

August 28, 2025

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

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

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned case, please find **Consumers Energy Company's Exceptions to the Proposal for Decision.**

This is a paperless filing and is therefore being filed only in PDF. Also included is a Proof of Service showing electronic service upon the parties.

Sincerely,

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cc: Parties to Attachment 1 to the Proof of Service

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for the)
distribution of natural gas and for other relief.)
_____)

Case No. U-21806

CONSUMERS ENERGY COMPANY'S EXCEPTIONS
TO THE PROPOSAL FOR DECISION

August 28, 2025

TABLE OF CONTENTS

	<u>Page</u>
I. INTRODUCTION AND OVERVIEW	1
II. RATE BASE.....	2
A. Net Utility Plant	2
1. Gas Transmission and Distribution Capital Expenditures	2
a. New Business Program	2
i. Mains Services & Meter Stands.....	2
(a.) Gas Line Extension Policy.....	2
(b.) Shareability of the Gas Engineering Model.....	4
b. Asset Relocation Program.....	6
i. Distribution Asset Relocation - 2023 Historical Projects.....	6
c. Regulatory Compliance	8
i. Transmission Regulatory Compliance.....	8
(a.) Pipeline Integrity – TOD	8
(b.) MAOP Project Expenditures.....	9
d. Material Condition Program	10
i. Material Condition Non-Modeled Program.....	10
(a.) High Pressure Waterway Crossings Project	10
ii. EIRP.....	12
iii. VSR.....	17
e. Capacity/Deliverability Program	19
i. Transmission Capacity/Deliverability Program.....	19
(a.) Deliverability Base Field Measurement Program.....	19
(b.) Deliverability Base Pipeline Program.....	21
(c.) TED-I - RCVs.....	22
f. Gas Operations Other Program.....	23
i. Compliance and Controls.....	23
(a.) Enterprise Corrective Action Program.....	23
(b.) Advanced Methane Detection.....	25
2. Gas Compression and Storage Capital Expenditures.....	27
a. Lyon 29/24 (Northville Storage) Dehydration Project	27

3.	Gas Operations Support Capital Expenditures	33
a.	Lansing, Kalamazoo, and Hastings Service Centers	33
4.	IT and Security Capital Expenditures	37
a.	Customer IT Expenditures	37
i.	Product Family Enhancements Customer Projects	37
(a.)	Web Chat AI	37
(b.)	Mobile Application	38
b.	Gas and Electric and Gas Shared IT Expenditures	39
i.	Gas SCADA Software Solution	39
c.	Security	42
i.	Forward Web Proxy Services	42
ii.	Physical Access Management and Alarm Response	44
d.	Enhancement Projects	46
e.	Asset Refresh Program	48
i.	ARP – Local Area Network	48
f.	IT/Digital Foundation	51
i.	Operational Technology Datacenter Migration	51
III.	CAPITAL STRUCTURE AND RATE OF RETURN	52
A.	Test Year Capital Structure – Equity Ratio	56
1.	The PFD Failed to Appropriately Consider Peer Utility Equity Ratios and Equity Ratios of ROE Proxy Utilities	57
2.	Given the Evidence and Analysis Presented on Peer Utility Equity Ratios and Equity Ratios of ROE Proxy Utilities, While Considering the Commission’s Stated 50% Equity Ratio Goal for Utilities, the PFD’s Equity Ratio Recommendation is Too Low	62
3.	The PFD Inappropriately Dismissed Trends in the Company’s FFO-to-Debt Ratio, Market Conditions, the Nationwide Utility Industry, and the Regulatory Environment	65
4.	Conclusion on Equity Ratio	71
B.	Return On Common Equity	72
1.	The ALJ Erred by Placing Undue Reliance on Recent ROE Decisions by Regulatory Agencies for Utilities that are Not Proxies for Consumers Energy	72
2.	The ALJ Erred by Incorrectly Limiting the Weight of the Company’s Quantitative Models	84

3.	The ALJ Erred By Failing to Appropriately Consider the Impact of Market Conditions – Flotation Costs, Capital Expenditures, and the Regulatory Environment – on the Determination of An Appropriate ROE	91
4.	ROE Conclusion	94
C.	Overall Rate Of Return – Conclusion.....	95
IV.	THROUGHPUT	95
V.	ADJUSTED NET OPERATING INCOME	99
A.	Other O&M Expense	99
1.	Gas Engineering and Supply O&M Expense.....	99
a.	Project Management and Quality Lean O&M Expense	99
b.	Gas Engineering Support	101
2.	Regulatory Compliance O&M Expense	102
a.	MAOP – Transmission	102
3.	Information Technology O&M Expense	103
a.	Asset Accounting Tax Upgrade	103
4.	Pension and Benefits Expense	104
a.	LIBA	104
5.	Incentive Compensation Expense.....	106
6.	Customer Experience O&M Expense.....	109
a.	Customer Interactions Expense.....	109
i.	Customer Order Service Tracker	109
7.	Voluntary Separation Program	110
8.	Inflation Rate	111
VI.	COST OF SERVICE, RATE DESIGN, AND TARIFF ISSUES.....	113
A.	Rate Design.....	113
1.	Transmission-Only Transportation Service Rate.....	113
2.	Customer Charges.....	116
a.	The Company Used the Commission-Approved Method to Set the Customer Charge	118
b.	Gradualism Principles Should Not Supersede Cost-Based Ratemaking Principles	119
VII.	OTHER ISSUES.....	122
A.	Natural Gas Delivery Plan	122
VIII.	CONCLUSION.....	124

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Case No. U-21806

**CONSUMERS ENERGY COMPANY’S EXCEPTIONS
TO THE PROPOSAL FOR DECISION**

I. INTRODUCTION AND OVERVIEW

On December 16, 2024, Consumers Energy Company (“Consumers Energy” or the “Company”) filed its application seeking an increase in its natural gas rates sufficient to produce additional revenues in the annual amount of approximately \$248 million. Subsequently, the Company reduced its requested annual increase to approximately \$217 million. After evidentiary hearings, Initial and Reply Briefs were filed. On August 14, 2025, Administrative Law Judge James M. Varchetti (“ALJ”) issued a Proposal for Decision (“PFD”) in which he recommended an annual revenue deficiency of \$142,202,000. This revenue deficiency projection does not include the effect of the recommended SAP S/4 HANA O&M expense deferral.

Consumers Energy submits that the rate relief recommended in the PFD, if adopted by the Michigan Public Service Commission (“MPSC” or the “Commission”) in its entirety, would be below a just and reasonable level. The revenue deficiency recommended in the PFD is significantly lower than the constructive position the MPSC Staff (“Staff”) proposed in this case, and the Company submits that the evidence supports a revenue deficiency higher than Staff’s recommendation. Many of the investments proposed in this case are needed, both directly and indirectly, to enhance and ensure the safety of the Company’s natural gas transmission and distribution systems. The PFD proposed unwarranted disallowances for many safety-related

projects without proper justification as discussed in more detail below. The PFD also recommended a significant decrease in the Company’s current ratemaking return on equity (“ROE”) to 9.75%, which is well below a level that investors would find sufficient to contribute the capital that Consumers Energy will need to keep the system safe for customers and the public. Notably, the 9.80% ROE that the Commission used for DTE Gas Company (“DTE Gas”) in November 2024 was received forcefully and negatively by the investment community. The economic uncertainty and business risk in the United States has only increased since last November, making a constructive return to incent and support appropriate investment even more important. A similar ROE result in this case would not be acceptable given the necessity of the work the Company has proposed. It is crucial that the Commission approve a constructive revenue deficiency and ROE in this case that will enable the Company to complete all of the important safety-related work planned and proposed in the Company’s filing. Accordingly, Consumers Energy is filing these Exceptions to the recommendations of the PFD.

II. RATE BASE

A. Net Utility Plant

1. Gas Transmission and Distribution Capital Expenditures

a. New Business Program

i. Mains Services & Meter Stands

(a.) Gas Line Extension Policy

In Case No. U-21291, in a DTE Gas rate case, the Commission determined that “the record in this case indicates that there is potential for shortfalls in recovery from CAP participants, which the company is then proposing to later include in base rates.” MPSC Case No. 21291, November 7, 2024 Order, page 246. To that point, the Commission ordered that:

...[I]n its next general rate case, DTE Gas shall provide a thorough justification for its CIAC and CAP methodology, including whether it is appropriate to revise its assumptions to include declining gas demand, customer adoption rates for the CAPs based on historical experience when calculating new attachment surcharges, and how the company intends to avoid subsidization by existing customers. [*Id.* at 247.]

Relying on the Commission's Order in that rate case, the PFD recommended that Consumers Energy "justify, in its next rate case, its CIAC methodology including whether it is appropriate to revise its assumptions to include declining natural gas demand and how to avoid unfair subsidization in that scenario." PFD, page 37

Consumers Energy's line extension policy is authorized by the Commission and is consistent with other Michigan natural gas utilities. The Commission authorized the Customer Attachment Program ("CAP") in June 1995. This program, initiated by Aquila Networks, Michigan Gas Utilities ("MGU"), Consumers Energy, Michigan Consolidated Gas Company, and SEMCO Energy Gas Company ("SEMCO"), was later extended to Wisconsin Public Service Corporation in April 1998 and to Northern States Power. This was to ensure that consistent programs were in place across the state. Consumers Energy attaches customers in accordance with its MPSC approved tariff, and nothing in the record shows that the Company is not following the tariff.

Additionally, Consumers Energy has thoroughly supported its line extension policy. The record in this case does not demonstrate that there is a potential shortfall in recovering costs from participants. Nor does the record demonstrate that the Company is providing increasing footage allowances that are subsidized by existing customers, that the Company's model uses outdated data and assumptions to calculate customers' contributions, or that the Company overstates the period of time that customers will receive natural gas service in the modeling of customer

contributions. See 2 TR 113-118; 2 TR 198-209. This information has also been extensively briefed. See Consumers Energy’s Initial Brief, pages 12-18; Consumers Energy’s Reply Brief, pages 10-15.

