.01%
Constant Growth DCF Model (Analysts' Growth)	10.06%	10.18%
Constant Growth DCF Model (Sustainable Growth)	9.59%	9.12%
Multi-Stage DCF Model	<u>8.97%</u>	<u>8.94%</u>
Average of Gas Group Results	9.54%	9.41%

IV.G. Risk Premium Model

Q PLEASE DESCRIBE YOUR BOND YIELD PLUS RISK PREMIUM MODEL.

A This model is based on the principle that investors require a higher return to assume greater risk. Common equity investments have greater risk than bonds because bonds have more security of payment in bankruptcy proceedings than common equity and the coupon payments on bonds represent contractual obligations. In contrast, companies are not required to pay dividends or guarantee returns on common equity investments. Therefore, common equity securities are considered to be riskier than bond securities.

This risk premium model is based on two estimates of an equity risk premium.

First, I quantify the difference between regulatory commission-authorized returns on

1 common equity and contemporary U.S. Treasury bonds. The difference between the
2 authorized return on common equity and the Treasury bond yield is the risk premium.
3 I estimated the risk premium on an annual basis for each year since January 1986.
4 The authorized ROEs were based on regulatory commission-authorized returns for
5 utility companies. Authorized returns are typically based on expert witnesses'
6 estimates of the investor-required return at the time of the proceeding.

7 The second equity risk premium estimate is based on the difference between
8 regulatory commission-authorized returns on common equity and contemporary
9 "A" rated utility bond yields by Moody's. I selected the period 1986 through 2023
10 because public utility stocks consistently traded at a premium to book value during that
11 period. This is illustrated in Exhibit AB-12, which shows the market-to-book ratio since
12 1986 for the utility industry was consistently above a multiple of 1.0x. Over this period,
13 an analyst can infer that authorized ROEs were sufficient to support market prices that
14 at least exceeded book value. This is an indication that commission-authorized returns
15 on common equity supported a utility's ability to issue additional common stock without
16 diluting existing shares. It further demonstrates that utilities were able to access equity
17 markets without a detrimental impact on current shareholders.

18 Based on this analysis, as shown in Exhibit AB-13, the average indicated equity
19 risk premium over U.S. Treasury bond yields has been 5.64%. Since the risk premium
20 can vary depending upon market conditions and changing investor risk perceptions, I
21 believe using an estimated range of risk premiums provides the best method to
22 measure the current return on common equity for a risk premium methodology.

23 I assessed the five-year and ten-year rolling average risk premiums over the
24 study period to gauge the variability over time of risk premiums. These rolling average
25 risk premiums mitigate the impact of anomalous market conditions and skewed risk

1 premiums over an entire business cycle. As shown on my Exhibit AB-13, the five-year
2 rolling average risk premium over Treasury bonds ranged from 4.17% to 7.17%, while
3 the ten-year rolling average risk premium ranged from 4.30% to 6.92%.

4 As shown on my Exhibit AB-14, the average indicated equity risk premium over
5 contemporary "A" rated Moody's utility bond yields was 4.27%. The five-year and
6 ten-year rolling average risk premiums ranged from 2.80% to 5.97% and 3.11% to
7 5.75%, respectively.

8 **Q WHY ARE THE TIME PERIODS USED TO DERIVE THESE EQUITY RISK PREMIUM**
9 **ESTIMATES APPROPRIATE TO FORM ACCURATE CONCLUSIONS ABOUT**
10 **CONTEMPORARY MARKET CONDITIONS?**

11 A Contemporary market conditions can change dramatically during the period that rates
12 determined in this proceeding will be in effect. A relatively long period of time where
13 stock valuations reflect premiums to book value indicates that the authorized ROEs
14 and the corresponding equity risk premiums were supportive of investors' return
15 expectations and provided utilities access to the equity markets under reasonable
16 terms and conditions. Further, this time period is long enough to smooth abnormal
17 market movement that might distort equity risk premiums. While market conditions and
18 risk premiums do vary over time, this historical time period is a reasonable period to
19 estimate contemporary risk premiums.

20 **Q PLEASE EXPLAIN OTHER MARKET EVIDENCE YOU RELIED ON IN**
21 **DETERMINING AN APPROPRIATE EQUITY RISK PREMIUM.**

22 A The equity risk premium should reflect the market's perception of risk in the utility
23 industry today. I have gauged investor perceptions in utility risk today in Exhibit AB-15,

1 where I show the yield-spread between utility bonds and Treasury bonds since 1980.
2 As shown in this schedule, the average utility bond yield-spreads over Treasury bonds
3 for "A" and "Baa" rated utility bonds for this historical period are 1.49% and 1.91%,
4 respectively.

5 A current 13-week average "A" rated utility bond yield of 5.54% when compared
6 to the current Treasury bond yield of 4.36%, as shown in Exhibit AB-16, page 1, implies
7 a yield-spread of 1.18%. This current utility bond yield-spread is lower than the long-
8 term average-spread for "A" rated utility bonds of 1.49%. The 13-week average yield
9 on "Baa" rated utility bonds is 5.77%. This indicates a current spread for the "Baa"
10 rated utility bond yield of 1.41%, which is lower than the long-term average of 1.91%.

11 **Q WHAT ARE THE RESULTS BASED ON YOUR RISK PREMIUM ANALYSES?**

12 A I give primary consideration to the Risk Premium results using Treasury bond and A-
13 rated utility bonds. My recommendation also takes the results of adding the Baa-rated
14 utility bond yield to the equity risk premium over A-rated utility bonds into consideration.

15 Considering the current and projected economic environment, current yield
16 spreads and equity risk premiums, as well as current levels of interest rates and interest
17 rate projections, a more normalized equity risk premium is warranted. As such, I
18 believe an average equity risk premium over Treasury yields of 5.64% is appropriate.
19 Adding this risk premium to the projected Treasury yield of 4.00% produces an ROE of
20 9.64%.

21 Applying a similar methodology as described above, the average of the rolling
22 five-year average risk premiums over A-rated utility bonds is 4.27%. The A-rated utility
23 bond yield has averaged 5.54% over the 13-week period ending April 5, 2024 while the
24 Baa-rated utility bond yield has averaged 5.77% over the same period. Adding this risk

premium to the 13-week A-rated utility bond yield of 5.54% produces an estimated cost of equity of 9.81%. Adding this risk premium to the 13-week Baa-rated utility bond yield of 5.77% produces an estimated cost of equity of 10.04%.

The A-rated utility bond yield has averaged 5.69% over the 26-week period ending April 5, 2024 while the Baa-rated utility bond yield has averaged 5.94% over the same period. Adding this risk premium to the 26-week A-rated utility bond yield of 5.69% produces an estimated cost of equity of 9.96%. Adding this risk premium to the 26-week Baa-rated utility bond yield of 5.94% produces an estimated cost of equity of 10.21%.

The results of my risk premium analyses are summarized in Table CCW-9.

Table CCW-9	
<u>Summary of Risk Premium Results</u>	
<u>Description</u>	
Projected Treasury Yield	9.64%
<u>13-Week Yields</u>	
A-Rated Utility Bond	9.81%
Baa-Rated Utility Bond	10.04%
<u>26-Week Yields</u>	
A-Rated Utility Bond	9.96%
Baa-Rated Utility Bond	10.21%

IV.H. Capital Asset Pricing Model ("CAPM")

Q PLEASE DESCRIBE THE CAPM.

A The CAPM method of analysis is based upon the theory that the market-required ROR for a security is equal to the risk-free rate, plus a risk premium associated with the

specific security. This relationship between risk and return can be expressed mathematically as follows:

$$R_i = R_f + B_i \times (R_m - R_f) \text{ where:}$$

- R_i = Required return for stock i
- R_f = Risk-free rate
- R_m = Expected return for the market portfolio
- B_i = Beta - Measure of the risk for stock

The term "beta" in the equation represents the stock-specific risk that cannot be reduced through diversification. In a well-diversified portfolio, specific risks related to individual stocks can be reduced by balancing the portfolio with securities that offset the impact of firm-specific factors, such as business cycle, competition, product mix, and production limitations.

Non-diversifiable risks, on the other hand, are related to market conditions and are referred to as systematic risks. These risks cannot be reduced through diversification and are considered market risks. Conversely, non-systematic risks, also known as business risks, can be reduced through diversification.

According to the CAPM, the market does not compensate investors for taking on risks that can be diversified away. Thus, investors are only compensated for taking on systematic, or non-diversifiable, risks. Beta is a measure of these systematic risks.

Q PLEASE DESCRIBE THE INPUTS TO YOUR CAPM.

A The CAPM requires an estimate of the market risk-free rate, the company's beta, and the market risk premium.

Q WHAT DID YOU USE AS AN ESTIMATE OF THE MARKET RISK-FREE RATE?

A As published in the *Blue Chip Financial Forecasts*, the projected 30-year Treasury bond yield is 4.00%.²⁶ The current 30-year Treasury bond yield is 4.36%, as shown in Exhibit AB-16 at page 1. Because the cost of equity is a forward looking exercise, I used *Blue Chip Financial Forecasts'* projected 30-year Treasury bond yield of 4.00% for my CAPM analysis.

Q WHY DID YOU USE LONG-TERM TREASURY BOND YIELDS AS AN ESTIMATE OF THE RISK-FREE RATE?

A Treasury securities are backed by the full faith and credit of the United States government, so long-term Treasury bonds are considered to have negligible credit risk. Also, long-term Treasury bonds have an investment horizon similar to that of common stock. As a result, investor-anticipated long-run inflation expectations are reflected in both common stock required returns and long-term bond yields. Therefore, the nominal risk-free rate (or expected inflation rate and real risk-free rate) included in a long-term bond yield is a reasonable estimate of the nominal risk-free rate included in common stock returns.

Treasury bond yields, however, do include risk premiums related to future inflation and liquidity. In this regard, a Treasury bond yield is not entirely risk-free. Risk premiums related to unanticipated inflation and interest rates reflect systematic market risks. Consequently, for a company with a beta less than 1.0, using the Treasury bond yield as a proxy for the risk-free rate in the CAPM analysis can produce an overstated estimate of the CAPM return.

²⁶Blue Chip Financial Forecast April 1, 2024.

Q WHAT BETA DID YOU USE IN YOUR ANALYSIS?

A As shown in Exhibit AB-17, the current proxy group average and median *Value Line* beta estimates are both 0.85. In my experience, these beta estimates are abnormally high and are unlikely to be sustained over the long-term. As such, I have also reviewed the historical average of the proxy group's *Value Line* betas. The historical average *Value Line* beta since 2014 is 0.75 and has ranged from 0.64 to 0.81. Prior to the recent pandemic, the high end of this range was 0.75.

In addition to *Value Line*, I have also included adjusted beta estimates as provided by Market Intelligence's Beta Generator Model. This model relied on a five-year period on a weekly basis ending April 5, 2024. The average and median Market Intelligence betas are 0.74 and 0.75, respectively. Market Intelligence betas, as calculated using its Beta Generator Model, are adjusted using the Vasicek method and calculated using the S&P 500 as the proxy for the investable market. This is in stark contrast with the *Value Line* beta estimates that are adjusted using a constant weighting of 67%/35% to the raw beta/market beta and use the New York Stock Exchange ("NYSE") as the proxy for the investable market. Because I rely on the S&P 500 to estimate the expected return on the investable market, it makes sense to rely on beta estimates that are calculated using the S&P 500 as the benchmark for the market. Further, as S&P explains:

The Vasicek Method is a superior alternative to the Bloomberg Beta adjustment. The Bloomberg adjustment is not appropriate for a vast number of situations, as it assigns constant weighting regardless of the standard error in the raw beta estimation (Bloomberg Beta = $1/3 \times \text{market beta} + 2/3 \times \text{Raw Beta}$). Given the statistical fact that a larger sample size yields a smaller error, the Vasicek method more appropriately adjusts the raw beta via weights determined by the variance of the individual security versus the variance of a larger sample of comparable companies. The weights are designed to bring the raw beta closer to

1 whichever beta estimation has the smallest error. This is a feature the
2 Bloomberg beta cannot replicate.²⁷

3 Notably, while S&P makes reference to the Bloomberg method of applying
4 2/3 and 1/3 weights to the raw beta and market beta, respectively, the comparison still
5 applies to *Value Line*'s methodology of applying 67% and 35% weights. Both methods
6 are forms of the Blume adjustment.²⁸ While the weights are slightly different between
7 the Bloomberg and *Value Line* methods, they are similar and apply a constant weight
8 without any regard to accuracy. As such, the criticisms of the betas offered by S&P
9 apply to both Bloomberg betas and *Value Line* betas.

10 **Q HOW DID YOU DERIVE YOUR MARKET RISK PREMIUM ESTIMATES?**

11 A My market risk premium estimates are derived using two general approaches: a risk
12 premium approach and a DCF approach. I also consider the normalized market risk
13 premium of 5.50% with the normalized risk-free rate of 4.47% as recommended by
14 Kroll, formerly known as Duff & Phelps.²⁹ Based on this methodology and utilizing a
15 “normalized” risk-free rate of 4.47%, Kroll concludes that the current expected, or
16 forward-looking, market risk premium is 5.50%, implying an expected return on the
17 market of 9.97%.³⁰

²⁷S&P Market Intelligence, Beta Generator Model.

²⁸The Blume adjustment is a tool used to refine a beta measurement in finance. In general, Beta attempts to explain how much a particular investment's price moves compared to the overall market. But beta is often based on historical data, which may not be an accurate method for predicting the future. The Blume adjustment tries to address this by considering the idea that, in the long run, most investments tend to become more similar in their riskiness to the overall market (represented by a beta of 1).

²⁹Kroll, and its predecessor Duff & Phelps, is a provider of economic, financial, and valuation data that is often relied on by finance professionals and cited in ROR testimony.

³⁰Kroll, *Kroll Increases U.S. Normalized Risk-Free Rate from 3.0% to 3.5%, but Spot 20-Year U.S. Treasury Yield Preferred When Higher*, June 16, 2022. The current 20-year yield of 4.47% exceeds the “normalized” yield of 3.5%. In accordance with Kroll's prescribed method, the greater of the two shall be used under the normalized Kroll methodology, i.e., 4.47%.

1 **Q PLEASE DESCRIBE YOUR MARKET RISK PREMIUM ESTIMATE DERIVED USING**
2 **THE RISK PREMIUM METHODOLOGY.**

3 A The forward-looking risk premium-based estimate was derived by estimating the
4 expected return on the market (as represented by the S&P 500) and subtracting the
5 risk-free rate from this estimate. I estimated the expected return on the S&P 500 by
6 adding an expected inflation rate to the long-term historical arithmetic average real
7 return on the market. The real return on the market represents the achieved return
8 above the rate of inflation.

9 The Kroll *2023 SBBI Yearbook* estimates the historical, arithmetic-average,
10 real-market return over the period 1926 to 2022 to be 8.90%.³¹ A current consensus
11 for projected inflation, as measured by the Consumer Price Index (“CPI”), is 2.30%.³²
12 Using these estimates, the expected market return is 11.40%.³³ The market risk
13 premium then is the difference between the 11.40% expected market return and the
14 projected risk-free rate of 4.00%, or 7.40%.

15 **Q PLEASE DESCRIBE YOUR MARKET RISK PREMIUM ESTIMATES DERIVED**
16 **USING THE DCF METHODOLOGY.**

17 A I employed two versions of the constant growth DCF model to develop estimates of the
18 market risk premium. I first employed the Federal Energy Regulatory Commission’s
19 (“FERC”) method of estimating the expected return on the market that was established
20 in its Opinion No. 569-A. FERC’s method for estimating the expected return on the
21 market is to perform a constant growth DCF analysis on each of the dividend-paying
22 companies of the S&P 500 index. The growth rate component is based on the average

³¹Kroll, 2023 SBBI Yearbook at 138.

³²Blue Chip Financial Forecast April 1, 2024.

³³ $[(1 + 8.90\%) * (1 + 2.30\%) - 1] * 100$.

1 of the growth projections excluding companies with growth rates that were negative or
2 greater than 20%.³⁴ The weighted average growth rate for the remaining companies is
3 10.10%. After reflecting the FERC prescribed method of adjusting the dividend yield
4 by $(1 + 0.5g)$, the weighted average expected dividend yield is 1.89%. Thus, the
5 DCF-derived expected return on the market is the sum of those two components, or
6 11.99%. The market risk premium then is the expected market return of 11.99%, less
7 the projected risk-free rate of 4.00%, or 8.00%.

8 My second DCF-based market risk premium estimate was derived by
9 performing the same DCF analysis described above, except I used all companies in
10 the S&P 500 index rather than just the dividend-paying companies. The weighted
11 average growth rate for these companies is 10.30%. After reflecting the
12 FERC-prescribed method of adjusting the dividend yield by $(1 + 0.5g)$, the weighted
13 average expected dividend yield is 1.68%. Thus, the DCF-derived expected return on
14 the market is the sum of those two components, or 11.98%. The market risk premium
15 then is the expected market return of 11.98% less the projected risk-free rate of 4.00%,
16 or 8.00%.

17 The average expected market return based on the DCF model is 11.99% and
18 the average market risk premium based on the two DCF estimates is 8.00%.

19 **Q HOW DO YOUR EXPECTED MARKET RETURNS COMPARE TO CURRENT**
20 **EXPECTATIONS OF FINANCIAL INSTITUTIONS?**

21 **A** As shown in Table CCW-10, my average expected market return of 11.12%³⁵ exceeds
22 long-term market expectations of several financial institutions.

³⁴Opinion No. 569-A, at 210.

³⁵ $11.12\% = (9.97\% + 11.99\% + 11.40\%) / 3$.

TABLE CCW-9

Long-Term Expected Return on the Market

<u>Source</u>	<u>Term</u>	<u>Expected Return Large Cap Equities</u>
BlackRock Capital Management ¹	30 Years	7.00%
JP Morgan Chase ²	10 - 15 Years	7.00%
Vanguard ³	10 Years	4.2% - 6.2%
Research Affiliates ⁴	10 Years	4.00%

Sources:

¹BlackRock Investment Institute, November 2023 report.

²JP Morgan Chase, Long-Term Capital Market Assumptions, 2024 Report.

³Vanguard economic and market outlook for 2024: A Return to Sound Money.

⁴Research Affiliates, Asset Allocation Interactive. Retrieved 1/05/2024.

1 When compared to the expected market returns of financial institutions above,
2 my average expected market return of 11.12% is greater than all of them. For these
3 reasons, my expected market returns, and the associated market risk premiums,
4 should be considered reasonable, if not high-end estimates.

5 **Q HOW DO YOUR ESTIMATED MARKET RISK PREMIUMS COMPARE TO THAT**
6 **ESTIMATED BY KROLL?**

7 **A**The Kroll analysis indicates a market risk premium falls somewhere in the range of
8 5.50% to 7.17%. My market risk premium estimates are in the range of 5.50% to
9 8.00%.

Q HOW DOES KROLL MEASURE A MARKET RISK PREMIUM?

A Kroll's range is based on several methodologies. First, Kroll estimated a market risk premium of 7.17% based on the difference between the total market return on common stocks (S&P 500) less the income return on 20-year Treasury bond investments over the 1926-2022 period.³⁶

Second, Kroll used the Ibbotson & Chen supply-side model which produced a market risk premium estimate of 6.35%.³⁷ Kroll explains that the historical market risk premium based on the S&P 500 was influenced by an abnormal expansion of P/E ratios relative to earnings and dividend growth. In order to control for the volatility of extraordinary events and their impacts on P/E ratios, Kroll takes into consideration the three-year average P/E ratio as the current P/E ratio. Therefore, Kroll adjusted this market risk premium estimate to normalize the growth in the P/E ratio to be more in line with the growth in dividends and earnings.

Finally, Kroll developed its own recommended equity, or market risk premium, by employing an analysis that takes into consideration a wide range of economic information, multiple risk premium estimation methodologies, and the current state of the economy by observing measures such as the level of stock indices and corporate spreads as indicators of perceived risk. Based on this methodology, and utilizing a "normalized" risk-free rate of 4.47%, Kroll concludes that the current expected, or forward-looking, market risk premium is 5.50%, implying an expected return on the market of 9.97%.³⁸

³⁶Kroll, 2023 SBBI Yearbook at 191.

³⁷*Id.* at 199.

³⁸Kroll, *Kroll Increases U.S. Normalized Risk-Free Rate from 3.0% to 3.5%, but Spot 20-Year U.S. Treasury Yield Preferred When Higher*, June 16, 2022.

Q WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A As shown in Exhibit AB-18, I have provided the results of nine different applications of the CAPM. The first three results presented are based on the proxy group's current average *Value Line* beta of 0.85. The results of the CAPM based on these inputs range from 9.15% to 10.80%.

The next set of three results presented are based on the proxy group's historical *Value Line* beta of 0.75. The results of the CAPM based on these inputs range from 8.58% to 9.97%.

The last set of three results presented are based on the proxy group's current S&P Global Market Intelligence beta of 0.74. The results of the CAPM based on these inputs range from 8.54% to 9.92%. My CAPM results are summarized in Table CCW-11.

Because current beta estimates are based on the most recent five years of historical stock returns and volatility, they are being heavily impacted by the market fallout in early 2020 as the global pandemic set in and the market reacted, with this S&P 500 falling more than 40%. For this reason, it is not reasonable to assume current beta estimates, particularly Blume-adjusted betas such as those published by *Value Line*, are reflective of investor expectations at this time. As such, I am giving primary consideration to the results of my CAPM analyses using long-term average *Value Line* betas.

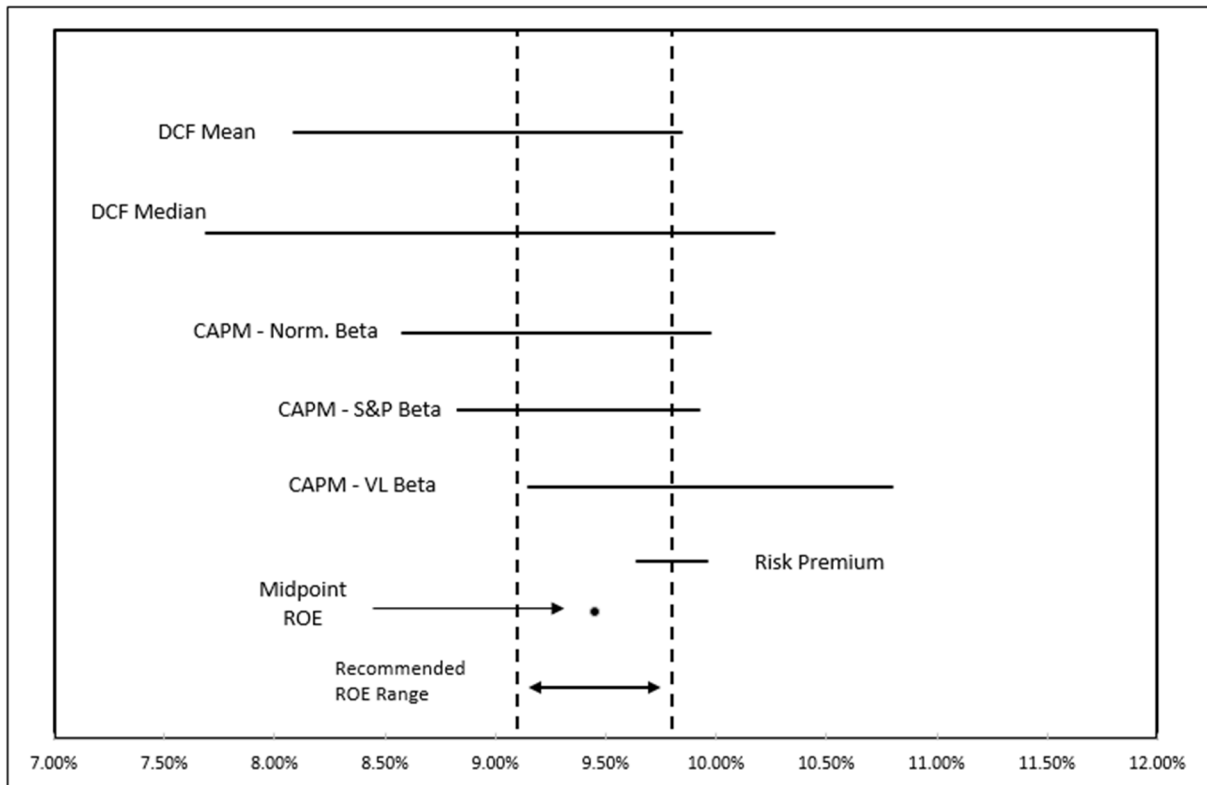
Table CCW-11			
<u>CAPM Results Summary</u>			
<u>Description</u>	<u>Current VL Beta</u>	<u>Historical VL Beta</u>	<u>Current S&P Beta</u>
Kroll Normalized Method	9.15%	8.58%	8.54%
Risk Premium Method	10.29%	9.53%	9.47%
FERC DCF Method	<u>10.80%</u>	<u>9.97%</u>	<u>9.92%</u>
Average	10.11%	9.36%	9.34%

1 **IV.I. Return on Equity Summary**

2 **Q BASED ON THE RESULTS OF YOUR RETURN ON COMMON EQUITY ANALYSES**
3 **DESCRIBED ABOVE, WHAT RETURN ON COMMON EQUITY DO YOU**
4 **RECOMMEND FOR THE COMPANY?**

5 **A** The results of my analyses are summarized in Figure CCW-5. In this figure, I present
6 the various measures of central tendency for each of my analytical models.

FIGURE CCW-5



Based on my analyses of the various methodologies described above, I estimate the Company's current market cost of equity to be in the reasonable range of 9.10% to 9.80%. My recommended range accounts for the unsustainable growth rates assumed in the constant growth DCF model and the irrational assumption that Value Line's current beta estimates are reflective of current investor expectations. In addition, my recommended range is captured by the range of results for each of the models and is consistent with measures of central tendency of those results. Based on my assessment of DTE's overall risk profile and the results of these analytical methods, I would recommend that this Commission authorize DTE an ROE of 9.45%, which is the midpoint of the range produced by these models.

V. RESPONSE TO DR. BENTE VILLADSEN

V.A. Summary of Response

Q WHAT ROE IS DTE PROPOSING FOR THIS PROCEEDING?

A Dr. Villadsen recommends a ROE of 10.0% based on her market-based model results. She concludes that DTE's recommended return of 10.25% is a "conservative estimate given DTE's higher than average risk."³⁹

Q PLEASE DESCRIBE DR. VILLADSEN'S METHODOLOGY SUPPORTING HER ROE RECOMMENDATION.

A Dr. Villadsen arrived at her estimate using several models that she applied to a sample group of natural gas and water companies including a traditional CAPM and an empirical CAPM ("ECAPM"), a simple DCF, and a multi-stage growth DCF.⁴⁰ Additionally, Dr. Villadsen performed a risk premium model.

Q IS DR. VILLADSEN'S ESTIMATED ROE FOR DTE REASONABLE?

A No. Dr. Villadsen's recommended ROE of 10.0% for DTE is excessive and unreasonable for a low-risk regulated utility company. Further, Dr. Villadsen asserts that DTE's risk is higher than average relative to her Full Sample.⁴¹ The unreasonableness of Dr. Villadsen's recommendation is evident from a detailed assessment of the rate of return models supporting her recommendation in this proceeding.

³⁹Dr. Villadsen Direct at 50.

⁴⁰*Id.*, at 13-14.

⁴¹*Id.*

1 **Q PLEASE SUMMARIZE DR. VILLADSEN'S ROE STUDY RESULTS.**

2 A Dr. Villadsen's ROE study results for her Full Sample are summarized in Table CCW-12
3 below. I present her Full Sample results. As I explain later, the table below clearly
4 demonstrates that, even when her financial leverage adjustments are included, her
5 recommended range and point estimate are unsupported.

TABLE CCW-12				
<u>Summary of Dr. Villadsen's Full Sample Results</u>				
<u>Model</u>	<u>Dr. Villadsen's Results</u>			<u>Corrected ROE¹</u>
	<u>Model Results</u>	<u>ATWACC Adjustment</u>	<u>Recommended ROE</u>	
	(1)	(2)	(3)	(4)
<u>DCF (Full Sample)</u>				
Simple DCF	10.4%	1.5%	11.9%	9.7%
Multi-Stage	8.7%	0.2%	8.9%	7.3%
<u>CAPM (Full Sample)</u>				
Traditional CAPM	8.7% - 9.9%	1.3%-1.6%	10.0% - 11.5%	8.7% - 9.9%
ECAPM (1.5%)	8.9% - 10.2%	1.4%-1.7%	10.3% - 11.9%	Reject
Traditional CAPM (Hamada)			9.7% - 11.5%	Reject
ECAPM (1.5%) (Hamada)			9.7% - 11.5%	Reject
Risk Premium			10.2%	9.8%
Recommended ROE			10.25%	9.45%
ROE = Return on Equity				
ATWACC = After-Tax Weighted Average Cost of Capital				
¹ Corrected ROE results for DCF and CAPM are based on her unadjusted median results.				

6 As shown in Table CCW-12 above, the model ROE results of Dr. Villadsen's
7 studies applied to her Full Sample indicate that the required ROE is in the range of
8 8.3% to 10.6%. She then increases her market ROE estimate by adjusting her results
9 upward in the range of 0.2%-1.7% using an overall cost of capital ("OCC")
10 methodology. Dr. Villadsen describes the OCC methodology at pages 12-14 of

Appendix B to her testimony. The OCC method employed by Dr. Villadsen is identical to the After-Tax Weighted Average Cost of Capital ("ATWACC") methodology previously rejected by regulatory commissions throughout the country. This ATWACC adjustment increases her recommended range up to 10.0%-10.7%. Dr. Villadsen asserts this ATWACC adjustment is necessary to properly recognize the difference of DTE's financial risk when applying a market ROE to its book value common equity.

Q DO DR. VILLADSEN'S ROE MODEL RESULTS SUPPORT THE COMPANY'S REQUESTED ROE OF 10.0%?

A No. As described below and illustrated in Table CCW-12 above, Dr. Villadsen's own studies, with reasonable adjustments, would support a ROE well below 10.25%.

Q PLEASE DESCRIBE THE ISSUES YOU HAVE WITH DR. VILLADSEN'S ANALYSES.

A The issues and concerns I have with Dr. Villadsen's analyses in support of the Company's requested ROE include the following:

1. Her ATWACC adjustment is unnecessary and has previously been rejected by several regulatory commissions.
2. The upper-end of her recommended range and her recommended point estimate rests solely on the inclusion of her unaccepted financial leverage adjustments.
3. Dr. Villadsen should have measured the median DCF results instead of removing what she determined to be low-end outliers.
4. For her CAPM analysis, she includes both an ATWACC adjustment, and alternatively a leveraged beta adjustment to the CAPM results.
5. Her Value Line betas are based on five years of historical stock prices and are significantly being impacted by the spike in volatility as a result of the pandemic and its impact on the market in early 2020. She failed to consider a more normalized estimate of beta.

- 1 6. She also relies on an ECAPM analysis and includes adjustments for her ATWACC
2 and leveraged beta methods. In addition to my concerns for these two adjustments,
3 Dr. Villadsen's ECAPM analysis is miscalculated because she uses adjusted betas
4 within an ECAPM format. This is inappropriate because an adjusted beta
5 accomplishes the same thing as an ECAPM analysis. Both levelize the security
6 market line in measuring a fair ROE based on a given level of systematic risk or
7 beta risk. Her ECAPM analysis double counts the increase in the CAPM return
8 estimates for companies with betas less than 1, which reflects her proxy group and
9 DTE in this case.
- 10 7. Dr. Villadsen's Risk Premium method is based on excessive risk premium
11 estimates.

12 **V.B. ATWACC**

13 **Q PLEASE DESCRIBE DR. VILLADSEN'S PROPOSED ATWACC ROE**
14 **ADJUSTMENT.**

15 A Dr. Villadsen calculates an ATWACC for each of her sample DCF and CAPM results
16 by using each sample company's market value capital structure and assumes cost
17 rates for the cost of debt and preferred stock based on each company's credit rating.
18 She also assumes DTE's composite tax rate of 25.7% is applicable to all companies in
19 her sample. Once she calculates the OCC or ATWACC, she then backs into the ROE
20 required to produce the same rate of return using DTE's book value capital structure
21 and embedded cost of debt.

22 These ATWACC adjustments to her ROE estimates are discussed in her
23 Technical Appendix and developed in the workpapers accompanying her schedules for
24 the CAPM and DCF return estimates.

25 **Q DO YOU BELIEVE THAT THE ATWACC METHODOLOGY IS A REASONABLE**
26 **POLICY FOR SETTING AN APPROVED ROE IN THE UNITED STATES?**

27 A An obvious concern is that DTE's common stock is not publicly traded. The ATWACC
28 methodology is poor regulatory policy and should be rejected for several reasons:

- 1 1. It does not produce clear and transparent objectives for management to use that
2 will accomplish the objective of minimizing DTE's overall rate of return while
3 preserving its financial integrity. It ignores a utility's need for capital discipline,
4 treating it as it would an unregulated utility affiliate. A regulatory commission cannot
5 oversee the reasonableness and prudence of management decisions in managing
6 its capital structure. Under the ATWACC theory, management's decisions to
7 manage its capital structure can be skewed by changes in market value which
8 change the market value capitalization mix. Management simply has no control
9 over the market value capital structure, but it does have control over the book value
10 capital structure. As such, setting the rate of return and measuring risk based on
11 book value capital structure creates a more transparent and clear path for regulatory
12 oversight of management's effort to maintain a balanced and reasonable capital
13 structure.
- 14 2. The ATWACC introduces significant additional instability and unreliability into the
15 utility's cost of service and tariff rates. Book value capital structure weights permit
16 the utility to hedge or lock-in a large portion of capital market costs in arriving at the
17 rate of return used to set rates. This rate of return cost hedge stabilizes the utility's
18 cost of service, which in turn helps stabilize utility rates. A stable method of setting
19 rates also allows investors to more accurately assess the future earnings and cash
20 flow outlooks for the utility, which will reduce the business risk of the utility. The
21 ATWACC, on the other hand, will produce an overall rate of return which will change
22 based on both changes to market value capital structure weights and also based
23 on changes to market capital costs. Hence, a major component of the cost structure
24 of the utility (i.e., the overall rate of return) will vary based on market forces from
25 rate case to rate case. This rate of return variability will introduce significant
26 instability in the utility's cost of service (via rate of return changes) and hence
27 instability in tariff rates. Introducing additional instability and unreliability in the
28 utility's cost structure and rates will not benefit either investors or ratepayers.
- 29 3. The ATWACC artificially increases rates to produce an excessive ROE opportunity
30 for utility investors, as if the utility were an unregulated affiliate. Inflating utility's
31 rates to provide this excessive earnings opportunity is unjust and unreasonable to
32 ratepayers and should be rejected.

33 **Q IS THE ATWACC METHODOLOGY PROPOSED BY DR. VILLADSEN COMMONLY**
34 **ACCEPTED IN RATE-SETTING PROCEEDINGS IN THE UNITED STATES?**

35 **A** No. This Commission has rejected the application of the ATWACC methodology in
36 Docket U-18014, stating:

37 "[...] the Commission does agree with the PFD that little or no weight
38 should be given to the utility's ATWACC calculations."⁴²

⁴²Michigan Public Service Commission, Case No. U-18014, Final Order, page 66, January 31, 2017.

1 The MPSC reaffirmed its rejection of the ATWACC methodology in Case No.
2 U-18255.⁴³

3 In a recent Nicor Gas rate case (Docket No. 21-0098), the Illinois Commerce
4 Commission explicitly rejected the application of any leverage ROE adjustments,
5 stating the following in regard to Dr. Villadsen's leverage adjustments:

6 Additionally, the Company's leverage adjustments improperly inflated the
7 Company's ROE recommendation, especially for the water companies.
8 Further, the leverage adjustments are based on the flawed argument that
9 a market-derived ROE does not produce a fair rate of return when applied
10 to a book value rate base. In the Commission's view, an ROE derived from
11 market-based models should be applied to the book value common equity
12 ratio of the Illinois utility because the book value capital structure reflects
13 the amount of capital a utility actually uses to finance the acquisition of
14 assets for providing utility service, which are included in rate base. In
15 contrast, market value typically includes appreciated value, which is not
16 used in establishing the overall or weighted average cost of capital in
17 ratemaking proceedings for Illinois utilities. The Commission has used this
18 approach to establish utility rates for decades and the results have
19 consistently provided Illinois utilities with adequate access to capital at
20 reasonable costs. In contrast, allowing upward adjustments to the allowed
21 ROE to reflect leverage adjustments would result in a never-ending upward
22 movement in the allowed rate of return, which would not properly balance
23 the interests of customers and the utility.

24 * * *

25 The Commission concludes that the Company's ROE recommendations
26 should not be adopted primarily because the Company's DCF and CAPM
27 estimates include leverage adjustments, which the Commission has
28 routinely rejected.⁴⁴

29 The ATWACC methodology is a flawed approach which leads to inflated cost
30 of equity estimates and is routinely rejected by regulatory commissions. The
31 Commission should reject it here as well.

⁴³Michigan Public Service Commission, Case No. U-18255, Final Order, page 32, April 18, 2018.

⁴⁴Illinois Commerce Commission, Docket No. 21-0098, *Northern Illinois Gas Company d/b/a Nicor Gas Company*, Final Order at 93-94, November 18, 2021.

V.C. Dr. Villadsen's DCF Analysis

Q PLEASE DESCRIBE DR. VILLADSEN'S DCF ANALYSIS.

A Dr. Villadsen develops two versions of the DCF model, a quarterly constant growth DCF and a multi-stage DCF. Her constant growth DCF model for her Full Sample is based on an average growth rate of 7.2% and produces an average and median result of 10.4% and 9.8% for the Full Sample, respectively, after she removes the growth rate and DCF result for American States Water. Her multi-stage DCF method is similar to mine and assumes a terminal growth rate of 3.95% based on the projected growth of the US economy. After she removes 10 of her 17 multi-stage DCF results, her average and median multi-stage DCF estimates are both 8.7%, for her Full Sample. She then applies her ATWACC adjustment and increases her constant growth DCF result from 10.4% to 11.9%, and her multi-stage DCF result from 8.7% to 8.9%.⁴⁵

Q WHAT CONCERNS DO YOU HAVE WITH DR. VILLADSEN'S DCF ANALYSIS?

A In addition to the inclusion of her financial leverage adjustments, I have two additional concerns. First, her recommendation places too much weight on the results of her constant growth DCF analysis and not nearly enough weight on her multi-stage DCF results. As I mention above, her Full Sample's average growth rate projection is 7.2%, and is assumed in perpetuity in her constant growth model. This growth rate exceeds her projected growth rate of 3.9% for the US economy by approximately 85%. Simply put, such a growth rate is unsustainable and defies economic logic.

Finally, Dr. Villadsen erroneously removes several results from her DCF analyses, ultimately causing a significant upward bias to her results. Notably, Dr. Villadsen only removes what she was determined to be low-end outliers and not high-

⁴⁵Villadsen Exhibit A-14, Schedules D5.6-5.8.

1 end outliers. Because Dr. Villadsen's DCF analyses include results as high as 16.0%
2 and as low as 4.4%, a more reasonable estimate for the DCF analysis would be based
3 on the medians of her unadjusted results of 7.2% (multi-stage DCF) and 9.7% (constant
4 growth DCF).