The primary objective and design of the Customer Attachment Tariff is to enable the expansion of cleaner, safer, more reliable, and more affordable gas utilities without requiring existing customers to subsidize these expansions. The costs of installing the necessary equipment for expansions are charged to new customers and are balanced by the revenue generated by the newly attached customers over a period of 20 years. 2 TR 208. The risk of subsidization only exists if the new service is retired prematurely, or the Company does not receive the forecasted revenue over the course of the next 20 years. However, the volume of natural gas services is not declining, and the customers who moved in to utilize the attached services are stable. *Id.* In fact, the annual reporting to the Commission shows that the number of natural gas customers in Michigan is growing – not declining. 2 TR 115. Additionally, in 2024, the Company received 8,896 gas service alteration requests, to either relocate the service or upgrade the service due to load increases, which is a 108% increase from the requests received in 2017. See Exhibit A-125 (LAB-7). The evidence supports the reasonable assumption that new gas customers will remain customers on the Company’s system for more than 20 years. The PFD’s recommendation is unreasonable as the record in this case supports the line extension assumptions.

(b.) Shareability of the Gas Engineering Model

In Case No. U-21148, on July 7, 2022, the Commission issued an Order Approving a Settlement Agreement. The Settlement Agreement provides that “Consumers Energy agrees to meet with MNS and Staff to review and update the line extension assumptions within 90 days of the Commission issuing an order in this case. Consumers Energy additionally agrees to transition to a new line extension model that is transparent and is capable of being shared with stakeholders

for review to be completed by the end of 2022.” MPSC Case No. U-21148, July 7, 2022 Order Approving Settlement Agreement, Exhibit A, page 4, paragraph 13.

Based on an argument raised by Michigan Environmental Council (“MEC”), Sierra Club, and Citizens Utility Board of Michigan (“CUB”) (collectively “MNSC”), the PFD determined that the Company’s line extension model is not truly “capable of being shared” with interested parties in the sense that the parties “likely contemplated” in the Settlement Agreement in Case No. U-21148. PFD, page 37. To that end, the PFD recommended directing the Company to develop a way to share the line extension model without requiring interested parties to attend an in-person demonstration. This recommendation fails to recognize the changes made to the model consistent with the Settlement Agreement.

The transition to the new model allowed for a more robust, transparent, user-friendly experience. This model better meets the needs of the Company’s team and stakeholders by providing more transparency in the calculations. The Company’s previous model was 20 years old, and the software was outdated, making it difficult to maintain and updates were unavailable. 2 TR 207, 251. The new .net application allows for continuous enhancements so that the model stays up-to-date and efficient. 2 TR 207. The model is more transparent and is built on a software platform commonly used by Project Managers, which improves accessibility and usability. *Id.* The new platform enables annual updates to these assumptions, ensuring its accuracy and relevance.

The new model is designed to offer a more transparent view of the inputs and outputs. The Company can share and provide information from the model that it previously could not. For example, the information that was provided in Exhibit A-120 (LAB-2) would not have been able to be shared with the previous model. 2 TR 256. Moreover, the new model can share information

that the old model did not have readily available. The Company can show that the net present value (“NPV”) over the 20 years in a graphical form, as well as provide the NVP cost, the NVP revenue, and the NVP gross-up. Additionally, with the new model the Company can share additional information when inquiries arise regarding the cost to provide service to customers. 2 TR 256. The new model provides a means to share significant information with customers, the Commission, and stakeholders. Thus, the new model complies with the terms of the Settlement Agreement.

b. Asset Relocation Program

i. Distribution Asset Relocation - 2023 Historical Projects

The Asset Relocation Program includes gas transmission and distribution infrastructure replacement projects, which are required due to civic improvement activities initiated by federal, state, or local governmental units. 2 TR 55; 4 TR 1252. These relocation projects are either based on individual customer requests or due to Company-initiated relocation of facilities. The Company’s projections are based upon recent history, projections of increased federal and state funding for infrastructure improvements, and knowledge of specific projects planned for the next several years. 2 TR 55; 4 TR 1254.

The PFD adopted a recommendation to disallow historic costs associated with two projects – Atlas Iron Belle Trail and the 9 Mile Road. This recommendation is based on the claim that the cost overruns for these projects “**could** be caused by the company’s own poor management.” PFD, page 45 (emphasis added). This recommendation is unsupported by the record, as there is no evidence in this case to support the claim that the increase in costs is due to poor Company management. Moreover, the proposed disallowance is related to work already undertaken and projects being used for the benefit of customers. The Iron Belle Trail project, in Detroit, provides bicycling and hiking opportunities on trails that extend more than 2,000 miles from the western tip

of Michigan's Upper Peninsula to Belle Isle in Detroit. 2 TR 59. At the time the Company filed this case, the project was 71% complete. The cost of this project increased due to the initial estimate for the project being lower than the actual scope of work that was needed. Exhibit AB-5, page 6. In the City of Eastpointe, the 9 Mile Road reconstruction and water infrastructure project has also already commenced. The project will include the addition of green space, benches, bike paths, and other enhancements that will make 9 Mile Road more pedestrian and bicycle friendly. 2 TR 59. The cost of this project increased due to heavy concrete restoration work that resulted in additional project cost. Exhibit AB-5, page 6. The Company explained these cost variances in the 2023 Gas Enhanced Infrastructure Replacement Program ("EIRP") - Annual Performance Report, Attachment 9 and in Exhibit AB-5.

Replacing utility infrastructure when undergoing a civic improvement project is complex. This work involves coordination of work scope and schedules with municipal project administrators and construction crews who may have project requirements that are specific to the local community. 2 TR 123. The Company rarely has complete information about the civic improvement projects when developing the project estimate at the time the annual budget projections were created. 2 TR 123. Large civic improvement project estimates used for the Company's 2023 budget were not intended to be precise estimates. 2 TR 123. The Company understands that there are variances within these projects. But, even still, the Company's actual 2023 Civic Improvement expenditures of \$83.5 million is only slightly higher than the 2019 to 2023 annual average Civic Improvement capital expenditure of \$81.6 million. 2 TR 123. This supports the fact that the Company reasonably managed its Civil Improvement projects in 2023.

The PFD's recommendation is unsupported by the evidence, does not reflect the nature of this completed work, and should be rejected.

c. Regulatory Compliance

i. Transmission Regulatory Compliance

(a.) Pipeline Integrity – TOD

Under the Pipeline Integrity – Transmission Operated by Distribution (“TOD”) Program, the Company performs assessments of TOD pipelines. These pipeline segments are operated on the distribution system above 20% Specified Minimum Yield Strength and thus are covered under the transmission regulations. 4 TR 1267. The assessments that occurred under this program include inspection digs for External Corrosion Direct Assessment, inspection digs for Internal Corrosion Threat Evaluation, or Internal Corrosion Direct Assessment (“ICDA”). *Id.* Included in the Pipeline Integrity –TOD Program are costs associated with the Risk Mitigation Program and the Casing Assessment Program. The Pipeline Integrity – TOD Program capital expenditures are projected to be \$6,119,000 in 2024, \$5,593,000 for the 10 months ending October 31, 2025, and \$9,998,000 for the 12 months ending October 31, 2026. Exhibit A-60 (MPG-4), line 2.

The PFD recommended removing \$2 million related to two casings projects in the projected test year. PFD, page 48. The PFD reasoned that removal of these projects is appropriate because these projects are premature for approval because they are too uncertain in their cost and their timeframe for completion. *Id.* This is incorrect. The Company has assessed casings on the system since the requirement when into effect in 2004. 4 TR 1302. Based on these previous assessments, the Company developed its projected amounts. Company witness Michael P. Griffin explained that “[t]he level of planning and cost to accomplish four examinations is complex and expensive. In order to levelize work and cost, the projects are spread across two years. To assess the casings within the system, the Company surveyed and tested them in 2023. The data is then analyzed, and four casings were selected in 2024 for examination in 2025 and 2026.” 4 TR 1302. For the casings within the Company’s system to be considered assessed, the 2025 and 2026 work

must be completed within seven years of the prior assessment. These projects are on track and following the normal cadence to meet the code requirements. Accordingly, the Company requests recovery of these required projects.

The PFD also recommended removal of \$2.953 million for risk mitigation projects contending that tripling the number of miles remediated from 2025 to 2026, at a significant cost increase, appears excessive. PFD, page 49. The Risk Mitigation Program expenditures are related to work pertaining to assessing and remediating non-high consequence areas (“HCA”) pipe. The Company is ramping up the mileage and costs for this program. This would allow the Company to secure the necessary resources to complete more mileage in a single year. 4 TR 1303. This is being done to align the non-HCA assessments with the HCA assessments, which will provide the Company with a better understanding of the cathodic protection of the pipe and allow the Company to address deficiencies in the cathodic protection system more holistically. 4 TR 1303. Therefore, the proposed test year reduction related to the Risk Mitigation Program should be rejected.

(b.) MAOP Project Expenditures

The Maximum Allowable Operating Pressure (“MAOP”) Compliance Pipeline Program involves MAOP verification and remediation of the Company’s transmission pipeline, including TOD pipelines. 4 TR 1272. This work initially began in 2012, in response to the Pipeline Safety, Regulatory, Certainty, and Job Creation Act of 2011, which required the Pipeline and Hazardous Materials Safety Administration (“PHMSA”) to instruct owners or operators of a gas transmission pipeline to provide verification that their records accurately reflect a pipeline’s MAOP. 4 TR 1272. On October 1, 2019, PHMSA published the Safety of Gas Transmission Pipelines Rule which codifies the MAOP requirement and establishes the need for documentation to meet the traceable, verifiable, and complete (“TVC”) criteria and specifies the manner in which this standard can be met.

The PFD recommended disallowing \$2.564 million in capital expenditures for currently unknown MAOP transmission projects that are unspecified. PFD, page 58. This recommendation fails to recognize how projects are identified under this program. The Company's MAOP projections are based on previously completed work orders of similar magnitude and requirements. The projects planned for 2024 include the retirement of drain piping at the Mt. Clemens City Gate on Line 1060, and capital projects planned for 2025 include the replacement of valves and piping at Metamora City Gate on Line 1900. 4 TR 1274. Future projects will be identified based on the Standardized Engineering Analysis. Company witness Griffin explained that:

...[t]he analysis will determine where work is required to meet the traceable, verifiable, and complete criteria, and upgrade the documentation archiving from a historical perspective to a newly developed engineering content management database integrated with the Company's geospatial information system database. The record database will link record files to the data mined from those records and entered into the geospatial information database for MAOP calculation from those design and testing values. For each transmission pipeline segment identified as not meeting the record criteria established by the newly published rule, the Company will address these segments through an engineering evaluation that will consider the six regulatory methods of MAOP Reconfirmation identified in 49 CFR 192.624 in conjunction with a solution that provides benefits in regard to pipeline safety, reliability, and deliverability. [4 TR 1272-1273.]

Thus, these costs are reasonable and should be approved by the Commission.

d. Material Condition Program

i. Material Condition Non-Modeled Program

(a.) High Pressure Waterway Crossings Project

On April 25, 2023, approximately 4,500 Consumers Energy customers experienced a natural gas service interruption around Hastings, Michigan as the result of a high pressure ("HP") distribution gas main that broke where the pipeline crossed the Thornapple River. 3 TR 405. Although this pipeline was originally designed and installed consistent with the standards at that

time, the flow of the river appears to have caused the pipeline to be elevated in the waterway, with about 1.5 to 2 feet of open water between the pipe and the riverbed. *Id.* This allowed debris and water flow to put unintended structural stress on the pipeline, which led to an overload condition during flooding and caused a failure. *Id.*

Consumers Energy performed an evaluation of the distribution system's GIS mapping overlaid with hydrologic data and identified 442 potential HP water crossings. 3 TR 405. The Company further evaluated these crossings by reviewing records and performing field visits. 3 TR 406. Through this process, the Company identified 15 pipe segments as exposed or visible in a flowing waterway. 3 TR 406. Accordingly, the Company developed a plan to remediate these exposed pipelines from 2025 through 2027. The projected capital expenditures for these projects are \$2.5 million in 2025 for three projects, \$5 million in 2026 for eight projects, and \$5 million in 2027 for three projects. This amounts to a projected \$2 million for the 10 months ending October 31, 2026 and \$5 million in the test year. See Exhibit AG-10, page 7.

Even though the PFD stated that it "does not object to the necessity of these projects," the PFD adopted the Attorney General's recommended reduction in capital expenditures in the amount of \$500,000 in the 10 months ending October 2025 and \$5 million in the test year because these projects were still in the "scoping" phase. PFD, page 63. The Commission should reject this recommendation because these projects are important to mitigate risk and are in no way premature.

These HP water crossing projects are important to mitigate the risk of HP distribution gas mains breaking in the future because of being exposed in waterways. Company witness Kristine A. Pascarello testified that the test year HP waterway crossings projects are progressing through the design process during 2025 and are following the Company's standard cadence before construction planned in 2026. 3 TR 449. Consumers Energy fully intends to complete the projects

that were presented in the case. See Exhibit AG-10, page 7. While some of these projects were in the “scoping” phase as of an April 7, 2025 discovery response (see Exhibit AG-10, pages 6 and 7), there is no evidence indicating that the projects will not be completed as planned. The Commission should approve the Company’s requested funding for these critical projects so that the Company can move forward with removing the risk associated with the exposure of these pipes.

ii. EIRP

The purpose of the EIRP is to replace all the Company’s highest risk mains, as classified by PHMSA, with more reliable and lower maintenance mains, and includes the replacement of associated older metallic services. 3 TR 383. Consumers Energy implemented the EIRP beginning in 2012 to ensure continued customer safety and reliable system operation. 3 TR 383. Under the EIRP, the Company replaces the highest risk materials (including cast iron, wrought iron, threaded and coupled (“T&C”), oxyacetylene welded, copper, and bare steel distribution main) with lower maintenance and more reliable plastic and steel main. 3 TR 383. The EIRP also replaces older metallic services or ties-over plastic services to the new main. *Id.* The EIRP also includes replacement of around 100 miles of transmission pipelines operated on the distribution system, 70 miles of low frequency electric resistance weld pipe in transmission and storage fields, and 105 miles of standard pressure pipe that is not covered in the vintage main miles. 3 TR 383.

Along with safety and reliability improvements, replacement of cast iron piping will enable the eventual elimination of the standard pressure system, which allows these areas to operate at more efficient pressures, lowers gas losses, reduces potential for water infiltration, and reduces greenhouse gas emissions. 3 TR 383-384. This work also allows for the elimination of certain regulating stations, lowering operating costs for those systems. 3 TR 384. Through 2023, the

Company retired 794 miles of vintage pipe to improve reliability and safety through the EIRP, including 286.7 miles of cast iron main, 286.3 miles of bare steel main, and 148.8 miles of T&C main. 3 TR 384-385. The EIRP is planned to be completed by the end of 2035, reducing the remaining vintage main miles by approximately 5% per year. 3 TR 385. The Company is forecasting installation of 149 miles of main and 9,175 associated services in the test year, with projected capital expenditures of approximately \$251 million. 3 TR 395-397, 438.

The PFD adopted the Attorney General's recommendation to reduce projected test year EIRP capital expenditures by \$84.889 million for seven projects scheduled to be completed in 2026 because the Company stated in a March 10, 2025 discovery response that design had not yet started for the projects. PFD, page 77; Exhibit AG-8. The Commission should reject this recommended reduction. Company witness Pascarello testified that these seven EIRP projects are progressing through the design process in 2025 and are all on schedule for construction in 2026. 3 TR 444. All seven of these projects are on track consistent with the standard engineering cadence before construction, including completing tasks such as order creation, design commencement, environmental review, ordering long lead-time materials, coordinating with gas control to determine optimal timing for project execution, and finalizing the construction schedule. 3 TR 444-445.

All seven of these projects are on track for construction in the test year, and no evidence suggests that these projects will not be constructed as planned. All seven of these projects also represent individual phases of larger EIRP projects, and if these phases are not constructed as planned, it could negatively impact the larger project and construction sequencing because each phase is typically designed to build on the previous one. 3 TR 445. If essential phases are skipped,

it can introduce new risks or exacerbate existing risks within the remaining vintage pipe, result in project delays, and waste resources in permitting, planning, and initiating each phase. *Id.*

The evidence does not support a claim that the Company is unlikely to perform these projects or is unlikely to complete the projected replacement miles at the projected costs. Rather, the most recently completed gas rate case test year shows that the Company completed more miles than agreed to at a slightly lower cost. In the Settlement Agreement in Case No. U-21308, the Company agreed that it would achieve a minimum of 110.8 installed miles in the EIRP at a cost of \$214 million for the 12 months ending September 30, 2024. 3 TR 398. The Company actually completed more miles – 126.1 miles – at a cost of \$203.6 million. *Id.*

The Commission should approve the entirety of the Company's projected EIRP funding, including the funding for these seven projects. The projects are on track for completion as planned, and Commission approval will allow the Company to move forward with these projects and avoid the risks of the remaining vintage pipe associated with the projects. 3 TR 445-446.

The PFD also recommended that if the Commission rejects the \$84.889 million reduction for the seven projects discussed above, the Commission should cap the test year EIRP expenditures at \$197 million as recommended by the Attorney General, stating that the resulting extension of the program is worth the reduced expenditures. PFD, pages 78-79. The Commission should reject this proposed test year spending cap, which would slow the pace of both the replacement of the at-risk pipe and the associated safety and reliability improvements.

The Company still has more than 1,400 miles of vintage mains, many of which were installed in the 1950s or earlier. 3 TR 443-444. At around 75 years and older, this pipe has reached the end of its useful life, and continuing prolonged use increases the likelihood of incidents as the pipe continues to deteriorate. Exhibit AG-9, page 1. Consumers Energy continues to experience

emergent incidents on this type of pipe, including two in early 2024 while EIRP crews were replacing pipe in other parts of the grid. Exhibit AG-9, page 1. In January 2024, water infiltrated a 4-inch cast iron main on the standard pressure system, and the water froze and blocked the flow of gas to customers. *Id.* In February 2024, a leak occurred in another section of this grid, requiring the Company to cut out the section of leaking pipe. *Id.* Also see Exhibit AG-9, pages 3-4, for more examples of historical incidents involving deteriorated pipe, leaks, and water infiltration. As these incidents illustrate, vintage mains are more susceptible to leaks, breaks, and other failures because of material degradation and outdated manufacturing practices. 3 TR 444.

According to PHMSA data from 2005 through 2024, 38% of cast/wrought iron main incidents caused a fatality or injury compared to only 19% of incidents on other types of mains, and 33% of all fatalities and 15% of all injuries on gas distribution mains involved cast or wrought iron pipelines. See Exhibit MEC-46, pages 2-3. The continued aging of vintage mains supports the Company's proactive replacement strategy to mitigate potential hazards and ensure the long-term integrity of the gas distribution system. 3 TR 444.

The Company expects to have retired approximately 51% of vintage mains by 2025 and is planning to reduce vintage mains by another 5% annually through 2035. See 3 TR 385, Figure 1. The Company's proposal mitigates risks associated with aging infrastructure, ensures compliance with modern safety standards, prevents hazardous incidents, and reduces maintenance costs. 3 TR 443. While the PFD expressed concern with "continuously increasing" spending, it is important to note that although the projected test year spending is 38% higher than 2023 levels, there is also a 37% increase in the number of projected miles from 108.9 in 2023 to 149 in the test year. 3 TR 446. In addition, the Company continues to look for EIRP cost reduction opportunities,

which resulted in the 2024 actual plastic pipeline cost per mile to be \$216,500 less than the 2023 cost per mile. 3 TR 443.