5 **V.D. Dr. Villadsen's CAPM Analysis**

6 **Q PLEASE DESCRIBE DR. VILLADSEN'S CAPM ANALYSIS.**

7 A Dr. Villadsen develops two versions of the CAPM model, a traditional CAPM and an
8 ECAPM. In her analyses, Dr. Villadsen relied upon two different scenarios. In the first
9 scenario, she used a risk-free rate of 3.95% with a market risk premium of 7.17%. In
10 the second scenario, she used the same forecasted yield of 3.95% and a market risk
11 premium of 5.72%. Applying these inputs with her *Value Line* betas, she produces her
12 bare-bones CAPM estimates of 9.9% and 8.7% for her Full Sample.⁴⁶

13 To these bare bones or "base" CAPM returns, Dr. Villadsen proposes two
14 separate adjustments to the model results in an attempt to capture the difference in
15 financial risk. First, she proposes to add to her base CAPM return estimate an
16 ATWACC ROE adjustment. This produces an ATWACC-adjusted CAPM return for her
17 Full Sample in the range of 10.0% to 11.5%.⁴⁷ For the reasons outlined above, this
18 ATWACC adjustment should be rejected.

19 Alternatively, Dr. Villadsen proposes a financial risk adjustment to reflect a
20 leveraged beta adjustment. This leveraged beta adjustment adds approximately 40 to
21 60 basis points to the base CAPM return estimates.⁴⁸ This leverage adjustment to the
22 base CAPM return estimate produces an excessive and unreasonable ROE for DTE.

⁴⁶Villadsen Direct at 33-39. See Exhibit A-14, Schedules D5.9-D5.15.

⁴⁷*Id.* at Exhibit A-14, Schedules D5.10-D5.12.

⁴⁸*Id.* at Exhibit A-14, Schedules D5.13-D5.15.

Q WHAT CONCERNS DO YOU HAVE WITH DR. VILLADSEN'S CAPM ANALYSIS?

A In addition to her various leverage adjustments, my concerns are that her Value Line betas are still being impacted by the market fallout caused by the pandemic in early 2020 and are not reflective of current investor expectations.

Q WHAT CONCERNS DO YOU HAVE WITH DR. VILLADSEN'S VALUE LINE BETA ESTIMATES?

A As I explain above in regard to my own CAPM analysis, these beta estimates are abnormally high and are unlikely to be sustained over the long-term. As such, I believe it to be reasonable to consider the historical average of the proxy group's *Value Line* betas. The historical average *Value Line* beta since 2014 is 0.75 and has ranged from 0.64 to 0.81. Prior to the recent pandemic, the high end of this range was 0.75.

Q WHAT WOULD DR. VILLADSEN'S CAPM RESULTS BE AFTER ACCOUNTING FOR A MORE NORMALIZED LEVEL OF BETA?

A Assuming her risk-free rate of 3.95% and market risk premiums of 5.72% and 7.17%, incorporating the historical average *Value Line* beta of 0.75 would produce CAPM results of 8.2% and 9.3% respectively.

Q PLEASE EXPLAIN DR. VILLADSEN'S LEVERAGED BETA ADJUSTMENT.

A As an alternative to her ATWACC adjustment to her CAPM results, Dr. Villadsen measures an additional ROE adjustment based on leveraged adjustments to the beta component of the CAPM study. In producing this adjustment, she applies the Hamada

method to de-lever and re-lever the beta component in both the CAPM and the ECAPM with and without the effect of income taxes.⁴⁹

Applying the Hamada formula increases the Full Sample *Value Line* beta from 0.83 to 1.06 (without taxes) and 1.01 (with taxes) for the Full Sample.⁵⁰ The Hamada model produces CAPM results in the range of 9.7% to 11.5% and ECAPM results in the range of 9.7% to 11.5% for the Full Sample.⁵¹

Q IS DR. VILLADSEN'S APPLICATION OF THE LEVERAGED BETA ADJUSTMENT REASONABLE?

A No. As described above, Dr. Villadsen's financial leverage adjustments are generally not accepted in establishing a fair ROE in regulated rate-setting proceedings such as this one.

Q DO YOU HAVE ANY CONCERNS WITH DR. VILLADSEN'S ECAPM RETURN ESTIMATES?

A Yes. I also have concerns with Dr. Villadsen's reliance on her ECAPM return estimates. Specifically, Dr. Villadsen included an adjusted beta within her ECAPM studies. This adjustment is inconsistent with the academic research supporting the development of an ECAPM methodology.⁵² Using adjusted betas within an ECAPM study double counts the purpose of the ECAPM study – that is, to flatten the security market line and

⁴⁹*Id.*

⁵⁰*Id.*

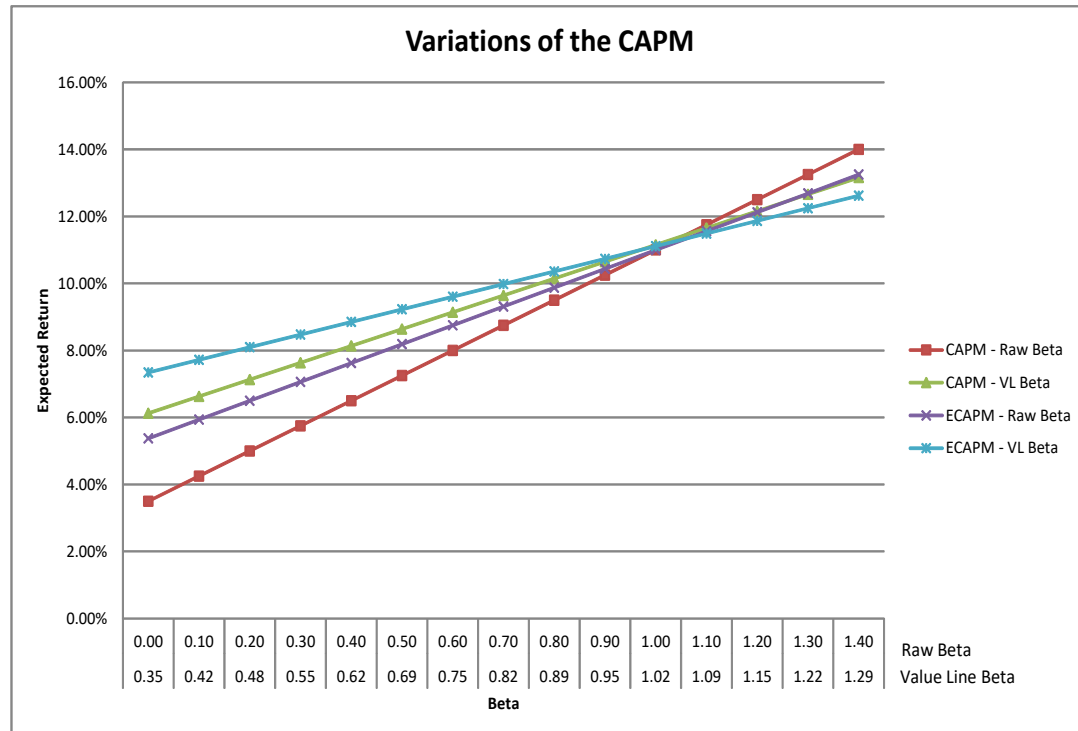
⁵¹*Id.*

⁵²See Black, Fischer, "Beta and Return," *The Journal of Portfolio Management*, Fall 1993, 8-18; and Black, Fischer, Michael C. Jensen and Myron Scholes, "The Capital Asset Pricing Model: Some Empirical Tests," 1972.

1 increase a CAPM return estimate for companies with betas less than 1, and decrease
2 the CAPM return estimate for betas greater than 1.

3 Dr. Villadsen discusses the objective of the ECAPM at pages 8-9 of her
4 Technical Appendix. As shown in Dr. Villadsen's Figure B-2, the ECAPM will raise the
5 intercept point of the security market line and flatten the slope. Again, this has the
6 effect of increasing CAPM return estimates for companies with betas less than 1, and
7 decreasing the CAPM return estimates for companies with betas greater than 1.
8 Importantly, however, the use of an adjusted beta such as those published by *Value*
9 *Line*, produces comparable adjustments to the security market line and CAPM return
10 estimate. In effect, using an adjusted beta within an ECAPM study has the effect of a
11 double adjustment to the slope and intercept of the security market line. This is
12 illustrated in my Figure CCW-6 below.

FIGURE CCW-6



Assumptions:
Market Risk Premium is 7.50%
Risk-Free Rate is 3.50%

As shown in Figure CCW-6, the CAPM using a *Value Line* beta, versus a CAPM using a raw beta shows that the *Value Line* beta raises the intercept slope and flattens the security market line. Further, the ECAPM using a raw beta, and an ECAPM using a *Value Line* beta, have a magnified effect of increasing the intercept slope and further flattening the security market line.

There is simply no legitimate basis to use an adjusted beta within an ECAPM because they are designed to produce the same effect on the CAPM return estimate.

V.E. Dr. Villadsen's Risk Premium Analysis

Q PLEASE DESCRIBE DR. VILLADSEN'S RISK PREMIUM ANALYSES.

A Dr. Villadsen's risk premium analyses are predicated on an inverse relationship between authorized ROEs for natural gas utilities and long-term Treasury yields during

1 the period 1990 through 2023 using a regression analysis.⁵³ In her analysis, she uses
2 the resulting regression formula to predict a risk premium based on the same
3 forecasted long-term Treasury yield of 3.95% she used in her CAPM analyses and
4 electric utility ROE decisions. This regression formula and her forecasted Treasury
5 yield of 3.95% produced an estimated risk premium of approximately 6.26%, which
6 resulted in a ROE of 10.2% for natural gas utilities.⁵⁴

7 **Q DO YOU HAVE ANY OBSERVATIONS REGARDING DR. VILLADSEN'S RISK**
8 **PREMIUM ANALYSIS THAT YOU WOULD LIKE TO POINT OUT?**

9 A Yes. Dr. Villadsen's regression-derived risk premium estimates of 6.26% for gas
10 utilities is significantly higher than the equity risk premiums realized in 2023. This
11 suggests her regression analysis produces an excessive risk premium estimate and
12 overstates the cost of equity. As I demonstrate below, Dr. Villadsen's regression
13 analysis estimates an equity risk premium that is nearly a full percentage point higher
14 than what was realized in 2023.

⁵³DTE Villadsen Direct Exhibit 2 at 74.

⁵⁴*Id.*

TABLE CCW-13

**Realized Equity Risk Premium vs.
Dr. Villadsen's Estimated Equity Risk Premium**

2023 Average ROE	9.60%
2023 Average 20-Year Yield	<u>4.26%</u>
2023 Average Risk Premium	5.34%
Dr. Villadsen's Risk Premium	<u>6.26%</u>
Difference	0.92%

1 A widening equity risk premium is contrary to what is expected to occur in 2024.
2 As Regulatory Research Associates explained in a recent report, the equity risk
3 premium is expected to narrow in 2024 relative to 2023 for several reasons as
4 “regulators navigate the ongoing energy transition and potential affordability challenges
5 posed by higher interest rates and rising costs.”⁵⁵

6 **Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

7 **A Yes, it does.**

⁵⁵S&P Capital IQ, RRA Regulatory Focus, Average authorized energy ROEs rise in 2023 amid record rate case activity, January 25, 2024.

Qualifications of Christopher C. Walters

1 **Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A Christopher C. Walters. My business address is 16690 Swingley Ridge Road,
3 Suite 140, Chesterfield, MO 63017.

4 **Q PLEASE STATE YOUR OCCUPATION.**

5 A I am a consultant in the field of public utility regulation and a Principal with the firm of
6 Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

7 **Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL
8 EMPLOYMENT EXPERIENCE.**

9 A I received a Bachelor of Science Degree in Business Economics and Finance from
10 Southern Illinois University Edwardsville. I have also received a Master of Business
11 Administration Degree from Lindenwood University.

12 As a Principal at BAI, I perform detailed technical analyses and research to
13 support regulatory projects including expert testimony covering various regulatory
14 issues. Since my career at BAI began in 2011, I have held the positions of Analyst,
15 Associate Consultant, Consultant, Senior Consultant, and Associate. Throughout my
16 tenure, I have been involved with several regulated projects for electric, natural gas
17 and water and wastewater utilities, as well as competitive procurement of electric power
18 and gas supply. My regulatory project work includes estimating the cost of equity
19 capital, capital structure evaluations, assessing financial integrity, merger and
20 acquisition related issues, risk management related issues, depreciation rate studies,
21 and other revenue requirement issues.

1 BAI was formed in April 1995. BAI and its predecessor firm have participated
2 in more than 700 regulatory proceedings in 40 states and Canada.

3 BAI provides consulting services in the economic, technical, accounting, and
4 financial aspects of public utility rates and in the acquisition of utility and energy
5 services through RFPs and negotiations, in both regulated and unregulated markets.
6 Our clients include large industrial and institutional customers, some utilities and, on
7 occasion, state regulatory agencies. We also prepare special studies and reports,
8 forecasts, surveys and siting studies, and present seminars on utility-related issues.

9 In general, we are engaged in energy and regulatory consulting, economic
10 analysis and contract negotiation. In addition to our main office in St. Louis, the firm
11 also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix,
12 Arizona.

13 **Q HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?**

14 A Yes. I have sponsored testimony before state regulatory commissions including:
15 Arizona, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Iowa, Kansas,
16 Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Missouri,
17 Montana, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, South
18 Carolina, Texas, Utah, and Wyoming. In addition, I have also sponsored testimony
19 before the City Council of New Orleans and an affidavit before the FERC.

20 **Q PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR**
21 **ORGANIZATIONS TO WHICH YOU BELONG.**

22 A I earned the Chartered Financial Analyst ("CFA") designation from the CFA Institute.
23 The CFA charter was awarded after successfully completing three examinations which

1 covered the subject areas of financial accounting and reporting analysis, corporate
2 finance, economics, fixed income and equity valuation, derivatives, alternative
3 investments, risk management, and professional and ethical conduct. I am a member
4 of the CFA Institute and the CFA Society of St. Louis.

CLARKHILL\07411\484370\277178149.v2-5/2/24/492702

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

**In the matter of the Application of DTE
 GAS COMPANY for authority to increase
 its rates, amend its rate schedules and
 rules governing the distribution and
 supply of natural gas, and for
 miscellaneous accounting authority.**

Case No. U-21291

Rebuttal Testimony of

Christopher C. Walters

On behalf of

Association of Businesses Advocating Tariff Equity

May 29, 2024



Project 11589

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

	)	
In the matter of the Application of DTE	)	
GAS COMPANY for authority to increase	)	
its rates, amend its rate schedules and	)	
rules governing the distribution and	)	Case No. U-21291
supply of natural gas, and for	)	
miscellaneous accounting authority.	)	
	)	

Rebuttal Testimony of Christopher C. Walters

1 **I. Introduction**

2 **Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3 A Christopher C. Walters. My business address is 16690 Swingley Ridge Road,
4 Suite 140, Chesterfield, MO 63017.

5 **Q ARE YOU THE SAME CHRISTOPHER C. WALTERS THAT FILED DIRECT**
6 **TESTIMONY IN THIS PROCEEDING ON MAY 7, 2024?**

7 A Yes, I am.

8 **Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

9 A I am appearing on behalf of the Association of Businesses Advocating Tariff Equity
10 ("ABATE"). ABATE consists of large usage customers that purchase substantial
11 amounts of natural gas and/or delivery service from DTE Gas Company ("DTE" or
12 "Company").

1 **Q PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.**

2 A In my rebuttal testimony, I respond to the rate of return (“ROR”) recommendation put
3 forward by Michigan Public Service Commission Staff (“Staff”) witness Mr. Joseph
4 Ufolla. In particular, I respond to Mr. Ufolla’s recommended capital structure including
5 a common equity ratio of 51.0% and I comment on his recommended ROE of 9.80%.

6 My silence on any particular issue raised in the direct testimony of Staff or other
7 interveners should not be construed as tacit agreement.

8 **II. Response to Mr. Ufolla**

9 **Q WHAT OVERALL ROR IS STAFF PROPOSING DTE BE ALLOWED IN THIS**
10 **PROCEEDING?**

11 A Through the testimony of its witness, Mr. Ufolla, Staff recommends DTE be allowed an
12 overall ROR of 5.78%. Staff’s recommended ROR is headlined by an allowed ROE of
13 9.80% and an investor-supplied capital structure that includes a 51.0% common equity
14 ratio. Staff’s ROR is summarized in Table 1 below.

TABLE 1					
<u>Staff Overall Rate of Return</u>					
<u>Description</u>	<u>Amount</u>	<u>Permanent Weight</u>	<u>Ratemaking Weight</u>	<u>Cost Rate</u>	<u>Weighted Cost</u>
Long-Term Debt	\$ 2,694,099	49.00%	38.80%	4.38%	1.70%
Preferred Stock	\$ -	0.00%	0.00%	0.00%	0.00%
Common Equity	\$ 2,804,062	51.00%	40.38%	9.80%	3.96%
Total Permanent Capital	\$ 5,498,161	100.00%			
Short-Term Debt	\$ 184,380		2.66%	4.46%	0.12%
Deferred FIT	\$ 1,261,422		<u>18.17%</u>	0.00%	<u>0.00%</u>
Total Capitalization	\$ 6,943,963		100.00%		5.78%

Staff Exhibit S-4, Schedule D-1

1 **Q DO YOU HAVE ANY CONCERNS WITH MR. UFOLLA'S ANALYSIS?**

2 A Yes. My primary concern with Mr. Ufolla's recommended ROR lies with his
3 recommendation that DTE be allowed to maintain its existing permanent common
4 equity ratio of 51.0% despite the explicit preference of this Commission that DTE's
5 common equity ratio move toward a balanced level of 50.0%. In addition, I have
6 concerns with the analyses supporting his recommended ROE of 9.80%.

7 **Q PLEASE SUMMARIZE MR. UFOLLA'S REASONING FOR MAINTAINING DTE'S**
8 **IMBALANCED COMMON EQUITY RATIO OF 51.0% IN THE INSTANT**
9 **PROCEEDING.**

10 A Generally, Mr. Ufolla defers the transition to a balanced capital structure to be
11 determined in a future rate case, despite acknowledging this Commission's stated

1 preference for DTE's common equity ratio make movement toward 50.0%. Specifically,
2 Mr. Ufolla states in his testimony that:

3 An equity ratio of 50.00%-51.00% is more appropriate. The
4 Company's currently approved equity ratio is 51%, thus Staff uses
5 51.00% for the development of exhibits in the instant case.
6 Additionally, an authorization of a 51.00% equity ratio in the instant
7 case would allow for a smoother transition to a balanced equity ratio
8 of 50% in a future case.¹

9 **Q WHAT CONCERNS DO YOU HAVE WITH MR. UFOLLA'S RECOMMENDED**
10 **EQUITY RATIO?**

11 A While Mr. Ufolla states that maintaining the Company's existing equity ratio of 51.0%
12 will allow for a "smoother transition to a balanced equity ratio of 50% in a future case,"
13 there is no transition taking place now at his recommendation of 51.0%. As I explained
14 in my direct testimony², this Commission has provided explicit directives for DTE to
15 move toward a capital structure consisting of 50% equity.³ Further, the Commission's
16 Order in U-20940 makes reference to additional instances where it explicitly stated a
17 preference for the Company to move toward a balanced capital structure in the August
18 20, 2020 Order in U-20642 as well as the September 13, 2018 Order in U-18999.⁴

19 Nevertheless, Mr. Ufolla ignores the Commission's stated preference and
20 recommends the status quo be maintained instead of transitioning to an equity ratio of
21 50.0%.

¹Direct testimony of Joseph Ufolla at 6.

²Direct testimony of Christopher Walters at 25-26.

³MPSC Case No. U-20940, Order at 77.

⁴*Id.* at 76.

1 **Q PLEASE SUMMARIZE THE ANALYTICAL METHODS MR. UFOLLA RELIES ON IN**
2 **SUPPORT OF HIS RECOMMENDED ROE.**

3 A Mr. Ufolla performed a DCF analysis and a traditional CAPM on a proxy group of eight
4 natural gas utility holding companies, and three iterations of a Risk Premium model.
5 He also observed the average authorized ROE for gas utilities in 2022 and 2023.
6 Based on these data, Mr. Ufolla opines that DTE's cost of equity is within a range of
7 9.30% to 10.30%. His recommended ROE of 9.80% is the midpoint of this range. The
8 high-end of Mr. Ufolla's recommended range appears to be based on the results of his
9 proxy group's average and median DCF results of 10.51% and 10.01%, respectively.
10 The low-end of his range appears to be supported by his Risk Premium model results,
11 which fall in the range of 8.97% to 9.34%. His CAPM results fall between his DCF and
12 Risk Premium results⁵.

13 **Q WHAT CONCERNS DO YOU HAVE WITH MR. UFOLLA'S ROE ANALYSIS?**

14 A My main concerns with Mr. Ufolla's ROE analyses are two-fold: (1) his proxy group
15 includes several inappropriate companies and (2) his failure to consider the results of
16 a multi-stage DCF analysis. Absent these flaws, the high-end of Mr. Ufolla's range
17 would be significantly lower than 10.3%.

18 **Q WHAT CONCERNS DO YOU HAVE WITH MR. UFOLLA'S PROXY GROUP?**

19 A Mr. Ufolla erroneously included Chesapeake Utilities, NiSource, and UGI Corporation.
20 Chesapeake Utilities should have been excluded for two reasons: (1) neither it, nor its
21 utility subsidiaries have credit ratings; and (2) it acquired Florida City Gas, a natural
22 gas utility in southern Florida, from NextEra Energy on November 30, 2023 for nearly

⁵Direct testimony of Joseph Ufolla at 23-24.

1 \$1 billion. This transaction represents approximately 40% of its post-acquisition market
2 capitalization and certainly affects its fundamental value. Similarly, NiSource was also
3 a party to a significant transaction involving the sale of a 20% stake in NIPSCO, a major
4 vertically integrated electric utility, for \$2.16 billion earlier this year during Mr. Ufolla's
5 study period. The divestiture represents approximately 20% of NiSource's market
6 capitalization, affecting its fundamental value. UGI Corporation should have been
7 excluded as it has significant foreign operations in Europe. Mr. Ufolla acknowledges
8 that Staff typically eliminates companies on the basis of not have credit ratings and/or
9 foreign investment, specifically Chesapeake Utilities and UGI. However, he states that
10 he included them in this case due to the limited number of proxy company candidates
11 at this time, even though the results for Chesapeake and UGI produced "nominally
12 higher outputs from the DCF and CAPM."⁶

13 **Q HAD MR. UFOLLA EXCLUDED THOSE THREE COMPANIES FROM HIS**
14 **ANALYSES, WHAT WOULD HIS PROXY GROUP'S DCF AND CAPM RESULTS**
15 **HAVE BEEN?**

16 **A** Excluding the results for these three companies would produce average and median
17 DCF results of 9.94% and 9.81%, respectively. These results are reductions of
18 57 basis points and 20 basis points from Mr. Ufolla's average and median results,
19 respectively. Similarly, his proxy group's average and median CAPM results would
20 have been 9.73% and 9.59%, respectively. The corrected CAPM average is 16 basis
21 points lower than the 9.88% average he estimated, while the median is unchanged.
22 Clearly, Mr. Ufolla's construction of a proxy group had a material impact on his model
23 results, recommended range, and ultimately his recommended ROE.

⁶Direct testimony of Joseph Ufolla at 13-14.

1 **Q WHAT OTHER CONCERNS DO YOU HAVE WITH MR. UFOLLA'S ROE**
2 **ANALYSIS?**

3 A I have concerns with Mr. Ufolla's DCF inputs and results. Specifically, Mr. Ufolla's
4 proxy group has an average growth rate of 6.06%.⁷ This level of growth cannot be
5 sustained in perpetuity as it is more than 46% higher than the expected long-term
6 growth rate of the US Economy of 4.14%. As I explained in detail in my direct
7 testimony, no company can feasibly grow faster than the economy it operates in
8 forever, which is the time period assumed in the constant growth DCF model.⁸ Had
9 Mr. Ufolla performed a multi-stage DCF model that gives consideration to GDP growth,
10 his DCF results would be significantly lower.

11 **Q DID ANY OTHER COST OF CAPITAL WITNESS PERFORM A MULTI-STAGE DCF**
12 **ANALYSIS?**

13 A Yes. Both Dr. Villadsen and I performed a multi-stage DCF analysis which gave
14 consideration to the long-term GDP growth forecast.

15 **Q WHAT RECOMMENDATION ARE YOU MAKING FOR THIS COMMISSION TO**
16 **CONSIDER?**

17 A I recommend that the Commission reject Mr. Ufolla's recommended ROR based on a
18 capital structure including a 51.0% permanent common equity ratio at an allowed ROE
19 of 9.80%. I reiterate my recommendation the Commission authorize (1) an ROE of
20 9.45%, which is the midpoint of my recommended range of 9.1% to 9.8%, and (2) a

⁷Ufolla Exhibit S-4, Schedule D-5.

⁸Walters Direct Testimony at 33, 37-38.

1 balanced capital structure including a permanent common equity ratio of 50.0% in-line
2 with its explicit preference over the past several rate cases.

3 **Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

4 **A** Yes, it does.

497309

1 MR. CAMPBELL: Thank you, your Honor.

2 Also, in lieu of cross-examination of DTE's witnesses and
3 pursuant to stipulation from DTE, I move for admission of
4 Exhibit AB-20, which consists of certain discovery
5 responses from the Company.

6 JUDGE THOITS: Are there any objections
7 to the admission of this exhibit? (No response.)

8 Hearing none, Exhibit AB-20 is admitted.

9 MR. CAMPBELL: Thank you your Honor.
10 That's all for ABATE.

11 JUDGE THOITS: Thank you. Is the
12 Michigan Attorney General ready to bind in?

13 MR. KING: Yes, your Honor. Thank you.
14 Pursuant to the stipulation of the parties, the Attorney
15 General at this time moves to bind in the prefiled Direct
16 Testimony of Sebastian Coppola, consisting of a cover
17 page, table of contents, 148 pages of questions and
18 answers, and an Appendix A that contains Mr. Coppola's
19 experience and qualifications. Also at this time and
20 pursuant to the stipulation of the parties, the Attorney
21 General moves for the admission of prefiled Exhibits AG-1
22 through AG-55, inclusive, which were filed with
23 Mr. Coppola's testimony, as well as hearing room exhibits
24 AG 56 through AG-73, inclusive, which were circulated
25 amongst the parties last week prior to this hearing and

1 have been uploaded to the SharePoint site for review in
2 this case. I do note that either a portion or all of
3 Exhibits AG-2 and AG-61 are confidential. As such, the
4 unredacted versions of those have been served on the ALJ
5 and all parties who signed an NDC in this case, and I
6 move also at this time to admit those into the
7 confidential record.

8 JUDGE THOITS: All right. And just for
9 clarification, you said the confidential exhibits were
10 AG-2 and AG-61?

11 MR. KING: I believe those were the only
12 two, your Honor, that included any confidential material.

13 JUDGE THOITS: All right. Are there any
14 objections to the admission of this testimony or these
15 exhibits? (No response.)

16 Hearing none, the Direct Testimony of
17 Sebastian Coppola is bound in the record, and Exhibits
18 AG-2 and AG-61 are admitted into the confidential record,
19 and Exhibits AG-1 through AG-73, excluding Exhibits AG-2
20 and AG-61 are admitted.

21 (Testimony bound in.)

22 - - -
23
24
25

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

MPSC Case No. U-21291

In the matter of the application of)
DTE GAS COMPANY)
for authority to increase its rates, amend)
its rate schedules and rules governing the)
distribution and supply of natural gas,)
and for miscellaneous accounting authority)

Direct Testimony
And Exhibits
of
Sebastian Coppola

On behalf of
Attorney General Dana Nessel

May 7, 2024

TABLE OF CONTENTS

I. Introduction	3
II. Summary Conclusions and Recommendations	8
III. Large Increase in Rate Base and Capital Expenditures	10
IV. Review of Capital Expenditures	16
A. Distribution Plant.....	17
B. Transmission Plant.....	42
C. Gas Storage	49
E. Transportation Vehicles & Equipment.....	52
E. Gas Information Technology.....	54
F. Capital Expenditures Adjustment - Summary	54
V. Working Capital.....	56
VI. Cost of Capital	61
VII. Revenue Adjustment.....	94
A. Gas Sales Revenue.....	94
B. End User Transportation Revenue	100
C. Midstream Revenue	102
D. Appliance Repair Service	103
VIII. O&M Expense Adjustments.....	105
A. Company Gas Use and LAUF Gas	107
B. Uncollectible Accounts Expense.....	109
C. Inflation Adjustment & Expense Realignment	110
D. TIMP Pipeline Integrity	115
E MAOP Records Review	117
F. Leak Detection & Repair	119
G. Health Care Expense	120
H. Rents-Capital Use Charges	123
I. Deferred Incentive Compensation Amortization	123
J. Incentive Compensation	124
K. Deferred OPEB Negative Expense	130
L. Credit/Debit Card Merchant Fees	133
M. Corporate Jet Travel Costs	136
N. Responsibly Source Gas.....	136
O. O&M Expense - Summary.....	146
IX. Depreciation Expense/ X. Property Taxes/ XI. AFUDC	147
XII. Adjustments to Revenue Deficiency	148
XIII. Rate Design	149

I. Introduction

2 **Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.**

3 A. My name is Sebastian Coppola. I am an independent business consultant. My office is
4 at 5928 Southgate Rd., Rochester, Michigan 48306.

5 **Q. PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.**

6 A. I am a business consultant specializing in financial and strategic business issues in the
7 fields of energy and utility regulation. I have more than forty years of experience in public
8 utility and related energy work, both as a consultant and utility company executive. I have
9 testified in several regulatory proceedings before the Michigan Public Service
10 Commission (“MPSC” or “Commission”) and other regulatory jurisdictions. I have
11 prepared and/or filed testimony in rate case proceedings, revenue decoupling
12 reconciliations, gas conservation programs, Gas Cost Recovery (GCR) cases and Power
13 Supply Cost Recovery (PSCR) cases. As accounting manager and later financial executive
14 for two regulated gas utilities with operations in Michigan and Alaska, I have been
15 intricately involved in regulatory proceedings related to gas cost recovery cases, gas
16 purchase strategies, rate case filings and power plant cost analysis. I have also supported
17 other witnesses in testimony before the MPSC in various rate settings and other regulatory
18 proceedings.

1 **Q. PLEASE LIST SOME OF THE MORE RECENT CASES YOU HAVE**
 2 **PARTICIPATED IN BEFORE THE MPSC AND OTHER REGULATORY**
 3 **AGENCIES.**

4 A. Here is a partial list of the most recent regulatory cases in which I have participated in the
 5 last two years:

- 6 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Gas
 7 Company (DTE Gas) 2022-2023 GCR reconciliation in case No. U-21065.
- 8 ○ Filed testimony on behalf of the Michigan Attorney General in Consumers
 9 Energy (CECo) 2023 gas rate case U-21490 on several issues, including sales,
 10 operation and maintenance expenses, capital expenditures, cost of capital, and
 11 other items.
- 12 ○ Filed testimony on behalf of the Michigan Attorney General in DTM Michigan
 13 Lateral Company (DMLC) 2023 Act 9 Transportation Service rate update in
 14 case No. U-21525.
- 15 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Electric
 16 Company (DTEE) 2022 PSCR reconciliation in case No. U-21051.
- 17 ○ Filed testimony on behalf of the Michigan Attorney General in Michigan Gas
 18 Utilities Corporation (MGUC) 2022-2023 GCR reconciliation case No. U-
 19 21067.
- 20 ○ Filed testimony on behalf of the Michigan Attorney General in CECo 2022
 21 PSCR reconciliation in case No. U-21049.
- 22 ○ Filed testimony on behalf of the Michigan Attorney General in the Indian
 23 Michigan Power Company's 2023 electric rate Case U-21461 on several issues,
 24 including sales, operation and maintenance expenses, capital expenditures, cost
 25 of capital, and other items.
- 26 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2023-
 27 2024 GCR plan in case No. U-21271.
- 28 ○ Filed testimony on behalf of the Michigan Attorney General in CECo 2023-
 29 2024 GCR plan in case No. U-21269.
- 30 ○ Filed testimony on behalf of the Michigan Attorney General in CECo 2023
 31 electric rate Case U-21389 on several issues, including operation and
 32 maintenance expenses, capital expenditures, cost of capital, and other items.
- 33 ○ Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy
 34 Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
- 35 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Electric
 36 Company (DTEE) 2023 rate Case U-21297 on several issues, including

operation and maintenance expenses, capital expenditures, cost of capital, and other items.

- Filed testimony on behalf of the Michigan Attorney General in MGUC 2023-2024 GCR plan in case No. U-21273.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2022 gas rate Case U-21308 on several issues, including sales revenues, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-2022 GCR plan reconciliation case No. U-20817.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2021 PSCR plan reconciliation case No. U-20827.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2021-2022 GCR plan reconciliation case No. U-20819.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2022 general rate case No. U-21286.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-2022 GCR plan reconciliation case No. U-20823.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2022-2023 GCR plan case No. U-21062.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2022-2023 GCR plan case No. U-21070.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2022 electric rate Case U-21224 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Public Counsel Division of Washington Attorney General in the Avista 2022 electric and gas rate cases on several issues, including operation and maintenance expenses, capital expenditures, and other items.

Appendix A elaborates further on my qualifications in the regulated energy field.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked by the Michigan Attorney General (AG) to perform an independent analysis of DTE Gas Company's ("Company" or "DTE Gas") Rate Case filing in Case No. U-21291. This testimony presents a report of that analysis with related recommendations.

1 **Q. WHAT TOPICS ARE YOU ADDRESSING IN YOUR TESTIMONY?**

2 A. I am addressing the following major topics in this case:

- 3 1. The level of gas sales, End-User Transportation, and Midstream revenues
- 4 2. The net margin from the Home Protection Plan (HPP)
- 5 3. Operations and maintenance expenses
- 6 4. Incentive compensation and deferred expense
- 7 5. Rate base and capital expenditures
- 8 6. The Main Replacement Program and IRM
- 9 7. The Company's proposal to include Cathodic Protection expenditures in the
- 10 IRM
- 11 8. The proposal for the Company to recover premiums paid to purchase gas supply
- 12 labeled as Responsibly Sourced Gas (RSG)
- 13 9. Cost of Capital and Working Capital
- 14 10. Depreciation and Property Tax Expense
- 15 11. Customer Monthly Charges

16 The absence of a discussion of other matters in my testimony should not be taken as an
17 indication that I agree with those aspects of DTE Gas's rate case filing. The narrow focus
18 of my testimony is, instead, a consequence of focusing on select issues within the available
19 resources.

20 **Q. IS YOUR TESTIMONY ON THESE TOPICS ACCOMPANIED BY EXHIBITS?**

21 A. Yes. I am sponsoring the following exhibits, which were either prepared by me or under
22 my direct supervision:

- 23 1. Exhibit AG-1 DTE Energy Investor Presentation Information
- 24 2. Exhibit AG-2 CONF CPI Forecast Publication
- 25 3. Exhibit AG-3 Main Renewals Units
- 26 4. Exhibit AG-4 Actual Capex Distribution Program Costs 2021-2023

- 1 5. Exhibit AG-5 Public Improvements information
- 2 6. Exhibit AG-6 System Reliability Units and Costs 2020-2025
- 3 7. Exhibit AG-7 Meters and Modules Purchases 2018-2025
- 4 8. Exhibit AG-8 LDAR O&M and Capex Current
- 5 9. Exhibit AG-9 Fort Street Mai Replacement Timeline
- 6 10. Exhibit AG-10 Van Born Project Costs
- 7 11. Exhibit AG-11 PRA Risk Ranked Projects
- 8 12. Exhibit AG-12 MRP Cost Overruns 2016-2023
- 9 13. Exhibit AG-13 Cathodic Protection reasons for IRM
- 10 14. Exhibit AG-14 Transmission Projects
- 11 15. Exhibit AG-15 ILI Projects
- 12 16. Exhibit AG-16 TARP Project Higher Costs
- 13 17. Exhibit AG-17 Gas Storage and Compression Projects
- 14 18. Exhibit AG-18 Transportation Vehicles and Equipment Purchases
- 15 19. Exhibit AG-19 IT Project Cap Savings-Gas Scheduler Optimizer
- 16 20. Exhibit AG-20 Capital Expenditures, Depreciation, Property Taxes Disallowance
- 17 21. Exhibit AG-21 Working Capital
- 18 22. Exhibit AG-22 Overall Cost of Capital
- 19 23. Exhibit AG-23 Cost of Common Equity Capital
- 20 24. Exhibit AG-24 Cost of Common Equity Capital-DCF
- 21 25. Exhibit AG-25 Cost of Common Equity-CAPM
- 22 26. Exhibit AG-26 Cost of Common Equity-Risk Premium
- 23 27. Exhibit AG-27 Peer Group Analysis-Capital Structure
- 24 28. Exhibit AG-28 Market to Book Ratios
- 25 29. Exhibit AG-29 Gas ROE Decisions by Regulatory Commissions
- 26 30. Exhibit AG-30 DTE Gas Calculation of CFO Pre-WC to Debt Ratio
- 27 31. Exhibit AG-31 Value Line Analysis of Stock Market Volatility
- 28 32. Exhibit AG-32 Gas Sales Analyses
- 29 33. Exhibit AG-33 Gas Sales External Adjustments and Customer Usage Trends
- 30 34. Exhibit AG-34 Gas Sales Revenue Adjustments
- 31 35. Exhibit AG-35 End-User Transportation Power Generation Volumes

- 1 36. Exhibit AG-36 Midstream Revenue 2018-2023
- 2 37. Exhibit AG-37 Midstream Revenue Adjustments
- 3 38. Exhibit AG-38 Appliance Program Revenue and Margin 2018-2023
- 4 39. Exhibit AG-39 Other O&M Expense Adjustments Summary
- 5 40. Exhibit AG-40 Company Use Gas and LAUF Gas
- 6 41. Exhibit AG-41 Cost of Gas Update
- 7 42. Exhibit AG-42 Uncollectible Accounts Expense Calculation
- 8 43. Exhibit AG-43 Inflation Adjustment
- 9 44. Exhibit AG-44 2023 O&M Reduction
- 10 45. Exhibit AG-45 2023 O&M Cost Savings
- 11 46. Exhibit AG-46 DTE Voluntary Separation Package
- 12 47. Exhibit AG-47 Health Care Cost Adjustment
- 13 48. Exhibit AG-48 Rents Adjustment
- 14 49. Exhibit AG-49 Incentive Compensation Measures Achieved
- 15 50. Exhibit AG-50 O&M Expense-MAOP Records Review
- 16 51. Exhibit AG-51 OPEB Credit Balance
- 17 52. Exhibit AG-52 Fees for EFT, ACH, etc.
- 18 53. Exhibit AG-53 Corporate Jet Travel
- 19 54. Exhibit AG-54 Deferred Incentive Compensation Accrual
- 20 55. Exhibit AG-55 Revenue Deficiency Calculation

21 **II. SUMMARY CONCLUSIONS & RECOMMENDATIONS**

22 **Q. PLEASE PROVIDE A SUMMARY OF YOUR CONCLUSIONS AND**
 23 **ADJUSTMENTS TO THE COMPANY'S REVENUE DEFICIENCY**
 24 **CALCULATION BEFORE YOU ADDRESS EACH TOPIC IN DETAIL.**

25 A. The Company filed for a base rate increase of \$265.5 million. This rate increase represents
 26 an increase in base rates of 27% and an overall increase in rates of 9.3%, with a 9% increase
 27 to residential customers. As a result of the rate case adjustments I propose in my

1 testimony, the average residential customer would see an increase of approximately 6.5%
2 in their total bill.

3 It is noteworthy to point out that during the five-year period from 2015 to 2019, the
4 Company earned a return on common equity on a regulatory basis generally at or above
5 the authorized ROE rate. In 2022, DTE Gas had an earned ROE of 11.7% and had a
6 revenue sufficiency (excess) of \$35.7 million.¹

7 Based on my analysis, I have identified several cost disallowances to the Company's
8 proposed cost levels and capital projects, which I recommend that the Commission
9 approve. As a result of these adjustments, I have determined that the Company has a
10 revenue deficiency of \$112.2 million. This result should not be surprising given the fact
11 that the Company reported a revenue sufficiency in 2022 and earned a return on equity
12 above the authorized level.