The PFD stated that “by the company’s own estimation, this [\$197 million] cap would only extend the estimated completion date for the EIRP program by three to five years.” PFD, page 78. The PFD’s statement does not accurately reflect the Company’s position. The additional 3 to 5 years that the Company indicated would need to be added to the EIRP in discovery was based on the same pipe replacement pace as in 2023, not the same capital expenditure level as 2023. See Exhibit AG-9, page 5. As Company witness Pascarello testified, Consumers Energy will increasingly need to use higher-cost segment projects to replace vintage main distribution pipe in areas where the Company only has a small amount of EIRP pipe to replace, including projects selected based on risk and replacement of HP steel and TOD pipe. 3 TR 392-393. And costs per mile for EIRP distribution projects are influenced by several factors, including location, number of associated services, pipe type, pipe size, permitting requirements, time of year, and standard pressure conversions. 3 TR 389-392. For example, the 2026 projected cost for steel projects is \$3.91 million per mile compared to the \$1.4 million per mile cost for plastic pipe installation. 3 TR 470. Thus, it would be incorrect to assume that the same amount of pipe replaced in 2023 can be replaced at the same cost plus inflation for the remainder of the program.

The Commission should reject the PFD’s recommendation to replace this high-risk vintage pipe at a slower pace. Reducing projected expenditures hinders EIRP progress and extends the timeline for removal of outdated and leak-prone pipes. 3 TR 470-471. The Company’s proposed expenditures are needed to meet the annual installed mileage required to timely complete the program. 3 TR 470. The Commission should reject the proposed reduction in expenditures and

should instead approve the Company's proposed expenditures to support the replacement of vintage material pipe under the EIRP by 2035.

The PFD also recommended that the Commission should direct the Company "to include risk-ranking information and a narrative description regarding the use of risk-ranking when selecting remediation for a particular project." PFD, page 79. The Commission should reject the PFD's recommendation because this additional reporting requirement is unnecessary. Consumers Energy already provides risk ranking information in both the EIRP Planning Report and the EIRP Performance Report by project, which the Company files annually. 3 TR 468-469. See, for example, the EIRP 2024 Performance Report filed on April 30, 2025 in Case No. U-21490, and the EIRP 2025 Planning Report filed on December 30, 2024 in Case No. U-21490. No additional EIRP reporting should be required.

iii. VSR

Under the Vintage Service Replacement ("VSR") Program, the Company replaces all copper and bare steel vintage service materials, and services where the material type is unknown, not otherwise replaced under the EIRP, Material Condition Renewals, Material Condition Non-Modeled, and Asset Relocation programs. 3 TR 414. These vintage service materials have a higher corrosion leak rate than current materials, and the Company targets the services with the highest potential for future leaks for replacement. 3 TR 414-415. As of the end of 2023, the Company had removed approximately 69,000 vintage services, and at the start of 2024, there were 112,157 vintage services remaining. 3 TR 418. In the VSR Program, the Company plans to replace 4,194 vintage services in 2025 and 5,913 vintage services in 2026. 3 TR 419.

The PFD adopted the Attorney General's recommendation to reduce the number of vintage services to be replaced in the VSR Program to the 2,564 services that the Company replaced in 2024, resulting in a capital expenditure reduction of \$11.631 million in the bridge period and

\$23.875 million in the test year. PFD, page 82. The PFD stated that the Company’s “projected 130% increase of services to be replaced appears to be somewhat ambitious.” *Id.* The Commission should reject the PFD’s recommendation.

The Company’s projected increase in the number of vintage services to be replaced in the VSR Program corresponds to the reduction in vintage services that will be replaced in the EIRP because of fewer large grid projects, which means fewer vintage services designed and constructed with EIRP projects. 3 TR 454. So, while it is correct that the Company is projecting more replacements under the VSR program compared with 2022 through 2024, a more apt comparison would be to the number of replacements performed prior to 2022 when the EIRP was only completing smaller segment projects. *Id.* During that time, VSR Program units ranged from 5,056 in 2021 to 9,381 in 2018, which is in line with the number of replacements the Company is projecting in this case. *Id.*

While it may appear, on a percentage basis, that the increase in the projected number of replacements for 2025 and 2026 in the VSR Program are “somewhat ambitious,” when considering total Company replacements, the planned increases are much more modest. Considering the total number of vintage services replaced in the VSR Program, the EIRP, and all other programs, the Company replaced a total of 6,877 vintage services in 2024, and is projecting to replace 7,366 in 2025 and 8,535 in 2026. Exhibit AG-11, page 2. This is represented in the following table:

	Actual 2024	Projected 2025	Projected 2026
VSR Program	2,564	4,194	5,913
EIRP/Other Programs	4,313	3,172	2,622
Total	6,877	7,366	8,535

Exhibit AG-11, page 2. Thus, for total vintage services replaced, the Company is only projecting to increase the number of replacements by about 7% in 2025 and by about 24% in 2026 when compared with 2024 – not 130%.¹

The PFD’s recommended reduction to 2,564 VSR Program replacements in 2025 and 2026 would in fact reduce the total number of vintage services replaced (including EIRP/Other Programs) compared with 2024. Based on the PFD’s recommendation, there would only be 5,736 total replacements in 2025 and 5,186 in 2026, which is about 16% and 24%² fewer total replacements of vintage services, respectively, than the total 6,877 replacements in 2024. See 3 TR 454; Exhibit AG-11, page 2. The Commission should not adopt the PFD’s recommendation that would reduce the replacement of vintage services to below 2024 levels and leave outdated and leak-prone services in use longer than necessary. Instead, the Commission should approve the Company’s proposed expenditures to continue to eliminate the highest risk services on the Company’s distribution system, thereby increasing safety, reducing future gas leaks, and reducing greenhouse gas emissions. See 3 TR 418, 472.

e. Capacity/Deliverability Program

i. Transmission Capacity/Deliverability Program

(a.) Deliverability Base Field Measurement Program

The Deliverability Base Field Measurement Program is essential to ensure accurate gas quality and measurement. 4 TR 1286. The capital expenditures are projected to be \$6,774,000 in 2024, \$10,255,000 for the 10 months ending October 31, 2025, and \$19,890,000 for the 12 months ending October 31, 2026. Exhibit A-61 (MPG-5) Revised, line 3. These projects are associated with remote gas measurement equipment monitoring, gas volume calculations, gas transmission

¹ Calculated as follows: $(7,366-6,877)/6,877=0.07$ for 2025 and $(8,535-6,877)/6,877=0.24$ for 2026.

² Calculated as follows: $(6,877-5,736)/6,877=0.16$ for 2025 and $(6,877-5,186)/6,877=0.24$ for 2026.

metering, Transport Metering Stations, Interstate Interconnection sites, gas quality improvement and processing, gas sampling systems, and other ancillary equipment. 4 TR 1286. Measurement equipment upgrades also are included in this program.

The PFD recommended disallowing some of the project costs associated with this program. Specifically, the PFD indicated that the Rose Center meter replacement project (\$302,000 in 2025 bridge period and \$818,000 in the projected test year) should be removed based on the ALJ's conclusion that it is premature since no design work has started for the project and such work is scheduled to begin later in 2025. The PFD also stated that the costs associated with six projects (B-GM-00042, B-GM-00043, and B-GM-00045 through B-GM-00048) totaling \$8.369 million in the projected test year should be removed because they are too premature to include in rate base since they have no design work started and engineering and design work is not slated to start until the end of 2025 or sometime in 2026. PFD, page 86. The Commission should reject these recommendations.

The Rose Center Meter Replacement project is important as it is replacing an asset that is at the end of its useful life. The Company is replacing this asset and moving to a less maintenance intensive measurement device as not proactively addressing the age of the measurement asset could impact over/under odorization and inaccuracies in volume measurement (gains or losses in Lost and Unaccounted for calculations for the site) due to inability to change the orifice plate. 4 TR 1312. Design for this project was set to occur at the end of the second quarter in 2025. Exhibit AG-18, page 6. This project is reasonable and not premature.

The ALJ also recommended removal of the costs related to six projects that are in the early phase of development. This is unreasonable. All of these projects are progressing and have activities that are commensurate with projects that will be constructed in 2026. 4 TR 1312.

Pre-engineering work is occurring. This includes survey work, SAP order creation, design commencement, environmental reviews, real estate evaluation, scoping, and long lead-time material ordering. 4 TR 1313. Engineering costs are being accumulated. These projects are being undertaken on the Company's normal cadence. Thus, the Commission should approve the Company's reasonable costs for the Deliverability Base Field Measurement Program.

(b.) Deliverability Base Pipeline Program

The Deliverability Base Pipeline expenditures support maintaining operations in accordance with the Michigan Gas Safety Standards. Projects undertaken as part of this program include: (i) the replacement of valves when inspection determines that the valves no longer perform as needed, pursuant to Michigan Gas Safety Standards Rules 192.145, 192.150, 192.179; (ii) the replacement of piping due to MAOP revisions identified as a result of class location changes in accordance with 49 CFR 192.5 and 192.611; (iii) construction of new sectionalizing valves and tap valves to improve system deliverability and help meet valve spacing requirements as specified by 49 CFR 192.179; (iv) reconfiguration of tap piping (i.e., laterals) and associated valving upstream of city gate facilities as companion projects to city gate rebuilds; and (v) installation or retirement of pipeline taps to Transport Metering Station facilities being attached to the Company's system. 4 TR 1288-1289. Expenditures for the Deliverability Base Pipeline Program are projected to be \$18,173,000 in 2024, \$19,403,000 for the 10 months ending October 31, 2025, and \$25,023,000 for the 12 months ending October 31, 2026. Exhibit A-61 (MPG-5) Revised, line 4.