13 Based on my analysis of the Company's case, I have reached the following summary
14 conclusions and recommendations:

- 15 1. I propose adjustments to increase gas sales, end-user transportation service,
16 and other revenues, which reduce the Company's filed revenue deficiency by
17 \$19.6 million.
- 18 2. I propose a lower level of Operations and Maintenance expenses of \$97.2
19 million for the test year.

¹ Exhibit A-1, Schedule A1 and A2, page 1.

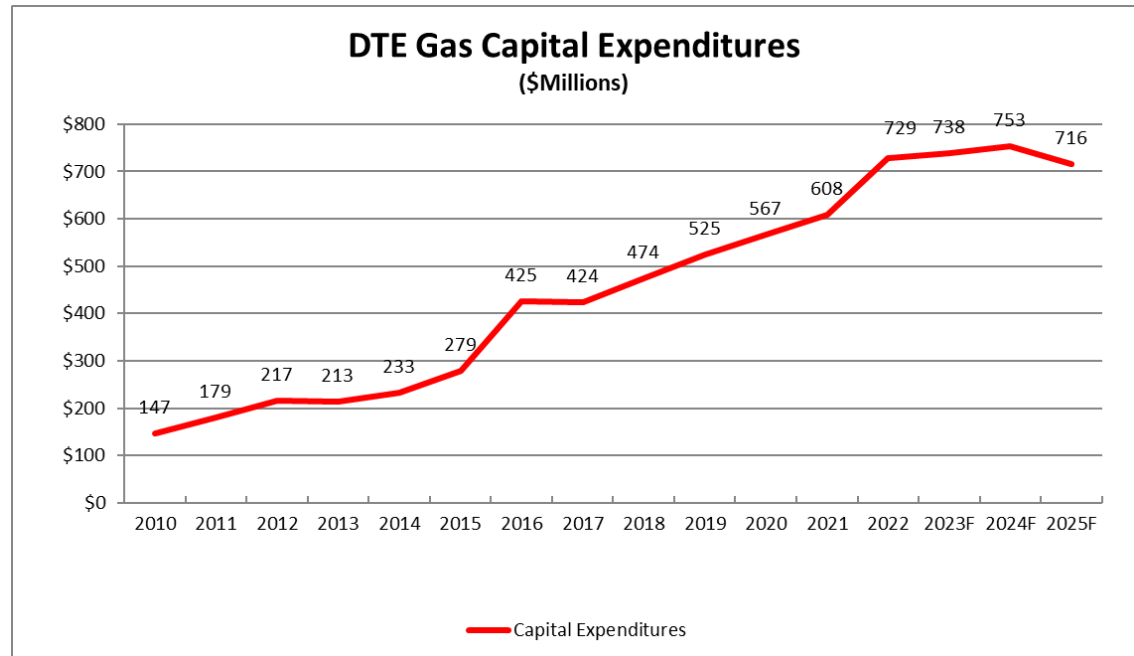
3. I propose a reduction in capital expenditures of \$172.3 million and a reduction in rate base of \$124.5 million, which reduce the revenue deficiency by \$9.8 million.
4. I propose a reduction in depreciation expense of \$3.4 million and property taxes of \$5.0 million pertaining to the proposed reductions in capital expenditures.
5. I recommend an authorized rate of return on equity of 9.85%, in comparison to the Company's proposed ROE rate of 10.25%, and a permanent capital structure with 50% common equity and 50% long-term debt, which results in a reduction in the revenue deficiency of \$21.1 million.
6. I recommend that the Commission reject the recovery of RSG premiums.
7. I recommend that the Commission approve the amortization of the deferred OPEB credit balance.
8. I recommend that the Commission reject the Company's proposed increase in the Monthly Customer Service Charges for Rate Schedules A, 2A, and GS-1 and preferably keep those monthly charges at the same current levels, or in the alternative increase Rate A and 2A by no more than \$1 per month.

The remainder of my testimony provides further details and support for these summary conclusions and recommendations.

III. LARGE INCREASE IN RATE BASE AND CAPITAL EXPENDITURES

Q. PLEASE DISCUSS YOUR CONCERNS WITH THE LEVEL OF CAPITAL EXPENDITURES PROPOSED BY THE COMPANY AND THE RESULTING INCREASE IN RATE BASE.

1 A. In this general rate case, DTE Gas proposes capital expenditures of \$730.6 million for
 2 2023, \$559 million for the 9 months ending September 2024, and an additional \$465
 3 million for the 12 months ending September 2025. In addition, the Company proposes to
 4 spend \$354 million in 2025 on the IRM program with similar amounts in the subsequent
 5 four years. The total proposed capital expenditures over this 36-month period are nearly
 6 \$2.1 billion.² These expenditures follow capital expenditures of \$1.9 billion made during
 7 the prior three years from 2020 to 2022.³ The following chart in Table 1 shows the
 8 dramatic increase in capital expenditures over recent years, in comparison to more
 9 moderate amounts in prior years.



10

² Exhibit A-12, Schedule B5.

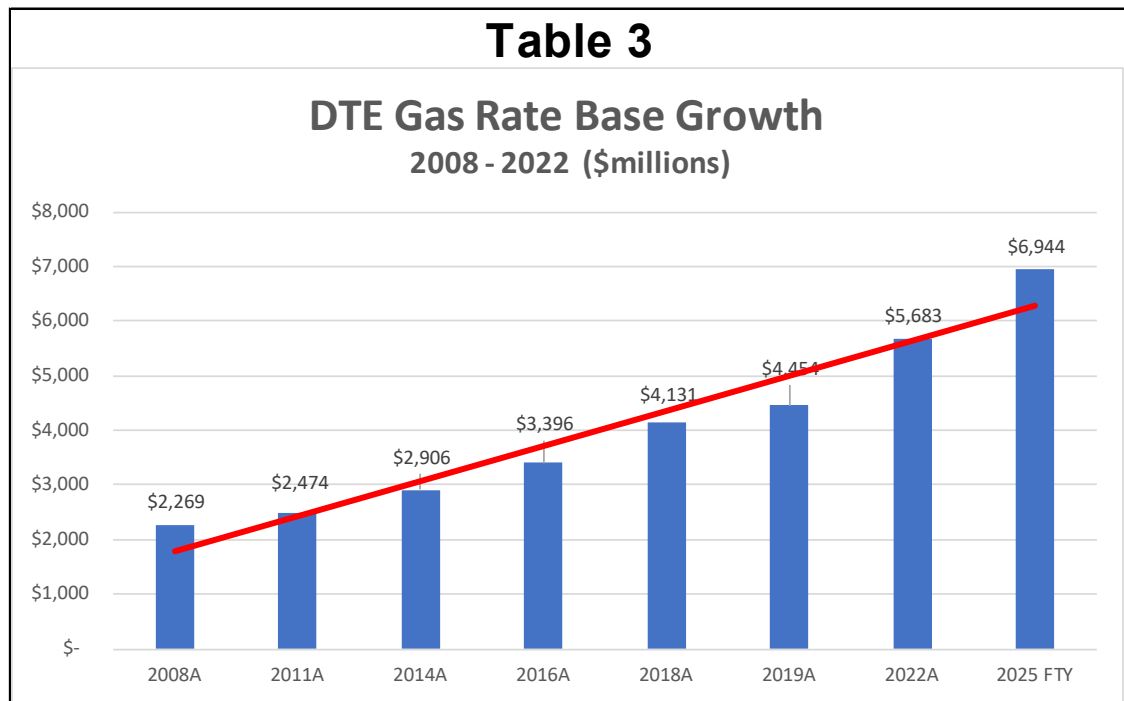
³ DTE Gas response to DR U-21291-AGDG-5.125.

Until 2012, the Company was able to keep capital expenditures below \$200 million annually. By 2016, annual capital expenditure had doubled and eight years later has nearly doubled again, to \$753 million.

The capital expenditures have fueled an alarming increase in rate base. As shown below in Table 2, rate base has been growing at high-single digit to double digit rates in recent years and the Company is proposing to increase rate base again in this rate case by 22%, to \$6.9 billion. The proposed level of rate base in this rate case is more than double the amount of rate base the Company had 9 years ago.

Table 2 DTE Gas Rate Base Growth 2008 to Projected 2022 Test Year								
Rate Base Year	2008A	2011A	2014A	2016A	2018A	2019A	2022A	2025 FTY
Docket No.	U-15985	U-16999	U-17999	U-18999	U-20642	U-20940	U-21291	U-21291
Rate Base ¹ (Millions)	\$ 2,269	\$ 2,474	\$ 2,906	\$ 3,396	\$ 4,131	\$ 4,454	\$ 5,683	\$ 6,944
Year over Year Change		9%	17%	17%	22%	8%	28%	22%
Cumulative Change over 2008 Rate Base		9%	28%	50%	82%	96%	150%	206%
¹ Historical actual rate base in each docket, except 2025 FTY is proposed amount.								

This significant increase in rate base is illustrated by the following chart, included in Table 3, which shows the accelerated trend of increases in recent years. The current trend has significant negative implications for customer bills, as discussed later in my testimony.



1

2 **Q. WHAT DO YOU BELIEVE IS DRIVING THIS DRAMATIC INCREASE IN**
 3 **CAPITAL EXPENDITURES AND RATE BASE AT LEAST IN THE LAST 10**
 4 **YEARS?**

5 A. I believe there are two main drivers. First, replacement of aging infrastructure and new
 6 capital spending to address market growth have required an increase in capital expenditures,
 7 which have accelerated investment to some degree. The Company continues to propose
 8 ever-increasing capital expenditures to replace cast iron mains, service lines and related
 9 facilities. Some of this work is necessary and must be done. However, the Company has
 10 intensified the pace of replacement of pipelines and other facilities without sufficient
 11 engineering analysis to support the increase in capital expenditures.

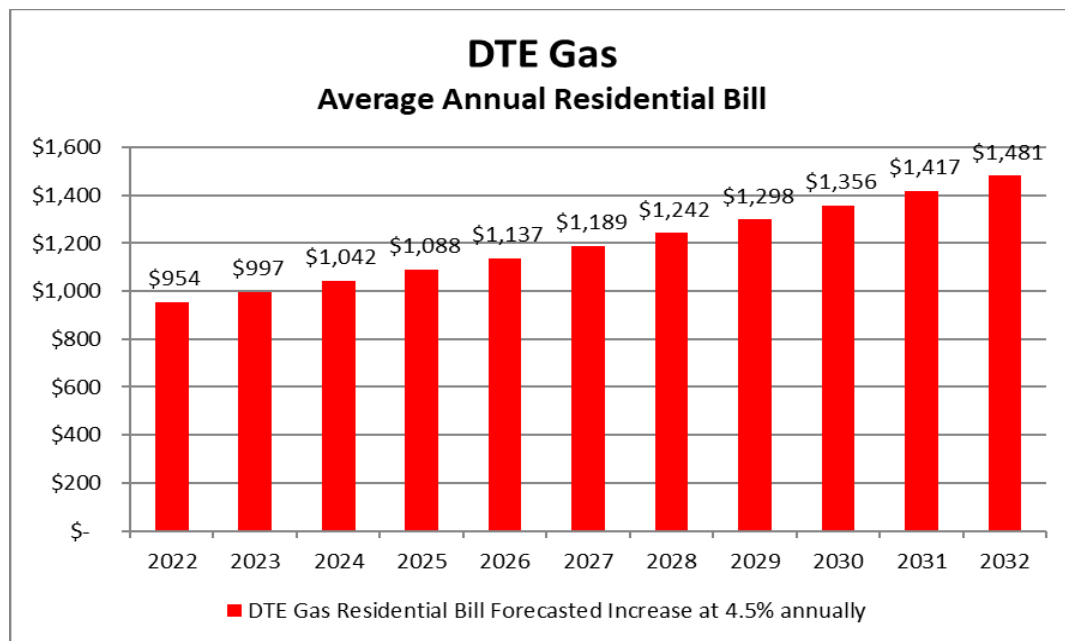
1 The Company also seems to be experiencing moderate customer growth in its market area.
2 However, moderate customer growth has existed in prior years. Prior to 2012, DTE Gas
3 was able to manage replacement of aging infrastructure and also invest in new facilities to
4 meet market growth within a more reasonable increase in rate base. Therefore, customer
5 growth and replacement of aging infrastructure by themselves do not fully explain the
6 significant increase in capital expenditures and rate base since 2011.

7 Second and perhaps a bigger driver, the replacement of aging gas infrastructure has given
8 the Company an opportunity to accelerate rate base growth in order to increase earnings
9 growth. For utility companies, earnings growth is directly related to rate base growth. As
10 shown in the tables above, large increases in capital expenditures result in double digit
11 increases in rate base, which in turn fuels earnings growth, dividend growth, and stock price
12 appreciation for shareholders.

13 The Company's parent company, DTE Energy, has been quite clear and aggressive in
14 communicating to investors and securities analysts its goal of increasing operating earnings
15 at the gas utility at an average annual rate of 7%. Exhibit AG-1 includes pertinent pages
16 from an April 2024 Investor Presentation, which show this drive to increase earnings
17 through increased capital spending at the utility. For a utility such as DTE Gas with limited
18 sales and revenue growth, the increase in earnings comes almost entirely from the increase
19 in capital expenditures and rate base. The presentation is devoid of any discussion about
20 sales or revenue growth to propel earnings growth at the utility. Recent investor
21 presentations reaffirm the same goals, showing how shareholders have been well rewarded.

1 **Q. HAVE YOU DETERMINED WHAT THE IMPACT ON RESIDENTIAL**
 2 **CUSTOMER BILLS COULD BE OVER THE COMING YEARS IF THE**
 3 **COMMISSION APPROVES THE PROPOSED RATE INCREASE AND THAT**
 4 **RATE OF INCREASE CONTINUES INTO FUTURE YEARS?**

5 A. Yes. The Company has proposed to increase residential rates in this rate case by 9%. If we
 6 assume that the Company continues its current pace of capital expenditures with bi-annual
 7 rate cases and rate increases, the average residential total annual gas bill in 10 years will
 8 increase by nearly 50%, from \$954 in 2022 to \$1,481 in 2032.⁴ Table 4 below shows the
 9 potential increase in the average residential gas bill if the current trend in rate base growth
 10 continues and gas commodity costs remain the same.



⁴ Current average gas bill (2022) of \$954 = Total Rate A revenue of \$1,190,770,000 divided by 1,248,500 Rate A/A2 residential customers per Exhibit A-16, Schedule F2, page 1 and Exhibit A-16, Schedule F3, page 1. Current bill escalated at 4.5% per year through 2032 (9% increase from 2022 to 2024 divided by 2).

1 Such an escalation in annual customer bills would pose a significant burden on all residential
2 customers, and especially those with fixed and low income. In addition, this dramatic
3 potential increase in residential bills does not take into consideration potential increases in
4 gas commodity costs and further escalations in capital expenditures. Should gas commodity
5 costs increase significantly in the coming years, customers may run into even greater bill
6 affordability problems.

7 The compounding effect of large additions to rate base will continue to increase customer
8 rates to unaffordable levels for many customers, particularly those in fixed and lower income
9 brackets. Simply put, this trend is not sustainable for customers. To avoid bill affordability
10 problems, the Company needs to moderate and be more selective in its capital spending in
11 the coming years.

12 **IV. Review of Capital Expenditures**

13 **Q. IN YOUR ANALYSIS, HAVE YOU DETERMINED SPECIFIC AREAS WHERE**
14 **CAPITAL EXPENDITURES COULD BE REDUCED?**

15 A. Yes. I analyzed the Company's forecasted capital expenditures by major department or
16 area, and I identified reasonable expenditure levels that the Commission should adopt. In
17 projecting adjusted capital expenditures for 2024 and the projected test year, where
18 applicable, I applied an inflation factor to the historical cost base to reflect inflationary
19 cost pressure that the Company may face in those years. The inflation factors are 2.6%

1 for 2024 and 2.2% for 2025. These rates reflect the increase in the forecasted Consumer
2 Price Index for the 2024-2025 periods published on March 1, 2024.⁵

3 **A. Distribution Plant**

4 As shown in Exhibit A-12, Schedule B5.1, the Company forecasted capital expenditures
5 for routine distribution facilities of \$234.0 million for 2023, \$186.1 million for the 9
6 months ending September 2024, and \$230.3 million for the 12 months ending September
7 2025. After reviewing the testimony of Company witness Emil Abona, related exhibits,
8 and responses to discovery, I have identified capital expenditure reductions applicable to
9 several areas.

10 **1. Main Renewals**

11 **Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES**
12 **FOR MAIN RENEWALS.**

13 A. As shown on page 2, line 3 of Exhibit A-12, Schedule B5.1, the Company had average
14 capital expenditures of \$5.8 million for main renewals during the 5 years from 2018 to
15 2022 and forecasted capital expenditures of \$5.8 million for 2023, \$7.0 million for the 9
16 months ending September 2024, and \$5.3 million for the 12 months ending September
17 2025. On page 8 of his direct testimony, Mr. Abona briefly discusses the forecasted
18 cumulative spending in this area over the 3-year period ending in 2025 in comparison to

⁵ Exhibit AG-2 CONF includes the publication with the forecasted CPI for 2024 and 2025.

1 the 5-year historical period ended in 2022 and noted the unplanned or emergent nature of
2 the capital expenditures.

3 In discovery, the Attorney General asked the Company to provide the historical and
4 forecasted number of feet of main renewals. In the response, the Company identified the
5 historical feet of main renewals from 2018 to 2023 and stated that it does not forecast the
6 units to be renewed. The response also stated that the capital expenditures for future
7 periods were forecasted based on the historical average.⁶ The discovery response shows
8 that historical feet of main replaced has been rather consistent in the past 3-years, ranging
9 from 13,455 to 17,980 feet and averaging approximately 15,000 feet annually. The three-
10 year average of main renewed is only slightly higher than the 14,200 feet renewed on
11 average over the past five years.

12 **Q. WHAT IS YOUR ASSESSMENT OF MAIN RENEWAL PROGRAM?**

13 A. Based on the more recent 3-year average, I determined that the Company incurred capital
14 spending for main renewals of \$7,313,000 on average annually over the 2021 to 2023
15 period. This amount was calculated based on actual expenditures provided by the
16 Company in response to discovery request STDG-1.1.⁷ After adjusting for inflation, I
17 determined that the forecasted capital expenditures for main renewals for 2024 should be
18 \$7,503,000 and \$5,627,000 for the 9 months ending September 2024.⁸ The Company
19 forecasted capital expenditures of \$7,019,000 for the 9 months ending September 2024.

⁶ Exhibit AG-3 includes DR AGDG-5.127.

⁷ Exhibit AG-4 includes DR STDG-1.1 with related attachment.

⁸ $\$7,313,000 \times 1.026 = \$7,503,000$ $\times 9/12 = \$5,627,000$.

1 This amount is excessive and overstated by \$1,392,000. For the projected test year ending
2 September 2025, I find the Company forecasted capital expenditures to be in line with
3 historical spending levels and I do not propose any adjustments.

4 Therefore, I recommend that the Commission remove the \$1,392,000 from the Company's
5 forecasted capital expenditures for the 9 months ending September 2024 included in rate
6 base.

7 **2. Public Improvements**

8 **Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES**
9 **FOR PUBLIC IMPROVEMENTS.**

10 A. On page 2, line 4 of Exhibit A-12, Schedule B5.1, the Company shows average capital
11 expenditures of \$22.1 million for public improvements during the 5 years from 2018 to
12 2022 and forecasted capital expenditures of \$32.2 million for 2023, \$19.9 million for the
13 9 months ending September 2024, and \$19.5 million for the 12 months ending September
14 2025. Beginning on page 8 of his direct testimony, Mr. Abona discusses the forecasted
15 cumulative spending in this area over the 3-year period ending in 2025 in comparison to
16 the 5-year historical period ended in 2022 and noted that the capital expenditures in this
17 area are dependent on projects undertaken by government agencies in the public right-of-
18 way (ROW) often requiring relocation or changes to the gas lines located in the ROW. In
19 his testimony, Mr. Abona discusses the East Jefferson and the Connor/I-94 projects as two
20 major projects included in this category of capital expenditures.

1 In discovery, the Attorney General asked the Company to provide the historical and
 2 forecasted number of units, miles, or quantity of work performed in this expenditure
 3 category and the related spending for both the historical and forecasted periods. In
 4 response, the Company provided the list of projects and related dollars spent for the
 5 historical three years of 2021 to 2023 and stated that it did not have a list of future projects
 6 past 2023, other than a few identified major projects.⁹

7 Based on the information provided by the Company in DR STDG-1.1 for 2021 through
 8 2023, I determined that the three-year average routine capital spending in this area was
 9 \$16,247,000. I arrived at this amount by removing four major projects from the historical
 10 periods (2021-2023), including the East Jefferson and the Connor/I-94 project costs.¹⁰
 11 After adjusting for inflation, I calculated forecasted capital expenditures of \$12,502,000
 12 for the 9 months ending September 2024 and \$16,944,000 for the projected test year.¹¹

13 I took a similar approach to determine the cost for routine of routine capital expenditures
 14 forecasted by the Company for this spending category. Page 1 of Exhibit A-12, Schedule
 15 B5.11, shows forecasted amounts for 2024 and 2025. For 2024, the Company identifies
 16 certain projects included in the total forecasted amount of \$24,869,000. To determine the
 17 routine level of capital expenditures in this spending category, I removed two large
 18 projects identified by the Company in the exhibit schedule. Those projects are the
 19 Conner/I-94 and the Springfield/I-94, which total to \$8,373,000 for 2024 and \$6,280,000

⁹ Exhibit AG-5 includes DR AGDG-5.128.

¹⁰ Exhibit AG-4 DR STDG-1.1 attachment under Public Improvements. Removed projects on sub-lines 4.1 to 4.4.

¹¹ 9 months 2024: $\$16,247,000 \times 1.026 = \$16,669,000 \times 9/12 = \$12,502,000$. PTY: $\$16,669,000 \times 1.022 = \$17,036,000 \times 9/12 + 16,690,000 \times 3/12 = \$16,944,000$.

1 for the 9 months ending September 2024. By removing this amount from the Company's
2 total forecasted amount of \$19,942,000, I determined routine capital expenditures for
3 public improvements in the Company's forecast for the 9 months ending September 2024
4 to be \$13,662,000. For 2025, the Company forecasted \$19,459,000 in capital
5 expenditures, but did not identify any projects supporting that amount.

6 In comparing my calculations of the forecasted capital expenditures for the 9 months
7 ending September 2024 of \$12,502,000 to the Company's adjusted forecasted amount of
8 \$13,372,000, I find that the Company's forecast is overstated by \$1,160,000. For the
9 projected test year, the Company's forecasted amount of \$19,518,000 is excessive in
10 comparison to my forecast of \$16,944,000 discussed above by \$2,574,000. The Company
11 did not provide any justification for the higher capital expenditures.

12 I recommend that the Commission remove \$1,160,000 for the 9 months ending September
13 2024 and \$2,574,000 from the capital expenditures forecasted by the Company for public
14 improvements.

15 **3. System Reliability**

16 **Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES**
17 **FOR SYSTEM RELIABILITY PROJECTS.**

18 A. On page 2, line 8 of Exhibit A-12, Schedule B5.1, the Company shows average capital
19 expenditures of \$26.4 million for system reliability projects during the 5 years from 2018
20 to 2022 and forecasted capital expenditures of \$35.9 million for 2023, \$34.9 million for

1 the 9 months ending September 2024, and \$31.0 million for the 12 months ending
2 September 2025. Beginning on page 19 of his direct testimony, Mr. Abona discusses the
3 forecasted cumulative spending in this area over the 3-year period ending in 2025 in
4 comparison to the 5-year historical period ended in 2022 and describes the type of work
5 performed.

6 In his testimony, Mr. Abona also discusses various cost pressure that affected the unit cost
7 historically and for the projected periods. In Table 6 on page 22 of his testimony, he shows
8 the unit costs and the number of units completed during 2020 to 2022 and forecasted for
9 2023 to 2025. The table shows the number of units increasing significantly in 2024 and
10 2025 from historical level. However, Mr. Abona's testimony does not explain or support
11 the increase in forecasted units.

12 In discovery, the Attorney General asked the Company to provide an updated Table 6 with
13 2023 actual data. The updated table provided in response to discovery shows that in 2023
14 the Company actually installed only 87 units instead of the forecasted 97 units planned
15 and at a higher unit cost.¹² From the actual units completed between 2021 and 2023, I
16 calculated an average of 86 units completed annually. In comparison, the 118 units
17 forecasted by the Company for 2024 is an increase of 37% over the three-year average.
18 For 2025, the 103 units forecast is an increase of 20% over the three-year average.

19 As stated above, the Company has not provided any justification to support the higher
20 number of forecasted units or projects. Furthermore, in response to discovery, the

¹² Exhibit AG-6 includes DR AGDG-5.134 with attachment.

1 Company stated that several of the listed projects are in the planning or early design phase,
 2 indicating that the projects have not yet been sufficiently developed through the
 3 engineering phase to be certain for completion within the 2025 projected test year.¹³

4 Based on the information provided by the Company, I calculated the reduction in
 5 forecasted capital expenditures in this spending category using the 86 units completed on
 6 average annually over the most recent three years versus the number of units forecasted
 7 by the Company. For 2024, the difference in the number of units is 32 (118 – 86). By
 8 multiplying the 32 units by the Company’s forecasted unit cost of \$292,458, I calculated
 9 lower capital expenditures of \$9,359,000 for 2024 and \$7,019,000 for the 9 months ending
 10 September 2024. Similarly, for 2025, the 17 fewer units (103 – 86) multiplied by the
 11 Company’s forecasted unit cost of \$332,039 results in lower capital expenditures of
 12 \$5,645,000. For the 12 months ending September 2025, the applicable adjustment is a
 13 reduction of \$6,573,000.¹⁴

14 I recommend that the Commission remove the \$7,019,000 from the Company’s forecasted
 15 capital expenditures for the 9 months ending September 2024 and \$6,573,000 for the 12
 16 months ending September 2025.

17 **4. Communications & Control - Meters**

18 **Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES**
 19 **FOR COMMUNICATIONS & CONTROL - METERS.**

¹³ Id. includes DR AGDG-5.149a and b.

¹⁴ \$9,359,000 x 3/12 + \$5,645,000 x 9/12 = \$6,573,000.

1 A. As shown on page 2, line 10 of Exhibit A-12, Schedule B5.1, the Company had average
2 capital expenditures of \$14.8 million for communication and control meters during the 5
3 years from 2018 to 2022 and forecasted capital expenditures of \$21.8 million for 2023,
4 \$18.3 million for the 9 months ending September 2024, and \$16.5 million for the projected
5 test year. Beginning on page 27 of his direct testimony, Mr. Abona discusses the drivers
6 for the forecasted capital expenditures for meters and related equipment, describing supply
7 chain issues, price increases, and volume changes.

8 In discovery, the Attorney General asked the Company to provide specific information of
9 quantity and related costs by meter type, modules, and related equipment for each year
10 2018 to 2023 and forecasted for 2024 and 2025. The granular information provided by the
11 Company shows that although average meter prices increased from 2018 to 2022 peaking
12 at \$220 in 2022, in 2023 the average price decreased to \$167. In contrast, the Company
13 forecasted average meter prices of \$215 for 2024 and \$190 for 2025.¹⁵ The forecasted
14 prices represent increases of 29% and 14%, respectively, over the 2023 actual price of
15 \$167.

16 For modules, average prices reached a peak of \$57 in 2023 and the Company forecasted
17 further increases to \$68 in 2024 and \$71 in 2025.¹⁶ The forecasted prices represent
18 increases of 19% and 25%, respectively, over the 2023 actual price of \$57.

¹⁵ Exhibit AG-7 includes DR AGDG-5.137b with attachment.

¹⁶ Id.

1 Although in his direct testimony, Mr. Abona provides general statements and reasons for
2 the price increases, there is no quantifiable evidence that historical price increases will
3 continue into the future and particularly at the rate of increases identified above. By
4 applying the forecasted rate of inflation for 2024 and 2025 to the actual price paid per
5 meter in 2023 of \$167, I calculated a forecasted price per meter of \$171 for 2024 and \$175
6 for 2025.¹⁷ Using these prices and the number of units forecasted by the Company of
7 38,627 for 2024 and 50,058 for 2025, I calculated forecasted capital expenditures of
8 \$6,605,000 and \$8,760,000, respectively for each year. These amounts are \$1,719,000
9 lower than the \$8,324,000 for 2024 and \$763,000 lower from the \$9,523,000 for 2025
10 shown in the attachment to DR AGDG-5.137b.¹⁸

11 For the module purchases, I applied the inflation factors for 2024 and 2025 to the actual
12 price of \$57 for 2023 to arrive at the forecasted prices of \$58 and \$59 for each year.¹⁹ By
13 applying these prices to the number of units forecasted by the Company of 88,454 for 2024
14 and 67,714 for 2025, I arrived at forecasted capital expenditures of \$5,130,000 and
15 \$3,995,000 for each respective year. These amounts are lower by \$898,000 from the
16 \$6,028,000 forecasted by the Company for 2024 and \$816,000 from the \$4,811,000
17 forecasted by the Company for 2025. The Company's forecasted costs are shown in the
18 attachment in DR AGDG-5.137 (Exh. AG-7).

¹⁷ $\$167 \times 1.026 = \$171 \times 1.022 = \$175$.

¹⁸ Exhibit AG-7.

¹⁹ $\$57 \times 1.026 = \$58 \times 1.022 = \$59$.

1 The total lower forecasted amounts for meters and modules, combined, for 2024 and 2025
 2 are \$2,617,000 and \$1,579,000, respectively. Based on the reasonable price forecasts I
 3 calculated for 2024 and 2025, I recommend that the Commission remove capital
 4 expenditures of \$1,963,000 for the 9 months ending September 2024 and \$1,406,000 for
 5 the 12 months ending September 2025.²⁰

6 **Q. ARE THERE ARE ADJUSTMENTS THAT YOU PROPOSE TO THE**
 7 **COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR**
 8 **COMMUNICATIONS AND CONTROL METERS?**

9 A. Yes. The detailed meter and module forecasted costs provided by the Company in
 10 response to DR AGDG-5.137b are significantly lower than the forecasted capital
 11 expenditures shown on line 10 of page 2 of Exhibit A-12, Schedule B5.11. Schedule B5.11
 12 shows forecasted capital expenditures of \$18,273,000 for 9 months ending September
 13 2024 and \$16,466,000 for the projected test year. In comparison, the attachment to DR
 14 AGDG-5.137b, when prorated for the 9 months ending September 2024 and 12 months
 15 ending September 2025 shows \$10,764,000 ($\$14,352,000 \times 9/12$) and \$14,338,000,
 16 respectively.²¹ The difference is \$7,509,000 for the 9 months ending September 2024 and
 17 \$2,128,000 for the 12 months ending September 2025. These amounts are unsupported
 18 and there is no explanation in Mr. Abona's testimony describing any other spending

²⁰ $\$2,617,000 \times 9/12 = \$1,963,000$ and $\$2,617,000 \times 3/12 + \$1,579,000 \times 9/12 = \$1,406,000$.

²¹ $\$14,352,000 \times 3/12 + \$14,334,000 \times 9/12 = \$14,338,000$.

1 category other the meters and module purchases. Furthermore, the Company did not
2 provide any schedules or data supporting data the remaining forecasted amounts.

3 Due to the lack of supporting evidence, I propose that the Commission remove the
4 forecasted capital expenditures differences of \$7,509,000 for the 9 months ending
5 September 2024 and \$2,128,000 for the 12 months ending September 2025.

6 **5. Leak Detection & Repair**

7 **Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES**
8 **FOR THE LEAK DETECTION AND REPAIR PROJECT.**

9 A. On page 2, line 16 of Exhibit A-12, Schedule B5.1, the Company shows forecasted capital
10 expenditures of approximately \$15.0 million for leak detection and repairs (LDAR) for the
11 projected test year. Mr. Abona discusses this expanded program beginning on page 36 of
12 his direct testimony. According to Mr. Abona, the incremental expenditures stem from a
13 pending rule to be issued by the Pipeline and Hazardous Materials Safety Administration
14 (PHMSA). As described by Mr. Abona, the rule would require the Company to perform
15 more intensive gas leak detection procedures and require more timely repairs of leaking
16 pipes and facilities along with other preventive measures. In Table 9 on page 37 of his
17 direct testimony, Mr. Abona identifies the capital expenditures that total to \$15.0 million.
18 These projected capital expenditures are incremental to the Company's current leak
19 detection and repair program.

1 **Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY’S SPENDING PLANS FOR**
2 **THE LDAR PROJECT?**

3 A. The forecasted expenditures are premature and not likely to occur in the amounts
4 forecasted in the projected test year. Furthermore, the Company has not presented a
5 detailed plan of how it plans to implement the new rule requirements and over what
6 timeframe, the equipment needed over that timeframe, and how the new requirements
7 dovetail into the Company’s current practices and procedures in detecting and repairing
8 gas leaks. The only information Mr. Abona has provided is contained in Table 9.

9 Based on information provided in discovery responses, the Company had nearly \$4.0
10 million of capital expenditures in 2023 related to leak detection and repairs, and an
11 additional \$19.5 million was spent on O&M expenses for leak detection and repairs during
12 the year. None of those expenditures are shown in Exhibit A-12, Schedule B5.1, or
13 addressed by Mr. Abona or other Company witnesses. The discovery responses also show
14 that the Company has forecasted \$27.4 million of capital expenditures for leak detection
15 and repairs for 2024 in addition to the \$15 million shown in Schedule B5.1. In his direct
16 testimony, Company witness Scotty Kehoe proposes an additional \$10.3 million in O&M
17 expense for LDAR related to the new PHMSA rule. Therefore, in total for all those
18 activities, the Company is proposing to spend in excess of \$53 million on leak detection
19 and repairs for the projected test year.²² It is not clear why, in less than one year, the total

²² Exhibit AG-8 includes DRs AGDG-2.30a, 2.30c, 5.142a, 5.143a-h.

1 spending would more than double or whether the Company would have the capability to
2 accomplish that level of increased activity and related spending.

3 According to the Company, the final rule is not expected to be issued before September
4 2024 and the rule would go into effect six months thereafter, which would place the initial
5 effective date in March 2025 at the earliest. It is also common for such rules to have a
6 provision to achieve compliance over several years. Therefore, the rush for the Company
7 to spend an additional \$15 million in capital expenditures and \$10.3 million in O&M
8 expense to comply with the new proposed rule requirements is unwarranted. Until the
9 Company is able to present a comprehensive plan of how and when it will expand the
10 current leak detection and repair program to be compliant with the final PHMSA LDAR
11 rule, it is premature to approve the significant increase in spending proposed by the
12 Company both for capital and O&M expenditures.

13 Therefore, I recommend that the Commission reject the \$14,970,000 of capital
14 expenditures and the \$10,276,000 of O&M expense forecasted by the Company for the
15 projected test year.

16 **6. Fort Street Main Replacement**

17 **Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES**
18 **FOR THE FORT STREET MAIN REPLACEMENT PROJECT.**

19 A. On line 6 of Exhibit A-12, Schedule B5.2, the Company shows capital expenditures of
20 \$13.2 million for the Fort Street Main Replacement project for 2022 and forecasted capital

1 expenditures of \$19.9 million for 2023, \$15.9 million for the 9 months ending September
2 2024, and \$32.8 million for the 12 months ending September 2025. Beginning on page 32
3 of her direct testimony, Company witness Kelly Fedeles discusses this multi-phase project
4 spanning over multiple years. The Company's capital forecast for 2023 through 2025
5 anticipates completion of Phases 5, 6, 7, and 7A and coordination with municipal and state
6 projects for reconstruction and modification to Jefferson Street and the I-375
7 Reconstruction project.

8 In discovery, the Attorney General asked the Company to provide the timing of the I-375
9 Reconstruction and other applicable municipal projects that will drive the timing of the
10 Fort Street project. In response, the Company stated that Phase 5 was completed in 2023
11 and Phase 7 around the Michigan Central Train Station would be completed by April 2024.
12 With regard to the I-375 Reconstruction project, no timing was provided and the Company
13 is waiting for more information from the Michigan Department of Transportation
14 (MDOT).²³

15 **Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S SPENDING PLANS FOR**
16 **THE FORT STREET MAIN REPLACEMENT PROJECT?**

17 A. Although the capital spending forecasted for 2024 appears likely to occur, the capital
18 spending for the projected test year is dependent on the timing of the I-375 Reconstruction
19 project and MDOT has not yet defined a specific timeline. It is premature to approve
20 capital spending on the Fort Street Main Replacement for the projected test year until there

²³ Exhibit AG-9 includes DR AGDG-5.106b.

1 is more clarity and specific plans from MDOT for the Company to act on. It would be
2 imprudent for the Company to proceed with construction activities without a firm timeline
3 and an approved project plan from MDOT and the City of Detroit.

4 As the Company discovered with the East Jefferson main replacement project, costs can
5 increase significantly if government agencies decide to postpone their project plans. With
6 the East Jefferson project, the Company proceeded with the main replacement project
7 anticipating that the City of Detroit would concurrently undertake the Jefferson Road
8 Reconstruction project and certain costs would be avoided by joint construction in the
9 street ROW. However, when the City of Detroit cancelled the project, the Company had
10 to incur an additional \$7.0 million to complete the main replacement project on its own.²⁴

11 Therefore, the \$32,753,000 forecasted by the Company for the projected test year for the
12 Fort Street Main Replacement project are not likely to be spent and I recommend that
13 Commission remove that amount for the Company's forecasted capital expenditures in this
14 rate case.

15 **7. Van Born Project**

16 **Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES**
17 **FOR THE VAN BORN PROJECT.**

18 A. On line 5 of Exhibit A-12, Schedule B5.2, the Company shows capital expenditures of
19 \$10.9 million for the Van Born project for 2022 and forecasted capital expenditures of

²⁴ Id. includes DR AGDG-5.129.

1 \$35.2 million for 2023, \$2.9 million for the 9 months ending September 2024, and \$1.3
2 million for the 12 months ending September 2025. Beginning on page 47 of her direct
3 testimony, Ms. Fedele discusses the purpose of the project, which is to prevent a potential
4 service outage if a pipeline failure were to occur along the length of the line. The Company
5 proposed a different and larger project in the two prior rate cases, and I filed testimony on
6 behalf of the Attorney General questioning the Company's plans and the level of proposed
7 capital expenditures. As explained by Ms. Fedele in her direct testimony in this rate case,
8 the Company revised its plans and project designs to achieve the same objective at a much
9 lower cost. The decision to change course on the project was made in May 2022.²⁵

10 However, from 2020 to May 2022, the Company incurred \$8.7 million in capital costs
11 related to the project. On page 57 of her direct testimony, Ms. Fedele states that the
12 Company wrote-off to expense \$1.9 million of the project costs incurred related to the
13 previous project. In response to discovery request AGDG-5.117b, the Company identified
14 the components of the \$1.9 million, which were rounded up to \$2.0 million, but did not
15 identify what the remaining \$6.7 million were specifically spent on and why they should
16 remain in rate base. Most of the remaining costs have been categorized as contracted
17 services, labor, and overheads.²⁶ With the project changing significantly from its initial
18 scope and the Company filing an expensive Act 9 application, which it subsequently
19 withdrew after the project scope changed, the \$1.9 million write-off seems considerably
20 insufficient.

²⁵ Exhibit AG-10 includes DRs AGDG-5.115a-c and 5.117a.

²⁶ Id. includes DR AGDG-5.117b.

1 In fact, it is likely that subsequent to its decision to change the scope of the project in May
2 2022, the Company incurred additional design and engineering costs, which the Company
3 also seeks to recover in this rate case. Given the lack of transparency for the remaining
4 \$6.7 million of project costs incurred prior to May 2022, I recommend that the
5 Commission remove this amount from rate base in this rate case.

6 **8. Gas Main Replacement Program (MRP/GRP) and IRM**

7 As shown in Exhibit A-12, Schedule B5.3, the Company spent \$347.7 million in 2022
8 under the Infrastructure Recovery Mechanism (IRM) and forecasted \$359.5 million for
9 2023, \$271.5 million for the first 9 months of 2024, and \$89.6 million for the partial 12-
10 month period ending September 2025. The Company also proposes to continue the IRM
11 for the five calendar years 2025 to 2029, with spending levels exceeding \$300 million
12 annually. Included in the IRM are the Main Replacement Program (MRP), the Meter
13 Move-Out (MMO) program, the MMO MAC Initiative program, the Pipeline Integrity
14 program, and in this rate case, the Company proposes to also include the Cathodic
15 Protection program.

16 Mr. Eric Janness's direct testimony discusses each of these programs and the IRM
17 proposed expenditures from 2022 to 2029. In his testimony and related exhibits, Mr.
18 Janness proposes to incorporate the MMO MAC Initiative program with the other MMO
19 program, which seems reasonable. With this change, the Company now refers to the MMO
20 program and the MRP as the Gas Renewal Program or GRP.

1 **Q. WHAT IS YOUR ASSESSMENT OF THE LEVEL OF SPENDING PROPOSED**
2 **BY THE COMPANY IN THE MRP, GRP, AND THE IRM?**

3 A. The Company has continued to escalate the size of the program in each prior rate case and
4 other cases specific to the MRP. Although not fully evident in Exhibit A-12, Schedule B6,
5 the Company proposed the MRP for the first time in August 2010 in Case No. U-16407.
6 At that time, the Company proposed to replace 30 miles of targeted mains for an annual
7 capital spending of \$17.4 million. Shortly thereafter, in 2012, in case No. U-16999, the
8 Company proposed, and the Commission approved, an escalation of the program for
9 replacement of 66 miles of main at an annual spending level of \$46.9 million. Case No.
10 U-16999 also established the IRM as a mechanism for the Company to more quickly
11 recover the cost of capital additions for the MRP and other programs.

12 In 2014, in Case No. U-17701, the Company proposed to again increase the annual
13 spending level to \$78.3 million by 2017 and to replace 103 miles of main annually. In
14 December 2015, the Company filed a rate case in Case No, U-17999 and requested a
15 further increase in the capital expenditures for the MRP to \$93.8 million for 2017 with
16 plans to replace 123 miles of main. Subsequent to that rate case, the Company scaled
17 down the number of miles of main to be replaced but maintained the same proposed
18 spending level.

19 In rate Case No. U-18999, filed in November 2017, the Company once more requested a
20 further escalation of the program capital expenditures to \$169.7 million for 2019 and
21 increases to \$193.0 million for 2020. In the subsequent two rate cases, spending levels

1 again increased, reaching \$340 million in 2022 for all the component programs within the
2 IRM. This trend of ever escalating spending on programs within the IRM continues in this
3 case with proposed spending of \$359 million in 2023 and comparable amounts annually
4 at least through 2027.

5 In other words, what began as a modest program of \$17.4 million to replace cast iron mains
6 and other unprotected and deteriorating gas mains has now mushroomed into a monstrous
7 program of more than \$350 million annually.

8 **Q. WHAT REASONS DOES THE COMPANY OFFER FOR THE FURTHER**
9 **ESCALATION OF PROGRAM COSTS IN THIS RATE CASE?**

10 A. In his testimony, Mr. Janness points to more complex projects, higher permit and
11 restoration costs, and higher contractor costs. It appears the new probabilistic risk model
12 is either selecting or aggregating more complex projects. Why this is occurring is not
13 entirely clear and may be a shortcoming of the model. However, the evidence provided
14 by the Company does not show that complex projects are a significant portion of the total
15 number of projects completed each year. In discovery, the Attorney General asked the
16 Company to provide the list of projects from which the projects targeted for 2024 and 2025
17 were selected. In response the Company provided a list of about 470 projects. On that
18 list, the number of identified complex projects is less than 20 and two were completed in

1 2019 through 2023 and five are scheduled for 2024.²⁷ No information was provided about
2 projects scheduled for 2025.

3 With regard to cost increases, higher permit costs, restoration costs, and contractor costs
4 are a function of activity and the increased demand for services placed on those
5 organizations by the Company and other utilities. More projects require more resources
6 to review and issue permits. More damage to streets and sidewalks inconvenience
7 customers and the public and there is more demand by municipalities for a wider
8 restoration span around the project damage area. More projects also increase the cost of
9 materials from pipe to valves and trench filling materials. Demand for contractor services
10 has also been increasing as other utilities regionally and around the country have expanded
11 their main replacement programs and have increased construction activity. With higher
12 demand for resources and materials, prices for contractor installation services increase and
13 so does the cost of completing construction projects.

14 This dramatic increase in demand for contractor services with limited availability of
15 resources has resulted in significant annual cost escalations. Unless the demand for
16 materials, contractor services, and other services ebbs with more rational limitations on
17 the pace of main replacement and construction activity by gas utilities, the cost escalation
18 problem will not improve and in fact may get worse.

²⁷ Exhibit AG-11 includes DR AGDG-6.167a with attachment.

1 **Q. HAS THE COMPANY PROVIDED ANY HARD EVIDENCE OR ANALYSIS TO**
2 **SUPPORT THE CONTINUED ESCALATION OF THE MRP IN THIS RATE**
3 **CASE OR PRIOR RATE CASES?**

4 A. No. There has been no evidence presented by the Company that deterioration of the legacy
5 mains is increasing to require an increase in spending. Although reducing risk and
6 increasing safety are laudable goals, there must be more quantitative and qualitative
7 analysis performed to show that the rate of deterioration of the gas mains and services is
8 accelerating to justify increasing annual capital expenditures by more than 10-fold
9 between 2010 and 2025. Without this quantitative evidence, the current pace of main
10 replacement and the escalating capital expenditures have become totally subjective.

11 The list of MRP/GRP projects provided the Company discussed above were risk scored
12 using the Probabilistic Risk Assessment (PRA) model. The 470 projects on the list have
13 risk scores ranging from 0.961 to zero. Most of the projects have a risk score of less than
14 0.005 and many are at zero or close to zero.²⁸ In other words, there is no compelling
15 evidence that keeping the current pace of main replacement, or even accelerating it, is
16 necessary.

17 **Q. HAS THE COMPANY SHOWN FINANCIAL DISCIPLINE IN REFRAINING**
18 **FROM OVER-SPENDING ON THE MRP AND STAYING WITHIN THE**
19 **ESTABLISHED COST PLAN?**

²⁸ Id.

1 A. No. In response to discovery, the Company provided an updated Exhibit A-12, Schedule
2 B6.1, to include actual expenditures through 2023. The updated schedule shows that the
3 Company overspent the plan by nearly \$60 million in 2023, or 21%. More alarming is the
4 fact that the Company overspent in each year since 2016 mostly by double digit percentage
5 as high as 33%. Exhibit AG-12 includes the attachment to the discovery response with the
6 percentages of over-spending added.

7 **Q. WHAT LEVEL OF CAPITAL EXPENDITURES FOR THE MRP AND OTHER**
8 **COMPONENTS OF THE IRM SHOULD THE COMMISSION APPROVE IN**
9 **THIS RATE CASE?**

10 A. The increasing cost trend of the IRM discussed above is not sustainable from a customer
11 affordability viewpoint and must be reversed. The Commission should set a maximum
12 spending level or a cap for the IRM and the related component programs to avoid the
13 current runaway cost. Most homeowners must live within their own cost budgets and do
14 not have unlimited resources to be able to afford ever increasing household costs. They
15 make hard choices every day as to where to spend their money within the available
16 resources. Similarly, the Company needs to set an annual budget and replace and install
17 the number of miles of main, MMO projects, and pipeline integrity projects that can be
18 completed within a set budget cap, unless justified by unexpected and critical safety
19 situations. The current practice of unlimited and increasing capital spending on the IRM
20 programs needs to be restrained.

1 In response to discovery request AGDG-6.179, the Company provided a schedule that
2 shows the capital spending on each of the programs included within the IRM from 2018
3 to 2029 with related quantity of work units. Based on the actual spending of \$240 million
4 in 2021, the Company retired 214 miles of legacy mains and replaced them with 252 miles
5 of new main under the MRP. During 2021, the Company also replaced 25,967 services as
6 part of the MRP.²⁹

7 Therefore, I recommend that the Commission approve a maximum capital spending level
8 of \$240 million for the MRP within the IRM instead of the \$274 million proposed by the
9 Company for 2025. I chose 2021 as the benchmark year because it was the last year when
10 spending on the MRP was still below \$250 million and the Company was able to retire
11 more than 200 miles of legacy mains. For 2024 through 2029, the Company's forecast is
12 to retire 206 miles of legacy mains, albeit at a higher cost per mile.

13 In total, for the MMO programs, the Company spent \$48.2 million in 2021 and forecasted
14 to spend approximately \$47.5 million in 2025. I recommend that the Commission approve
15 inclusion of \$48 million in capital expenditures in the IRM for 2025 for the combined
16 MMO programs. For Pipeline Integrity, the Company spent \$11.7 million in 2021 and
17 forecasted to increase spending on this program to \$23 million in the IRM for 2025.

18 According to Mr. Janness, the Company plans to accelerate spending in this area to meet
19 its goal of completing 97% of the total HCA assessments by 2025.³⁰ The assessments

²⁹ AG-12 includes DR AGDG-6.179 with attachment.

³⁰ Eric Janness direct testimony at page 32.

1 should be stretched over a longer period. No compelling reason has been provided by the
2 Company that the 97% goal must be achieved in 2025. The Company's capital
3 expenditures forecast for Pipeline Integrity from 2025 to 2029 total to \$72.1 million, which
4 average to \$14.4 million annually over the five-year period. Therefore, I recommend that
5 capital expenditures for this program under the IRM for 2025 be set at no higher than \$15
6 million.

7 In total, I recommend that the Commission approve a spending level of \$303 million for
8 the IRM for 2025 and allow the Company to increase that amount by an inflation factor of
9 2.5% annually beginning in 2026 and in subsequent years.

10 Although the lower spending level that I propose may somewhat reduce the number of
11 miles that the Company planned to retire and install in 2025 and subsequent years, the
12 inflation adjusted spending cap beginning in 2026 should give the Company more room
13 to absorb cost increases. The lower capital spending level will also give the Company
14 added incentive to reduce the cost per mile of main installed and reduce pressure on scarce
15 resources. As stated earlier, the competition for limited resources has contributed to the
16 higher cost of pipe replacement under the Company MRP program during recent high
17 inflationary periods. A more moderate pace of pipe replacement will help take the pressure
18 off the competition for those resources.

19 It is also noteworthy to point out that through the risk-based approach to pipe replacement
20 that the Company has employed over the past 12 years, most of the high-risk mains and
21 services should already have been replaced. The Company has not provided any

1 compelling evidence that the planned increase in spending is tied to any increased safety
2 risks. Therefore, if the completion of the MRP program is extended a few more years past
3 the current 2035 target date, it is a reasonable trade-off to balance against customer
4 affordability from uncontrolled capital spending on the program.

5 **Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL TO INCLUDE**
6 **CATHODIC PROTECTION CAPITAL EXPENDITURES IN THE IRM?**

7 A. No. The Company has not provided any compelling reasons why cathodic protection costs
8 need to be included in the IRM. Mr. Janness discusses this program beginning on page 47
9 of his direct testimony. The reasons to include the cathodic protection program within the
10 IRM mentioned by Mr. Janness, such as assurance that the expenditures would be
11 reasonable and prudent and that sufficient expenditures will be dedicated to cathodic
12 protection, apply whether the capital expenditures are in base rates or in the IRM. The
13 Company should make prudent spending decisions irrespective of how cost recovery
14 occurs and should allocate sufficient resources to the program irrespective of the cost
15 recovery methodology. As to formalizing a holistic and programmatic approach to
16 cathodic protection, the Attorney General asked the Company to explain what such a
17 program would look like and why it could not be done also with cost recovery in base
18 rates. In response, the Company states that it had not determined yet that cathodic
19 protection cannot continue to be included in bases rates, but seems to prefer the automatic
20 cost recovery through the IRM.³¹

³¹ Exhibit AG-13 includes DR AGDG-6.172b.

1 The Company has not made a convincing case that capital expenditures for cathodic
2 protection should be included in the IRM. Therefore, I recommend that the Commission
3 reject the Company's proposal and instead add \$7,400,000 of cathodic protection costs to
4 the \$2,200,000 already included the projected test year for a total amount of \$9,600,000.

5 **Q. ARE YOU PROPOSING ANY DISALLOWANCES OR ADJUSTMENTS TO THE**
6 **MRP OR THE MMO FORECASTED CAPITAL EXPENDITURES FOR 2024?**

7 A. No. Cognizant of the fact that capital programs for 2024 have already being scheduled
8 and are being implemented and the fact that a Commission order in this rate case would
9 not be issued until later in the year, it would not be productive to propose adjustments to
10 the two capital expenditure programs for 2024.

11 **B. Transmission Plant**

12 Transmission plant additions consist of both routine projects and large capital projects.
13 Below, I will discuss adjustments to both routine transmission projects and large capital
14 projects.

15 **1. Routine Transmission Plant**

16 As shown on page 2, line 19 of Exhibit A-12, Schedule B5.1, the Company spent an
17 average annual amount of \$11.6 million on routine transmission plant additions during the
18 five years from 2018 to 2022 and forecasted capital expenditures of \$12.7 million for 2023,
19 \$14.2 million for the 9 months ending September 2024, and \$12.7 million for the projected

1 test year. Page 6 of Exhibit A-12, Schedule B5.11, shows a list of some of the capital
2 projects included in the forecasted amounts for 2023-2025.

3 In discovery, the Attorney General asked the Company to identify the current phase of
4 development for four large projects forecasted for 2025. The projects with related 2025
5 capital expenditures are: the MLV7 Replacement (\$2,800,000), the Au Gres Tributary Pipe
6 Replacement (\$2,350,000), the Willow Gate Station (\$2,000,000), and the MLV 5C Line
7 Replacement (\$1,928,000). The total forecasted cost for the four projects is \$9,078,000
8 for 2025 and \$6,809,000 for the projected test year.³²

9 The Company evaded answering the question about the current phase of development and
10 instead stated that engineering and construction phases would occur sometime in 2024 and
11 2025.³³ The evasive answer indicates that the four projects are currently in the initial
12 conceptual or planning phase with no stated start and completion date for project
13 engineering. These projects are still in the early phase of development with no assured
14 timeline and thus premature to include in rate base in this rate case. Therefore, I
15 recommend that the Commission disallow \$6,809,000 of capital expenditures for the
16 projected test year.

17 **2. Pipeline Integrity – ILI Projects**

18 Line 19 of Exhibit A-12, Schedule B5.3, shows the Company's forecasted spending on
19 Pipeline Integrity of \$27.7 million for 2023, \$16.0 million for the 9 months ending

³² \$9,078,000 x 9/12 = \$6,809,000.

³³ Exhibit AG-14 includes DR AGDG-5.150b.

1 September 2024, and \$6.3 million for the three-month stub period in the projects test year
2 plus \$23.1 million in the IRM for 2025.

3 In discovery, the Attorney General asked the Company to provide the current phase of
4 development for four large ILI projects shown on pages 27, 29, 36, and 44 of Exhibit A-
5 12, Schedule B5.5. In response, the Company reported that three of the four projects are
6 currently in the conceptual design phase. Those projects are the Muskegon-Ludington 10
7 Scott Tie-in, the Belle River Field Headers 12 & 16, and the Belle River Field Header 24.³⁴
8 The forecasted amount for the three projects for the 9 months ending September 2024 is
9 \$3,588,000 and \$8,576,000 for the 12 months ending September 2025.³⁵

10 These projects are still in the early phase of development with no assured timeline and thus
11 premature to include in rate base in this rate case. Therefore, I recommend that the
12 Commission disallow \$3,588,000 of capital expenditures for the 9 months ending
13 September 2024 and \$8,576,000 for the projected test year.

14 **3. Large Transmission Projects Not Approved**

15 On page 27 of her direct testimony, Ms. Fedele identifies three projects that have not yet
16 received formal corporate approval to proceed with project development. Those projects
17 are the Austin-Detroit A&B Lines replacement, the Belle River/Detroit Interconnect &
18 Loop, and the Taggart Compressor Replacement. In addition, those projects have not yet
19 completed the engineering design phase and will not be placed in service until well past

³⁴ Exhibit AG-15 includes DR AGDG-6.180.

³⁵ Sourced from individual project documents on pages 29, 36, and 44 of Exhibit A-12, Schedule B5.5.

1 the end of the projected test year. Nevertheless, the Company included capital
2 expenditures for those projects in rate base in this rate case. The Company stated that it
3 recorded an Allowance for Funds Under Construction (AFUDC) credit that offsets the
4 revenue requirement from including the project costs in rate base.

5 According to the amounts shown on lines 9, 11, and 12 of Exhibit A-12, Schedule B5.2,
6 the total forecasted capital expenditures for the three projects are \$1.3 million for 2023,
7 \$4.7 million for the 9 months ending September 2024, and \$27.1 million for the projected
8 test year.

9 **Q. WHAT IS YOUR ASSESSMENT OF THE CAPITAL EXPENDITURES**
10 **INCLUDED IN THIS RATE CASE FOR THE THREE PROJECTS?**

11 A. It is premature to include any amount of capital expenditures for the three projects in rate
12 base. As Ms. Fedele stated in her testimony, the projects have not yet been formally
13 approved. Therefore, it is still uncertain whether the projects will proceed as anticipated
14 by the Company. Furthermore, the Belle River/Detroit Loop and the Taggart Compressor
15 Replacement projects have not yet been designed and according to the timeline in the
16 project description document in Exhibit A-12, Schedule B5.5, pages 13 and 35, the design
17 will not be completed until late in 2025, past the end of the projected test year in this rate
18 case.

19 These projects have not yet been approved and are still in the early phase of development
20 with no assured timeline and thus premature to include in rate base in this rate case,
21 irrespective of the fact that an AFUDC cost offset has been recorded to operating income.

1 Therefore, I recommend that the Commission remove the capital expenditures of \$1.3
2 million for 2023, \$4.7 million for the 9 months ending September 2024, and \$27.1 million
3 for the projected test year. Later in my testimony, I discuss the necessary adjustment to
4 the AFUDC recorded by the Company for the three projects.

5 **4. Oakland Resilience Interconnect (CMS Line 2700)**

6 Line 10 of Exhibit A-12, Schedule B5.3, shows the Company's forecasted spending for
7 the Oakland Resilience Interconnect project of \$100,000 for 2023, \$1.1 million for the 9
8 months ending September 2024, and \$4.7 million for the projected test year. The project
9 development timeline in the project description document on page 16 of Exhibit A-12,
10 Schedule B5.5, shows that engineering design work on the project has not yet been
11 completed. The project appears to be still in the conceptual design phase. Furthermore,
12 the project will not be in service until after the end of the projected test year for this rate
13 case. It is also premature to include this project in rate base in this rate case.

14 Therefore, I recommend that the Commission disallow the forecasted capital expenditures
15 of \$100,000 for 2023, \$1.1 million for the 9 months ending September 2024, and \$4.7
16 million for the projected test year.

17 **5. Traverse City Alpena Reinforcement**

18 Line 4 of Exhibit A-12, Schedule B5.3, shows actual capital expenditures for the Traverse
19 City Alpena Reinforcement (TCARP) project of \$40.7 million for 2022 and \$3.4 million
20 forecasted for 2023. Ms. Fedele discusses this project beginning on page 91 of her direct
21 testimony and on page 93 states that the cost of the project increased from the initial

1 estimate of \$100.8 million to a final cost of \$114.8 million. On page 95, she attributes the
2 higher cost of the project to three factors: (1) \$3.0 million due to the one-year delay by DT
3 Midstream Michigan Lateral Company (DTMLC) in receiving its Act 9 certificate to build
4 a portion of the project, (2) \$9.8 million due to higher construction costs than previously
5 estimated, and (3) \$1.2 million to add pressure regulators not previously anticipated.

6 In discovery, the Attorney General asked the Company to explain why the one-year delay
7 would cause an additional \$3.0 million in higher internal labor costs, higher contractor and
8 material costs, and higher corporate overhead costs, and to provide the amount related to
9 each item. In response, the Company repeated the reason for the project delay but failed
10 to explain why the delay would cause internal labor to increase by \$1,800,000, overhead
11 costs to increase by \$1,100,000, and contractor and material costs to increase by \$50,000
12 each.³⁶ The response provides no justification for the higher costs. Although the delay
13 seems plausible due to the Act 9 proceedings, no work took place during that time and no
14 new employees were hired to justify the additional \$1.8 million of internal labor costs
15 while the Company waited for DTMLC to obtain the Act 9 certificate. The overhead costs
16 of \$1.1 million follow the labor cost and at 61% seem excessive. The additional contractor
17 and material costs are relatively small at \$50,000 each but also befuddling given than the
18 project was on hold during the one-year period.

19 The Company has failed to adequately justify the additional \$3.0 million in project costs,
20 mostly arising from internal labor and overheads. Therefore, I recommend that the

³⁶ Exhibit AG-16 includes DR AGDG-5.124a.

1 commission remove the \$3.0 million from rate base in this case and instruct the Company
2 to also remove the amount permanently from future rate cases.

3 **Q. ARE THERE OTHER COST DISALLOWANCES THAT YOU PROPOSE FOR**
4 **THE TCARP PROJECT?**

5 A. Yes. In my involvement as an expert witness on behalf of the Attorney General in Case
6 No. U-21525, which pertains to establishing revised transportation rates for the converted
7 Michigan wet header pipeline and related interconnections owned by DTMLC and
8 supporting the TCARP project, I discovered that DTE Gas incurred additional costs to
9 build temporary facilities to correct a problem with excessive moisture in the gas stream
10 transported by DTMLC to the DTE Gas pipeline system. In response to DR U-21525-
11 AGDG-2.7 and 2.8, DTE Gas admitted that it should have billed the incremental costs to
12 DTMLC and instead included them in rate base, which it seeks to recover in this rate
13 case.³⁷

14 In response to further discovery on this matter in this rate case, the Company identified the
15 total incremental costs to be \$323,000, consisting of \$155,000 to build the Saginaw Bay
16 interconnect loop and \$168,000 for the West Branch interconnect loop. ³⁸ These costs
17 should have been paid by DTMLC due to problems they should have addressed and
18 prevented. Customers of DTE Gas should not pay for those costs. Therefore, I recommend
19 that the Commission remove the \$323,000 from rate base in this case and instruct the
20 Company to remove the amount permanently from future rate cases.

³⁷ Id. includes DR U-21525-AGDG-2.7 and 2.8.

³⁸ Id. includes DR AGDG-5.123.

C. Gas Storage Plant

As shown on page 2, line 22 of Exhibit A-12, Schedule B5.1, the Company spent an average annual amount of \$4.3 million on routine storage plant additions during the five years from 2018 to 2022 and forecasted capital expenditures of \$3.4 million for 2023, \$3.6 million for the 9 months ending September 2024, and \$4.1 million for the projected test year. Also, on line 24 of the exhibit schedule, the Company shows capital expenditures for storage compression of \$16.6 million for the 2018-2022 period and forecasted amounts of \$18.7 million for 2023, \$16.2 million for the 9 months ending September 2024, and \$10.9 million for the projected test year. Mr. Abona discusses the storage plant additions beginning on page 42 of his direct testimony.

In discovery, the Attorney General asked the Company to provide the number of projects or work units underlying the historical and forecasted periods for the gas storage and storage compression programs. In response, the Company provided the work units for each program from 2018 to 2025.³⁹ The forecasted number of work units for 2024 and 2025 are generally lower for those years than the previous three years from 2021 to 2023. For gas storage, the Company forecasted 44 work units for 2024 and 37 for 2025. In comparison, the Company completed 63 work units on average annually during 2021-2023. For the storage compression program, the Company forecasted 78 units for 2024 and 60 units for 2025. On average over the 2021-2023 period, the Company completed 110 units.

³⁹ Exhibit AG-17 includes DR AGDG-5.145a.

1 To establish the reasonableness of the Company's forecasted capital expenditures for the
 2 forecasted periods for the gas storage routine program, I calculated the historical average
 3 cost per work unit for the 2021-2023 period at \$54,642.⁴⁰ After applying the inflation
 4 factor, I calculated a unit cost of \$58,980 for 2024, which when multiplied by the 44 units
 5 forecasted by the Company resulted in a forecasted cost of \$2,467,000 for the year, or
 6 \$1,850,000 for the 9 months ending September 2024.⁴¹ In comparison, the Company
 7 forecasted capital expenditures of \$3,108,000 for the 9-month period. The Company's
 8 forecast is overstated by \$1,258,000.

9 For the projected test year, I increased the 2024 unit cost by the inflation factor for 2025
 10 to determine a unit cost of \$57,296. By multiplying this amount by the 37 units forecasted
 11 by the Company, I calculated forecasted capital expenditures of \$2,120,000 for 2025 and
 12 \$2,207,000 for the 12 months ending September 2025.⁴² In comparison, the Company
 13 forecasted capital expenditures of \$4,067,000 for the 12-month period. The Company's
 14 forecast is overstated by \$1,860,000.

15 For the storage compression program, I followed a similar process. The average cost per
 16 unit for the three years 2021-2023 was \$132,812.⁴³ After applying the inflation factor, I
 17 calculated a unit cost of \$136,265 for 2024, which when multiplied by the 78 units

⁴⁰ Actual capital expenditures for 2021-2023 from line 23 of the attachment to DR STDG-1.1 (Exh. AG-4) of \$10,382,000 divided by the number of units each year of 190 from DR AGDG-5.145a (Exh. AG-17) result to a cost of \$54,642 per unit.

⁴¹ $\$54,642 \times 1.026 = \$56,063 \times 44 = \$2,467,000 \times 9/12 = \$1,850,000$.

⁴² $\$56,063 \times 1.022 = \$57,296 \times 37 = \$2,120,000$. PTY: $\$2,120,000 \times 9/12 + \$2,467,000 \times 3/12 = \$2,207,000$.

⁴³ Actual capital expenditures for 2021-2023 from line 25 of the attachment to DR STDG-1.1 (Exh. AG-4) divided by the number of units each year from DR AGDG-5.145a (Exh. AG-17): $\$43,695,000 / 329 \text{ units} = \$132,812$ per unit.

1 forecasted by the Company resulted in a forecasted cost of \$10,629,000 for the year, or
2 \$7,972,000 for the 9 months ending September 2024.⁴⁴ In comparison, the Company
3 forecasted capital expenditures of \$16,220,000 for the 9-month period. The Company's
4 forecast is overstated by \$8,248,000.

5 For the projected test year, I increased the 2024 unit cost by the inflation factor for 2025
6 to determine a unit cost of \$139,263. By multiplying this amount by the 60 units forecasted
7 by the Company, I calculated forecasted capital expenditures of \$8,356,000 for 2025 and
8 \$8,924,000 for the 12 months ending September 2025.⁴⁵ In comparison, the Company
9 forecasted capital expenditures of \$10,883,000 for the 12-month period. The Company's
10 forecast is overstated by \$1,959,000.

11 In total, for the gas storage and compression programs, the Company's forecasted capital
12 expenditures are overstated by \$9,506,000 for the 9 months ending September 2024 and
13 \$3,819,000 for the 12 months ending September 2025. The Company's forecasted capital
14 expenditures in this spending category are not reasonable and the Company has not
15 adequately justified the higher forecasted costs in comparison to recent historical unit cost
16 plus forecasted inflation. Therefore, I recommend that the Commission remove the excess
17 capital expenditures of \$9,506,000 for the 9 months ending September 2024 and the
18 \$3,819,000 for the 12 months ending September 2025.

⁴⁴ $\$132,812 \times 1.026 = \$136,265 \times 78 = \$10,629,000 \times 9/12 = \$7,972,000$.

⁴⁵ $\$56,063 \times 1.022 = \$57,296 \times 37 = \$2,120,000$. PTY: $\$2,120,000 \times 9/12 + \$2,467,000 \times 3/12 = \$2,207,000$.

D. Transportation Vehicles & Equipment

On page 2, line 27 of Exhibit A-12, Schedule B5.1, the Company shows capital expenditures for transportation vehicles and equipment of \$10.4 million from 2018 to 2022 and forecasted capital spending of \$12.9 million for 2023, \$10.0 million for the 9 months ending September 2024, and \$20.3 million for the projected test year. On pages 49 and 50 of his direct testimony, Mr. Abona discusses the challenges that the Company has experienced in obtaining new vehicles in recent years due to limited availability of certain models. Mr. Abona also discusses generally the higher prices paid for vehicles and equipment purchases but does not identify any specific amounts or percentages for either the historical or forecasted years.

In discovery, the Attorney General asked the Company to provide the number of vehicles and equipment purchases by vehicle class from 2018 to 2023 and forecasted for 2024 to 2025 with related purchase costs. The information provided by the Company shows forecasted 2024 vehicle and equipment purchase costs with a cost per vehicle of \$136,783 and 2025 forecasted purchases with a cost per vehicle of \$126,145. In contrast, the Company spent \$79,010 per vehicle in 2023 and for the three year 2021-2023 the average purchase cost per vehicle was \$80,439.⁴⁶ The forecasted cost per vehicle in 2024 is 70% above the three-year average cost and the 2025 forecasted unit cost is 57% over the same average cost. Clearly, the forecasted cost per vehicle for 2024 and 2025 is significantly inflated and overstated.

⁴⁶ Exhibit AG-18 includes DR AGDG-5.147a with attachment and unit costs added.

1 Using the historical three-year average cost per vehicle of \$80,439 and after adjusting it
2 for the 2024 inflation factor to \$82,530, I determined that for the 47 vehicles and
3 equipment that the Company plans to purchase in 2024 the forecasted cost is \$3,879,000
4 and \$2,909,000 for the 9 months ending September 2024.⁴⁷ In comparison, the Company
5 forecasted capital expenditures for the 9-month period of \$10,006,000. The Company's
6 forecast is overstated by \$7,097,000.

7 Similarly, by escalating the 2024 unit cost by the inflation factor, the 2025 unit cost is
8 \$84,346. After multiplying this amount by the 125 vehicles the Company plans to
9 purchase, I determined the total forecasted cost for 2025 at \$10,543,000. For the 12
10 months ending September 2025, the forecasted cost is \$8,877,000.⁴⁸ In comparison, the
11 Company forecasted capital expenditures of \$20,255,000. The Company's forecast is
12 overstated by \$11,378,000.

13 The Company did not provide any evidence to justify the large unit cost increase of 57%
14 to 70% over recent historical levels. The Company's forecast is not reasonable and is not
15 adequately supported. Therefore, I recommend that the Commission remove the excess
16 capital expenditures of \$7,097,000 for the 9 months ending September 2024 and
17 \$11,378,000 for the projected test year.

⁴⁷ $\$82,530 \times 47 = \$3,879,000$ $\times 9/12 = \$2,909,000$.

⁴⁸ $\$82,530 \times 1.022 \times 125 = \$10,543,000$. PTY: $\$10,543,000 \times 9/12 + \$3,879,000 \times 3/12 = \$8,877,000$.

E. Gas Information Technology

Q. PLEASE DISCUSS WHAT ADJUSTMENT YOU PROPOSE TO FORECASTED CAPITAL EXPENDITURES FOR INFORMATION TECHNOLOGY.

A. In my review of the information technology (IT) projects presented by the Company in this rate case, I discovered that the Company did not include a reduction in capital expenditures pertaining to the recent implementation of the Gas Scheduling Optimizer system. In response to discovery, the Company admitted that capital savings of \$450,000 were not included as a reduction to the IT capital expenditures forecasted by the Company for the projected test year in this rate case.⁴⁹ Therefore, I recommend that this amount be removed from the projected test year capital expenditures.

F. Capital Expenditures Adjustments - Summary

Q. WHAT IS YOUR OVERALL RECOMMENDATION REGARDING THE TOTAL AMOUNT OF ADJUSTMENTS TO THE COMPANY'S CAPITAL EXPENDITURES AND RATE BASE?

A. The chart below summarizes my proposed reductions in capital expenditures in those areas where the level of capital expenditures presented by the Company is excessive, unnecessary, or unsupported.

⁴⁹ AG-19 includes DR AGDG-5.151c.

Summary of AG Disallowed Capital Expenditures	
	Amount (millions)
Distribution Plant	
Main Renewals	1.4
Public Improvements	3.7
System Reliability	13.6
Communications & Controls - Meters	13.0
Leak Detection and Repair	15.0
Fort Street Main Replacement	32.8
Van Born project	6.7
Transmission Plant	
Routine Transmission Projects	6.8
ILI Projects	12.2
Austin-Detroit A&B Lines	21.0
Belle River Detroit Loop	8.1
Taggart Compression Replacement	4.0
Oakland Resilience Interconnect	5.9
TCARP-DTML Interconnect/Dehydration	3.3
Cathodic Protection	(7.4)
Gas Storage & Compression	13.3
Transportation Vehicles	18.4
Other	0.5
Total	\$ 172.3

Based on my analysis and information presented in my testimony above, the Commission should reduce the Company's proposed capital expenditures by \$172.3 million and average rate base by \$124.5 million, including a \$10.1 million reduction in working capital. Exhibit AG-20 provides additional details and calculations of these amounts.

V. Working Capital

Q. ON EXHIBIT A-12, SCHEDULE B4, THE COMPANY PROPOSES A WORKING CAPITAL AMOUNT OF \$872.9 MILLION FOR THE PROJECTED TEST YEAR. DO YOU AGREE WITH THE COMPANY'S FORECASTED AMOUNT?

A. No. I propose an adjustment to reduce the Company's forecasted working capital amount by \$10,083,000. This adjustment pertains to the deferred Regulatory Asset-Incentive Tracker balance of \$13.3 million calculated by the Company and shown on line 37 of Exhibit A-12, Schedule B4. In Case No. U-20940, the Commission approved only 20% of the Company's proposed incentive compensation related to operating performance measures and directed the Company to establish a two-way cost tracking mechanism for actual incentive compensation earned in the projected test year. The pertinent section of the December 9, 2021 Order states:

Therefore, the Commission is persuaded that DTE Gas should not recover as if it will achieve all operating measures at the 100% target level. Instead, the Commission adopts the proposal from the Attorney General to allow recovery of 20% of the incentive compensation for meeting operating metrics. In addition, the Commission authorizes DTE Gas to implement a two-way tracker mechanism, which will require refunds to customers if the 20% target level is not achieved or will allow the company to recover additional funds if it exceeds the 20% target level, up to a maximum of 100% target level. DTE shall record the over-or underrecovery, compared to the 20% base, in a regulatory asset or liability to be included in the company's next general rate case.

To arrive at the \$13.3 million balance, the Company added \$6,378,000 of expense to the \$1,057,000 incentive compensation expense approved by the Commission in Case U-20940. The information provided in response to discovery shows that the \$6,378,000 included in the deferred regulatory asset is a new calculated amount by the Company that

1 does not conform to the amount requested by the Company in Case No. U-20940 for
2 achieving 100% target level performance in 2022 for operating performance measures.⁵⁰

3 The amount forecasted by the Company in Case U-20940 was \$5,286,000, consisting of
4 the sum of \$1,277,000 for the AIP and \$4,009,000 for the REP, assuming the Company
5 achieved all measures at 100% of target. This information is shown on page 53 of Mr.
6 Cooper's direct testimony in that rate case and should be the base on which the actual
7 performance percentage should be applied, as I discuss below in my testimony. The
8 \$6,378,000 used by the Company is incorrect and should not be adopted by the
9 Commission.

10 The \$13.3 million working capital balance in the deferred compensation regulatory asset
11 also included accruals that the Company has added for 2023, and 9 months of 2024. Page
12 5 of Exhibit A-13, Schedule C5.6 shows the build-up of the deferred incentive
13 compensation balance proposed by the Company. The accruals for 2023 and 2024 are
14 premature because the Company has not provided any evidence that it has achieved 100%
15 of the operating target measures. The direct testimony of Ms. Uzenski, who sponsors the
16 deferred compensation regulatory asset, is devoid of any details supporting those amounts
17 and the underlying performance goals achieved for 2023 and 2024. It is premature and
18 unnecessary to include those amounts in the deferred regulatory asset in this rate case. The
19 Company seeks to recover only the amortization of the incremental amount of incentive

⁵⁰ Exhibit AG-54 includes DR AGDG-7.201a.

1 compensation earned in 2022 in this rate case and the regulatory asset deferred amount
2 should only reflect those incremental costs.

3 **Q. HAVE YOU DETERMINED WHAT THE APPROPRIATE REGULATORY**
4 **ASSET BALANCE AND AMORTIZATION EXPENSE SHOULD BE FOR THE**
5 **DEFERRED INCENTIVE COMPENSATION AMOUNT?**

6 A. Yes. In Exhibit AG-21, I applied the percentage of actual performance achieved for the
7 operational performance measures in each of the two incentive plans in 2022 to the amount
8 of incentive payout at 100% of target that Mr. Cooper had forecasted on page 53 of his
9 direct testimony in Case No. U-20940. The result is \$4,643,000 owed to the Company for
10 2022, which was the projected test year in Case No. U-20940. This amount is \$3,586,000
11 higher than the \$1,057,000 that the Commission approved for inclusion in rates in Case
12 No. U-20940. The \$3,586,000 is the only and proper amount that has been earned and
13 supported and should be included in the regulatory asset and amortized over five years at
14 an annual amount of \$717,000.

15 Therefore, as shown in Exhibit AG-21, the regulatory asset deferred balance that should
16 be included in working capital is \$3,227,000. The Company's working capital balance of
17 \$13,310,000 is overstated by \$10,083,000. I recommend that the Commission remove the
18 \$10,083,000 from the Company's forecasted working balance amount for the projected
19 test year.

1 **Q. YOU STATED ABOVE THAT THE DEFERRED INCENTIVE COMPENSATION**
2 **BALANCE SHOULD BE AMORTIZED OVER FIVE YEARS. WHY DO YOU**
3 **BELIEVE FIVE YEARS IS A REASONABLE AMORTIZATION PERIOD?**

4 A. In her direct testimony, Ms. Uzenski proposes a three-year amortization period but does
5 not explain or support why that short amortization period is reasonable or appropriate. In
6 discovery, the Attorney General asked the Company to justify the three-year amortization.
7 In response, the Company focuses on wanting to achieve a timely recovery of the deferred
8 balance and reduce future amortization amounts if the deferred balance grows in future
9 years.⁵¹ Although the Company may prefer a faster recovery of the deferred expense,
10 customers are absorbing significant cost increases in other areas of this rate case and future
11 rate cases to come, and would certainly appreciate a more gradual amortization period of
12 at least five years as I have proposed.

13 With regard to the deferred balance growing over time, it is not certain yet what level of
14 performance the Company will achieve for the operating performance measures in coming
15 years. Therefore, it is premature to speculate as to how much or how fast the deferred
16 balance may grow. Nevertheless, if it were to grow significantly, a longer amortization
17 period instead of a shorter period would be preferable to smooth out the amount of
18 expense that would be included in rates in future rate cases.

19 Furthermore, it is unknown how soon the Company will file its next rate case. With the
20 current case, the Company waited three years to file a new rate case since the prior case.

⁵¹ DR AGDG-7.189b.

1 If the Company delays filing another rate case past three years and the deferred balance is
2 amortized over three years, the Company would continue to recover the amortization
3 expense past the three-year period while it is no longer incurring the expense. Therefore,
4 it is preferable to amortize deferred balances over a longer time period to prevent cost
5 over-recovery from occurring. By amortizing the deferred balance over five years, the
6 Company does not forfeit recovery and any changes in the deferred balance and
7 amortization amount would be properly adjusted and re-established if and when the
8 Company files its next rate case.

9 For the reasons provided above, I recommend that the Commission approve an
10 amortization period of five years with an amortization expense of \$717,000 in this rate
11 case.