The PFD recommended removal of \$18.466 million in the projected test year related to 11 projects for which no design work has yet been initiated. This PFD maintained that these projects are premature for inclusion in rate base. PFD, page 88. This recommendation ignores the fact that these projects are progressing and have activities that are commensurate with projects that will be constructed in 2026. 4 TR 1314. Engineering costs are being accumulated for these

projects. The Company engineers primarily manage projects being constructed in the current year up until late spring when these projects start to be released for construction. Then work begins on the project for the next year, which includes pre-engineering work, design commencement, environmental reviews, alignment with gas control, and long lead-time material ordering. 4 TR 1314. This is the normal project cadence. Thus, the Commission should approve the Company's reasonable costs for the Deliverability Base Pipeline Program.

(c.) **TED-I - RCVs**

The projects in the Transmission Enhancement for Deliverability and Integrity ("TED-I") Program are for the purpose of maintaining deliverability and integrity, and improving the ability to control gas flows. 4 TR 1278. Major projects include replacing transmission pipeline segments that contain higher-risk type pipe to ensure integrity and safe operation. City gates can be upgraded under this program to enable abandonment of a pipeline or to reduce pressures on pipeline segments to comply with any new MAOP requirements of replacement pipelines. 4 TR 1279. The TED-I Program also includes the installation of Remote Control Valves ("RCVs") and Pressure-Limiting Devices ("PLDs") to control pressure and flows during normal operations and in the event of abnormal operation. 4 TR 1279. The TED-I Program capital expenditures are projected to be \$146,790,000 in 2024; \$20,192,000 for the 10 months ending October 31, 2025; and \$19,145,000 for the 12 months ending October 31, 2026. Exhibit A-61 (MPG-5) Revised, line 1.

The PFD recommended disallowing \$14.145 million in the projected test year related to seven RCV projects that are still in the planning and scoping project phase. PFD, page 92. This finding ignores that these projects are in the normal phase for projects that will be constructed in the following year. 4 TR 1318. Company witness Griffin described the normal project process for RCVs. He stated that:

The project process for RCVs is the following. The creation of the project scope documents, and potential surveying and material selection typically occur the year prior to construction (in 2025 in this case). The year of construction (2026) includes site survey work not completed in the prior year, the receipt of materials, the engineering and design work, release of design packages, contractor bidding and selection, and finally construction and project closeout. [4 TR 1318.]

These projects are following the normal cadence for RCV projects and are thus not premature to be included in rate base. The PFD's proposed reduction to the RCV Program should be rejected by the Commission.

f. Gas Operations Other Program

i. Compliance and Controls

(a.) Enterprise Corrective Action Program

Consumers Energy initiated the Enterprise Corrective Action Program ("ECAP") in 2020. The ECAP is an issue management and compliance program that supports safe and excellent operations by focusing risk reduction efforts, informing operational business decisions, and promoting the integrity and deliverability of the energy infrastructure. 3 TR 428. ECAP provides customer benefits such as resolving non-confirming conditions, reducing customer concerns, promoting continuous improvement, and standardizing problem-solving methods. 3 TR 456. The PFD recommended disallowances of \$49,000 in 2023, \$204,000 in 2024, \$167,000 in the 10 months ending October 2025, and \$33,000 in the projected test year based on the PFD's conclusion that the program had not been adequately explained or justified. PFD, page 94. The Commission should reject this recommended reduction in funding for the ECAP because it improves Company processes to reduce risks and ensure Company compliance with regulatory requirements.

The ECAP developed a standard platform and methodology to enable the Company to identify compliance or safety issues and trends, and to address any identified concerns by implementing corrective actions and controls. 3 TR 428. This common process and technology fully integrates corrective and preventive action (“CAPA”) management. 3 TR 361. The Company uses CAPA as a fundamental tool to support the elimination or prevention of compliance issues through a strong problem-solving structure. *Id.* The CAPA system collects and analyzes incident information and manages the timely implementation of all CAPAs after problem solving. Exhibit AG-13. The ECAP organization then confirms that the corrective and preventative actions are effective to reduce the potential for repeat issues. *Id.* Examples of where this standard process has been used to address issues and support improvements include the areas of regulatory compliance, failure investigations, and damage prevention. *Id.*

The Company is implementing ECAP in phases, with Phase 1 beginning in 2022. In Phase 1, ECAP’s functionality was used to support Gas Operations, Engineering, and Regulatory’s adherence to Gas Safety Management System standards established in American Petroleum Institute Recommended Practice (“API RP”) 1173. 3 TR 429. Phases 2 and 3 implemented the program for the electric operations and supply side of the business. *Id.* Phase 4 extends the ECAP to Corporate Safety & Health and Environmental in 2025, which is expected to contribute to cost savings through a reduction in lost time and expense. 3 TR 457. The 2023 through 2025 ECAP expenditures involve developing the statement of work execution for Phase 4, ECAP platform modifications to support Phase 4, and closing out the project. 3 TR 429.

The Commission should support the Company’s efforts to improve its identification of compliance or safety issues and implementation of corrective actions and controls, and approve

funding of this structured ECAP platform that supports issue management and compliance within the Company.

(b.) Advanced Methane Detection

The Advanced Methane Detection (“AMD”) project updates the Company’s leak detection technology. AMD can detect methane leaks with exceptional precision, with devices able to detect methane in parts per billion instead of traditional leak detection equipment that measures methane in parts per million. 3 TR 421. This technology allows for identification of the smallest leaks, can measure the rate at which methane is being emitted, helps in tracking the path of methane emissions, provides precise geospatial data of potential methane indications, and provides a detailed record of methane emissions over time. 3 TR 422. These several improvements made possible through AMD contribute to improved public safety and environmental sustainability. 3 TR 423.

The PFD adopted the Attorney General’s recommendation to disallow AMD capital expenditures in the amounts of \$4.65 million in 2024, \$221,000 for the 10 months ending October 2025, and \$3.181 million in the projected test year. PFD, page 97. The PFD determined that absent a legal requirement to purchase and use AMD equipment, AMD technology does not offer additional “significant value” and the costs should not be approved at this time. *Id.* The PFD’s recommendation should be rejected because AMD technology provides significant safety and environmental benefits.

AMD offers several benefits as a powerful tool to monitor and manage methane emissions more effectively than traditional leak detection methods. 3 TR 422. AMD enables the Company to find and prioritize higher risk leaks to improve public safety. AMD improves the Company’s ability to detect and pinpoint leaks more accurately and prioritize the remediation of high-risk leaks. AMD also provides emissions rate data that allows the Company to assess and address leaks

based on their potential risk. The Company is using AMD in its Super Emitter Program, which uses risk-based prioritization and algorithms to identify the largest methane emitting leaks on the gas distribution system for investigation and escalated remediation. 3 TR 422. AMD provides for the better classification and remediation of leaks because of the heightened sensitivity. 3 TR 423. And AMD identifies and quantifies large emission sources to allow for effective targeting and remediation efforts to aid the Company in achieving net zero methane emissions. *Id.*

In the Company's experience, AMD has been seven times more effective at finding below ground leaks and 5% more effective at detecting above ground leaks compared to traditional methods. 3 TR 427. AMD also provides for more precise detection of leaks, with exact search areas that minimize the chances of human error during leak detection. *Id.* Because of these improvements, the Company can identify and repair more leaks using AMD, enhancing safety and system integrity. *Id.*

The Company is transitioning to use of AMD as the primary method for compliance leak surveys, and will continue to use AMD for emission surveys, super emitter, and pre- and post-construction surveys. 3 TR 426. The PFD stated that AMD "only supplements and does not replace existing leak detection equipment." PFD, page 97. But traditional leak detection tools do not have the capability to detect leaks from a distance or measure emission rates, and AMD technology makes leak detecting processes more efficient. See Exhibit AG-12, page 3. When a potential leak is found through AMD, the leak detection team will walk the mains and services within, and 50 feet beyond, the AMD-generated search area to investigate the potential leaks and address any leaks that are found. 3 TR 426. Thus, rather than being required to use traditional leak detection devices on all the Company's mains and services in a leak detection survey, the

Company will be able to focus its leak detection efforts to those areas identified through AMD. See Exhibit AG-12, page 8.

AMD technology provides several important safety and environmental benefits that represent a “significant value” to Consumers Energy and its customers. The Commission should approve the AMD funding to support the realization of these benefits and to enable the Company to find and repair more leaks and prioritize higher risk leaks.

2. Gas Compression and Storage Capital Expenditures

a. Lyon 29/24 (Northville Storage) Dehydration Project

The PFD recommends that the Commission disallow all of the Company’s capital investments for its Lyon 29/34 Dehydration Project at the Northville storage field dating back to 2022. The PFD offers essentially three reasons for its proposed disallowance, none of which are valid. The Commission should not adopt the recommended disallowance.

Company witness Timothy K. Joyce explained that, due to the current excess moisture problem at the Lyon 29/34 fields, the Company has not been able to utilize these fields to the fullest extent of their design specification. On peak days, the Northville site is an important additional source of natural gas supply to the metro Detroit area – a significant metro area within Consumers Energy’s service territory. 4 TR 1511. To ensure safe and reliable service to customers in this important and densely populated region, the Company needs to be able to utilize the Northville storage field when demand is high and when having adequate gas to heat people’s homes is most urgent. However, due to the moisture issues, Mr. Joyce explained that, during the coldest winter conditions in recent years, there were multiple times that water content in the gas exceeded the regulatory threshold and forced the Company to shut-in withdrawal from the field prematurely. 4 TR 1511-1512. To control the problem, the Company has been forced to operate the storage fields on a “last on, first off” basis, where the fields are limited in use and manually

controlled to avoid excess moisture entering the Company's transmission and distribution systems. 4 TR 1534-1535.

Despite Mr. Joyce's explanation of the circumstances at the Northville storage field, the ALJ concluded that "the company was able to meet peak demand in 2023 and 2024 without the use of the Northville field and was able to meet peak demand in 2022 with limited use of Northville." PFD, page 109. That is not a valid reason for the proposed disallowance. There are at least two problems with the ALJ's reasoning.