12 **Q. ON PAGE 35 OF HER TESTIMONY, MS. UZENSKI RECOMMENDS CERTAIN**
13 **MODIFICATIONS TO THE INCENTIVE COMPENSATION TRACKER**
14 **MECHANISM. DO YOU AGREE?**

15 A. No. On page 35 of her direct testimony, Ms. Uzenski proposes three modifications. The
16 first modification pertains to setting a new base amount of approved compensation to use
17 for future deferral. This proposal is appropriate and should be adopted if the Commission
18 decides to continue the mechanism. The second proposal is to include also incentive
19 compensation related to financial measures. This proposal should be rejected. The
20 Commission has made it clear repeatedly that inclusion in rates of incentive compensation

1 related to financial measures is inappropriate and no convincing evidence has been
2 provided in this rate case that the Commission should change its prior decisions.

3 The third proposal is to include compensation payout above 100% of target. This proposal
4 also should be rejected. As I have stated in my testimony below in the Incentive
5 Compensation section, several of the operating performance measures have a very low
6 threshold to achieve payout under the plan and it is relatively easy for the Company to
7 exceed the 100% target level without achieving superior performance. The deferral
8 mechanism should not bypass what the Commission has previously accepted as reasonable
9 recovery of incentive compensation capped at 100% of target.

10 In summary, the Commission should reject the second and third proposed modifications
11 to the mechanism.

12 **VI. Cost of Capital and Capital Structure**

13 **A. CAPITAL STRUCTURE**

14 Q. **WHAT IS THE CAPITAL STRUCTURE YOU RECOMMEND FOR USE IN THE**
15 **OVERALL RATE OF RETURN CALCULATION?**

16 A. I recommend that the capital structure shown on page 1 of Exhibit AG-22 be used in this
17 case. Lines 1 and 3 show the projected long-term debt and common equity (the permanent
18 capital of the Company) for the test period ending September 2025. The permanent capital
19 balances in this exhibit reflect two changes. First, I reduced the level of common equity
20 to \$2.749 billion, which is an \$82 million reduction from the Company's case. Second, I
21 have included this \$82 million amount as additional long-term debt. The result is the

1 allocation of the total permanent capital of \$5.5 billion to 50% long-term debt and 50%
2 common equity.

3 **Q. WHY DID YOU INCREASE LONG TERM DEBT AND REDUCE COMMON**
4 **EQUITY TO ACHIEVE A 50%/50% CAPITAL STRUCTURE?**

5 A. The Company has proposed a permanent capital structure with a common equity
6 component of 51.5%. While this percentage is lower than the 2022 historical test year
7 percent of 52.60%, there are other factors to consider, which are discussed below.

8 First, the common equity ratio of the peer group is approximately 46%. Exhibit AG-25
9 shows this information. It is worth pointing out that this lower average common equity
10 level supports these companies' utility operations as well as non-utility operations, which
11 tend to be somewhat riskier. The riskier non-utility operations require a higher common
12 equity cushion to maintain similar credit ratings. Therefore, if we adjusted for the higher
13 equity capital required by the non-utility businesses, the equity capital for the utility
14 portion of the peer group's capital structure would be lower than 46%.

15 Second, in Case U-18999, the Commission directed the Company to develop a plan to
16 move to a 50%/50% balanced capital structure, which I discuss in more detail below.

17 Third, DTE Gas is a captive subsidiary of DTE Energy. DTE Energy, which is a publicly
18 traded company, had a permanent capital common equity ratio of 36.1% and 63.9% long-
19 term debt at the end of 2023 and 36.5% equity to 63.5% debt at the end of 2022. DTE
20 Energy can make the common equity ratio of DTE Gas whatever it wants. The same

1 executive management that runs DTE Energy controls the Company's major decisions.
2 Management can direct at any time how much in capital it wants to inject into the Company
3 from the parent company and call it "equity capital" even though in reality it is debt. As
4 a result, DTE Energy management has artificially set the common equity ratio of DTE Gas
5 at nearly 52.6%, when the parent company only has a common equity ratio of
6 approximately 36.5%. Such freedom to inject phantom equity capital in the capital
7 structure would not exist if DTE Gas itself was a publicly traded company.

8 **Q. YOU STATED THAT THE COMMON EQUITY RATIO OF THE PEER GROUP**
9 **USED TO ASSESS THE COST OF COMMON EQUITY IS AROUND 46%.**
10 **PLEASE EXPLAIN WHY THIS IS RELEVANT IN DETERMINING THE**
11 **COMMON EQUITY RATIO FOR THE COMPANY IN THIS CASE.**

12 **A.** As shown in Exhibit AG-25, the average common equity ratio of the peer company group
13 for 2023 was 45.7%. The cost of equity capital for those companies in the peer group is
14 highly dependent on the financial risk reflected in their capital structure. Thus, it is critical
15 to synchronize the capital structure of the Company to the peer group average as closely
16 as possible in order to have consistency with the cost of equity capital derived from those
17 peer group companies. The Company's proposed common equity capital ratio of 51.5%
18 creates a disconnect that is not acceptable. Additionally, it is more costly to customers.

19 **Q. DO YOU AGREE WITH MR. LEPCZYK'S ANALYSIS ON THE NEED FOR A**
20 **51.5% COMMON EQUITY RATIO?**

1 A. No. On pages 11 through 17 of his direct testimony, Mr. Lepczyk makes several claims
2 in an attempt to support his recommendation that a 51.5% common equity ratio should be
3 approved by the Commission in this rate case. His key points are summarized below.

- 4 1. Peer equity ratios are higher
- 5 2. The capital structure is balanced if short-term debt is included
- 6 3. The Company's use of short-term debt is higher versus other Michigan
7 utilities
- 8 4. The Company is significantly smaller compared to other Michigan utilities
- 9 5. The Company needs to maintain access to the capital markets for its large
10 capital expenditures program.

11 In my testimony below, I respond to each of Mr. Lepczyk's claims.

12 **Q. WHAT IS YOUR OPINION OF MR. LEPCZYK'S CLAIM THAT THE PEER**
13 **GROUP EQUITY RATIO IS HIGHER THAN THE COMPANY'S PROPOSED**
14 **51.5% RATIO?**

15 A. In Exhibit A-17, Schedule G-3, Mr. Lepczyk calculated a 53.8% equity ratio from a group
16 of purported peer utilities. There are several flaws with the 53.8% ratio presented by Mr.
17 Lepczyk. First, the exhibit states that the information presented is as of year-end 2022.
18 After reviewing the data presented in the exhibit, I discovered that some of the information
19 is more than a year old as of September 2022, with other underlying data as of December
20 2022. The equity ratios were calculated on those dates at a single point in time for each of
21 the companies. In addition to the time inconsistency, the calculation of the equity ratios
22 for the companies is not based on common equity and long-term debt balances over
23 multiple periods during the most recent year. The convention when calculating a

1 regulatory capital structure is to use a 13-month average. At minimum, Mr. Lepczyk
2 should have used an average equity ratio over a 12-month period or over four quarters to
3 develop an appropriate comparison to the Company's proposed equity ratio.

4 Second, and even more critical, the equity ratio of 53.8% does not represent the average
5 equity ratio approved by the state commissions regulating those companies. Although the
6 Company attempts to portray the equity ratios of the companies in Exhibit A-17, Schedule
7 G3, as representative of the equity ratios approved in each company's rates, they are far
8 from that. The equity ratios were calculated by the Company using equity capital balances
9 reported by the companies in their public financial reports as of either September 2022 or
10 December 2022 and as published by S&P Global Market Intelligence, with no further
11 adjustments by the Company.

12 Third, the utility companies included in this peer group are captive subsidiaries and, as
13 stated above, management can set the capital structure of those companies to any desired
14 level for financial reporting and are not necessarily reflective of the permanent capital
15 structure approved in rates.

16 Fourth, the peer group of companies included in Exhibit A-17, Schedule G3, includes only
17 a select group of utilities and is not the same list of companies used by the Company's cost
18 of equity witness in determining the cost of equity. This selective list of purported peer
19 companies is disconnected from the capital structure and equity ratio of the peer companies
20 used to calculate the cost of equity capital.

1 In summary, the common equity ratios presented by Mr. Lepczyk in Exhibit A-17,
2 Schedule G3, are significantly flawed and the Commission should not rely on that
3 information in setting an appropriate and balanced capital structure in this rate case.

4 **Q. DO YOU AGREE WITH MR. LEPCZYK THAT THE COMPANY'S USE OF**
5 **HIGHER AMOUNTS OF SHORT-TERM DEBT REQUIRES A HIGHER**
6 **COMMON EQUITY RATIO?**

7 A. No. In Table 4 on page 16 of his direct testimony, Mr. Lepczyk shows that the DTE Gas
8 short-term debt is higher on a percentage basis than the short-term debt of DTE Electric
9 and of Consumers Energy on December 31, 2022. However, there are a few problems
10 with this comparison. First, short-term has a seasonal pattern and balances vary throughout
11 the year. Electric utilities tend to have higher sales during the summer and late fall. The
12 higher revenues during those periods diminish the need for short-term debt once the billed
13 revenues are collected. In contrast, gas utilities need to finance gas inventories going into
14 the winter months and therefore their short-term debt peaks late in the calendar year before
15 revenue billed in December, January, and February is collected and short-term debt is paid
16 down.

17 Second, the issuance of long-term debt and the timing of those issuances affect the amount
18 of short-term debt at any point in time, as cash raised from long-term financing pays down
19 short-term debt used to temporarily finance capital programs. The table below shows the
20 different seasonal pattern of short-term debt balances between the electric and gas utility
21 with the peak balance highlighted in yellow.

Short-term Debt (\$ Millions)*

<u>Quarter End</u>	<u>DTE Electric</u>	<u>DTE Gas</u>	<u>Consumers</u>
Dec. 2022	\$ 568	\$ 242	\$ 95
Mar. 2023	-	-	-
Jun. 2023	222	-	6
Sep. 2023	679	190	327
Dec. 2023	385	77*	93

Source: SEC reports on 10K and 10Q for each company.

*In October 2023, DTE Gas issued long-term debt of \$295 million reducing short-term debt.

1

2

3

4

Mr. Lepczyk's claim that the Company's level of short-term should be a factor in setting the percent of common equity in the permanent capital structure is flawed and should be disregarded by the Commission.

5

Q. MR. LEPCZYK STATES THAT THE SMALLER SIZE OF DTE GAS COMPARED TO OTHER MICHIGAN UTILITIES JUSTIFIES A HIGHER COMMON EQUITY RATIO. DO YOU AGREE?

6

7

8

A. No. Certainly, compared to Consumers Energy (a combination gas and electric company) and DTE Electric, DTE Gas is a smaller company. As is generally the case, most electric utility companies are far larger than natural gas distributors. Therefore, the comparison of DTE Gas to electric utilities or combination gas and electric companies is inappropriate and not relevant in setting the equity ratio for the Company's capital structure. I will also point out that DTE Gas is far larger than the other two gas utilities in Michigan: Michigan Gas Utilities Corporation and SEMCO Energy Gas Company. Additionally, as can be easily observed from Exhibit A-17, Schedule G3, DTE Gas is the fifth largest gas utility of the 14 companies shown in the exhibit based on total capitalization. Accordingly, DTE

9

10

11

12

13

14

15

16

1 Gas is one of the largest natural gas distribution companies in the United States today.
2 Therefore, the smaller size claim is another red herring.

3 **Q. MR. LEPCZYK STATES THAT HIS PROPOSED EQUITY RATIO OF 51.5%**
4 **WOULD FACILITATE ACCESS TO THE CAPITAL MARKETS TO FINANCE**
5 **THE COMPANY’S CAPITAL EXPENDITURE PROGRAMS. DO YOU AGREE?**

6 A. No. Mr. Lepczyk presents no evidence that a 51.5% equity ratio is necessary to access the
7 capital markets or that a balanced capital structure with 50% equity and 50% long-term
8 debt would inhibit access to the capital markets. To the contrary, as discussed later in my
9 testimony, other utilities are able to easily access the capital markets with lower equity
10 ratios and lower approved return on equity rates.

11 On page 13 of his testimony, Mr. Lepczyk alleges that a move to a 50/50 capital structure
12 may be seen as an adverse change in the regulatory environment. However, he offers no
13 analysis or other evidence to support that claim. The Commission has signaled its desire
14 for a balanced 50/50 permanent capital structure for Michigan utilities for several years
15 and in a March 2024 order in Case No. U-21389, the Commission approved a common
16 equity ratio of 50.02% for Consumers Energy. Moreover, in the latest Moody’s report on
17 the Company dated July 25, 2023, the rating agency stated that “a rating upgrade could be
18 possible if DTE Gas’s financial metrics remain at current levels, such as the cash flow to
19 debt ratio continuing to be in excess of 19%.” Therefore, the concern by Mr. Lepczyk that
20 rating agencies and investors would somehow interpret a balanced structure as “an adverse
21 change in the regulatory environment” is not credible.

1 **Q. PLEASE DISCUSS THE COMMISSION’S DIRECTIVE TO DTE GAS IN ITS**
2 **ORDER OF SEPTEMBER 13, 2018 IN CASE No. U-18999 RELATING TO THE**
3 **CAPITAL STRUCTURE.**

4 A. In paragraph J on page 127 of the September 13, 2018 rate order, the Commission directed
5 that “DTE Gas shall, in its next rate case, articulate its strategy to return to a balanced
6 capital structure and the steps it will take to reach the goal.”

7 **Q. DID THE COMPANY ADDRESS THIS ISSUE IN TESTIMONY AND EXHIBITS**
8 **IN THE SUBSEQUENT RATE CASE IN CASE U-20642?**

9 A. No. This was a troubling omission by the Company with significant implications,
10 particularly given the fact that both the Commission and the ALJ in U-18999 discussed
11 this issue at length. In the discussion of this issue on pages 43 and 44 of the U-18999 rate
12 order, the Commission stated:

13 The Commission agrees with the ALJ and adopts the PFD’s recommendation that
14 the Commission should encourage DTE Gas to move to a more balanced 50/50
15 capital structure. As the Commission has stated, “[a] common equity ratio that is
16 unnecessarily equity-heavy burdens ratepayers because equity capital is more
17 expensive than debt capital and carries with it the additional expense of a tax
18 burden that is not present with debt capital.” The Commission directs DTE Gas
19 to, in its next rate case, present its strategy for returning to a balanced capital
20 structure and a detailed outline of the steps it plans to take to accomplish this goal.
21 Id., p. 46. If the company is unable to do so, a more complete analysis should be
22 included to explain why such a result is reasonable and prudent. For example, a
23 pro-forma debt capacity analysis using rating agency methodology ratio
24 benchmarks could be included to bolster DTE Gas’ arguments.

25 Case No. U-20642 was concluded with a settlement agreement and the Commission did
26 not have an opportunity to adjudicate this matter further in that rate case.

1 **Q. WAS THE ISSUE OF DTE GAS MOVING TOWARD A BALANCED CAPITAL**
2 **STRUCTURE ADDRESSED IN THE SETTLEMENT AGREEMENT FOR CASE**
3 **U-20642?**

4 A. Yes. In paragraph 12 of the Settlement Agreement, DTE Gas agreed to file a plan in the
5 next rate case (Case No. U-20940) that would move the Company toward a more balanced
6 capital structure.

7 **Q. WHAT EQUITY RATIO DID THE COMPANY PROPOSE IN CASE NO. U-20940**
8 **AND WHAT RATIO DID THE COMMISSION APPROVE WITH FURTHER**
9 **INSTRUCTIONS TO THE COMPANY?**

10 A. While the Company proposed only a slight decline in common equity ratio from 52% to
11 51.9%, the Commission approved a 51% common equity ratio and stated the following on
12 page 77 of the December 9, 2021 of the rate order.

13 The Commission agrees with the ALJ and the Staff's proposed 51/49 equity ratio
14 should be adopted. As stated by Staff, DTE Gas "can operate at any capital
15 structure it chooses", and as noted by Mr. Coppola, DTE can infuse as much
16 equity capital into DTE Gas as it sees fit. 5 TR 1682, 1856. However, the capital
17 structure must fairly balance the interests of the company and its customers. The
18 Commission finds that a capital structure of 51% equity and 49% debt is a
19 reasonable transition to a more balanced capital structure.

20 **Q. HAS THE COMPANY COMPLIED WITH THE COMMISSION REPEATED**
21 **DIRECTIVES TO PRESENT A BALANCED CAPITAL STRUCTURE?**

22 A. No. Despite the Commission's directives in Case U-18999 and subsequent orders to move
23 to a balanced capital structure, the Company has not presented a plan to do so and is

1 making arguments in this case for a higher common equity ratio of 51.5%, rather than the
2 51% approved in the last rate case. The Company continues to flaunt the Commission's
3 repeated directives. It is now clear that, left to its own discretion, the Company will not
4 propose a balance capital structure unless the Commission orders it.

5 **Q. DID YOU CALCULATE THE IMPACT ON THE MOODY'S CASH FLOW TO**
6 **DEBT COVERAGE RATIO BASED ON A 50% EQUITY RATIO IN THE**
7 **COMPANY'S CAPITAL STRUCTURE AND AN AUTHORIZED ROE OF 9.85%**

8 A. Yes. In Exhibit AG-30, I calculated the Company's key cash flow to debt ratio for 2022
9 adjusted for the ROE of 9.85% that I advocate for in this case and a 50% common equity
10 ratio on a pro forma basis, as discussed below.

11 For my calculation of the 2022 pro-forma cash flow to debt ratio, I start with Moody's
12 actual calculated ratio of 22.1% on line 1. On line 2, I adjust the debt level to a 50%/50%
13 capital structure versus the 52.6% common equity level shown in Exhibit A-4, Schedule
14 D1, page 1. This change results in the addition of \$117 million in additional debt in
15 determining the Company's ratio results. Also, on line 2 I adjusted the Company's earnings
16 downward by \$13 million due to the reduction in common equity and increase in debt. On
17 line 3, I adjusted the cash flow downward to reflect my recommended 9.85% ROE versus
18 the 11.5% ROE actually achieved by the Company in 2022. The overall pro-forma results
19 are shown on line 4 with a cash flow to debt ratio of 19.3%. This ratio is well above the
20 16% sustained ratio threshold that could trigger a credit rating downgrade, as stated by

1 Moody's in its July 25, 2023 report.⁵² I did not present any ratio results for S&P since the
2 ratio calculations are similar and the S&P downgrade threshold is lower at 11%.

3 By starting with actual Moody's 2022 results, items such as leases and short-term debt are
4 already reflected in the cash flow and debt elements to calculate the cash flow to debt
5 coverage ratio. This analysis shows that the 9.85% ROE and 50% common equity ratio
6 metrics positions the Company's cash flow ratios well above the threshold ratio where it
7 could face a downgrade of its debt. Furthermore, the 19.3% I calculated is slightly above
8 the current ratio that Moody's stated could trigger an upgrade of the Company's debt.
9 Accordingly, Mr. Lepczyk's concerns that a 50% equity ratio would trigger a ratings
10 downgrade are unfounded.

11 **Q. DID YOU CALCULATE THE DIFFERENCE IN REVENUE REQUIREMENT OF**
12 **INCREASING THE COMMON EQUITY RATIO FROM 50% TO 51.5%?**

13 A. Yes. If the Commission were to adopt a 51.5% common equity level in this case, the
14 annual revenue requirement would be higher by approximately \$7.8 million. This reflects
15 the Company's shift of approximately \$81 million from long term debt to common equity
16 capital and the difference between the Company's pretax cost of common equity of 14%
17 versus the pretax cost of long-term debt of approximately 4%.

18 **Q. DID YOU MAKE ANY OTHER ADJUSTMENTS TO OTHER ITEMS INCLUDED**
19 **IN THE COMPANY'S PROPOSED CAPITAL STRUCTURE?**

⁵² Moody's indicates this to be "16% on a sustained basis".

1 A. No.

2 **B. COST OF CAPITAL**

3 **Q. WHAT RETURN ON EQUITY AND OVERALL RETURN ON CAPITAL DO YOU**
4 **RECOMMEND IN THIS CASE?**

5 A. I recommend an overall after-tax return on capital of 5.82%, which includes a return on
6 common equity of 9.85%, as shown in Exhibit AG-22.

7 **Q. WHAT COST RATE DID YOU UTILIZE FOR LONG TERM DEBT?**

8 A. I used the 4.44% rate determined by Company witness Lepczyk.

9 **Q. WHAT COST RATE DID YOU UTILIZE FOR SHORT TERM DEBT AND THE**
10 **OTHER COMPONENTS OF THE CAPITAL STRUCTURE?**

11 A. For Short-Term Debt and Deferred Taxes, I utilized the cost rates recommended by
12 Company witness Lepczyk.

13 **Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE OVERALL COST OF**
14 **CAPITAL IN EXHIBIT AG-22.**

15 A. To develop the overall cost of capital on line 12, column (f), I have first developed the
16 percentage weighting of each capital component in column (d) by dividing the individual
17 capital balances in column (b) by the total of all capital components in that column. Next,
18 I have multiplied the weightings in column (d) by the cost rates in column (e) to arrive at

1 the values in column (f). The total of the individual values in column (f) is the total cost
2 of capital of 5.82%.

3 Regarding the pretax weighted cost of capital on line 12, column (h), I have multiplied
4 each cost component in column (f) by the conversion factors in column (g). These
5 conversion factors are included to reflect the impact of income and other taxes paid by the
6 Company for calculation of the pretax weighted cost of capital of 7.20% in column (h).

7 **Q. WHAT GENERAL PRINCIPLES HAVE YOU CONSIDERED IN DETERMINING**
8 **THE COST OF COMMON EQUITY FOR THE COMPANY?**

9 A. A utility company is entitled to a fair return that will allow it to attract capital and be
10 sufficient to assure investors of its financial soundness. In its opinion in Bluefield Water
11 Works and Improvement Company v Public Service Commission of West Virginia (the
12 “Bluefield Case”) 262 U.S. 679 (1923), the United States Supreme Court stated that:

13 A public utility is entitled to such rates as will permit it to earn a return on the value
14 of the property which it employs for the convenience of the public equal to that being
15 made at the same time...on investments in other business undertakings which are
16 attended by corresponding risks and uncertainties; but it has no constitutional right
17 to profits such as are realized or anticipated in highly profitable enterprises or
18 speculative ventures. The return should be reasonably sufficient to assure
19 confidence in the financial soundness of the utility and should be adequate, under
20 efficient and economical management, to maintain and support its credit and enable
21 it to raise the money necessary for the proper discharge of its public duties....

22 The principals of the Bluefield Case were re-affirmed by the U.S. Supreme Court in 1944
23 in the case FPC v Hope Natural Gas Company, 320 U.S. 591.

1 **Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE COST OF COMMON**
2 **EQUITY IN EXHIBIT AG-23.**

3 A. Determining the cost of common equity for an enterprise or an industry group is an inexact
4 science, since investors can only estimate what the future cash flows from any enterprise
5 may be over time. Because of this uncertainty, most financial experts will not rely solely
6 on any one particular method. To determine the cost of common equity, I have utilized
7 three distinct methods. They are the Discounted Cash Flow (DCF) Method, the Capital
8 Asset Pricing Model (CAPM), and the Utility Risk Premium approach. These
9 methodologies have previously been accepted by the Commission and have been generally
10 accepted by regulatory commissions in other jurisdictions in the United States. Also, I
11 have considered the circumstances in the Capital Markets in 2023 and early 2024 and any
12 potential changes in the risk profile of DTE Gas and the economy in the state of the
13 Michigan. While Exhibit AG-23 shows a weighted average cost of common equity of
14 9.81% using the three methods, I recommend an authorized rate of return on equity of
15 9.85% for the reasons explained later in this section of my testimony. In connection with
16 these methods for determining the cost of common equity, I have considered the cost of
17 common equity for a proxy group of peer companies.

18 **Q. PLEASE EXPLAIN THE DEVELOPMENT OF YOUR PROXY GROUP OF PEER**
19 **COMPANIES?**

20 A. To develop my peer group, I started with the nine gas utility companies followed by the
21 Value Line Investment Survey in its “Natural Gas Utility Industry” section. I removed

1 two companies from consideration for the following reasons. The companies that I
2 removed are (1) UGI Corporation due to its foreign investments and propane investments,
3 which is 50% of its business; and (2) Southwest Gas Holdings, which has announced that
4 it will either sell or spin-off its large infrastructure unit — Centuri. Also, I have added
5 Black Hills Corporation (Black Hills), which is classified by Value Line as an electric
6 utility but which derives approximately 50% of its earnings from natural gas distribution.

7 The result is the group of eight companies shown in Exhibit AG-24, all of which have
8 growing earnings and dividends.

9 **Q. HOW DOES YOUR PEER GROUP OF EIGHT COMPANIES COMPARE TO**
10 **THE COMPANY'S PEER GROUP?**

11 A. The Company's peer group presented by witness Dr. Bente Villadsen consists of a group
12 of 17 companies. These companies include nine water utility companies, seven of the
13 eight gas utility companies that comprise my peer group, and Southwest Gas Holdings,
14 which I did not include for the reason discussed above. Witness Villadsen presents these
15 companies (1) as a gas group; (2) as a water group; and (3) as a combined group.

16 **Q. DO YOU BELIEVE THAT THE COMPANY'S PROPOSED PEER GROUP IS**
17 **APPROPRIATE?**

18 A. No. The inclusion of the nine water companies is not necessary and should be rejected.
19 Four of the nine water companies selected by witness Villadsen are small entities with
20 annual revenues of approximately \$200 million or less and with one as low as \$53 million

1 in revenue. In comparison, DTE Gas reported more than \$1.7 billion in revenue for the
2 year 2023.⁵³ Smaller companies have unique characteristics, such as low stock trading
3 volume and illiquidity in the financial markets, which increase their cost of doing business
4 and their cost of capital. As such, they are not appropriate comparable companies to
5 include in a peer group for calculation of the cost of common equity in this case.

6 Moreover, the Company has included these water utility companies in its rate cases in
7 recent years and in the Company's most recent fully contested rate case, the Commission
8 stated that the inclusion of water utilities and the use of ATWACC and the Hamada
9 approach were all inappropriate. The Commission stated:

10 Accordingly, the Commission agrees with the ALJ that water utilities are not
11 appropriately included in a proxy group for determining an appropriate ROE for a gas
12 utility. In addition, the Commission acknowledges the Staff's and Attorney General's
13 concern that the application of an ATWACC or Hamada adjustment may excessively
14 inflate ROE's, stock prices, and market-to-book ratios for utilities.⁵⁴

15 In addition, the common stocks of three of the nine water companies have been trading at
16 Price to Earnings (P/E) ratios of between 25 to 37 times trailing earnings in late April 2024
17 and also at high market to book equity ratios well above the gas utilities in the peer group.
18 In comparison, the common stocks of the gas utilities peer group have been trading at an
19 average P/E ratio of 17 times trailing earnings during April 2024.

20 Some of the water companies are likely acquisition targets due to their smaller size and
21 the continuing consolidation taking place in the water industry.

⁵³ DTE Energy 2023 Form 10-K, page 35.

⁵⁴ Commission order dated December 9, 2021 in Case U-20940, page 91.

1 **Q. ARE WATER COMPANIES COMPARABLE TO GAS UTILITIES?**

2 A. No. There are significant structural differences between gas utilities and water companies.
3 Gas companies are subject to volatility in natural gas prices, state mandated energy
4 conservation programs, and the risk of gas explosions among other unique factors affecting
5 the gas industry. On the other hand, water utilities do not face the same water supply price
6 volatility, and with the exception of arid areas on the west coast, do not have state-
7 mandated water conservation programs or similar risks as gas utilities. Because of the
8 factors enumerated above, I find the inclusion of water companies in a gas utility peer
9 group inappropriate, unwise, and unnecessary. The gas peer group I have proposed is
10 adequate and appropriate.

11 **Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING**
12 **THE COMPANY’S PROPOSED WATER COMPANY PEER GROUP AND THE**
13 **COMBINED PEER GROUP WITH WATER UTILITIES?**

14 A. The Commission should reject the Company’s peer groups which include water utilities
15 and Southwest Gas Holdings due to its pending divestiture of its pipeline construction
16 business. Instead, the Commission should adopt my proposed peer group as a better
17 comparable group of companies for DTE Gas.

18 **Discounted Cash Flow (DCF) Approach**

19 **Q. PLEASE DESCRIBE THE DISCOUNTED CASH FLOW (“DCF”) APPROACH.**

1 A. The DCF approach is based on the proposition that the price of any security reflects the
 2 present value of all future cash flows (dividend flows) from the security discounted at a
 3 single discount rate, which in the case of common stocks, is the required return of equity.
 4 Expressed mathematically, the resulting equation can be reconfigured to solve for the
 5 required rate of return and this equation is:

$$6 \quad R = D/P + g$$

7 *where "R" = the Required Equity Return*

8 *"D/P" = the Dividend Yield on the Security*

9 *and "g" = the expected growth rate in dividends*

10 Generally, the "D" or dividend is known, and the "P" or stock price is also known as the
 11 stock trades each day. Also, recent growth in the dividends and earnings is known or
 12 estimates of growth furnished by stock analysts can be relied upon with some degree of
 13 certainty. With this information, one can solve for "R" which is the required rate of return.

14 **Q. PLEASE EXPLAIN THE RESULTS OF YOUR DCF ANALYSIS.**

15 A. The results of my DCF analysis are summarized in Exhibit AG-24. The stock price
 16 information in column (c) on this exhibit reflects the average of the high and low prices
 17 for each of these equity securities on each of the 30 trading days from February 15, 2024
 18 March 31, 2024. The annual dividend in column (d) is the projected average annual
 19 dividend level for the 2024-2025 period as projected by the Value Line Investment Survey.
 20 Column (h) shows the average long-term earnings growth rate based on Value Line
 21 projections of earnings per share through the year 2028 and Yahoo Finance analysts'

1 projected growth over the next five years. The resulting calculation of the DCF Method
2 indicates an average required return on common equity of 9.51% for the proxy group.

3 This result is lower than the Company's "simple" DCF study result for the gas group of
4 11.1%, but comparable to the Company's "multi-stage" DCF result of 9.02% calculated
5 by witness Villadsen and shown in Figure 14 on page 43 of her testimony. It is important
6 to keep in mind that the Company's results were determined using witness Villadsen's
7 ATWACC process which, as discussed later, should be rejected.

8 **Q. PLEASE EXPLAIN WHY WITNESS VILLADSEN'S DCF COST OF EQUITY**
9 **FOR THE GAS SAMPLE IS SO MUCH HIGHER.**

10 A. The key differences between my 9.5% DCF cost of capital and witness Villadsen's DCF
11 estimate for the gas group at 11.1% are (a) the growth rates utilized, which bring the
12 outcome to 10.3%; and (b) the ATWACC process, which increases the result further to
13 11.1%. The growth rates she uses average to 6.6%, which was determined in the later part
14 of 2023 and are stale at this point. My DCF average growth rate of 5.4% was developed
15 in April 2024, is more recent, and is 120 basis points lower than the Company's growth
16 rate. Also, the inclusion of Southwest Gas Holdings with a higher growth rate contributes
17 to the higher outcome in the Company's calculations. Witness Villadsen's pre ATWACC
18 DCF cost of capital for her gas group is 10.3%.⁵⁵ As mentioned above, the application of
19 the ATWACC calculations inflate the DCF ROE rate to 11.1%.

⁵⁵ Exhibit A-14, Schedule D5.7 Panel A, column 3.

1 **Q. PLEASE DESCRIBE THE ATWACC PROCESS AND WHY ITS APPLICATION**
2 **BY THE COMPANY IN THIS CASE IS FLAWED.**

3 A. Witness Villadsen's 11.1% Simple DCF for the gas group can be explained as follows.
4 First, in Exhibit A-14, Schedule D5.7, she computes and shows the basic DCF result of
5 10.3% for her peer group of gas companies.

6 Second, starting with the 10.3% result noted in the preceding paragraph, witness Villadsen
7 derives a 7.8% after-tax cost of capital for the gas peer group based on the market value
8 of each of the companies in the peer group. The 7.8% result is shown in column 10 of the
9 Schedule D5.7, Panel A. It is important to recognize that this outcome is a function of an
10 average common equity ratio of 63% as noted in column 4 of Schedule D5.7.

11 Third, on Schedule D5.8, witness Villadsen redistributes the average after tax cost of 7.8%
12 back to the debt and common equity components based on a 51.5% common equity ratio
13 (not the 63% common equity ratio previously used), which results in her ROE
14 determination of 11.1%.

15 The key driver in this complex process of calculations is the ratio by which the stock
16 market equity exceeds book value equity. This process of determining the After-Tax
17 Weighted Average Cost of Capital is simply a mathematical process to drive an upward
18 adjustment of the final ROE rate using stock market premiums over book equity values.

19 The resulting effect of this ATWACC approach is that higher market to book ratios in the
20 utility industry (due to lower interest rates and other factors), if embraced by regulatory

1 commissions, would lead to higher ROEs awarded in rate cases and a form of future bonus
2 earnings for achieving higher stock prices for utility investors.

3 Also, the Commission should recognize the inherent circularity of the ATWACC process.
4 For example, if the ATWACC approach was to become universally embraced by
5 regulatory commissions, the ROEs awarded in regulatory proceedings would increase.
6 The inflated ROEs would result in higher utility earnings, stock prices, and higher market
7 to book ratios for utility common stocks. The subsequent calculated ROEs in new rate
8 cases under the ATWACC method would then produce even higher awarded ROEs
9 because the ATWACC would use the higher stock market equity capitalization.

10 Most likely, because of this cost inflating circularity and the complexity of the
11 methodology, the ATWACC method has not been embraced in the utility industry. In fact,
12 the Company could not cite any state regulatory commissions in the U.S. that have adopted
13 this methodology for purposes of setting an authorized ROE in a utility rate case.
14 According to testimony by a colleague of witness Villadsen in case No. U-18999, the
15 instances where this methodology has been used involve (1) property taxation disputes in
16 Colorado; (2) a valuation dispute before the FERC; and (3) revenue adequacy hearings for
17 railroads, as well as a revenue adequacy hearing involving Alabama Power related to its
18 special rate RSE. Therefore, the Commission should disregard the ATWACC approach
19 in calculating the DCF cost of common equity.

20 **Q. PLEASE ASSESS THE RESULTS OF THE DCF ANALYSIS YOU PERFORMED.**

1 A. The DCF analysis relies upon financial market information for the dividend yield portion
 2 of the equation. However, it also relies upon judgments of growth prospects of security
 3 analysts that may or may not be consistent with the beliefs of investors. I will point out
 4 that the forecasted growth rates for the proxy group include some very high growth rates,
 5 which in some cases are as high as 7.60%.

6 These high growth rates appear to be the result of a temporary rebound in earnings from a
 7 low point in recent years. While these earnings may materialize in the short term, such
 8 high rates are not sustainable long-term growth rates for gas utilities given that customer
 9 and revenue growth continue to be barely in low single digits. As such, the results of the
 10 DCF analysis in some cases reflect a return on equity rate that is somewhat higher than
 11 what investors currently expect in the long term. Nevertheless, I place a fairly high degree
 12 of reliability in the DCF results when considered in conjunction with the results of other
 13 approaches to determining the cost of common equity.

14 **Capital Asset Pricing Model Approach**

15 **Q. PLEASE EXPLAIN THE CAPITAL ASSET PRICING MODEL APPROACH TO**
 16 **DETERMINING THE COST OF COMMON EQUITY CAPITAL.**

17 A. The Capital Asset Pricing Model (CAPM) is based on the proposition that the expected
 18 return on a common equity security is a function of risk as measured by the “Beta” of that
 19 security. In equation form, CAPM is as follows:

20
$$k_e = R_f + (B \times R_p) \text{ where}$$

21 $k_e = \text{The market cost of common equity for a specific security}$

1 *R_f = the “risk free” rate of return*

2 *R_p = the overall return of the market less the risk-free rate (over several years)*

3 *B = the systematic risk of a particular common equity security vs. the market*

4 **Q. PLEASE EXPLAIN THE BETA OR “B” COMPONENT OF THE EQUATION.**

5 A. This measure of risk reflects the extent to which the price of a particular security varies in
6 relationship to the movement of the overall market. Some securities vary less in price over
7 time than the overall market. In these cases, the Beta will be less than 1.00. Securities
8 that vary over time more than the overall market will have a Beta that is greater than 1.00.

9 **Q. PLEASE EXPLAIN EXHIBIT AG-25 SHOWING THE RESULTS OF THE CAPM**
10 **APPROACH.**

11 A. Exhibit AG-25 shows the results of the CAPM method based upon (1) a projected 30-year
12 U.S. Treasury bond rate; (2) Beta information available from Value Line; and (3)
13 Historical Market Risk Premium (*R_p*) information of 7.17% based on the Ibbotson Classic
14 Yearbook through 2022.

15 As shown in Exhibit AG-25, I have added the peer group risk premium of 6.32% to the
16 4.1% risk-free rate to arrive at the 10.42% ROE rate under the CAPM method.

17 The 6.32% group risk premium is the risk premium for the total stock market of 7.17%
18 shown in column (d) multiplied by the average beta of 0.88 from column (c). These factors
19 are explained further in Exhibit AG-25.

20 **Q. PLEASE ASSESS THE CAPM APPROACH.**

1 A. I believe that CAPM has value in assessing the relative risk of different stocks or portfolios
2 of stocks. As such, it can be useful. However, the key issue with CAPM is that it assumes
3 that the entire risk of a stock can be measured by the “Beta” component and as such the
4 only risk an investor faces is created by fluctuations in the overall market. In actuality,
5 investors take into consideration company-specific factors in assessing the risk of each
6 particular security. As such, I give the CAPM approach less weight than the DCF approach
7 in determining the cost of common equity.

8 **Q. PLEASE COMMENT ON WITNESS VILLADSEN’S GAS GROUP CAPM**
9 **COMMON EQUITY COST RATES RANGING FROM 9.4% TO 9.9%.**

10 A. In Figure 13 on page 39 of her direct testimony, witness Villadsen presents 4 different
11 CAPM cost of equity estimates and 4 different ECAPM estimates for her gas sample
12 companies. The Commission should not rely upon any of these CAPM or ECAPM results.
13 All of the estimates have been determined utilizing the Hamada Adjustment process with
14 non-standard betas. This method provides faulty and inflated results.

15 In Figure 11 on page 37 of her testimony, witness Villadsen shows the market risk
16 premium (MRP) data she uses for her two scenarios. In Scenario 1, she uses the same
17 7.17% MRP that I use, which is the long-term 1926-2022 result based on the classic
18 Ibbotson study. Scenario 2 reflects a lower 5.72% MRP rate, which she claims is based
19 on a recent Bloomberg projection. She also notes the use of a 3.95% risk free rate. Her
20 explanation for the development of this rate is covered on pages 34 and 35 of her
21 testimony.

1 Witness Villadsen uses these data inputs and Value Line betas as shown on her Exhibit A-
2 14, Schedule D5.10 to develop her basic CAPM estimates of 10.1% and 8.8% for her gas
3 group sample estimates. These results are shown on her Exhibit A-14, Schedule D5.11
4 Panel A and Panel B. These results and the inputs used are reasonable.

5 However, what is not reasonable is the use of the Hamada approach in her workpaper
6 schedules in Exhibit A-14. In this regard, she derives a non-standard beta of approximately
7 1.0. This non-standard beta is approximately 18% higher than her average Value Line beta
8 average of 0.85 and this leads to the higher CAPM ROE outcome at 11.2% under her
9 Scenario 1.

10 **Q. WHAT IS YOUR ASSESSMENT OF WITNESS VILLADSEN'S ECAPM**
11 **RESULTS?**

12 A. First, it is worth noting that her ECAPM results have been developed using the Hamada
13 methodology discussed earlier and are corrupted by this faulty approach. Witness
14 Villadsen explains the ECAPM approach beginning on page 37 of her testimony. She
15 states that research has shown that "...low-beta stocks tend to have higher risk premiums
16 than predicted by the CAPM..." Her equation for the ECAPM is very similar to the
17 CAPM equation except that she introduces an alpha factor into the equation at 1.5%.⁵⁶

18 I will point out that the classic CAPM approach typically uses short-term treasury rates as
19 the risk-free rate. However, most witnesses in rate cases use the 30-year treasury bond as

⁵⁶ Villadsen testimony page 39, lines 1 and 2.