First, it implicitly relies on a couple of unsupported assumptions. It (i) assumes that the Company was able to utilize its peaking fields most efficiently and at the lowest reasonable cost in 2022, 2023, and 2024 despite the limitations on the use of the Northville storage field and (ii) fails to consider that none of the years between 2022 and 2024 included conditions severe enough to test the limits of the Company's ability to call on peaking capacity to meet customer demands. Put another way, it assumes that the Company successfully achieved all the peaking capacity coverage in 2022, 2023, and 2024 that it will ever need to meet. There is no evidence to support those assumptions. In fact, the evidence in the record undermines those incorrect assumptions.

With respect to the first assumption, Exhibit AG-22, page 14, identifies the purposes for the Lyon 29/34 dehydration project. One of the reasons for the project is that it is "[l]ess expensive than [firm transportation] contracts for equivalent pipeline deliverability." In other words, without this project, the Company will continue to require *more expensive* "equivalent pipeline deliverability" – i.e. market purchases of gas – to compensate for the inability to utilize the storage field to its full design capability. Merely observing that the Company managed to get through 2023 and 2024 without using Northville for peaking does not support the conclusion that the

current conditions are satisfactory to utilize its peaking fields most efficiently and at the lowest reasonable cost. The ALJ failed to recognize that the inability to use Northville to design specifications necessarily means using some other resource to ensure continued service. The PFD takes no account of what those alternative resources are or what they cost. Exhibit AG-22, page 14, also identifies the need for diversification of peak day supply as a reason for pursuing the dehydration project at Northville. Even if it were true that the Company's other peaking plants (plus "equivalent pipeline deliverability") sufficiently obviated the need to rely on Northville for peaking capacity in 2022, 2023, and 2024, that doesn't mean the Company can assume those other plants will be available to do so in the future. Mr. Joyce testified that the Lyon 29/34 site has been in operation for more than 22 years. 4 TR 1511. Yet, the moisture problem at the site only began to manifest a few years ago, beginning around 2018. 4 TR 1511. Just as Northville experienced new problems providing compliant gas, so might other peaking plants in Consumers Energy's portfolio. If that occurs while Northville remains unable to operate to design specifications, the Company might not be as successful in meeting peak demand in future years as it was in 2022, 2023, and 2024. The PFD's first implicit assumption is not supported by the evidence.

With respect to the second assumption, Mr. Joyce explained that the Northville dehydration project is needed for "improved system resiliency," 4 TR 1535, suggesting that the Company's overall system could be at risk of being unable to maintain service during a period of extremely high demand or system emergency absent the full design functionality of the Northville storage field. Mr. Joyce specifically pointed to the Ray Compression Station fire incident in 2019 as one such incident where Northville was needed for system resiliency. 4 TR 1534. Exhibit AG-22, page 14, shows that the project provided "[i]mmediate system pressure stabilization" during the Ray incident. Recent history with the Ray fire already proves that the conditions on the Company's

system requiring peaking capacity can be – and have been – much more severe than they were in 2022, 2023, and 2024. So, successful management of peak capacity demands in those years does not support the conclusion that Northville’s full design capacity is not really needed. The PFD’s second implicit assumption is also not supported by the evidence.

Second, the ALJ’s reasoning fails to recognize the “chicken or egg” problem with the Northville storage field. The Company cannot fully utilize the Northville storage field to its design specifications without the dehydration equipment, but the limited use of the Northville storage field is used as a reason not to support the needed investment in the dehydration equipment. That reasoning is circular and, hence, invalid. Contrary to the ALJ’s finding, Consumers Energy has been clear throughout this case that Northville will be utilized more once the dehydration project is completed and the Company is able to move compliant gas onto its system through those facilities again. 4 TR 1534-1535. The limited use of the facilities in recent years is not a valid reason for disallowing the investments needed to eliminate the limitations.

On page 109 of the PFD, the ALJ also observes that the Company has done additional testing and monitoring of the moisture content at Northville but then states that the Company “does not provide any explanation when this testing occurred or the result.” It is not clear if the ALJ offered this commentary as one of his reasons for recommending disallowance, but if so, it is also not a valid reason. The ALJ was referring to rebuttal testimony from Mr. Joyce in which he responded to the Attorney General’s false claim that the Company had not taken moisture readings at the plant since March 2021. See 4 TR 1535, responding to 4 TR 1916. In that testimony, Mr. Joyce was simply pointing out that the Company routinely tests and monitors for moisture content that exceeds the Commission’s standards of 7 lbs/MMcf and has paid special attention to the moisture content at Northville since the problems were discovered. 4 TR 1535. This testing

has occurred continuously “since recognizing the issue with moisture content exceeding the regulatory” and is done to “verify performance up to the moisture content threshold of 7 lbs/MMcf.” 4 TR 1535. The result is obviously that the plant continues to have problems exceeding the moisture threshold. That is the entire thrust of Mr. Joyce’s testimony about this project. The ALJ’s reasoning that there is some unexplained testing is not valid.

Next, the PFD claims that the Company’s alternatives to installing the dehydration equipment “were not discussed in detail in the presented testimony” and, therefore, concludes that the Company did not demonstrate the costs of the project are reasonable and prudent. PFD, page 110. Contrary to the ALJ’s claim, however, the alternatives *were* presented in this case. The ALJ has apparently overlooked the evidence. The Company’s explanation of the alternatives to the dehydration project was presented and discussed in detail in Exhibit AG-22, pages 12-28, which is the Company’s own internal review document for the project. Among other things, it includes (i) a detailed description of the alternatives considered, (ii) forecasted capital and operating and maintenance (“O&M”) costs for each option, (iii) scoring of the economic, operation, and technical value for each alternative, (iv) an assessment of project risks and opportunities, and (v) an assessment of the project’s alignment with the Company’s Natural Gas Delivery Plan. Company witness Joyce did not discuss the alternatives further in his rebuttal testimony because the Attorney General had already included sufficient record evidence in the case by presenting the Company’s analysis as an exhibit. The Attorney General admitted the exhibit for different purposes but never directly questioned or contradicted the Company’s evaluation of alternatives to the dehydration project presented in the exhibit. Because the detailed materials about the alternatives considered were present in the record, the ALJ’s reasoning that the disallowance is justified by its absence is invalid.

Finally, the Company notes that the PFD offered seemingly inconsistent recommendations related to its proposed disallowance for the Northville dehydration project. On the one hand, the PFD proposed a complete disallowance of all costs for the project dating back to 2022, meaning that it even recommends disallowing the historical costs for the project that pre-date the bridge period and test year.³ PFD, page 110. If that recommendation is adopted by the Commission, it would result in an immediate write-off and permanent loss of those historical costs. On the other hand, the PFD found that, if the Company proceeds with the project, it should “provide more robust support for cost recovery in a future rate case, which could include a more detailed explanation of alternative approaches considered and their suitability or lack thereof.” PFD, page 110. The latter recommendation is more akin to the type of finding, common in Commission cases, that the go-forward costs have not been sufficiently supported to include in rates yet, but the Commission is reserving judgment on the reasonableness of the project *overall* pending additional evidence in a future case. When the Commission adopts that type of finding, it is generally not coupled with a disallowance of any sunk costs that would lead to a write off because the Commission is only concluding that there is not justification to add *incremental* rates *yet*. Sunk costs do not add incremental rates.

Because the Company has shown that the reasons for disallowance are not valid, the Commission should reject either understanding of the PFD’s disallowance recommendation. But, if the Commission adopts the recommendation, it should not disallow any historical costs for this project, which will add nothing further to rates. It is questionable whether those costs ever added anything to rates in the first place. The Company has settled the last several rate cases in which

³ Company witness Joyce testified that the historical costs incurred so far on the Northville dehydration project are for “project engineering and design” (in 2022) and for “concluding engineering, design and securing long lead time materials” (in 2023). 4 TR 1512.

the Northville dehydration project was first presented. The settlements were black-box settlements that didn't call out specific projects as being included or excluded from the rates. So, either the historical costs for this project were included in the settlement agreement, which would mean that they were previously approved by the Commission and the historical disallowance is a violation of the previous settlements, or they were excluded from the settlements, meaning that a historical disallowance in this case would force a write-off of sunk costs that never increased rates in the first place. Either way the Commission conceives of it, a historical disallowance under these circumstances is unjust. At most, the Commission should hold back its judgment about the future costs for this project pending further evidence in a future rate case. The more appropriate decision would be to reject the PFD's recommended disallowance entirely. The project is needed and benefits customers by diversifying peak day supply, enhancing system resiliency, and allowing the Company to avoid more expensive firm transportation contracts for equivalent pipeline deliverability.

3. Gas Operations Support Capital Expenditures

a. Lansing, Kalamazoo, and Hastings Service Centers

The Company included projected bridge period and test year capital expenditures for new construction at the Lansing Service Center and Hasting Service Center, and for renovations at the Kalamazoo Service Center. See Exhibit A-69 (QAG-3). CUB witness Joshua W. Denzler recommended removal of \$14.937 million in the 22-month bridge period and \$7.199 million in the test year for the Lansing Service Center because of a lack of progress as discussed in Case No. U-21585. 4 TR 2477-2478. For the same reason, Mr. Denzler also recommended removing \$114,000 in the 22-month bridge period for the Hastings Service Center. 4 TR 2478-2479. Consumers Energy agreed that it would not oppose these recommended reductions based on the Commission's determination in Case No. U-21585, except that the Commission should approve

the actual 2024 capital expenditures of \$1.817 million for the Lansing Service Center and \$95,000 for the Hastings Service Center because they are dollars that were actually spent on the projects and show progress that was actually made in 2024. 4 TR 1468-1469.

The PFD recommended a full disallowance of Lansing Service Center and Hastings Service Center costs, including those actually spent in 2024, because of the PFD's finding that the Company did not "adequately support those actual 2024 costs and instead relies on a discovery response that does not appear to have been admitted into evidence." PFD, page 123. The PFD's characterization of the record support for the actual 2024 costs is incomplete. While Company witness Quentin A. Guinn's rebuttal testimony identified a discovery response where the Company had provided 2024 actual amounts to the parties, there was no need for that response to have been admitted into evidence because Mr. Guinn himself testified that the Company actually spent \$1.817 million for the Lansing Service Center and \$95,000 for the Hastings Service Center in 2024. See 4 TR 1468-1469. Thus, the Company is not relying on a discovery response that is not in the record, but is relying on uncontroverted testimony stating the actual amount spent in 2024 for these service center projects. Nothing in the record calls into question the accuracy of these amounts, and the PFD's suggestion that the record does not support these actual amounts must be rejected.

In Case No. U-21585, the Commission removed Hastings Service Center bridge period projections due to the "slow pace" of the project and the "uncertainty of costs going forward." MPSC Case No. U-21585, March 21, 2025 Order ("U-21585 Order"), page 176. Similarly, for the Lansing Service Center Project, the Commission removed bridge period and test year expenditures because of concerns with the Company's lack of progress. *Id.* at 173-174. In Case No. U-21585, the bridge period included all of 2024 and the first two months of 2025, and

the record closed in that case prior to the end of 2024 and before 2024 actual spending was complete. See U-21585 Order, pages 3, 5. In this case, the Company presented 2024 actual spending, and there is no “uncertainty” surrounding those costs. Since the Company actually spent \$1,817,000 in 2024 on the Lansing Service Center and \$95,000 in 2024 on the Hastings Service Center, the Commission should approve those actual amounts.

CUB witness Denzler also originally argued that the Kalamazoo Service Center is being overbuilt by 40% and recommended a 40% disallowance of project costs. 4 TR 2479-2480. The Company explained that the Company is renovating an existing facility at the Kalamazoo Service Center and is not adding space to the existing facility. While it would be possible to reduce the size of the facility by demolishing a portion of the building, that would only increase the cost of the project. 4 TR 1470. In its Initial Brief, MNSC abandoned its argument that there should be a 40% reduction in Kalamazoo Service Center costs, and instead argued for the first time that the Commission should remove Kalamazoo Service Center bridge period and test year costs for the same reason as Mr. Denzler recommended removing the Hastings Service Center and Lansing Service Center costs. MNSC’s Initial Brief, page 69.

The PFD recommended that the Commission adopt MNSC’s proposed removal of Kalamazoo Service Center bridge period and test year costs. The PFD stated that the Company is not prejudiced by this reduction, even though MNSC first argued it in briefing, because the recommendation relies on Case No. U-21585 and is based on the same rationale as the other service center cost reductions. PFD, page 123. The PFD’s recommendation should be rejected. MEC’s recommendation to completely remove Kalamazoo Service Center costs was made for the first time in MNSC’s Initial Brief, and must be rejected because it is not based on any record evidence. See MCL 24.285. While the proposal relies on the same reasoning as the reductions for

the Lansing Service Center and Hastings Service Center, that does not mean that the Company's evidence would have been the same if the Company had the opportunity to respond to MNSC's proposal for the Kalamazoo Service Center. MNSC's proposal made for the first time in its Initial Brief raises serious due process concerns because the Company did not have the opportunity to present evidence to address or challenge this recommendation.

Even if the Commission agrees that there should be a reduction in Kalamazoo Service Center costs, which it should not, the 2024 projected capital expenditures of \$3.358 million (see Exhibit A-69 (QAG-3)) should at a minimum be approved for the same reasons discussed above regarding the Hastings Service Center and Lansing Service Center. The PFD disagreed with this alternative proposal, stating that "it would be premature to approve Consumers' *projected* 2024 costs for the Kalamazoo project." PFD, page 123 (emphasis in original). The PFD's finding highlights the prejudice the Company is facing in being unable to present evidence to respond to the recommended Kalamazoo Service Center reduction.

Unlike for the Lansing and Hastings service center projects, the Company did not (and had no reason to) offer rebuttal testimony stating the actual 2024 expenditures for the Kalamazoo Service Center project. The Company cannot now be penalized for failing to offer evidence to address an argument that MNSC made for the first time in briefing. If the Commission determines that a removal of Kalamazoo Service Center project costs is warranted, to avoid undue prejudice to the Company arising from the inability to address MNSC's argument in evidence, the Commission should approve the \$3.358 million of 2024 projected Kalamazoo Service Center capital expenditures that were identified in the record.

4. IT and Security Capital Expenditures

a. Customer IT Expenditures

i. Product Family Enhancements Customer Projects

(a.) Web Chat AI

The Web Chat AI tool is an alternative tool to calling a service center. 4 TR 1123-1124. Chat functionality engages and allows the customer to chat with an AI tool to find answers to questions or concerns. Exhibit S-11.10. This is an added functionality that differs from chat tools that allow customers to chat with a person. The tool will be able to rapidly respond to customer inquiries with specific information related to the customer's unique situation. 4 TR 1124.

The PFD recommends a disallowance of \$180,565 in capital expenditures for the test year and disallowance of \$14,929 in O&M expense associated with the Web Chat AI tool. PFD, page 180. The PFD finds the tool to be redundant and claims it provides basic information that should be available on the website. PFD, page 179. The PFD also argues that the Company could make the same information available through its website at a lower cost. PFD, page 180. This aligns with Staff's belief that a "comprehensive frequently asked questions page" could provide the same answers. PFD, page 179.

An AI chat tool is not the same thing as a frequently asked questions page, but an experience that more closely simulates speaking with a Company employee. An AI chat tool can quickly retrieve relevant information tied to specific customer inquiries. It goes far beyond merely making information available and would allow customers to resolve specific inquiries without searching through common inquiries that may or may not be directly relevant to their situation. 4 TR 1124.

Further, the PFD is incorrect in stating there is a lack of evidence of customer interest. PFD, page 179. The Company supported evidence for three tools (Click to Chat, Web Chat AI,

and Self-Service Mobile App) noting that all three digital tools are “based on industry research that supported customer desire for chat-based applications” showing that “live chat has become the leading digital contact method for online customers with 42% of customers preferring live chat compared to just 23% for email.” 4 TR 1121. The Web Chat AI mimics a live chat without the need for a Company employee to be involved in the transaction. Therefore, the Commission should disregard the PFD’s incorrect assertion regarding the Web Chat AI tool and approve the related costs.

(b.) Mobile Application

The Mobile App is an alternative communication channel that offers an additional option to meet customer needs. 4 TR 1125. The popularity of the Mobile App has continued to increase over the years and exceeds desktop web page use. *Id.* The Mobile App is not a carbon copy of the website and has a separate functionality from the Company’s website. *Id.* Adoption statistics for the Mobile App show customers prefer to perform more complex interactions in the Mobile App and functionality should be expanded in response. *Id.*

The PFD recommends a modified version of Staff’s alternative to a full disallowance and recommends a disallowance of \$498,727 of capital expenditures in the bridge period and \$649,770 of capital expenditures in the test year, as well as \$6,510 of O&M expenses.⁴ PFD, pages 180-184. The PFDs recommendation is tied to emergent work and mistakenly follows Staff’s argument tying the majority of spending to emergent work which is not supported in the record.

A thorough review of Staff’s own Exhibit S-11.19 and Staff Exhibit S-11.9 show that the amount requested related to emergent needs is tied to enhancements that the Company quantified in Staff Exhibit S-11.9, yet the PFD proposes a full disallowance related to the proposed

⁴ The PFD notes that the modified amounts are based on the Company’s analysis at 4 TR 765.

enhancements ignoring the costs that were supported in the audit response. Staff's disallowance is not based on the entirety of the Company's audit responses as the PFD posits but based on a fraction of what the money is requested for. The PFD states "Staff's disallowance is based on the company's audit responses, which provide inadequate information to distinguish between costs based on emergent needs and all other costs." PFD, pages 183-184. This is simply not true, Staff Exhibit S-11.9 explains the costs of the enhancements apart from emergent work listed in Staff Exhibit S-11.19 and shows at a minimum that enhancements planned in 2025 will cost around \$213,410, and \$305,185 in 2026. The PFD noted that two enhancements had unspecified costs but proceeded to ignore the five others that had specified costs. PFD, page 183.

As the Company stated in brief, the recommended disallowance ties some spending to emergent needs but ignores the costs that were explicitly supported. While the Company believes full cost recovery should be allowed related to the Mobile App enhancements, the Commission should at least grant recovery for the costs that were explicitly supported on the record.

b. Gas and Electric and Gas Shared IT Expenditures

i. Gas SCADA Software Solution

The Company's current Gas Supervisory Control and Data Acquisition ("SCADA") software solution was originally implemented in 2000, but the gas system has outgrown the current capabilities. 4 TR 673. As the system ages, increased effort is required to address obsolete application and database software architecture, and enhancements to the system are limited. The Company has developed custom interim fixes, but each requires maintenance and support, which adds complexity and cost to solution upgrades and troubleshooting issues. *Id.* The current Gas SCADA solution also limits the ability of the Company to pursue digital solutions for increased system health monitoring and preventive maintenance capabilities. *Id.* The Gas SCADA Software Solution results in several benefits, including (i) reducing risk of non-compliance and improving

customer safety, (ii) improving efficiency and reliability of routine software upgrades, (iii) reducing maintenance costs, (iv) improving Gas Control management capabilities, (v) improving reliability by using a standardized software with configuration features, and (vi) avoiding multiple customer applications and specially coded programs. 4 TR 673.

The Company had projected total Gas SCADA Software Solution costs to be \$11.491 million in Case No. U-21490, but updated that projection to \$18.016 million in this case. 4 TR 675-677. The PFD accepted MNSC's argument that the Company should be held to its \$11.491 million projection in Case No. U-21490, and thus recommended a disallowance of capital expenditures in the amount of \$6,524,840. PFD, page 143. The Commission should reject this disallowance in capital expenditures because the Company fully supported the reasonableness of the increased project costs.