1 the risk-free rate, which usually is higher than short-term treasury rates. Accordingly, the
2 corrections made within the ECAPM are unnecessary.

3 To my knowledge, the ECAPM is not widely accepted as a cost of equity methodology
4 among gas and electric regulatory commissions in the United States. One of the few
5 regulatory commissions outside of the U.S. that has spoken on the subject of ECAPM is
6 the Alberta Utilities Commission of Canada in its order of October 7, 2016. That
7 regulatory commission noted on page 45, paragraph 199, of the order that the ECAPM
8 *"...appears to be a model that could contribute to the Commission's determination of a*
9 *fair allowed ROE...."* However, later in the same paragraph, the commission noted the
10 high degree of judgement required by the ECAPM methodology, and reached the
11 conclusion that *"...Consequently, the Commission will not rely heavily on the ECAPM*
12 *results in this proceeding."*

13 In summary, the use of the 30-year treasury rate (not short-term rates) as the risk-free rate
14 in the CAPM method resolves the need to use the ECAPM method and the inflated results
15 that it produces.

16 **Q. WHAT IS YOUR OVERALL ASSESSMENT OF THE COST OF EQUITY**
17 **METHODOLOGIES USED BY WITNESS VILLADSEN?**

18 A. While witness Villadsen's various methods used to calculate the cost of equity capital are
19 inventive, they are highly unconventional and not generally accepted. The Commission
20 should reject these alternative approaches for the reasons previously discussed and because

1 they are clearly a brazen attempt to inflate the Company's true cost of common equity in
2 this case.

3 **Utility Risk Premium Approach**

4 **Q. PLEASE EXPLAIN THE UTILITY RISK PREMIUM METHOD OF**
5 **ESTIMATING THE COST OF COMMON EQUITY.**

6 A. In general, one can estimate the cost of common equity by estimating three components
7 and adding them together. The three components are (1) the risk-free rate of return on 30-
8 year U. S. Treasury Bonds; (2) the historical differential between yields of the rated utility
9 bonds of the Company and the 30-year U.S. Treasury Bonds; and (3) the average return
10 differential of utility common stocks over utility bonds.

11 **Q. PLEASE EXPLAIN YOUR UTILITY RISK PREMIUM ANALYSIS RESULTS.**

12 A. Exhibit AG-26 shows the three components required to estimate the cost of common equity
13 under this approach. The results for this approach reflect a return on common equity of
14 9.82%. To arrive at this result, I used the historical spread of gas utility common stock
15 returns relative to utility bonds of 4.05%. Also, I used a 1.67% average spread for utility
16 bonds (A rated and BBB rated) over the 30-year U.S. Treasury bond rate. This spread is
17 the average spread of new utility bonds issued during the 12 months ended October 2020
18 period over 30-year U.S. Treasuries for (1) A rated bonds of 157 basis points; and (2) BBB
19 rated bonds of 177 basis points. For the risk-free rate, I used the projected 30-year
20 Treasury rate of 4.1% discussed under the CAPM section of my testimony.

1 Q. HOW HAS THE ECONOMIC AND INTEREST RATE ENVIRONMENT
2 CHANGED IN RECENT YEARS FOR THE COMPANY?

3 A. Despite higher interest rates, the economy remains strong. Inflation has receded from
4 approximately 8.5% in early 2022 to approximately 3% in recent months. Lower inflation
5 and gas prices should benefit the Company in the projected test year and further interest
6 rate decreases are expected should inflation reach nearer to the Federal Reserve Bank's
7 2% target.

8 The Company's access to the capital markets and also for its sister company, DTE Electric,
9 is strong as witnessed by (1) DTE Gas issuing \$295 million of 7-year and 12-year long-
10 term debt with rates ranging from 5.57% to 5.73% in October 2023; and (2) DTE Electric
11 issuing \$2.9 billion of 5-year to 30-year long-term debt at rates ranging from 5.57% to
12 5.73% at various times in 2023.

13 The Company's senior secured debt is rated at A/A1 and its commercial paper program is
14 rated P-2 by Moody's Investor Service.

15 Accordingly, the Company's recommendation that the authorized rate of return on
16 common equity should be increased to 10.25% to continue to have access to capital
17 markets is unsupported by the evidence. The proposed ROE is largely based on
18 unconventional methodologies applied to CAPM and DCF cost of equity calculations. The
19 results of my DCF analysis, CAPM analysis, and Utility Risk Premium Approach point to
20 a calculated cost of equity closer to 9.81%, which I have rounded up to 9.85%.

1 **Q. PLEASE DISCUSS WHAT RETURN ON EQUITY RATES OTHER**
2 **REGULATORY COMMISSIONS HAVE GRANTED IN 2022 AND 2023?**

3 A. Exhibit AG-29 shows the ROEs granted by state regulatory commission to U.S. gas
4 utilities in 2022 and 2023. The majority of the 33 ROE decisions in 2022 and 36 decisions
5 in 2023 are at rates well below 9.9%. As noted on page three of this exhibit, only 2
6 decisions in 2022 and 3 decisions in 2023 are at rates of 9.9% or greater. These higher
7 rates are from California, Florida, and Michigan. ROEs in California have been over 10%,
8 reflecting the unique challenges of that state (wildfires and earthquakes). Decisions in
9 Florida pertain to smaller utility companies as explained in my Exhibit AG-29.

10 For most of the other gas utilities that have business and financial risks comparable to DTE
11 Gas, the ROE rates have averaged around 9.50% in the past two years. This evidence
12 supports my proposed ROE rate of 9.85% and makes the Company's current ROE rate of
13 9.90% somewhat excessive. The Company's proposed ROE rate of 10.25% is even further
14 removed from reality and clearly unsupportable.

15 **Q. SHOULD THE COMMISSION BE CONCERNED THAT ESTABLISHING AN**
16 **AUTHORIZED ROE OF 9.85% IN THIS CASE WILL LEAD TO IMPAIRMENT**
17 **OF THE COMPANY'S ABILITY TO ACCESS THE CAPITAL MARKETS?**

18 A. No. In recent general rate case proceedings, certain rate case applicants have raised
19 arguments that they should receive a ROE of 10% or higher to ensure the financial
20 soundness of the business and to maintain its strong ability to attract capital in addition to
21 being compensated for risk. Exhibit AG-29 shows several gas utilities that have accessed

1 the capital markets at competitive interest rates since receiving a ROE near or below the
2 average rate of 9.50%.

3 Similarly, there is no evidence equity investors have abandoned utilities that have been
4 granted ROEs below 9.9%. On the contrary, stock investors continue to migrate to utility
5 stocks, recognizing that authorized ROEs are still above the true cost of equity. Exhibit
6 AG-28 shows the market to book ratios for each of the peer group companies, and many
7 of these companies have received rate orders during the past few years reflecting ROEs as
8 low as 9.3%. Yet this group of companies has an average Market to Book common equity
9 value ratio of nearly 1.5 times.

10 This information is provided to dispel the myth that the Company must receive a ROE near
11 or above 10%, or it will face dire consequences in the financial markets.

12 The fact that the Company needs to raise capital because of a large capital investment
13 program to upgrade its infrastructure and for other purposes is not unique to DTE Gas.
14 Other gas utilities face the same issues and are able to raise capital with ROEs of 9.85%
15 or below. Therefore, this issue is another red herring.

16 **Q. ON PAGE 52 OF ITS SEPTEMBER 13, 2018 ORDER IN CASE NO. U-18999, THE**
17 **COMMISSION POINTED TO INCREASED VOLATILITY IN THE CAPITAL**
18 **MARKETS AS A REASON TO AUTHORIZE A 10% ROE RATE. SHOULD**
19 **STOCK MARKET VOLATILITY OR THE VIX INDEX BE A CONCERN IN**
20 **ESTABLISHING A FAIR ROE RATE FOR THE COMPANY?**

1 A. No. Witness Villadsen discusses the stock market volatility at length on pages 29 through
2 31 of her direct testimony, stating “A measure of the market’s expectations for volatility
3 is the VIX index, which measures the 30-day implied volatility of the S&P 500 index.”
4 She then goes on to discuss higher levels of the VIX “...in December 2018 and again in
5 early August 2019, each time concurrent with a significant drop in the stock market....”

6 The stock market has historically been very volatile. In some periods, stock prices move
7 up and down more dramatically than at other times. The key factor is that the VIX is
8 telling us something about risk in the market over the next 30 days and not the risk several
9 months in the future. In setting ROE rates for utilities, the Commission’s focus is the long-
10 term financial health of the utility not the short-term gyrations of the stock market.

11 As a second point, in Exhibit AG-31, I have included a Value Line Funds article written
12 by Mitchell Appel, President of Value Line Funds. Mr. Appel states that volatility is not
13 risk. For example, he also points out that volatility in 2017 was low by historical standards
14 and it was near normal levels in 2018. Mr. Appel goes on to say later in this article that
15 “...volatility is only risk if you act during down times, that is, only if you sell a stock.”

16 Additionally, I will submit that those who invest money in equity portfolios over longer
17 periods of time and particularly in utility stocks have an aversion to market volatility and
18 the VIX. In fact, utility stocks are a safe haven for investors during times of uncertainty
19 and volatility because they are not as susceptible to volatility as the general stock market.
20 This is reflected in the average Beta value of 0.88 of the utility peer group used in the
21 CAPM discussed earlier, in contrast with the general stock market value of 1. Therefore,

1 the Commission should not give any weight to arguments that the Company's ROE should
2 reflect investors' concerns with stock market volatility.

3 **Q. PLEASE EXPLAIN YOUR CONCLUSION CONCERNING THE APPROPRIATE**
4 **RETURN ON EQUITY RATE THE COMMISSION SHOULD USE IN THIS CASE.**

5 A. In Exhibit AG-23, I summarized the cost of equity rates from the three methods I discussed
6 above. The range of returns for the industry peer group is from 9.51% at the low end,
7 using the DCF approach and 10.42% at the high end using the CAPM approach.

8 As explained earlier in my testimony, I give 50% weight to the DCF method as a more
9 reliable approach to estimating the cost of equity, which from my analysis is a rate of
10 9.51%. In this regard, on line 4 of Exhibit AG-23, I calculated a weighted return on equity
11 of the three methodologies using a 50% weight for DCF and 25% for each of the other two
12 methods. The result is a weighted average cost of common equity of 9.81%. I have
13 rounded this result upward to 9.85%.

14 **Q. IF THE COMMISSION APPROVES A 9.90% COST OF COMMON EQUITY IN**
15 **THIS CASE (AS IT DID IN CASE NO. U-20642), WHAT IS THE COST TO**
16 **CUSTOMERS COMPARED TO AN ROE OF 9.85%.**

17 A. If the Commission were to grant a 9.90% ROE in this case versus a 9.85% ROE, the
18 additional cost to customers is approximately \$2.1 million annually. There is absolutely
19 no need to burden customers with this additional cost, when historically the Company has
20 been earning well above its true cost of common equity.

1 I recommend that the Commission take note of the evidence and arguments I have
2 presented in my testimony and grant the Company a ROE of no more than 9.85%.

3 **VII. Revenue Adjustment**

4 **Q. WHAT ADJUSTMENTS ARE YOU PROPOSING WITH REGARD TO THE**
5 **COMPANY'S FORECASTED REVENUE FOR THE PROJECTED TEST YEAR?**

6 A. In my analysis, I have discovered that the Company's projected revenues for Gas Sales,
7 End-User Transportation, Midstream Services, and the Appliance Service Program are
8 significantly understated. The total incremental revenue that I propose is \$19,640,000.
9 In the testimony below I explain further the reasons for this proposed revenue
10 adjustment.

11 **A. Gas Sales Revenue**

12 **Q. WHAT ARE YOUR FINDINGS FROM ANALYZING THE COMPANY'S**
13 **PROJECTED LEVEL OF GAS SALES?**

14 A. On line 14 of page 1 of Exhibit A-15, Schedule E1, Company witness George Chapel
15 presents the Company's forecast of gas sales for the projected test year built up from the
16 2022 historical year. The Company has forecasted total gas sales of 159.1 Bcf for the
17 projected test year. This level of sales represents a decrease of approximately 3.6 Bcf, or
18 2.2%, from the actual weather-normalized gas sales of 162.7 Bcf in 2022.

19 According to Mr. Chapel, the Company calculated the forecasted sales based on various
20 regression projection models applied to customers' historical gas consumption during the

1 two-year period from August 2021 to July 2023. The models also make use of other
2 historical and projected data, including number of customers, weather degree days,
3 expected energy efficiency factors, population growth, manufacturing activity, and other
4 econometric data. Additionally, the Company included adjustments to forecasted gas sales
5 to take into consideration the reduction in sales from its Energy Waste Reduction (EWR)
6 program and a slight difference in the heat content of the gas (BTU factor) between the
7 historical gas usage period and more recent data.

8 After reviewing the sales forecast, I have determined that the Company has significantly
9 underestimated the gas sales volume for residential and commercial customers and the
10 related test year revenue.

11 **Q. WHAT IS THE BASIS FOR YOUR CONCLUSION THAT FORECASTED GAS**
12 **SALES ARE UNDERSTATED?**

13 A. In response to discovery, the Company provided actual weather-normalized gas sales and
14 the number of customers for each year from 2018 to 2023 and for the forecasted years
15 2024, 2025, and the projected test year.⁵⁷ From the data provided by the Company, in
16 Exhibit AG-32, I calculated the average weather-normalized annual gas usage per
17 customer for each of the customer classes. The analysis on lines 2 and 3 of Exhibit AG-
18 32 shows that from 2018 to 2023, the average annual gas usage per residential customer
19 (Rate A) declined from 95.67 Mcf to 92.62 Mcf, or an average of 0.6% annually. In
20 contrast, the Company has projected a decline in gas usage of 1.0% in 2024 with an

⁵⁷ The historical normalized sales are for the 12 months ended August of each year.

1 additional decline of 1.6% in 2025 for a cumulative decline of 2.3% between 2023 and the
2 projected test year. The Company's projected test year sales forecast results in average
3 annual gas usage per residential customer of 90.52 Mcf, which is the lowest level since at
4 least 2018.

5 For commercial customers (Rate GS-1), the analysis on lines 11 and 12 of Exhibit AG-32
6 shows that the average usage per customer decreased between 2018 and 2023 from 461.91
7 Mcf to 446.37 Mcf. Over this period, the average annual decrease in usage per customer
8 was 0.7%. However, the Company's sales forecast shows the average usage per customer
9 declining 2.0% in 2024 from 2023, with a further decrease of 1.6% in 2025, for a
10 cumulative decline of 3.3% from 2023 to the end of the projected test year. This decline
11 comes despite the Company forecasting an increase of approximately 462 commercial
12 sales customers from 2023 to 2025, as shown on line 34 of Exhibit AG-32. Although the
13 EWR program pursued by the Company will have some impact on customer usage, the
14 forecasted increase in the number of residential and commercial customers should be a
15 mitigating factor against the loss of sales from the 1% targeted reduction in energy
16 conservation.

17 Although the same or even large inconsistencies exist with the sales forecasts for the other
18 customer classes and rate schedules, the volume difference are significantly smaller and
19 therefore I decided not to pursue them.

20 However, the decline in Rate A residential and Rate GS-1 commercial sales between 2023
21 and the projected test year is significant, highly unusual, and unsupported.

1 **Q. DID THE COMPANY’S FILED TESTIMONY EXPLAIN THE CHANGES IN**
2 **CUSTOMER USAGE THAT YOU HAVE HIGHLIGHTED ABOVE?**

3 A. No. In his direct testimony, Mr. Chapel describes the forecasting process for gas sales and
4 explain major changes in the aggregate at a high level, but does not analyze, explain, or
5 support changes in gas volumes usage between historical and forecasted periods by rate
6 schedule or customer class. Exhibit A-15, Schedules E3 and E4, provide customer usage
7 data for residential and commercial customers, but no analysis of the data has been
8 provided. In discovery, the Attorney General asked the Company to provide any
9 adjustments to the forecasted gas deliveries made outside of the forecasting models used
10 to develop the base forecast. In response, the Company provided two external adjustments
11 and stated that no other adjustments were made to either historical or forecasted customer
12 sales.⁵⁸

13 The first adjustment pertains to the EWR lost sales, which the Company forecasted at
14 approximately 1% of recent historical sales. This rate of decline appears to be overly
15 optimistic, given that over the five-year period from 2018 to 2028 the average annual gas
16 usage for residential customers has decline by only 0.6%, or about half the EWR assumed
17 rate of reduction. Although customer growth may have offset some of the EWR losses,
18 the 1% EWR loss rate does not appear realistic, and it is likely understating future customer
19 gas usage in the Company’s forecast.

⁵⁸ Exhibit AG-33 includes DRs AGDG-4.58d-e, 4.60, 4.65a, 4.65c.

1 The second adjustment is relatively small, pertaining to the difference in the BTU value of
2 the gas supply, which Mr. Chapel describes on pages 13-15 of his direct testimony.

3 However, more concerning is the historical gas usage period selected by the Company to
4 forecast future gas sales. As stated above, the Company used two years of historical gas
5 usage from August 2021 to July 2023 to develop the average customer historical gas usage
6 factors. There are two events that impacted customer usage during this period, which
7 negatively affected customer gas usage. First, the lingering effect of the Covid-19
8 pandemic continued into 2021 and likely continued to depress customer gas usage during
9 the August to December 2021 period and potentially subsequent months into early 2022.
10 Second, in 2022 gas prices spiked considerably, more than doubling from prior years.
11 Such a large increase in gas bills forces customers to undertake added energy conservation
12 steps, at least temporarily, until gas prices subside, which occurred beginning in early
13 2023.

14 With the short two-year period of gas usage used in the Company's forecasting model, one
15 or both of those events would have significantly affected the gas forecast outcome and
16 result in gas sales being understated for the projected test year. In discovery, the Attorney
17 General asked the Company if it had taken into consideration the lingering impact of
18 Covid-19 or made other adjustments to the historical or forecasted sales. In response, the
19 Company stated that no other adjustments were necessary.⁵⁹

⁵⁹ Id. Includes DR AGDG-4.60.

1 In the response, the Company also included a chart with a graph that shows the significant
2 decline in gas usage per customers with the start of Covid-19 in early 2020 and the partial
3 bounce back in early 2022 before a further decline in 2022 and early 2023.⁶⁰ The graph
4 validates my analysis above that the two years of historical gas usage has understated the
5 Company's sales forecasted.

6 Given those shortcomings, the Commission should not rely on the Company's forecasted
7 sales volumes for Rate A residential and GS-1 commercial sales. As discussed below, a
8 better approach is to use the latest year of actual gas sales and apply the actual five-year
9 percentage decline trend that represents the net effect of sales losses from EWR and sales
10 increases from customer additions and other changes in customer gas usage over a longer
11 time period than two years.

12 **Q. DID YOU CALCULATE REVISED RESIDENTIAL AND COMMERCIAL SALES,**
13 **AND THE RELATED DISTRIBUTION REVENUE ADJUSTMENTS BASED ON**
14 **YOUR ANALYSIS?**

15 A. Yes. Pages 1 and 2 of Exhibit AG-34 show the calculations of the incremental volumes
16 and revenue for the forecasted test year for Rate A residential and Rate GS-1 commercial
17 sales customers. To arrive at the revised volumes, I started with the actual weather-
18 normalized sales per customer for 2023 from Exhibit AG-32 and adjusted those volumes
19 down based on the underlying average annual rate of decline in sales from the five-year
20 period 2018 to 2023. The calculation includes those sales volume adjustments for the 9

⁶⁰ The annual data in the graph ends in August of each year.

1 months ending September 2024 and for the 12 months ending September 2025. The
2 adjusted gas usage per customer for the projected test year was then multiplied by the
3 number of customers forecasted by the Company for the projected test year.

4 Based on those calculations, I forecasted Rate A residential sales of 113,767 MMcf for the
5 projected test year, which is an increase of 1,303 MMcf over the Company's forecast.
6 Based on the current distribution rate billed to residential customers, the additional sales
7 result in incremental revenue of \$5,063,000 for the projected test year. Similarly, for Rate
8 GS-1 commercial sales, I forecasted higher sales of 848 MMcf for the projected test year
9 for additional distribution sales revenue of \$3,227,000.

10 In total, the incremental forecasted revenue for the projected test year is \$ 8,290,000.

11 **B. End-User Transportation (EUT) Revenue**

12 **Q. WHAT ARE YOUR FINDINGS FROM ANALYZING THE COMPANY'S**
13 **PROJECTED LEVEL OF GAS DELIVERIES TO END-USER**
14 **TRANSPORTATION CUSTOMERS?**

15 A. On page 1 of Exhibit A-15, Schedule E7, Mr. Decker presents the Company's forecast of
16 gas transportation volumes for the 2025 projected test year. The Company forecasted total
17 transportation volume of 150.7 Bcf for the projected test year. This level of transportation
18 deliveries represents an increase of 4.1 Bcf, or 2.8%, from the actual transportation
19 volumes billed in 2022. As shown on page 2 of the exhibit, the increase is mostly due to
20 higher deliveries to power generation plants since 2022.

1 **Q. ARE YOU PROPOSING ANY ADJUSTMENTS TO END-USER GAS**
2 **TRANSPORTATION DELIVERIES FOR THE PROJECTED TEST YEAR?**

3 A. Yes. In Table 2 on page 17 of his direct testimony, Company witness Henry Decker shows
4 the annual deliveries to power generation customers during the past five years and
5 calculates an average volume of 61.5 Bcf. As shown on page 2 of Exhibit A-15, Schedule
6 E7, the Company uses a similar volume of 61.4 Bcf for the projected test year to compare
7 to the 56.7 Bcf actually delivered in 2022 and determine an increase of 4.7 Bcf.

8 In discovery, the Attorney General asked the Company to provide the latest twelve months
9 of gas deliveries as of March 2024 to power generation customers. The information
10 provided by the Company shows that gas deliveries to this customer segment continued to
11 increase since the twelve months ended August 2023 volumes of 64.1 Bcf. The gas
12 deliveries to power generation customers for the twelve months ended March 2024 were
13 72.4 Bcf.⁶¹ Using this latest information, I calculated an updated five-year average of gas
14 deliveries of 64.1 Bcf. This updated volume is 2.6 Bcf higher than the 61.5 Bcf previously
15 calculated by the Company and included in the EUT gas delivery forecast for the projected
16 test year.

17 I recommend that the Commission adopt this adjustment to increase end-user
18 transportation volumes by 2.6 Bcf for transportation Rate XXL.T.

⁶¹ Exhibit AG-35 includes DR AGDG-4.73a.

1 **Q. DID YOU CALCULATE THE ADDITIONAL REVENUE FOR ADJUSTMENT TO**
2 **THE GAS DELIVERIES TO CUSTOMERS IN RATE SCHEDULE XXLT FOR**
3 **THE PROJECTED TEST YEAR?**

4 A. Yes. The current volumetric rate for Rate schedule XXLT is \$0.1933 per Mcf.⁶² After
5 multiplying this rate by the incremental volumes of 2,600,000 Mcf, I calculated additional
6 revenue of \$503,000. I recommend that the Commission increase the Company's
7 forecasted end-user transportation revenue by this amount.

8 **C. Midstream Services Revenue**

9 **Q. WHAT ARE YOUR FINDINGS FROM ANALYZING THE COMPANY'S**
10 **PROJECTED LEVEL OF REVENUE FOR MIDSTREAM SERVICES?**

11 A. In Exhibit A-13, Schedule C3.3, Mr. Decker presents the Company's forecast of revenues
12 for Contract Storage, Park & Loan, Off-system Transportation, and Exchange Services for
13 the projected test year. After reviewing Mr. Decker's direct testimony and responses to
14 discovery requests, I determined that the revenue forecasts for Contract Storage and Park
15 & Loan are reasonable. However, I found that the revenue forecasts for Off-System
16 Transportation and Exchange Gas services are significantly understated.

17 **Q. PLEASE DISCUSS YOUR FINDINGS WITH REGARD TO THE SERVICES**
18 **THAT ARE UNDERSTATED.**

⁶² Exhibit A-16, Schedule F3, page 4.

1 A. In determining its Midstream Services forecasted revenues for the projected test year, the
2 Company generally used a three-year average of the actual revenues billed from 2020 to
3 2022. In response to discovery, the Company provided actual revenues from 2018 to 2023,
4 with 2023 being the most recent year currently available. In addition, the Company
5 provided the monthly adjustments made to monthly gas deliveries to DTE Electric from
6 January 2020 to May 2022, which were previously included with Exchange Gas Services
7 and beginning in June 2022 are included with Off-System Transportation services.⁶³

8 In Exhibit AG-37 I calculated revised forecasted revenue for Off-System Transportation
9 revenue of \$63,779,000 using the most recent three years of actual revenues (2021-2023)
10 after adjusting for the DTE Electric volumes. This revised revenue is \$3,398,000 higher
11 than the Company's projected test year revenue of \$60,381,000. Similarly, for Exchange
12 Gas Services, I calculated revised revenues of \$15,625,000 for the projected test year. This
13 amount is \$2,832,000.

14 I recommend that the Commission adopt these more recent revenue forecasts and increase
15 the Company's projected test year revenues by the total amount of \$6,230,000.

16 **D. Appliance Service Program Revenue**

17 **Q. ARE YOU PROPOSING ANY OTHER ADJUSTMENTS TO THE COMPANY'S**
18 **PROJECTED REVENUE?**

⁶³ Exhibit AG-36 includes DR AGDG-4.83 and 4.96a.

1 A. Yes. I propose an adjustment to the Appliance Service Program's ("ASP" or "HPP") profit
2 margin for the projected test year.⁶⁴ The profit margin is the difference between program
3 revenues and related program expenses. In Exhibit A-13, Schedule C3, line 11, the
4 Company forecasted the same revenue of \$99.3 million for the HPP/ASP for the projected
5 test year as it billed for 2022.

6 In response to discovery, the Company provided the actual revenues for the HPP/ASP
7 from 2018 to 2023 with related operating expenses. The revenue and cost schedule with
8 the response shows a steady increase in revenues, with 2023 revenues reaching \$103.9
9 million, or \$4.0 million above the 2022 level.⁶⁵ The schedule also shows the profit margin
10 or net operating income between revenues and operating expenses. From this calculation,
11 it is apparent that the year 2022 is not representative of the revenue and profit margin
12 earned in the most recent year of 2023, or for that matter in any of the prior five years. In
13 other words, using the 2022 revenues, operating expenses, and profit margin as a proxy
14 for future test year amounts would result in an inaccurate and unreasonable forecast
15 amount.

16 Adopting the Company's preferred approach of using the most recent revenue amount for
17 this item, I propose to use the actual revenue of \$103,901,000 for 2023 and the related
18 operating expenses of \$73,602,000 with the profit margin of \$30,299,000, as the best

⁶⁴ Company witness Henry Decker discusses the Appliance Service program beginning on page 50 of his direct testimony.

⁶⁵ Exhibit AG-38 includes DR AG 4.89a with attachment.

1 forecast of operating income for the projected test year. This results in an increase in
2 operating income of \$4,617,000 over the Company's forecast.

3 **Q. HAS THE COMPANY SHOWN AN INCLINATION TO UNDERSTATE THE**
4 **FORECASTED REVENUE AND OPERATING INCOME OF THE APPLIANCE**
5 **SERVICE PROGRAM?**

6 A. Yes. At least in the last three rate cases, the Company has proposed to use the actual
7 revenue amount and related operating income from the historical test year in forecasting
8 for the projected test year. As shown from the uptrend in revenue in Exhibit AG-38, those
9 forecasts have fallen short of actual in every case.

10 **Q. WHAT IS YOUR RECOMMENDATION?**

11 A. I recommend that the Commission adopt the 2023 revenue and operating expenses shown
12 in Exhibit AG-38 and increase the Company's projected operating income by \$4,617,000.

13 **VIII. O&M Expense Adjustments**

14 **Q. WHAT AMOUNT OF O&M EXPENSE DID THE COMPANY INCUR DURING**
15 **2022 AND WHAT IS THE AMOUNT OF PROJECTED EXPENSE REQUESTED**
16 **FOR THE 12 MONTHS ENDING SEPTEMBER 2025?**

17 A. In 2022, the Company had total O&M expense of \$523.5 million. In this rate case, for the
18 projected test year, the Company's total O&M expense request is \$616.6 million. This
19 amount consists of three main components. First, the Company requests recovery of \$43.2

million for Company Use & LAUF gas, as shown in Exhibit A-15, Schedule E8. Second, the Company requests recovery of expenses for Uncollectible Accounts of \$35.1 million, as shown in Exhibit A-13, Schedule C5.7. Third, the Company is requesting recovery of \$538.3 million in Other O&M expenses, as shown in Exhibit A-13, Schedule C1. The increases in expense between the historical year and the projected test year are summarized in the following table.

<u>Millions of Dollars</u>			
<u>O&M Expense Category</u>	<u>2022 Test Yr.</u>	<u>Increase (Decrease)</u>	<u>Projected 2025 Test Yr.</u>
Company Use & LAUF	\$41.4	\$1.8	\$43.2
Uncollectible Accounts Exp.	19.0	16.1	35.1
Other O&M	<u>463.1</u>	<u>75.2</u>	<u>538.3</u>
Total O&M	<u>\$523.5</u>	<u>\$93.1</u>	<u>\$616.6</u>

In my testimony below, I discuss each of these expense categories forecasted by the Company and propose necessary adjustments. With regard to the Other O&M expense, the \$75.2 million increase in expense includes \$30.4 million of projected inflation adjustments and several other projected cost increases for new or expanded programs. Some of the cost increases are not adequately justified or supported and will result in proposed cost disallowances. Exhibit AG-39 summarizes the proposed adjustments discussed in my testimony.

A. Company Use & LAUF Gas Expense

Q. THE COMPANY'S PROJECTED TEST YEAR INCLUDES COSTS FOR COMPANY USE GAS AND LAUF GAS OF \$19.6 MILLION AND \$23.6 MILLION RESPECTIVELY. DO YOU AGREE WITH THESE PROJECTIONS?

A. No. The Company projected these costs partially based upon NYMEX gas futures prices for the projected test year, which were determined in early September 2023. Since then, gas costs have declined substantially. In response to discovery, the Company provided updated forecasted gas prices for the projected test year as of February 2024, which shows that NYMEX gas prices have fallen from \$3.831 per MMBTU assumed in the rate case filing to \$3.123 per MMBTU. Based on this information, the Company calculated a change in the cost of gas of \$0.28 per Mcf to reflect a revised cost of gas rate of \$4.10 per Mcf.⁶⁶

In Exhibit AG-40, I applied the reduction in the cost of gas rate to the volumes forecasted by the Company to reduce the O&M expense for both Company Use Gas and LAUF Gas by \$2.8 million.

Q. DID YOU MAKE ANY OTHER CHANGES TO COMPANY USE AND LAUF GAS?

A. Yes, I reduced the LAUF volume by 529 MMcf, which represents 9.8% of the LAUF gas volume forecasted by the Company for the projected test year. Many of the Company's

⁶⁶ Exhibit AG-41 includes DR AGDG-2.24 parts a and b.

1 witnesses discuss programs that should result in lower LAUF gas volumes. These include
2 efforts to reduce gas theft, the replacement of aging infrastructure, and the expected
3 implementation of new federal government rules to improve leak detection. Also, in June
4 2020 the Company announced an ambitious goal to reduce greenhouse gas emissions,
5 which includes methane emissions, to net zero by 2050 and reduce greenhouse gas
6 emissions by customers by 35% by 2050.⁶⁷

7 Given the significant expenditures by the Company for infrastructure replacement and
8 other programs, it is reasonable to expect progressively lower LAUF gas volumes in the
9 coming years. Working toward the goal to achieve net-zero emissions by 2050 is a
10 reasonable approach to use in forecasting reductions in LAUF gas. In this regard, the year
11 2050 is 28 years into the future from the 2022 historic test year. The average improvement
12 over this 28-year period would be 3.57% ($100\% / 28 = 3.57\%$). Multiplying this 3.57%
13 reduction rate by the 2.75 years between the historic and projected test years in this case
14 results in a 9.8% likely savings in LAUF gas volumes in the projected test year.

15 The 529 MMcf adjustment multiplied by the Company's revised \$4.10 per Mcf cost of gas
16 rate results in lower LAUF gas expense of \$2.2 million.

17 **Q. PLEASE SUMMARIZE YOUR RECOMMENDATION FOR COMPANY GAS**
18 **USE AND LAUF GAS EXPENSE.**

⁶⁷ Henry Decker direct testimony at page 36.

1 A. I recommend that the Commission reduce the expense for Company Gas Use and LAUF
2 gas from the Company's forecasted amount of \$43,209,000 to \$38,276,000 for a total
3 expense reduction of \$4,932,000. This includes the cost savings of \$2,762,000 due to a
4 lower cost of gas rate and the \$2,170,000 related to lower LAUF volumes.

5 Therefore, in total I recommend that the Commission reduce the Company's forecasted
6 expense for Company Gas Use and LAUF gas by \$4,932,000 for the projected test year.

7 **B. Uncollectible Accounts Expense**

8 **Q. PLEASE SUMMARIZE HOW THE COMPANY ARRIVED AT ITS PROPOSED**
9 **\$35.1 MILLION EXPENSE AMOUNT FOR UNCOLLECTIBLE GAS ACCOUNTS**
10 **FOR THE PROJECTED TEST YEAR.**

11 A. Company witness Jason Sparks discusses the uncollectible expense beginning on page 18
12 of his direct testimony and also sponsors Exhibit A-13, Schedule C5.7.

13 Exhibit A-13, Schedule C5.7, shows that the Company started its calculation of the
14 uncollectible expense for the test year by using the methodology previously approved by
15 the Commission of developing an average loss ratio from the most recent three years of
16 net charge-offs to revenues and applying the loss ratio to future revenues to develop an
17 estimate of uncollectible accounts expense. Mr. Sparks used the loss ratios for 2020, 2021,
18 and 2022, which averaged to 1.58%, and applied this percentage to forecasted revenues
19 for the projected test year to arrive at \$33.7 million of uncollectible accounts expense for
20 the projected test year. He then added \$1.4 million (related to other revenues) to the \$33.7

1 million to determine the \$35.1 million of uncollectible accounts expense that the Company
2 proposes to recover in this rate case.

3 **Q. WHAT IS YOUR PROJECTED AMOUNT FOR UNCOLLECTIBLE EXPENSE**
4 **FOR THE PROJECTED TEST YEAR ENDING IN SEPTEMBER 2025?**

5 A. In response to discovery, the Company provided the most recent revenues and net charge-
6 offs for 2023. Using this more recent information and similar data from 2022 and 2021, I
7 calculated uncollectible accounts expense of \$26,018,000 for the projected test year.
8 Exhibit AG-42 shows the calculation. Line 4 shows the average percentage of 1.17% as
9 the ratio of net charge-offs to revenue for the three-year historical period. This percentage
10 is multiplied by the projected test year revenues of \$2.134 billion on line 5 to derive the
11 forecasted amount of uncollectible expense of \$24,928,000 on line 6. I then added \$1.1
12 million to the previous amount related to write-offs of amounts not included in the test
13 year revenues which is similar to what the Company did in its projection. The result is a
14 total uncollectible accounts expense of \$26,018,000, which is lower than the Company's
15 forecast of \$35,149,000 by \$9,131,000.

16 I recommend that the Commission adopt my forecast of \$26,018,000 for Uncollectible
17 Accounts expense and reduce the Company's O&M expense by \$9,131,000.

18 **C. Inflation and Corporate Expense Realignment Adjustments**

19 **Q. DO YOU AGREE WITH THE COMPANY'S INFLATIONARY COST**
20 **INCREASES INCLUDED IN THE PROJECTED TEST YEAR O&M EXPENSE?**

1 A. No. In Exhibit A-13, Schedule C5, the Company shows that \$30.4 million of the total
2 other O&M expense increase of \$75.2 million pertains to inflationary cost increases
3 calculated by the Company based on a blend of the Consumer Price Index (CPI) forecasted
4 inflation rate and a 3% forecasted annual wage increase for union, non-union, and
5 contractor employee costs. The blended annual inflation rates developed by the Company
6 are 3.2% for 2023, 2.9% for 2024, and 2.9% for 2025, as shown on Exhibit A-13, Schedule
7 C12. The use of a “blended rate” inclusive of wage increases has been rejected in recent
8 general rate cases and the Commission should do so again in this rate case. Instead, the
9 Commission has previously adopted the use of the CPI-Urban area inflation rates to
10 forecast future cost increases when warranted.

11 The Commission has made it clear that it expects utilities to create cost efficiencies from
12 the implementation of IT systems and other technology, and that those efficiencies should
13 translate into tangible cost savings that reduce, and potentially even fully offset, future cost
14 increases.

15 In that regard and in response to discovery, the Company provided actual 2023 O&M
16 expense information with significant cost savings achieved in 2023, which I have partially
17 incorporated in this rate case as a new base upon which to calculate CPI inflation
18 adjustments for 2024 and to the end of the projected test year. In the discovery response,
19 the Company reported that actual other O&M expense for 2023 was \$466.1 million and

1 after eliminations, reclassifications, and normalizations, it incurred \$452.1 million of pro-
2 forma O&M expense.⁶⁸

3 In Exhibit AG-43, I used this new base of expense adjusted for \$103.6 million of cost items
4 that are not directly affected by inflation. For the resulting adjusted O&M expense base,
5 I applied the inflation rate of 2.6% for 2024 and 2.2% for 9 months of 2025, to calculate
6 the cumulative inflation adjustment of \$14,961,000. In comparison, the Company had
7 calculated inflation adjustment for the same 21 months of \$18,962,000. The difference is
8 \$4,001,000.

9 The \$4,001,000 reduction in inflation adjustments reflects the change from blended
10 inflation rates to using only the CPI forecasted inflation rate and also the lower base of
11 O&M expense for 2023 normalized and adjusted by the Company. I recommend that the
12 Commission adopt my inflation cost adjustment and remove \$4,001,000 from the
13 Company forecasted O&M expense for the projected test year.

14 **Q. DID YOU MAKE OTHER O&M EXPENSE COST ADJUSTMENTS FOR THE**
15 **PROJECTED TEST YEAR AS RESULT OF LOWER O&M EXPENSE**
16 **EXPERIENCED BY THE COMPANY IN 2023?**

⁶⁸ Exhibit AG-44 includes DR AGDG-3.43 with related attachment.

1 A. Yes. According to the response to DR AGDG-3.43, DTE Gas took a number of measures
2 to reduce 2023 costs due to financial challenges at both the Company and its affiliate DTE
3 Electric Company that resulted in lower O&M expenses.⁶⁹

4 Excluding Uncollectible Accounts expense and costs for Company Gas Use and LAUF
5 gas, the base O&M expense before reclassifications and normalizations fell from \$527.2
6 million in 2022 to \$466.1 million in 2023. The decrease in expense of \$61.1 million
7 reflects primarily avoided overtime, deferred training and expenses, lower employee levels
8 from deferred hiring, and work with contractors also being deferred. In the discovery
9 response, the Company normalized the actual expense for 2023 stating that most of those
10 costs would return in subsequent years, as open employee positions are filled, overtime
11 work resumes, and contractor services are reestablished. However, even after normalizing
12 the 2023 O&M expenses to \$452.1 million, those costs are still lower than the 2022
13 historical normalized expenses of \$463.1 million by \$11.0 million.

14 **Q. HAVE YOU INCORPORATED SOME OF THE 2023 COST REDUCTIONS INTO**
15 **THE O&M EXPENSE FOR THE PROJECTED TEST YEAR IN THIS CASE?**

16 A. Yes. In Exhibit AG-45, I compared the normalized 2023 O&M expense of \$452.1 million
17 to the Company's forecasted O&M expenses of \$474.5 million for the same year to
18 calculate O&M expense savings of \$22,431,000, which should be included in the projected
19 test year. The Company's previously calculated O&M expense of \$474.5 million for 2023
20 started with 2022 adjusted O&M expense of \$463.1 million and added \$11.5 million of

⁶⁹ Id.

1 inflation at the blended rate of 3.2%, to arrive at the forecasted 2023 O&M expense of
2 \$474.5 million.

3 Based on the actual normalized 2023 O&M expense of \$452.1 million recently provided
4 by the Company in response to DR AGDG-3.43 (Exh. AG-44), the \$474.5 million
5 forecasted by the Company is no longer reasonable. The latest information provided by
6 the Company shows that the projected test year O&M expense filed by the Company and
7 built-up from a stale 2022 base is overstated by \$22,431,000.

8 Therefore, I recommend that the Commission removed this additional amount of
9 \$22,431,000 from the Company's projected test year O&M expense.

10 **Q HAS THE COMPANY INITIATED ADDITIONAL COST REDUCTIONS IN 2024**
11 **THAT WILL FURTHER REDUCE O&M EXPENSE IN THE PROJECTED TEST**
12 **YEAR?**

13 A. Yes. In response to discovery, the Company stated that in January 2024, it offered a
14 Voluntary Separation Incentive Plan to 422 DTE Gas employees and 1,622 DTE Corporate
15 Services employees. Of those eligible employees, 42 DTE Gas employees and 249
16 Corporate Services employees accepted the separation plan, with employee reductions
17 occurring during the first half of 2024. In the discovery responses, the Company also
18 stated that up to \$6.3 million of labor cost savings could be achieved in 2025.⁷⁰ The \$6.3

⁷⁰ Exhibit AG-46 includes DR AGDG-4.49a-c.

1 million does not include employee benefit savings from lower active health care costs,
2 401K plan matching, and other benefits.

3 However, conservatively, I have included only half, or \$3.2 million, of the currently
4 estimated labor cost savings of \$6.3 million as a reduction to the O&M expense for the
5 projected test year. I recommend that the Commission accept this additional adjustment of
6 \$3.2 million to the forecasted O&M expense for the projected test year.

7 **D. TIMP Pipeline Integrity**

8 **Q. PLEASE DISCUSS THE COMPANY’S TIMP PIPELINE INTEGRITY EXPENSE**
9 **FOR THE HISTORICAL AND PROJECTED TEST YEAR.**

10 A. Witness Kehoe discusses Transmission Pipeline Integrity on pages 18 and 19 of his
11 testimony. For the historical 2022 period, the Company had expenses of \$16.3 million for
12 TIMP Pipeline Integrity.⁷¹ For the projected test year, the Company forecasted expenses
13 of \$23.0 million, which is a \$6.7 million increase over 2022. In Case No. U-20642 and
14 specifically on page 14 (lines 16 to 23) of his direct testimony, witness Mark Johnson
15 stated that the Company would be ramping up expenses in this area to get on a “seven-
16 year inspection cycle” and increase the number of miles inspected by ILI.⁷² In Exhibit A-
17 13, Schedule C5.2, in Case No. U-20642, the Company forecasted an increase of \$8.4
18 million for TIMP Pipeline Integrity for the projected test year ended September 2021 from

⁷¹ Transmission Integrity Management Program (TIMP).

⁷² ILI is a pipeline In Line Inspection electronic tool that provides information on the internal characteristics and integrity of the pipeline inspected.

1 the 2018 historical expense of \$10.3 million. This should have placed the total expense at
2 more than \$18 million for the 12 months ended September 2021.

3 However, the forecasted ramp up in TIMP Pipeline Integrity expense has not materialized
4 as forecasted. In response to discovery request AGDG-4.128b in case U-20940, the
5 Company reported only \$10.3 million of expense in 2020 and 13.5 million for 2021. This
6 was after the Company had increased the expense level to just over \$17 million in 2019.

7 Since 2021, when expenses reached \$18.6 million, the Company has steadily reduced
8 pipeline inspection costs to \$16.3 million in 2022 and \$8.6 million in 2023 with the number
9 of inspections dropping from 12 in 2021 to only 4 in 2023.

10 The Company has not made a consistent commitment to a higher expense level in order to
11 achieve the 7-year inspection cycle and will likely spend less than it requested in Case No.
12 U-20642. This lack of consistency in spending to achieve the 7-year inspection cycle
13 undermines the Company's credibility about its expense forecast of \$23.0 million for the
14 projected test year in this rate case. In connection with the Company's 2023 O&M
15 expenses discussed above, the Company provided normalized Transmission pipeline
16 inspection expenses of \$16.6 million for 2023 after a normalizing adjustment of \$7.5
17 million.⁷³

18 The normalized expense for 2023 is \$1.5 million higher than the average expense of the
19 past three years. The \$23.0 expense level forecasted by the Company for the projected

⁷³ Exhibit AG-44 includes DR AGDG-3.43 and the attachment showing Transmission expenses.

1 test year is not credible and not likely to be incurred given the historical record discussed
2 above. Therefore, I recommend that the Commission reject the expense increase of \$6.7
3 million from 2022 to the projected test year and remove this amount from the Company's
4 forecasted test year O&M expense.

5 **E. MAOP Records Remediation Expense**

6 **Q. PLEASE DISCUSS THE COMPANY'S PROPOSED MAOP EXPENSES FOR THE**
7 **PROJECTED TEST YEAR AND ANY REQUIRED ADJUSTMENTS.**

8 A. Beginning on page 35 of his direct testimony, Mr. Janness discusses federal rules that
9 require the Company to undertake a records review of its pipelines' MAOP to resolve
10 records defects, including reaffirmation of MAOP if the Company does not have traceable,
11 verifiable, and completed (TVC) records. Mr. Janness discusses the steps that the
12 Company is taking to validate its records and take remediation action. In discovery, the
13 Attorney General asked the Company to identify what deficiencies, inaccuracies, and other
14 problems the Company has discovered in reviewing the pipeline records to reestablish
15 MAOP. In response, the Company stated that it has identified pressure test records that
16 are from incomplete to missing and also discovered other pipe material records issues. In
17 a related discovery response, the Company stated that to review and remediate its records
18 it plans to spend \$1.3 million in 2024 and \$1.9 million in 2025.⁷⁴ From these amounts, I

⁷⁴ Exhibit AG-50 includes DR AGDG-6.17a and b.

1 calculated the projected test year O&M expense included by the Company in this rate case
2 to be \$1,750,000.

3 **Q. WHAT IS YOUR ASSESSMENT OF THE COSTS THAT THE COMPANY IS**
4 **INCURRING TO ASCERTAIN IT HAS TRACEABLE, VERIFIABLE, AND**
5 **CORRECT RECORDS TO REESTABLISH MAOP ON CERTAIN OF ITS**
6 **PIPELINES?**

7 A. As a result of federal regulatory requirements, the Company must verify that it has
8 sufficient records to ascertain the physical and operational characteristics of its gas
9 transmission pipelines in High Consequence Areas and be able to verify that its records
10 can substantiate the MAOP. Where gaps in records exist, the Company must remedy the
11 shortfalls by performing physical inspection of the pipeline, including reestablishing its
12 MAOP through pressure tests and other procedures.

13 Although the requirements that transmission pipeline operators have adequate records to
14 verify the MAOP and other pipeline operating characteristics was preliminary issued in
15 2011, it does not mean that DTE gas should not have kept adequate records of the
16 construction of its pipelines and facilities prior to that date. This includes records of
17 pressure tests performed before placing those pipelines and facilities into service. The
18 requirements now imposed by PHMSA are basic operating requirements to ensure the safe
19 installation and operation of high-pressure facilities, going back to the 1960s, 1950s and
20 even prior decades.

1 The Company has the sole responsibility to ensure it maintains adequate records of its
2 pipelines and related facilities, both now and in the past. The fact that adequate records
3 do not exist is not a problem that should be remedied entirely on the backs of customers.
4 Although a strong argument can be made that the cost to remedy the record gaps should
5 be entirely absorbed by the Company, it is fair and reasonable for the Company to absorb
6 at least 50% of the cost and recover the other 50% in base rates, as an accommodation for
7 the long passage of time since the pipeline was installed.

8 Therefore, I recommend that the Commission remove \$875,000 (50% of \$1,750,000) from
9 the O&M expense proposed by the Company for the projected test year.

10 **F. Leak Detection and Repair (LDAR) Expense**

11 **Q. PLEASE DISCUSS THE ADJUSTMENT YOU PROPOSE TO O&M EXPENSE**
12 **FOR THE PROJECTED TEST YEAR FOR THE NEWLY PROPOSED OR**
13 **EXPANDED LDAR PROGRAM.**

14 A. On pages 45 through 47 of his direct testimony, Mr. Kehoe briefly discusses the anticipated
15 notice of rulemaking from PHMSA that will likely require the Company to undertake a
16 more extensive program to detect and repair gas leaks. In Table 24 on page 47 of his
17 testimony, he identifies \$10.3 million of incremental O&M expense included in the
18 projected test year. As I stated above in my testimony on this same program under the
19 Capital Expenditures section, it is still unknown when the new rule will be issued and how
20 soon thereafter the Company will be required to be fully comply with the requirements
21 within the new rule. Even if the Company's expectations of an initial implementation date

1 of March 1, 2025 were to occur, it will not likely be able to fully implement and spend the
2 entire \$10.3 million by the end of project test year ending in September 2025, which is
3 only seven months after the initial implementation date.

4 Furthermore, the Company has not presented a comprehensive implementation plan that
5 takes into consideration the leak detection and repair program that the Company currently
6 has in place. As stated above in my testimony, the Company is currently spending about
7 \$20 million annually on leak detection and repairs that are charged to O&M expense. The
8 Company has not explained why some or all of those costs cannot be redirected to comply
9 with the new rule in 2025, if it becomes effective then, or why an additional \$10.3 million
10 of expense will be needed for the last seven months of the projected test year.

11 The Company has not adequately supported the need for the additional \$10.3 million of
12 O&M expense for the LDAR program or made a convincing case that those additional
13 expenses are needed in the projected test year. Therefore, I recommend that the \$10.3
14 million be removed from the Company's forecasted O&M expense in the projected test
15 year.

16 **G. Health Care Costs**

17 **Q. THE COMPANY FORECASTED THAT ITS ACTIVE EMPLOYEE HEALTH**
18 **CARE EXPENSES (MEDICAL, DENTAL, AND VISION) WILL INCREASE**
19 **FROM \$18.1 MILLION IN 2022 TO \$22.0 MILLION IN THE PROJECTED TEST**
20 **YEAR. DO YOU AGREE WITH THIS INCREASE?**

1 A. No. The forecasted health care O&M expense to \$22.0 million for the projected test year
2 represents a cumulative increase of approximately 21% from the adjusted actual expense
3 of \$18.1 million in 2022.⁷⁵ Mr. Cooper accomplishes this feat by taking a novel and
4 unorthodox approach to forecasting health care costs. First, he determines an average cost
5 per employee of \$10,897 by adjusting 2018 to 2022 costs through a “constant dollar
6 normalization” process to establish a base cost for 2022.⁷⁶ This involves escalating actual
7 costs from 2018 to 2021 by national average health care trend rates of between 4.0% to
8 5.7%. It is important to point out that Mr. Cooper’s constant dollar average is \$759 higher
9 per employee than the Company’s actual cost per employee. Second, he multiplied the
10 \$759 cost per employee by 2,809 employees to arrive at a \$1.336 million dollar adjustment
11 after allocating 62.7% of the total amount to O&M expense and the rest to capital costs.
12 Third, Mr. Cooper added the \$1.336 million to the actual 2022 cost of \$18.1 million to
13 produce an adjusted historical 2022 cost of \$19.4 million. Fourth, he then further escalated
14 the 2022 adjusted cost by 5.1% for 2023, 5.0% for 2024 and by 4.0% for 2025.

15 **Q. WHAT IS YOUR ASSESSMENT OF THE CALCULATIONS PERFORMED BY**
16 **MR. COOPER AND THE RESULTING FORECAST?**

17 A. The problem with Mr. Cooper’s analysis and calculations is that the \$10,897 constant
18 dollar adjusted cost per employee for 2022 is divorced from reality. This amount is 7.5%
19 higher than the actual cost of \$10,138 for 2022. Mr. Cooper is simply compounding

⁷⁵ The \$18.1 million excludes cost savings achieved in 2023 due to a temporary cost reduction initiative, which resulted in active medical costs decreasing to an actual amount of \$16.5 million.

⁷⁶ Actual costs per employee are escalated by PWC trend rates as shown on Exh. A-13, Sch. C5.9.3.

1 inflationary increases on top of inflationary increases over the seven-year period from
2 2018 to 2025. The Commission should not accept this brazen attempt to inflate forecasted
3 O&M expenses. In fact, the Commission has repeatedly rejected Mr. Cooper's
4 methodology in previous rate cases for the Company and DTE Electric Company.

5 **Q. HAVE YOU CALCULATED A MORE APPROPRIATE EXPENSE FOR HEALTH**
6 **CARE FOR THE PROJECTED TEST YEAR?**

7 A. Yes. In Exhibit AG-47, I calculated a forecasted expense of \$17,157,000 for the projected
8 test year. To arrive at this amount, I used information obtained from Exhibit A-13,
9 Schedule C5.9.3, which has the cost of health care from 2018 to 2022. As can be seen
10 from my exhibit, the annualized increase in the Company's costs is 2.4% between 2018
11 and 2022. The 2.4% average rate of increase already reflects any inflationary increase in
12 costs year over year as actually experienced and therefore it is not necessary to further
13 inflate it as Mr. Cooper has done.

14 Using the 2.4% annual rate of increase and applying it to the actual costs in 2023 of \$16.5
15 million for subsequent years through the end of the projected test year, I calculated the
16 forecasted expense at \$17,157,000 after allocating a portion of the costs to capital
17 expenditures. This is a reasonable forecast of health care expense for the projected test
18 year based on actual cost trends. In contrast with the Company's artificially derived
19 expense of \$22.4 million, I recommend that the Commission remove the difference of
20 \$4,884,000 from the Company's forecasted test year O&M expense.

1 It is also noteworthy to point out that while starting with actual 2023 to determine the
2 projected test year expense level captures the savings in Health Care costs due to the 2023
3 cost reduction initiative, it does not reflect the savings related to the Voluntary Incentive
4 Separation Plan which became effective in 2024. As such, my forecast may be still
5 somewhat overstated but is certainly far more reasonable than the forecast proposed by the
6 Company.

7 **H. Rents - Capital Use Charges**

8 On line 15 of Exhibit A-13, Schedule C5.6, the Company shows forecasted Rents expense
9 (capital use charges) of \$56.1 million. This amount represents an increase of \$4.8 million,
10 or 9%, over the 2022 adjusted historical period. In response to discovery, the Company
11 reported that the forecasted expense in this area was based on forecasted costs in the DTE
12 Electric rate case, which the Commission reduced in its rate order in that rate case. The
13 Company reported that the expense for Rents was overstated by \$2.5 million.⁷⁷ Therefore,
14 I recommend that the Commission remove this amount from the Company's forecasted
15 O&M expense in this rate case.

16 **I. Deferred Incentive Compensation Amortization**

17 **Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED AMORTIZATION**
18 **EXPENSE OF THE DEFERRED INCENTIVE COMPENSATION COSTS?**

19 **A.** No. As shown in Exhibit A-13, Schedule C5.6, page 5, the Company proposes to recover
20 \$1,774,000 of amortization expense in the projected test year related the amount of

⁷⁷ Exhibit AG-48 includes DR AGDG-2.36b and d.

incentive compensation recorded in a regulatory asset account. As discussed in the Working Capital section of my testimony and shown in Exhibit AG-21, I propose an amortization expense amount of \$717,000. This amount is \$1,057,000 lower than the Company's proposed amount. For the reasons discussed in the Working Capital section of my testimony, I recommend that the Commission remove the \$1,057,000 of excess amortization expense from the Company's O&M expense for the projected test year.

J. Incentive Compensation Expense

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE COMPANY'S INCENTIVE PAY PLANS AND THE AMOUNT OF EXPENSE THE COMPANY SEEKS TO RECOVER IN THIS RATE CASE.

A. In this rate case, the Company seeks to recover \$18.5 million of employee incentive compensation in O&M expense, which has been included in the projected test year.⁷⁸ Based upon the information provided by the Company, \$3.1 million pertains to the Annual Incentive Plan (AIP), \$9.5 million pertains to the Rewarding Employees Plan (REP), and \$5.9 million pertains to the Long-Term Incentive Plan (LTIP). I will also point out that 62% of the \$18.5 million requested is to recover costs related to the DTE Corporate Services LLC employees (the LLC employees), whose performance metrics are often related to the performance of DTE Energy (not just DTE Gas).

⁷⁸ Page 56 of Michael Cooper's revised direct testimony shows approximately \$18.5 million of O&M expense for incentive compensation. The revised table does not show any column headings pertaining to each plan. I assumed that the same headings applied from Mr. Cooper's original testimony.

1 2023 Annual Incentive Plan – the AIP is an annual bonus program focused on the
2 following major categories and specific measures:

- 3 1. 40% on Financial Performance: For DTE Gas employees the metrics are DTE Gas
4 Operating Earnings, DTE Gas Adjusted Cash Flow, and DTE Energy Earnings per
5 Share). For the LLC employees in this plan, the financial metrics are 100%
6 dependent upon DTE Energy EPS and DTE Energy Cash Flow.
- 7 2. 20% on Customer Satisfaction (Net Promoter Score and MPSC Customer
8 Complaints).
- 9 3. 15% on Employee Engagement (Employee Engagement Gallup rating, OSHA
10 Incident Rate, and DTE Energy high energy, serious injury/fatality prevention).
- 11 4. 25% on Operating Excellence (Gas Open Leak balance, Gas Distribution response
12 time, percent of HCA miles assessed with TVC, pressure test records remediated).

13 It should be noted that the LLC employee metrics for Customer Satisfaction and Employee
14 Engagement are dependent on all of DTE Energy performance (not that of just DTE Gas).

15 These measures are for the year 2023. A review of the measures in place for the prior five
16 years reveals that certain measures and target levels have varied from year to year. These
17 changes make a direct comparison over the years more challenging.

18 2023 Rewarding Employees Plan – The REP is very similar in design and function to the
19 AIP with some variations in the non-financial measures. Where the AIP is designed for
20 senior level managers at DTE Gas and its affiliates, the REP covers all other non-union
21 employees of these companies.

22 The REP is also applicable to the LLC employees providing support services to DTE Gas.

1 2023 Long Term Incentive Plan – The LTIP is an annual stock grant plan focused on
2 achieving three-year goals and specifically on the following measures:

- 3 1. 80% on Common Stock Total Shareholder Return vs. a Peer Group.
- 4 2. 20% Three Years Cumulative Operating EPS.

5 The testimony of Company witness Michael Cooper provides more details on the AIP,
6 REP, and LTIP.

7 **Q. WHAT IS YOUR ASSESSMENT OF EACH OF THESE INCENTIVE PAY PLANS?**

8 A. My overall assessment is that the three incentive plans are too heavily skewed toward
9 measures that directly benefit shareholders and not customers. Additionally, the customer
10 benefits presented by the Company are based on a faulty premise of historical cost savings
11 and an expectation that future targets of performance will be achieved.

12 With regard to the AIP and REP, nearly half of the incentive payout at target level relates
13 to the Company and its parent, DTE Energy, achieving net income, earnings per share, and
14 cash flow goals. Despite the argument by the Company that achieving these goals
15 somehow benefits customers, there is no direct relationship to customer benefits. These
16 goals are in place to maximize profits and increase cash flow to pay dividends to
17 shareholders. It is even more inappropriate to charge customers for incentive pay costs
18 related to achieving DTE Energy earnings per share since those earnings include earnings
19 from the electric and non-utility businesses of DTE Energy. The Commission should not
20 allow recovery of incentive payments related to these financial goals.

1 As to the Customer Satisfaction grouping of measures, this category in 2023 represents
2 20% of the total measures. However, as shown in Exhibit A-19, Schedule I5, the benefits
3 achieved are far less than the costs as measured by the Company.

4 With regard to the Employee Engagement category, the measures contained therein do not
5 rise to the level of being measures that are visible to customers nor do they create direct
6 customer benefits. They are primarily internal goals related to employee satisfaction and
7 deployment of safe practices in the workplace.

8 As to the Operating Excellence category, the measures contained therein are basic
9 operating goals. Again, they have no direct visibility to customers. The only measure that
10 has a visible link to customers is the Gas Distribution Response Time metric, which
11 represents a small portion of the expected payout.

12 **Q. WHAT IS YOUR ASSESSMENT OF THE LTIP?**

13 A. The LTIP is a plan strictly designed to induce management to create shareholder value. It
14 is weighted heavily (80%) on total shareholder return for DTE Gas employees and 80% in
15 the case of the LLC employees, which is stock price appreciation and dividends paid over
16 a period of time. The Company's total return is then measured against a group of peer
17 companies to trigger a payout. This has nothing to do with creating direct benefits for
18 DTE Gas customers and everything to do with creating value for DTE Energy
19 shareholders. Similarly, the other measure which is three-year cumulative operating EPS
20 is also very removed from any quantifiable benefits that directly accrue to customers.

1 The arguments put forth by Mr. Cooper in his testimony that some of these measures will
2 create a financially healthier company and therefore customers should pay for LTIP
3 expenses are not convincing.

4 Q. **WHAT IS YOUR OPINION OF THE CUSTOMER BENEFITS CALCULATED BY**
5 **MR. COOPER TO JUSTIFY RECOVERY OF THE INCENTIVE PAYMENTS?**

6 A. In Exhibit A-19, Schedule I5, Mr. Cooper presents a calculation which purports to show
7 that the expected operating and financial cost savings in 2023 of \$21.2 million will exceed
8 the incentive plan payments by \$2.8 million.

9 Although the Operating Excellence cost savings appear to exceed the allocation of
10 incentive expense allocated to these measures, actual results are doubtful. For example,
11 in 2023, the Company engaged in large cutbacks in operating expenses for its own internal
12 reasons and its ability to achieve these non-financial metrics may have been impaired.

13 The Company's claim that it has realized cost savings by preventing higher interest rates
14 by managing its credit ratings is unconvincing. It is management's basic task to manage
15 the finances of the Company so as to maintain healthy credit ratings without an incentive
16 to do so.

17 Mr. Cooper's calculated benefits for Customer Satisfaction and Employee Engagement
18 have been determined by considering avoided costs related to customer complaints, lower
19 employee absenteeism, higher productivity of employees, as well as fewer safety incidents.
20 Unfortunately, the Company has generally fallen short of its performance targets in these
21 areas.

1 Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO INCENTIVE
2 PAYMENTS BEING RECOVERED IN CUSTOMER RATES?

3 A. Page 56 of Mr. Cooper's revised testimony shows the components of the incentive
4 compensation expense that the Company has included in its O&M expense for the
5 projected test year, which includes \$12.1 million pertaining to financial measures. For the
6 reasons described above, I recommend that the Commission remove the entire \$12.1
7 million related to financial performance measures.

8 With regard to the portion of incentive compensation relating to operating measures, my
9 initial instinct is to also disallow this portion in its entirety, as I have recommended in prior
10 cases due to the fact that the Company has not made a sufficiently compelling case to
11 justify recovery of these costs. However, I am cognizant of the fact that the Commission
12 has recently allowed recovery of a portion of the short-term incentive pay related to
13 operating performance measures for DTE Gas, DTE Electric, and Consumers Energy.

14 In that vein, I recommend that the Commission allow recovery of only 55% of the
15 incentive compensation expense that the Company has identified pertaining to operating
16 performance measures. The 55% represents the percentage of performance measures that
17 have been achieved at target level or higher over the past five years from 2019 to 2023. In
18 calculating the incentive compensation expense in this rate case, the Company has
19 assumed in that it will achieve the target level for all operating performance measures.
20 The last five years of actual performance results show that the Company was able to
21 achieve target level performance only 55% of the time with certain years as low as 36%
22 and some years as high as 89%. Exhibit AG-49 shows the source data provided by the

1 Company and the calculation of the level of the annual performance achieved at target or
2 better along with the overall average percentage rate for the five years at the bottom of the
3 schedule.

4 The Company calculated \$6.4 million of incentive compensation related to operating
5 performance measures per Mr. Cooper's revised direct testimony. However, as stated
6 earlier, this amount assumes that 100% of the operating measures will be achieved at the
7 100% target level. I recommend that the Commission allow recovery of only 55% of the
8 \$6.4 million, or \$3.5 million, and disallow the remaining \$2.9 million.

9 Therefore, in total, the Commission should deny recovery of \$15.0 million in incentive
10 compensation expense proposed by the Company (\$12.1 million related to financial
11 measures and \$2.9 million of operating measures).

12 **K. Deferred OPEB Negative Expense**

13 **Q. PLEASE DISCUSS YOUR CONCERN WITH THE OPEB NEGATIVE EXPENSE**
14 **THAT THE COMPANY HAS DEFERRED AND RECORDED TO A**
15 **REGULATORY LIABILITY ACCOUNT.**

16 **A.** Several years ago, the Company closed the OPEB retiree healthcare plan to new retirees
17 and established a new Retiree VEBA Plan. As a result of this change and other changes
18 to the OPEB plan, the Company has been reporting negative expense in recent years.
19 Instead of recording the negative expense against current O&M expense, subsequent to a
20 rate case order, the Company began to record the negative expense to a regulatory liability

1 account. As of December 2023, the regulatory deferred liability account balance is
 2 \$68,123,000. The liability balance through additional negative OPEB expense is
 3 forecasted to grow to \$81.3 million by the end of December 2025.⁷⁹

4 At the time when the deferred regulatory liability was proposed, the expectation was that
 5 in future years positive expense would offset the negative balance over the coming year.
 6 However, this phenomenon has not occurred. Instead, the liability balance continues to
 7 grow. In response to discovery, the Company stated that OPEB expense will likely
 8 continue to be negative through at least 2030.⁸⁰ With the new VEBA and a declining
 9 retiree base in the OPEB plan, it is more than likely that the OPEB expense will continue
 10 to be negative for many years to come and the regulatory liability will continue to grow
 11 past December 2025.

12 **Q. WHAT DO YOU PROPOSE TO DO WITH THE LARGE NEGATIVE EXPENSE**
 13 **RECORDED TO THE REGULATORY LIABILITY ACCOUNT?**

14 **A.** With the large increase proposed by the Company in this rate case, it is not fair or
 15 reasonable for the Company to continue to defer the OPEB negative expense and not pass
 16 through to customers a portion of the deferred regulatory liability balance in this rate case
 17 and continuing into the future.

18 Therefore, I propose that the Company begin to amortize the balance of \$68,136,000 as of
 19 December 2023 over a seven-year period and include the resulting amortization expense

⁷⁹ Exhibit AG-51 includes DR AGDG-7.191a with attachment showing the growing liability balance.

⁸⁰ Id., includes DR AGDG-7.191b.

1 of \$9,734,000 in the projected test year as a reduction to O&M expense. I chose a seven-
2 year amortization as a reasonable period that will gradually reduce the liability balance
3 and still retain a sufficient negative balance in case OPEB expense reverses from negative
4 to positive.

5 In rebuttal, the Company may raise the issue that the OPEB negative expense is a non-
6 cash item and will impact the Company's cash flow and also raise concerns with the rating
7 agencies. Those concerns have been raised before and are not significant enough to
8 continue to defer the negative expense indefinitely. The seven-year amortization period
9 minimizes any impact on cash flow. It should be noted that the amortization of the OPEB
10 liability account balance is akin to the amortization of deferred taxes that resulted from the
11 TCJA of 2020 and is still continuing.

12 Therefore, I recommend that the Commission approve this proposal and accordingly
13 reduce the Company's projected O&M expense for the projected test year ending
14 September 2025 by \$9,734,000.

15 **Q. DID THE COMMISSION RECENTLY APPROVE A SIMILAR PROPOSAL?**

16 A. Yes. In Case No. U-21297, I made a similar proposal in the DTE Electric rate case and
17 the Commission found merit to the proposal and approved it. My proposal in this rate case
18 is the same and I recommend that the Commission approve it as well.

L. Credit/Debit Card Merchant Fees

Q. ARE YOU PROPOSING ANY CHANGES TO THE COMPANY'S CREDIT/DEBIT CARD PAYMENT PROGRAM OR ADJUSTMENTS TO RELATED O&M EXPENSE?

A. Yes. The Company currently allows residential and commercial/industrial (non-residential) customers to pay their gas bills with a credit or debit card. Until about 2016, the Company charged the customer a convenience fee to use a credit or debit card given the high fees required by merchant banks and institutions that issue credit/debit cards. On or about 2016, the Company removed the convenience fee and since that time we have seen an explosive growth in the use of credit/debit cards by customers. For DTE Gas, merchant fees reached nearly \$7.1 million in 2021 and have ebbed somewhat in the past two years after the Company imposed certain limitations on the use of credit/debit cards by non-residential customers.

Beginning on page 60 of his direct testimony, Mr. Decker discusses the recent history of debit/credit cards and presents data on merchant fees paid by the Company. Although, the Company in recent years began to limit the use of credit/debit cards for non-residential customers, the cost is still rather significant. For the projected test year, the Company forecasted \$4,042,000 in merchant fees pertaining to residential customers and \$2,218,000 for non-residential customers, for a total forecasted expense of \$6,260,000.

Q. WHAT IS YOUR PROPOSAL?

1 A. I propose that the Commission disallow recovery of merchant fees for non-residential
2 customers beginning with the costs included in the projected test year in this rate case.
3 This proposal will remove \$2,216,000 from forecasted expense for the projected year.
4 Non-residential customers, which consists primarily of small to medium size commercial
5 and industrial businesses, have more options and sophistication than residential customers
6 to pay their gas and electric bills through other less costly means, such as Electronic Funds
7 Transfer (EFT) and Automatic Clearing House (ACH). In response to discovery, the
8 Company reported that an EFT or ACH transaction charge is approximately 10 to 11 cents.
9 In contrast, the merchant fee for the use of a credit/debit card for non-residential customers
10 is \$4.72 per transaction.⁸¹ This large disparity in cost is not reasonable and should be
11 avoided.

12 In late 2023, Consumer Energy came to the realization that removing the credit/debit card
13 convenience fee previously charged to customers was neither sustainable nor in the best
14 interest of the majority of its customers due to the large escalation in merchant fees.
15 Beginning in 2024, Consumers Energy reimposed a convenience fee for all customers,
16 both residential and non-residential, who want to use a credit card. This is a step that the
17 Company should evaluate in coming months and address accordingly. With the large
18 escalation in merchant fees in recent years, more businesses from restaurants to retail shops
19 are imposing a convenience fee when customers pay for goods and services with a credit

⁸¹ Exhibit AG-52 includes DR AGDG-4.93c. The \$4.72 merchant fee is stated on page 61 of Mr. Decker's direct testimony on line 16.

1 card. Of course, gasoline stations placed a premium on gasoline sales with a credit card
2 long ago.

3 Therefore, at this time, I recommend that the Commission disallow recovery of the \$2.2
4 million of merchant fees pertaining to non-residential customers so that the Company can
5 take appropriate actions to avoid those costs beginning with the projected test year in this
6 rate case.

7 **M. Corporate Jet Travel Costs**

8 **Q. PLEASE DISCUSS THE INCLUSION OF CORPORATE JET TRAVEL COSTS IN**
9 **O&M EXPENSES FOR THE PROJECTED TEST YEAR.**

10 A. In discovery, the Attorney General asked the Company to report cost and use of privately
11 hired corporate jet aircraft by Company employees or employees of the parent company
12 and affiliates who bill the Company for reimbursement of those costs. In response, the
13 Company reported that it leases a fractional share of an aircraft for use by executives at
14 the Vice President level and above for business travel.

15 The information provided by the Company shows that several executives of the Company,
16 DTE Electric, and DTE Energy, along with certain members of DTE's Board of Directors,
17 took 16 trips on the corporate leased aircraft in 2022 to investor and security analyst
18 meetings and conferences, as well as to out of state Board of Directors meetings. The
19 portion of the cost billed to the Company in 2022 was \$68,910. No information was
20 provided about 2023 costs and travel activity, although the information was requested. In

1 the response the Company stated that \$74,769 of expense was included in the projected
2 test year in this rate case.⁸²

3 **Q. WHAT IS YOUR RECOMMENDATION?**

4 A. I recommend that the Commission disallow recovery of costs for privately-hired corporate
5 jet use, particularly since the travel pertains to investor and board of director matters that
6 do not directly benefit customers but instead may benefit shareholders. Although
7 commercial flights may be less convenient, they are less costly and less impactful on the
8 environment relative to the emissions of private jets for the few individuals that they carry.
9 In 2020, DTE Energy announced its goal of achieving net zero emissions by 2050. Private
10 jet travel certainly goes counter to that goal.

11 Therefore, I recommend that the Commission remove the \$75,000 of costs that the
12 Company reported it included in the projected test year.

13 **N. Responsibly Sourced Gas Expense**

14 **Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSAL TO RECOVER FROM**
15 **CUSTOMERS THE PREMIUM PAID FOR RESPONSIBLY SOURCED GAS**
16 **(RSG).**

17 A. Beginning on page 35 of his direct testimony, Mr. Decker discusses the Company's
18 proposal to purchase RSG at a premium over other competitively bid gas prices. Mr.

⁸² Exhibit AG-53 includes DR AGDG-4.50.

1 Decker presents this proposal as part of the Company's corporate goal to reduce
2 greenhouse gas emissions by 35% by 2050, from unspecified levels in 2005.

3 Mr. Decker's direct testimony in this rate case generally mirrors the direct testimony of
4 other Company witnesses on this matter in Case Nos. U-21064 and U-21271. In Case No.
5 U-21064, the Commission warned the Company that the RSG premiums paid for gas
6 purchases were not likely to be recovered in the Gas Cost Recovery reconciliation case.
7 In the order in that case, the Commission suggested that the Company try to make a case
8 to recover the premiums paid in a general rate case. It appears that the Company has
9 decided to make its attempt for recovery of RSG premium costs in this rate case. The costs
10 that the Company seeks to recover in this rate case are \$180,000. As discussed later in my
11 testimony, this would only be the beginning of a much larger program that the Company
12 seeks to implement if the Commission approves recovery of these initial costs.

13 Mr. Decker defines RSG as natural gas that, during the production stage, has gone through
14 a third-party certification process and regular monitoring to ascertain that it was produced
15 in a way that meets the highest standards of responsibility with respect to air, water, land,
16 and community. The Company has met with industry peers, suppliers, and other industry
17 participants to ascertain their position on RSG and found a wide range of familiarity and
18 opinion. According to Mr. Decker, certification of RSG is still developing, with a wide
19 range of options from certification of only methane intensity to assessment of
20 Environmental, Social, and (Corporate) Governance (ESG) attributes. The Company sees
21 itself as an ESG leader and aspires to be the "Best in the world and best for the world."

1 In his testimony, Mr. Decker identifies various organizations in which the Company
2 participates and plays a role in defining standards and protocols on sustainability and RSG.
3 He states that the intent of establishing protocols is to encourage upstream producers,
4 processors, and transporters to report their methane intensity and opines that it may be too
5 early to determine if this voluntary reporting is occurring. Mr. Decker admits that although
6 much work has been done in the area of certification of RSG, the industry is still
7 developing. He states that the Company has not committed to a specific certification
8 process and will continue assessing its options to determine the most prudent
9 methodology. The Company believes that unless certification of RSG is demanded by gas
10 buyers, the industry will not evolve in this area.

11 On pages 44 and 45 of his direct testimony, Mr. Decker reports that the Company issued
12 requests for information (RFI) for purchasing up to 2 Bcf of RSG and that the Company
13 was able to purchase 1,134,200 Dth at a cost of \$7,858,562 during 2022. That cost consists
14 of the commodity cost of \$7,821,754, plus a premium of \$36,808 for the RSG certification.
15 The premium paid equates to 3.2 cents per Dth ($\$36,808 \div 1,134,200$).

16 On pages 46-47 of his testimony, Mr. Decker states that the Company made additional
17 purchases of RSG of 1,990,200 Dth in 2023 with a premium price of \$29,853. From these
18 purchases and from the program's objectives, he concludes that the Commission should
19 allow recovery of premium costs in general rate cases. From his testimony, it is not clear
20 if the Company is also seeking recovery of premium costs incurred outside of the projected
21 test year.

1 Mr. Decker states that during the project year, the Company anticipates purchasing
2 4,000,000 Dth of RSG at a premium of \$0.045 per Dth, which translates to a total premium
3 amount of \$180,000. At minimum, this is the amount that the Company wants to include
4 in rates in this rate case.

5 **Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S PURCHASE OF RSG**
6 **GAS, THE PAYMENT OF A PREMIUM, AND THE PROPOSAL TO**
7 **UNDERTAKE A WIDER RSG PROGRAM IN THE FUTURE?**

8 A. There are four main issues that arise from the Company's RSG purchases and long-term
9 proposal. The first issue is whether the Company should impose its corporate goal of net
10 zero emissions on suppliers, at the expense of customers, in the absence of laws and
11 regulations that require compliance with business practices that the Company and others
12 in the industry seek to achieve. Second, there is the issue of whether the Company should
13 recover excess costs over the cost of the commodity that would otherwise be avoided by
14 purchasing alternative gas supply. Third, there is the issue of whether producers and gas
15 suppliers should pass on costs to gas buyers in the form of premiums for selling natural
16 gas produced with "best" environmental practices that should be integral to *all* gas
17 produced and not only a portion of it. Fourth, although there may be some small emission
18 gains applicable to society in general, there are no tangible or direct benefits to customers
19 from the purchase of RSG. I will discuss each of these issues below.

20 **Q. PLEASE DISCUSS THE ISSUE WITH THE COMPANY'S GOALS AND LACK OF**
21 **MEANINGFUL MEASURES.**

1 A. The Company has set a corporate goal to reduce greenhouse emissions to net-zero from its
2 operations and from suppliers by 2050 and reduce customer emissions of greenhouse gas
3 emissions by 35% by 2050 from 2005 levels. The Company has not shared what the level
4 of greenhouse gas emissions was in 2005, how much in emission volumes the 35%
5 reduction represents, how it plans to achieve that goal, how RSG fits into the plan, or how
6 much it will contribute to the total reduction.

7 In response to discovery, the Company reported that the forecasted purchases of 4,000,000
8 Dth of RSG would reduce CO₂e emissions by 1% of the emissions along the natural value
9 stream. However, it is not clear what the value stream includes. Also, asked to identify
10 how much these gas purchases would reduce the Company's total carbon footprint, the
11 Company did not provide an answer. Therefore, the Company has put forth bits and pieces
12 of information with little to no substance to allow an adequate assessment of whether the
13 proposal to purchase RSG will make a significant contribution to the Company's total
14 greenhouse gas reduction goals by 2050 or the larger benefit to society.

15 In his testimony, Mr. Decker admits that the purchase of RSG is still a nascent issue within
16 the natural gas industry and for gas utilities serving consumers. RSG is fraught with
17 controversy as to how and at what pace to proceed with embracing certification of RSG
18 and the ensuing costs. There are no laws or regulatory mandates that require producers to
19 implement the business practices that RSG certification attempts to ascertain. Therefore,
20 buyers of natural gas, such as DTE Gas, are seeking to impose their own standards on
21 producers, who in turn are demanding to be paid for the incremental cost of certifying that
22 they follow the desired processes and policies.

1 Although gas producers and transporters need to do the utmost to reduce emissions in the
2 production and transportation of natural gas, the natural gas industry and subgroups within
3 the larger industry can establish standards that producers, transporters, and distributors
4 should follow. Once accepted, those standards should guide parties transacting with each
5 other by confirming that they are in compliance with those standards. If certification is
6 necessary, that is a cost of doing business and should not require a separate premium to be
7 paid by entities buying their product.

8 As I stated by way of an example in my testimony in Case No. U-21064 on this matter, in
9 the automotive manufacturing industry, there are the International Standard of
10 Organization (ISO) standards that equipment and parts suppliers need to meet and
11 demonstrate that they are compliant with in order to do business in the industry.⁸³
12 However, General Motors, Ford, and Chrysler do not pay a separate premium to those
13 suppliers that are compliant with the ISO standard, while also doing business with other
14 suppliers that are not ISO compliant, as the Company's proposal would do.

15 **Q. ARE THERE INITIATIVES AT THE FEDERAL LEVEL THAT COULD RENDER**
16 **THE COMPANY'S PROPOSED RSG PROPOSAL UNNECESSARY?**

17 A. Yes. The Inflation Reduction Act of 2022 (IRA), among other provisions, includes a
18 charge on methane emissions. The emissions charge applies only to methane emissions
19 from specific types of facilities that are required to report their greenhouse gas (GHG)
20 emissions to the EPA's Greenhouse Gas Emissions Reporting Program (GHGRP). The

⁸³ ISO = The International Organization for Standardization is an international standard development organization composed of representatives from the national standards organizations of member countries.

1 charge starts at \$900 per metric ton of methane, increasing to \$1,500 after two years. This
2 emissions charge is the first time the federal government has directly imposed a charge,
3 fee, or tax on GHG emissions.⁸⁴ The EPA will likely promulgate new regulations to
4 implement the provisions of the IRA on methane reductions and related fees.

5 In 2021, the EPA also proposed regulations that aimed to reduce methane emissions at gas
6 production facilities.⁸⁵

7 These legislative and regulatory initiatives will likely render the Company's proposal
8 duplicative and unnecessary.

9 **Q. IF THE COMPANY WERE TO PAY AN RSG PREMIUM FOR 50% TO 100% OF**
10 **ITS GAS PURCHASES, HOW MUCH WOULD THE ADDITIONAL COST BE**
11 **ANNUALLY?**

12 A. The Company forecasted 148,816,000 Dth of gas purchases for the 2023-2024 GCR year.
13 If the Company were to pay an RSG premium of 4.5 cents per Dth on half of the purchases,
14 the incremental annual cost would be in excess of \$3.3 million. On 100% of the volumes,
15 the incremental cost would be more than \$6.6 million annually.

16 **Q. ARE THERE OTHER QUESTIONABLE STATEMENTS IN MR. DECKER'S**
17 **TESTIMONY WITH REGARD TO RSG?**

18 A. Yes. On page 36 of his direct testimony, Mr. Decker states that the reduction of
19 greenhouse gas emissions and any related climate impact is one of the defining public

⁸⁴ <https://crsreports.congress.gov/product/pdf/R/R47206>.

⁸⁵ <https://www.epa.gov/system/files/documents/2021-11/2021-oil-and-gas-proposal.-overview-fact-sheet.pdf>.

1 policy issues of our time. If Mr. Decker's premise is true, producers should be fully
2 embracing the reduction of CO2 and other greenhouse gas emissions voluntarily as part of
3 their gas production operations.

4 In discovery in Case No. U-21064, the Attorney General asked the Company to explain
5 what producers are doing differently operationally to reduce the methane intensity of RSG
6 and why they cannot do the same with all gas produced and thus avoid the need for
7 certification. In response, the Company stated that each producer has its own criteria for
8 RSG and there is no defined standard. The Company also could not answer why producers
9 choose to certify only a portion of their supply instead of their entire production.

10 In discovery, the Company was also asked if it is likely that the natural gas produced and
11 sold by the same producers that has not been RSG certified would have the same methane
12 intensity as RSG. The Company admitted that it is possible that both RSG and non-RSG
13 may have the same methane intensity.⁸⁶ Gas is a fungible commodity. Once injected in
14 the pipelines it comingles with other gas. Therefore, there is no way for the Company to
15 be sure that it would receive the low carbon intensity natural gas that it paid a premium to
16 purchase. In fact, it is likely it would not receive the same gas supply it purchased at a
17 premium. This basic problem makes the entire undertaking unappealing.

18 It is also befuddling why a supplier who has committed to RSG would still produce non-
19 RSG natural gas. Such a practice raises questions about the seriousness of the entire
20 undertaking when producers and other parties simply go along with some certification

⁸⁶ Case U-21271, Exhibit AG-8 includes DR AGDG-1.18a and b.

1 process for only a portion of their operations to appear to be socially and environmentally
2 responsible.

3 On page 50 of his direct testimony, Mr. Decker states that the purchase of RSG will benefit
4 Michiganders and the Company's customers. However, other than the small reduction in
5 CO2 emissions discussed above, it is not clear what the other benefits are. In discovery in
6 Case No. U-21271, the Attorney General asked the Company if it had surveyed its
7 customers to determine if they are willing to pay a premium for gas purchases in order for
8 the Company to meet its net-zero carbon goal. In response, the Company stated that it had
9 not surveyed its customers and also stated that the Company's net-zero goal was not a
10 regulatory program that required approval by the Commission.⁸⁷

11 **Q. IS AN RSG PILOT PROGRAM NECESSARY AS PREVIOUSLY**
12 **RECOMMENDED BY THE COMPANY?**

13 A. No. On page 60 of his direct testimony in Case No. U-21271, Company witness Joseph
14 Madigan stated that the Company was piloting the RSG program and is still in the
15 exploration, analysis, and development stages of developing a robust RSG purchase
16 strategy. In discovery, the Attorney General asked the Company what there is further to
17 understand about RSG purchases that requires piloting a program. In response, the
18 Company pointed to unknowns, such as many different certifications and locations to
19 purchase RSG and the lack of current state and federal regulations.⁸⁸ Although these may
20 be unknown items, the solution is not to plunge into a program that entails paying

⁸⁷ Id. includes DR AGDG-1.17 and 1.21.

⁸⁸ Id. includes DR AGDG-1.20.

1 premiums for gas cost, but to wait for the market to sort itself out and avoid paying
2 additional costs for gas supply.

3 The Company's eagerness to purchase RSG seems highly influenced by its corporate goal
4 of achieving net-zero carbon emissions by 2050 and burnishing its image as a socially
5 responsible ESG company. If this is true, the payment of premiums to purchase RSG is
6 no different than advertising costs to enhance the Company's and its parent company's
7 corporate image and those costs should be paid by shareholders.

8 **Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?**

9 A. While reducing greenhouse gases is a laudable goal, the Company has not made a
10 compelling and convincing case that purchasing RSG is in the best interest of customers
11 or that it will make a significant difference in reducing greenhouse gas emissions.
12 Although the costs appear small now, they will grow significantly quickly if the Company
13 is allowed to recover premium costs above the normal cost of gas. The recovery of the
14 premium cost in a rate case is also problematic because those costs are related to the quantity
15 of gas purchased and the timing and accuracy of the costs recovered in base rates cannot
16 be easily ascertained and reconciled.

17 Therefore, I recommend that the Commission reject the Company's proposal to include
18 \$180,000 of RSG premium costs in this rate case based on a determination that the
19 Company's RSG proposal is still incomplete and does not adequately identify a
20 significantly beneficial impact to reduce greenhouse emissions or to customers. The
21 Commission should also determine that the Company's RSG proposal is premature given

the current state of this issue within the natural gas industry, the lack of industry standards for all participants to adhere to as part of routine business operations, and recent legislative and EPA initiatives on methane reductions in the gas production areas.

O. O&M Expense Summary

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS FOR O&M EXPENSES.

A. Operations and maintenance expenses represent a large part of the Company's cost structure. My analysis of the expense level proposed by the Company has determined that expenses in certain areas are excessive or unnecessary and should be removed. I recommend total reductions to O&M expenses of \$97.2 million as discussed above and summarized in the following table. Exhibits AG-39, AG-40, and AG-42 provide additional details of the areas where I have proposed O&M expense adjustments.

<u>Summary of O&M Expense Reductions</u>	<u>Amount (\$Millions)</u>
Company Gas Use and Lost Gas	\$ 4.9
Uncollectible Accounts Expense	9.1
Inflation Expense Adjustment	4.0
Corporate Expense Realignment	25.6
Pipeline Integrity and MAOP Records	7.6
Leak Detection and Repairs	10.3
Health Care Benefits	4.9
Employee Incentive Compensation	16.1
OPEB Liability Amortization Expense	9.7
Credit/Debit Card Fees	2.2
Responsibly Sourced Gas	0.2
Rents & Other Expenses	2.6
Total Reductions	\$ 97.2

IX. Depreciation Expense

1
2 Q. DO YOU PROPOSE AN ADJUSTMENT TO DEPRECIATION EXPENSE FOR
3 THE PROJECTED TEST YEAR?

4 A. Yes. As a result of the reductions in capital expenditures proposed above in my testimony
5 and the impact on capital additions included in rate base, I have calculated a reduction in
6 depreciation expense of \$3,409,000. The calculation of this amount is shown in Exhibit
7 AG-20.

8 I recommend that the Commission reduce the depreciation expense proposed by the
9 Company for the projected test year by \$3,409,000.

10
X. Property Tax Expense

11 Q. PLEASE DISCUSS THE PROPERTY TAX EXPENSE ADJUSTMENT THAT
12 YOU PROPOSE.

13 A. In Exhibit AG-20, I identified the adjustments to be made to the Company's proposed
14 capital expenditures. Those reductions lower the amount of property tax expense that the
15 Company will incur during the projected test year. On the same exhibit, I have calculated
16 the reduction in property tax expense of \$5,019,000 million. I recommend that the
17 Commission reduce the Company's property tax expense by this amount for the projected
18 test year.

19
XI. AFUDC

20 Q. WHAT ADJUSTMENTS TO AFUDC DO YOU PROPOSE?

1 A. In Exhibit A-13, Schedule C11, the Company shows \$4.7 million of Allowance for Funds
2 Used During Construction (AFUDC) pertaining to several project costs included in
3 construction work in process for large projects that will not be in-service before the end of
4 the projected test year. Included on this list of projects are four projects where I
5 recommend that the Commission remove the capital expenditures from construction work
6 in process and rate base. Those projects are (1) the Fort Street Main Replacement project,
7 (2) the Austin-Detroit A&B Lines, (3) Oakland Resiliency (CMS Line 2700) project, and
8 (4) the Belle River Detroit Loop Line. To avoid a duplication of reduction in the revenue
9 requirement, I removed \$2,210,000 of AFUDC from my calculation of the revenue
10 requirement in this rate case.

11 **XII. Adjustments To Revenue Deficiency**

12 **Q. WHAT ARE THE TOTAL ADJUSTMENTS AND THE REVISED REVENUE**
13 **DEFICIENCY YOU RECOMMEND?**

14 A. Exhibit AG-55 summarizes the adjustments to rate base and operating income. The net
15 result is a revised revenue deficiency of \$112.2 million, which is a reduction of \$153.3
16 million from the Company's requested level of \$265.5 million.

17 I recommend the Commission adopt these adjustments and issue an order granting rate
18 relief to the Company in an amount not exceeding \$112.2 million.

XIII. Rate Design

1
2 **Q. WHAT INCREASE IN THE MONTHLY SERVICE CHARGE FOR**
3 **RESIDENTIAL CUSTOMERS HAS THE COMPANY PROPOSED?**

4 A. In his direct testimony, Company witness Timothy Krysinski proposes to increase the
5 monthly service charge for residential customers (Rate Schedules A and 2A) from \$13.50
6 to \$17.60 per month. Mr. Krysinski also proposes to increase the monthly customer service
7 charge for small commercial customers in rate schedule GS-1 from \$40.00 to \$50.00.

8 **Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?**

9 A. No. The proposed change from \$13.50 to \$17.60 per month represents an increase of 30%.
10 Such a large increase could cause rate shock to customers in smaller households who use
11 less gas than the average customer. They would see their monthly gas bill increase
12 drastically without using any more gas.

13 Fixed monthly charges also discourage energy conservation. It is best to increase the
14 volumetric rate paid by customers because the higher cost encourages conservation. The
15 customer can take steps to reduce usage and thus lower the gas bill. The customer cannot
16 reduce fixed monthly charges.

17 Similarly, small commercial customers who take service under rate GS-1 would see an
18 increase of 25% in their monthly charge. This is also a significant increase for smaller
19 commercial customers.

1 **Q. WHAT DO YOU RECOMMEND?**

2 A. I recommend that the Commission maintain the current residential monthly customer
3 charge of \$13.50. The monthly service charge was increased \$1.25 in 2022 in the
4 Company's last rate case. The Company's proposed monthly charge of \$17.60 would
5 result in an annual charge of \$211, which would represent a large portion of the total annual
6 gas bill for small households. However, if the Commission sees some merit in increasing
7 the monthly service charge, in the interest of rate gradualism, I recommend that the
8 Commission not increase the monthly charge by more than \$1 to \$14.50.

9 Similarly, for the GS-1 rate, the Commission should maintain the current monthly charge
10 of \$40.00, which was increased by \$8.00 in 2022. This last increase of 20% was rather
11 large and another increase should be avoided at this time.

12 **Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?**

13 A. Yes, it does. However, I reserve the right to amend, revise and supplement my testimony
14 to incorporate new information that may become available.

Experience and Qualifications of Sebastian Coppola

Mr. Sebastian Coppola is an independent energy business consultant and president of Corporate Analytics, Inc., whose place of business is located at 5928 Southgate Rd., Rochester, Michigan 48306.

EMPLOYMENT BACKGROUND

Mr. Coppola has been an independent consultant for 22 years. Before that, he spent three years as Senior Vice President and Chief Financial Officer of SEMCO Energy, Inc. with responsibility for all financial operations, corporate development and strategic planning for the company's Michigan and Alaska regulated and non-regulated operations. During the period at SEMCO Energy, he had also responsibility for certain storage and pipeline operations as President and COO of SEMCO Energy Ventures, Inc. Prior to SEMCO, Mr. Coppola was Senior Vice President of Finance for MCN Energy Group, Inc., the parent company of Michigan Consolidated Gas Company (now DTE Gas Company).

ENERGY INDUSTRY EXPERTISE

During his 27-year career at SEMCO Energy, MCN Energy and MichCon, Mr. Coppola held various analytical, accounting, managerial and executive positions, including Manager of Gas Accounting with responsibility for maintaining the accounting records and preparing financial reports for gas purchases and gas production. In this role, he had also responsibility for preparing Gas Cost Recovery (GCR) reconciliation analysis and reports, and supporting preparation of testimony for the cost of gas reconciliation proceedings before the MPSC. Over the years, Mr. Coppola also held the positions of Treasurer, Director of Investor Relations, Director of Accounting Services, Manager of Corporate Finance, Manager of Customer Billing and Manager of Materials Inventory and Warehousing Accounting. In many

Experience and Qualifications of Sebastian Coppola

of these positions he interacted with various operating areas of the company and was intricately involved in construction and operating programs, defining gas purchasing strategies, rate case analysis, cost of capital studies and other regulatory proceedings.

Mr. Coppola is intricately knowledgeable of capital markets and financial institutions. As Treasurer and Vice President of Finance, he directed the issuance of more than \$2 billion in securities, including common stock, corporate bonds, tax-deductible preferred stock and high-equity value convertible securities. He established bank lines of credit, commercial paper and asset acquisition facilities. He has had extensive interactions with equity and debt investors, financial analysts, rating agencies and other members of the financial community.

ENERGY INDUSTRY AND REGULATORY EXPERIENCE

As a business consultant, Mr. Coppola specializes in financial and strategic business issues in the fields of energy and utility regulation. He has more than forty years of experience in public utility and related energy work, both as a consultant and utility company executive. He has testified in several regulatory proceedings before State Public Service Commissions. He has prepared and/or filed testimony in electric and gas general rate case proceedings, power supply and gas cost recovery mechanisms, revenue and cost tracking mechanisms/riders, multi-year rate plans and incentive ratemaking, and other regulatory matters.

Mr. Coppola has extensive experience with gas and electric utilities in the areas of gas operations, gas supply and regulatory proceedings. He has led or participated in the financial operations, gas supply planning and/or gas cost recovery arrangements of two major gas utilities in Michigan and in Alaska. He has prepared

Experience and Qualifications of Sebastian Coppola

testimony in multiple electric and gas general rate cases, Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) reconciliation proceedings, Cast Iron and Pipeline Replacement Programs and other regulatory cases on behalf of the Michigan Attorney General, Citizens Against Rate Excess (CARE), the Public Counsel Division of the Washington Attorney General, the Illinois Attorney General, the Maryland Office of Public Counsel, and the Ohio Office of Consumers Counsel in electric and gas utility rate cases, including AEP Ohio, Ameren-Illinois Utilities, Avista, Consumers Energy, DTE Electric Company, MichCon (DTE Gas Company), Michigan Gas Utilities Corp, Nicor Gas, PacifiCorp, Peoples Gas, Puget Sound Energy, SEMCO, Upper Peninsula Power Company, Washington Gas, and Wisconsin Public Service Company.

Mr. Coppola has also provided assistance and proposals to the Maryland Office of Peoples Counsel on Multi-Year Rate Plans and Performance-Based Ratemaking. Additionally, he prepared a report on the financial condition and risks of AltaGas and Washington Gas Light Company which was filed with the Maryland Public Service Commission in July 2019 in Case No. 9449.

As accounting manager and later financial executive for two regulated gas utilities, he has been intricately involved in construction materials procurement, gas purchase strategies and CGR reconciliation cases. He has had direct responsibility for preparing GCR reconciliation analysis and reports, and supporting preparation of testimony for the cost of gas reconciliation proceedings before the Michigan Public Service Commission (MPSC). He is intricately familiar with construction projects, the power supply and gas cost recovery mechanisms, gas supply and pricing issues, and regulatory issues faced by utilities.

Experience and Qualifications of Sebastian Coppola

During his long career at DTE Gas, among other responsibilities, Mr. Coppola was responsible to oversee the operation of the MichCon Wet Header System, a pipeline that transported natural gas and gas liquids from Michigan gas producing fields in the Niagaran Reef in the northern area of the lower peninsula of Michigan to processing plants in Kalkaska, MI. His responsibility included ensuring the day-to-day flow of gas and liquids, and identifying operating issues requiring corrective action.

He was also responsible for the study to assess the feasibility of building the Saginaw Bay Pipeline, a transmission line to move Praire Du Chein natural gas reserves in the eastern area of Michigan to processing plants. Prior to the construction of the pipeline, Mr. Coppola worked with operating management to prepare requests for proposal for the construction project and the selection of qualified bids. During and subsequent to the construction of the pipeline, Mr. Coppola assisted in the management and oversight of the pipeline, including review of operating performance and profitability.

Additionally, as Manager of Materials Inventory, Warehousing and Procurement at DTE Gas, Mr. Coppola worked closely with suppliers of pipe, control valves, flanges, meters, fittings, equipment and thousands of other parts and materials used in the construction, repair and maintenance of DTE Gas's transmission, distribution and storage facilities, including repairs and upgrades to compressor stations, and replacement of cast iron mains, bare and wrapped steel pipelines and service lines. His responsibilities included the review of design and construction blueprints and plans with frequent visits to construction sites during excavation of new pipeline trenches, and during replacement of defective or leaky

Experience and Qualifications of Sebastian Coppola

pipes, and replacement of control valves. Mr. Coppola also made frequent visits and inspection to storage facilities owned by DTE Gas to understand materials requirements during planned construction projects. Mr. Coppola was also responsible to ensure that materials and equipment were ordered to meet material standards and safety codes.

Through these responsibilities, Mr. Coppola gained knowledge and expertise with field construction project procedures, pipeline trenching problems, installation inspections, operation and maintenance cycles, and the material procurement of pipe, valves, flanges, meters and thousands of other parts and equipment used in the construction of natural gas transmission, distribution and storage facilities.

During his career with MCN Energy Group, Mr. Coppola was responsible for the evaluation of investments in interstate pipelines, new gas storage facilities, gas cogeneration plants, and construction of new power plants in the U.S. and India. Mr. Coppola was a key member of the negotiating team with contractors and suppliers tasked to build the power facilities, including the evaluation of Engineering, Procurement and Construction (EPC) bids and contracts.

Subsequent to his move to SEMCO Energy Corporation in 1999, Mr. Coppola was responsible for the acquisition and integration of pipeline construction companies providing services to gas utilities and interstate pipelines. In addition to its gas utility business in Michigan and Alaska, serving approximately 350,000 customers, SEMCO Energy owned SEMCO Pipeline Construction, a non-regulated business providing gas pipeline and natural gas facilities construction services to gas utilities and interstate pipelines in the Midwest and Eastern regions of the U.S.

Experience and Qualifications of Sebastian Coppola

SEMCO Pipeline Construction provided construction services similar to KS Energy, Northern Pipeline and other contractors used by the Company. During his tenure at SEMCO Energy, Mr. Coppola reviewed dozens of pipeline construction companies and acquired six companies. Mr. Coppola's responsibilities included management of the performance and profitability of the pipeline construction services business requiring field visits to construction projects and quality reviews. In this process, Mr. Coppola learned firsthand how pipeline construction companies operate, construction project challenges, their bidding practices and the bidding of construction projects, including pricing, bidding procedures and policies both from the contractor's side and the gas utility side.

Mr. Coppola has testified extensively on gas utility pipeline, service lines and inside meters replacement programs related to at-risk pipes that provide safety issues to customers and the general public.

In his role as Treasurer and Chairman of the MCN/MichCon Risk Committee from 1996 through 1998, Mr. Coppola was involved in reviewing and deciding on the appropriate gas purchase price hedging strategies, including the use of gas future contracts, over the counter swaps, fixed price purchases and index price purchases.

In March 2001, Mr. Coppola testified before the Michigan House Energy and Technology Subcommittee on Natural Gas Fixed Pricing Mechanisms. Mr. Coppola frequently participates in natural gas issue forums sponsored by the American Gas Association and stays current on various energy supply issues through review of industry analyst reports and other publications issued by various trade groups.

Experience and Qualifications of Sebastian Coppola

Mr. Coppola performed rate case analyses and filed testimony in several electric general rate cases addressing issues on revenue requirement, sales level determination, operation and maintenance expenses, capital expenditures, cost allocations, cost of capital, cost of service and rate design, and various cost tracking mechanisms. In addition, he has performed analysis of power costs and filed testimony in power supply cost recovery cases, including reconciliation of annual power supply costs.

In his position as Senior Vice President of Finance at MCN, Mr. Coppola also had responsibility for project financing of independent power generation plants in which MCN was an owner. In this regard, he was intricately involved and became knowledgeable of PURPA qualified cogeneration plants in Michigan and other states. In addition, he was involved in negotiating the development and financing of power generation and electricity distribution plants in other countries, such as India.

➤ Specific Regulatory Proceedings and Related Experience:

- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2022-2023 GCR reconciliation in case No. U-21065.
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy (CECo) 2023 gas rate case U-21490 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTM Michigan Lateral Company (DMLC) 2023 Act 9 Transportation Service rate update in case No. U-21525.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2022 PSCR reconciliation in case No. U-21051.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2022-2023 GCR plan in case No. U-21067.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 PSCR reconciliation in case No. U-21049.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in Indiana Power Company 2023 electric rate Case U-21461 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE 2023-2024 GCR plan in case No. U-21271.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2023-2024 GCR plan in case No. U-21269.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2023 electric rate Case U-21389 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2023 rate Case U-21297 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2023-2024 GCR plan in case No. U-21273.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2022 gas rate Case U-21308 on several issues, including sales revenues, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-2022 GCR plan reconciliation case No. U-20817.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2021 PSCR plan reconciliation case No. U-20827.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2021-2022 GCR plan reconciliation case No. U-20819.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2022 general rate case No. U-21286.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-2022 GCR plan reconciliation case No. U-20823.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2022-2023 GCR plan case No. U-21062.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2022-2023 GCR plan case No. U-21070.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2022 electric rate Case U-21224 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Public Counsel Division of Washington Attorney General in the Avista 2022 electric and gas rate cases on several issues, including operation and maintenance expenses, capital expenditures, and other items.
- Filed testimony on behalf of the Michigan Attorney General in the Act 9 application in Case No. U-20993 by Saginaw Bay Pipeline Company to set transportation rates for services to DTE Gas Company.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2022 electric rate Case U-20836 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed rebuttal testimony on behalf the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gaslight & Coke Company (Peoples Gas) in Docket 17-0137.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2021 gas rate Case U-21148 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2020-2021 GCR plan reconciliation case No. U-20554.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure

Experience and Qualifications of Sebastian Coppola

Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 20-0330.

- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2020-2021 GCR plan reconciliation case No. U-20552.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2020-2021 GCR plan reconciliation case No. U-20546.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2020 PSCR plan reconciliation case No. U-20526.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2020 PSCR plan reconciliation case No. U-20528.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2019-2020 GCR plan reconciliation case No. U-20236.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Ameren Illinois Company (Ameren) in Docket 20-0323.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-2022 GCR plan case No. U-20816.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-2022 GCR plan case No. U-20822.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2021 electric rate Case U-20963 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021 gas rate Case U-20940 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Michigan Lateral Company (DMCL) 2021 Act 9 filing to convert a pipeline and build two interconnections for transportation services to DTE Gas Company in case No. U-20894.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in DTEE 2021 power plant and tree trimming securitization costs in case No. U-21015
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2021 PSCR plan case No. U-20802.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2019-2020 GCR reconciliation case No. U-20234.
- Filed testimony on behalf of the Maryland Office of Public Counsel in Washington Gas Light Company's 2020 rate Case 9651 on several issues, including operation and maintenance expenses, capital expenditures, and other items.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2020 Karn 1 & 2 Retirement Cost and Bond Securitization Case U-20889.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Reconciliation in case U-20222.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2020-2021 GCR plan case No. U-20543.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Gas Company (SEMCO) 2020-2021 GCR plan case No. U-20551.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2020 electric rate Case U-20697 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in in the complaint against Upper Peninsula Power Company's (UPPCO) Revenue Decoupling Mechanism (RDM) in Case No. U-20150.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2019 gas rate Case U-20650 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company 2019 gas rate Case U-20642 on several issues, including

Experience and Qualifications of Sebastian Coppola

sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.

- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018-2019 GCR reconciliation Case U-20210.
- Prepared a report on the financial condition and risks of AltaGas and Washington Gas Light Company on behalf of the Maryland Office of People's Counsel filed with the Maryland Public Service Commission in July 2019 in Case No. 9449.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2018-2019 GCR reconciliation case U-20209.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2018-2019 GCR reconciliation case U-20215.
- Provided assistance and proposals to the Maryland Office of Peoples Counsel on Multi-Year Rate Plans and Performance-Based Ratemaking.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 PSCR Reconciliation in case U-20203.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2018 PSCR Reconciliation in case U-20202.
- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 electric rate Case U-20561 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in Indiana Michigan Power Company (I&M) 2019 electric rate Case U-20239 on several issues, including operation and maintenance

Experience and Qualifications of Sebastian Coppola

expenses, capital expenditures, cost of capital, rate design and other items.

- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019 gas rate Case U-20479 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019-2020 GCR Plan case U-20245.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2019-2020 GCR Plan case U-20233.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Plan case U-20221.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2019-2020 GCR Plan case U-20235.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2019-2020 GCR plan case U-20239.
- Filed rebuttal testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017-2018 GCR reconciliation case U-20076.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2017-2018 GCR reconciliation case U-20075.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2018 gas rate Case U-20322 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in I&M Tax Credit C Calculation in case U-20317.
- Filed direct testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Tax Credit C Calculation in case U-20298.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2017-2018 GCR Reconciliation case U-20078.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co Tax Credit C Calculation for the Gas and Electric Divisions in case U-20309.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2018 electric rate Case U-20276 on several issues, including excess deferred taxes, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2017 PSCR Reconciliation in case U-20068.
- Filed testimony on behalf of the Michigan Attorney General in DTE 2018 rate Case U-20162 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2018 Tax Credit B refund for the Electric Division in case U-20286.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2018 Integrated Resource Plan in case U-20165.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2018 Tax Credit B refund case U-20287 for the natural gas business.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit B refund case U-20189.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2018 electric rate Case U-20134 on several issues, including capital expenditures, cost of capital, rate design and other items.
- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 16-0197.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR reconciliation case U-17941-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2018-2019 GCR Plan case U-18417.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2018 Tax Credit A refund case U-20102.
- Filed testimony on behalf of the Michigan Attorney General in I&M 2018 PSCR Plan case U-18404.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018-2019 GCR Plan case U-18412.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company (UPPCO) 2018 Tax Credit A refund case U-20111.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit A refund case U-20106.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 PSCR Plan case U-18403.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2018 PSCR Plan case U-18402.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017 gas rate Case U-18999 on several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2017 gas rate Case U-18424 on several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2016 PSCR reconciliation case U-17918-R.
- Assisted the Michigan Attorney General in the review of several GCR and PSCR cases during 2017 and 2018, and proposed terms for settlement of those cases.

Experience and Qualifications of Sebastian Coppola

- Assisted the Michigan Attorney General in the filing of comments with the Michigan Public Service Commission relating to rate case filing requirements in case U-18238, refunds of tax savings from the lower federal tax rate in case U-18494 and Performance Based Regulation.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 15-0209.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 electric Rate Case U-18255 on a several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2017 electric rate Case U-18322 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital and other items.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the re-opening of proceedings in the restructuring of the Peoples Gas's main replacement program and gas system modernization plan in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in the Upper Michigan Energy Resources Corporation (UMERC) application for a certificate of public necessity and convenience to build two power plants in the Upper Peninsula of Michigan in case U-18202.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO application for a certificate of public necessity and convenience to build a pipeline in the Upper Peninsula of Michigan in case U-18202.
- Filed testimony on behalf of the Public Counsel Division of the Washington Attorney General in Puget Sound Energy's 2016 Complaint for Violation of Gas Safety Rules in Docket No. UE-160924.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 PSCR Plan case U-18143.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in CEC0 2015 Power Supply Cost Recovery (PSCR) reconciliation case U-17678-R.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2016 gas general rate case U-18124 on a several issues, including revenue, operations and maintenance costs, capital expenditures, working capital, cost of capital and other items.
- Filed testimony on behalf of the Illinois Attorney General for the restructuring of the Peoples Gas's main replacement program in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2014-2015 GCR Plan reconciliation case U-17332-R.
- Filed testimony on behalf of the Michigan Attorney General in the formation of UMERG and the transfer of Michigan assets of Wisconsin Public Service Corporation and Wisconsin Electric Company to UMERG in Case U-18061.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 Court of Appeals Remand Case U-17087 for review of the Automated Meter Infrastructure (AMI) opt-out fees.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2016 electric Rate Case U-17990 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2016-2017 GCR Plan case U-17940.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 electric Rate Case U-18014 on a several issues, including revenue, revenue decoupling, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2016-2017 GCR Plan case U-17942.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR Plan case U-17941.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015 gas general rate case U-17999 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, Revenue Decoupling Mechanism (RDM) program, cost of capital and other items.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2016-2017 GCR Plan case U-17943.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2016 PSCR Plan case U-17918.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2014-2015 GCR Plan reconciliation case U-17334-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 PSCR Plan case U-17920.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan reconciliation case U-17333-R.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2015 gas general rate case U-17882 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, infrastructure cost recovery mechanism, cost of capital and other items..
- Filed testimony on behalf of the Michigan Attorney General in CEC Co Gas Choice and End-User Transportation tariff changes case U-17900.
- Analyzed the gas rate case filings of MGUC in Case U-17880 and assisted the Michigan Attorney General in settlement of the case.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2014 PSCR reconciliation case U-17317-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2013-2014 GCR Plan reconciliation case U-17131-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2014 electric Rate Case U-17767 on a several issues, including operations and maintenance costs, capital expenditures, AMI program, cost of capital and other items.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015-2016 GCR Plan case U-17691.
- Filed testimony on behalf of the Illinois Attorney General in Ameren Illinois Company's 2015 general rate case on operation and maintenance costs in Docket 15-0142.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2014 electric Rate Case U-17735 on a several issues, including sales, operations and maintenance costs, capital expenditures, cost of capital, AMI program, revenue decoupling and infrastructure cost recovery mechanisms.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2015-2016 GCR Plan case U-17693.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2015-2016 GCR Plan case U-17690.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2015 PSCR Plan case U-17678.
- Analyzed the electric rate case filings of Northern States Power in Case U-17710 and Wisconsin Public Service Company U-17669, and assisted the Michigan Attorney General in settlement of these cases.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2013-2014 GCR Plan reconciliation case U-17133-R.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan reconciliation cases U-17130-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan reconciliation case U-17132-R.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2014 gas general rate case U-17643 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, cost of capital and other items..
- Filed testimony on behalf of the Illinois Attorney General in Wisconsin Energy merger with Integrys on the Peoples Gas and Coke Company's Accelerated Main Replacement Program Docket 14-0496.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of Citizens Against Rate Excess in Wisconsin Public Service Company's 2013 PSCR plan reconciliation case U-17092-R.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2014 PSCR plan case U-17317.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2014 OPEB Funding case U-17620.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan case U-17333.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2014-2015 GCR Plan case U-17331.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2014-2015 GCR Plan case U-17334.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Company's 2014 PSCR plan case U-17299.
- Filed testimony in March 2013 on behalf of the Michigan Attorney General in CEC0's electric Rate Case U-15645 on remand from the Michigan Court of Appeals for review of the AMI program.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 PSCR plan case U-17298.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2012-2013 GCR Reconciliation case U-16920-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company 2012-2013 GCR Reconciliation case U-16921-R.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2012-2013 GCR Reconciliation case U-16924-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2012-2013 GCR Reconciliation case U-16922-R.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) reconciliation case U-16881-R.
- Filed testimony in Puget Sound Energy's 2013 Power Cost Only Rate Case on behalf of the Public Counsel Division of the Washington

Experience and Qualifications of Sebastian Coppola

Attorney General in Docket No. UE-130167 on the power costs adjustment mechanism.

- Filed testimony in PacifiCorp's 2013 General Rate Case on behalf of the Public Counsel Division of the Washington Attorney General in Docket No. UE-130043 on power costs, cost allocation factors, O&M expenses and power cost adjustment mechanisms.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan case U-17132.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan case U-17130.
- Filed testimony on behalf of the Michigan Attorney General in CEC's 2012 electric Rate Case U-17087 on a several issues, including cost of service methodology, rate design, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism and other revenue/cost trackers.
- Filed reports on gas procurement and hedging strategies of four gas utilities before the Washington Utilities and Transportation Commission on behalf of the Washington Attorney General – Office of Public Counsel in April 2013.
- Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2011-2012 GCR Plan reconciliation cases U-16481-R and U-16483-R.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) plan case U-17091.
- Filed testimony in MichCon's 2012 gas Rate Case U-16999 on a several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism.
- Filed testimony on behalf of the Washington Attorney General – Office of Public Counsel on executive and board of directors' compensation in the 2012 Avista general rate case.

Experience and Qualifications of Sebastian Coppola

- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2011 Power Supply Cost Recovery (PSCR) reconciliation case U-16421-R.
- Filed testimony on behalf of the Ohio Office of Consumers Counsel in AEP Ohio's power supply restructuring case in June 2012.
- Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2012-2013 GCR Plan cases U-16920 and U-16922.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 PSCR plan case U-16881.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Corporation's 2012 PSCR plan case U-16882.
- Filed testimony for the Michigan Attorney General in CEC's gas business Pilot Revenue Decoupling Mechanism in case U-16860.
- Filed testimony for the Michigan Attorney General in Consumers Energy Gas 2011 Rate Case U-16855 on several issues, including sales volumes, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in SEMCO and MGUC 2010-2011 GCR Plan reconciliation cases U-16147-R and U-16145-R.
- Filed testimony for the Michigan Attorney General in Consumers Energy 2011 electric Rate Case U-16794 on several issues, including electric sales forecast, revenue decoupling mechanism, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in CEC's electric business Pilot Revenue Decoupling Mechanism in case U-16566.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO and MGUC 2011-2012 GCR Plan cases U-16483 and U-16481.
- Filed testimony for the Michigan Attorney General in Detroit Edison 2010 electric Rate Case U-16472 on several issues, including revenue decoupling mechanism, operations and maintenance cost, executive compensation and benefits, capital expenditures and cost of capital.

Experience and Qualifications of Sebastian Coppola

- Filed testimony for the Michigan Attorney General in SEMCO 2009-2010 GCR reconciliation case U-15702-R.
- Filed testimony for Michigan Attorney General in MGUC 2009-2010 GCR reconciliation case U-15700-R.
- Filed testimony for Michigan Attorney General, in Consumers Energy Gas 2010 Rate Case U-16418 on several issues, including sales volumes, operations and maintenance costs, capital expenditures and cost of capital.
- Filed testimony for Michigan Attorney General, in SEMCO 2010 Rate Case U-16169 on several issues, including sales volumes, rate design, operations and maintenance cost, executive compensation and benefits, capital expenditures and cost of capital.
- Filed testimony, for Michigan Attorney General in Consumers Energy 2009 electric Rate Case U-16191 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost and capital expenditures.
- Filed testimony for Michigan Attorney General, in MichCon 2009 gas Rate Case U-15985 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost, capital expenditures and cost of capital.
- Filed testimony for Michigan Attorney General and was cross-examined in Consumers Energy 2009 gas Rate Case U-15986 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost, capital expenditures and cost of capital.
- Prepared testimony and assisted the Michigan Attorney General in discussions and settlement of SEMCO and MGUC 2010-2011 GCR Plan cases U-16147 and U-16145.
- Prepared testimony and assisted Michigan Attorney General in settlement of SEMCO 2009-2010 GCR case U-15702.
- Prepared testimony and assisted Michigan Attorney General in settlement of MGUC 2009-2010 GCR case U-15700.

Experience and Qualifications of Sebastian Coppola

- Prepared testimony and assisted the Michigan Attorney General in discussions and settlement of SEMCO 2008-2009 GCR case U-15452 and reconciliation case U-15452-R.
- Prepared testimony and assisted Michigan Attorney General in discussions and settlement of MGUC 2008-2009 GCR reconciliation case U-15450-R.
- Prepared testimony for Michigan Attorney General in SEMCO GCR 2007-2008 Reconciliation Case U-15043-R.
- Prepared testimony for Michigan Attorney General filed in MGUC 2007-2008 GCR Reconciliation Case U-15040-R.
- Participated in drafting of testimony for all aspects of SEMCO rate case filing with the Regulatory Commission of Alaska (RCA) in 2001.
- Filed testimony in 2001 before the (RCA) and was cross-examined on the financing plans for the acquisition of Enstar Corporation and the capital structure of SEMCO.
- Developed a cost of capital study in support of testimony by company witness in the Saginaw Bay Pipeline Company rate request proceeding in 1989.
- Prepared testimony for company witness on cost of capital and capital structure in MichCon 1988 gas rate case.
- Filed testimony in MichCon gas conservation surcharge case in 1986-87.
- Testified before MPSC ALJ in MichCon customer bill collection complaints in 1983.
- Participated in analysis of uncollectible gas accounts expense for inclusion in rate filings between 1975 and 1988.
- Participated in analysis of allocation of corporate overhead to subsidiaries and use of the “Massachusetts Formula” at MichCon and at SEMCO in 1975 and 2000.
- Prepared support information on GCR and rate case-O&M testimony at MichCon from 1975 to 1988.
- Filed testimony in MichCon financing orders in 1987 and 1988.

Experience and Qualifications of Sebastian Coppola

- Participated in rate case filing strategy sessions at MichCon and SEMCO from 1975 to 2001.
- Provided Hearing Room assistance and guidance to counsel on financial and policy issues in various cases from 1975 to 2001.

EDUCATIONAL BACKGROUND

Mr. Coppola did his undergraduate work at Wayne State University, where he received the Bachelor of Science degree in Accounting in 1974. He later returned to Wayne State University to obtain his Master of Business Administration degree with major in Finance in 1980.