The Company refined the initial Gas SCADA projections as the project progressed through investment planning and subsequent project stages in 2022 and 2023. 4 TR 677. As with all projects, the Company performed the preliminary project stage activities to ensure the Company is making prudent technology investments. 4 TR 781. But IT investment forecasts can evolve and can result in project execution at costs that are lower or higher than initially estimated. *Id.* In the Project Management Body of Knowledge ("PMBOK"), rough order of magnitude ("ROM") estimated projects could end up costing between 25% less to 75% more than the initial estimate. *Id.* The approximate 57% increase in the projected costs of this project (from \$11.491 million to \$18.016 million) is within that PMBOK expectation.

Consumers Energy fully explained the reason for the additional \$6.6 million required for the project. The Company experienced a \$4.4 million increase in contractor costs, a \$1.75 million increase in software costs, and a \$0.46 million increase in materials. 4 TR 678. Contractor costs

increased because the Company determined that a third party needed to support internal resources with testing since the technology was new to the Company, and the original ROM estimate for vendor professional services was less than the actual cost. The software licensing costs increased because the ROM estimate planned for five years, but six years will be required due to the length of implementation. The material cost increased because of the Company's decision to use virtual servers that provide cost efficiency and more flexibility. *Id.*

The Gas SCADA Software Solution project scope includes the following: (1) significant planning, including consulting assistance, to define the implementation given the magnitude of the technology effort; (2) selection and implementation of a new software solution; (3) planning a phased rollout of new hardware and software; and (4) retirement and decommissioning of the legacy gas SCADA solution and equipment. Exhibit A-20 (SHB-5), page 12, line 171. The current legacy system is operating well beyond its original design specification, and if the SCADA project is not completed, the legacy system could become unstable and impact the Company's ability to operate and monitor real-time system conditions, maintain safe operations, and comply with regulatory requirements. *Id.* Failure to complete the project could also impact the ability to commission new facilities which require remote monitoring or control, or require 24/7 manual field monitoring of certain facilities. *Id.*

Consumers Energy detailed the annual project costs necessary to complete the Gas SCADA Software Solution project and explained why those costs have increased since Case No. U-21490. See 4 TR 676-678. The mere fact that the cost projection is higher than the original estimate does not mean that the Company's current cost projection is inaccurate or unreasonable. The Commission should approve the projected funding for this project to support the Company's ability

to operate and monitor real-time system conditions, maintain safe operations, and comply with regulatory requirements.

Even if the Commission agreed with the PFD's recommended \$6,524,840 disallowance, which it should not, some of that disallowance would be duplicative because the Company already agreed to a \$5,558,000 reduction in IT capital expenditures based on 2024 actuals, which amount includes a reduction of \$4,623,400 in 2024 Gas SCADA Software Solution costs. 4 TR 783. Thus, at a minimum, the \$6,524,840 disallowance would need to be reduced by \$4,623,400.

The PFD disagreed that there should be any reduction to the disallowance "given questions surrounding whether the ostensible SCADA 2024 underspend was appropriately documented by the company." PFD, page 143. But the Company "documented" this reduction as part of its rebuttal testimony and exhibits, and there should be no question as to its accuracy. Company witness Baker testified that the Company would not oppose the Attorney General's proposed \$5.668 million reduction in capital expenditures to reflect 2024 actual expenditures. 4 TR 780. The \$5.668 million IT reduction is reflected in Exhibit A-148 (HLR-54), line 3, column (c), and Exhibit A-149 (HLR-55), line 2. And Ms. Baker explained that \$4,623,400 of that amount related to 2024 Gas SCADA Software Solution costs. 4 TR 783. Thus, in agreeing to reflect 2024 actual IT capital expenditures in the revenue requirement, the Company is already reflecting a reduction of \$4,623,400 for the 2024 Gas SCADA Software Solution costs. If there is any disallowance approved for the Gas SCADA Software Solution project, that disallowance must be reduced by \$4,623,400 to avoid double counting that reduction in this case.

c. Security

i. Forward Web Proxy Services

The Forward Web Proxy Services project replaces the current web proxy service platform, which has had ongoing operational issues related to web filtering and connectivity, with a new

platform to provide advanced filtering to filter out unwanted or harmful content from the internet. 4 TR 738-739. A web proxy service is a type of proxy server that sits between a client and the internet, acting as an intermediary that evaluates, modifies, and forwards the client's requests to the destination web server. 4 TR 738. When there is a degradation of service, such as the Company has experienced with its current service, Company employees and contractors are unable to access internet or cloud-based resources. 4 TR 739. With the continued use of cloud services, consistent access to and communication with these services is imperative while still protecting the Company from cyber threats. *Id.* The project creates value by (i) increasing service reliability for employees and contractors to internet and cloud-based resources, (ii) promoting the availability of technology from varying geographic locations, (iii) using a mature and scalable web proxy service provider, and (iv) continuously verifying every connection request. 4 TR 739.

The PFD adopted the Attorney General's recommended disallowance of \$939,000 in capital and \$149,967 in O&M for this project, questioning the need for the project because of the PFD's understanding that the current vendor resolved many issues with the current proxy service and the number of incidents has declined. PFD, page 145. The Commission should reject this recommendation.

The Company is replacing the current web proxy services platform because of consistent operational issues that have made the platform unreliable. 4 TR 739. An unreliable system results in Company employees and contractors being unable to access business critical services such as email, Teams, ServiceNow, and SharePoint Online. *Id.* Although there has been a reduction in incidents from 2022 to 2024, there were still seven incidents in 2024 affecting individual users or groups who could not perform work, resulting in 111 impacted days. Exhibit AG-31, pages 3-4. Importantly, the Company explained that the "year over year reduction in impacted days is a result

of Security no longer using built in functionality of the current product due to the impact on business stability,” which “creates risk and additional controls to mitigate risk.” Exhibit AG-31, page 3. And the Company continues to have common problems with the service, particularly with standard maintenance tasks such as software upgrades that often lead to undiscovered defects. Exhibit AG-31, page 4.

Accordingly, the PFD’s suggestion that this project is no longer needed is not supported by the evidence. The Commission should approve the requested funding to improve the Company’s safe access to the internet and cloud-based services.

ii. Physical Access Management and Alarm Response

The Physical Access Management and Alarm Response project will replace the Company’s Physical Access Management System to establish a centralized platform to manage user identities, authenticate users, and audit user activities. 4 TR 740. The Company is experiencing operational issues with the current physical access management system, which is out of date, inconsistent, and results in frozen jobs. These issues result in waiting for the manual process of un-freezing jobs, lost productivity, rework since frozen jobs do not always run correctly when unfrozen, and impacts to system stability and security visibility. 4 TR 740. This project will consolidate and modernize the Company’s physical security systems to enable enhanced security monitoring and prevent unauthorized entry into sensitive corporate areas. The project includes (i) developing an alarm and event monitoring system, (ii) adding automation to streamline remediation processes and improve efficiency, (iii) refining access revocation and badge access management, and (iv) introducing new access control readers that allow for the use of mobile device badges for employees, contractors, and visitors. *Id.*

The PFD adopted the Attorney General’s proposed disallowance of the Physical Access Management and Alarm Response funding in the amount of \$677,559 in capital and \$101,685 in

O&M for the test year. PFD, pages 165-168. The PFD stated that it was not persuaded that the expense of an entirely new system is supported. PFD, page 168. The Commission should reject the PFD's recommended disallowance because the current physical access control system is outdated, increasingly expensive to support, does not include modern capabilities, and does not reduce waste and cost. See Exhibit A-21 (SHB-6), page 98.

Company witness Baker testified that failing to move to the proposed new technology carries a growing risk of system failure, which could result in unauthorized physical access and negatively impact the Company's ability to operate efficiently. 4 TR 779. While the PFD minimized the 14 operational issues that the Company identified over the previous two years (see PFD, page 168), these operational issues impact productivity and create risk by causing delays when the system freezes and is unavailable, requiring resubmission of requests and reduced visibility to physical access at Company sites. Exhibit AG-31, page 8.

Not only does the current system have operational issues, but it does not support the adoption of new physical access control methods that will avoid costs and improve control and responsiveness. Exhibit AG-31, page 8. For example, the use of mobile device credentials for entrance to Company facilities offers a higher level of security, but the current solution does not provide the ability to implement this enhanced security option. Exhibit AG-31, page 9. The Company will realize cost savings by reducing future purchases of badge printers and associated consumables, and will achieve waste reduction by improving system stability, increasing automation, and eliminating manual processing of alarms. Exhibit AG-31, page 8. Alarms are currently processed manually by security teams, but the new system will streamline automation of over 2,500 alarms per year. *Id.*

The Commission should approve the Company's projected funding to move to this new technology to address the increasing operational issues, mitigate the growing risk of system failure and unauthorized physical access to Company facilities, and support the Company's ability to function efficiently.

d. Enhancement Projects

IT enhancement projects are smaller, short-cycle efforts to implement new or improved functionality in rapidly changing business and customer circumstances. 4 TR 715. Enhancements typically result from new or changing business conditions, compliance requirements, customer feedback, automation efforts, waste elimination efforts, and other ideas for improvement. *Id.* Benefits of these enhancements include cost savings, cost avoidance, productivity improvements, safety improvements, efficiencies, regulatory compliance, and improved customer experience. 4 TR 715-716. The Company maintains a worklist of enhancements, provided as Exhibit A-25 (SHB-10). To be approved for funding in cross-functional business team reviews, enhancements must provide a cost estimate and expected benefits. 4 TR 716-717. Failing to make these enhancements can have a negative effect on key customer and business processes and increase support costs. 4 TR 719.

The PFD recommended projecting the Enhancement capital expenditures using a three-year average adjusted for inflation, which results in a capital expenditure reduction of \$2,209,214 for the 10 months ending October 31, 2025 and \$2,160,254 in the test year. PFD, page 148. The Commission should reject this recommended reduction.

As of October 2024, the Company's enhancements worklist included 639 requests throughout the Company to improve multiple applications and systems. 4 TR 717. The demand for enhancements has grown an average of 49% over the past three years to support the Company's increased automation efforts, focus on waste elimination and cost optimization, optimization of

aging applications, and enhanced functionality for newly implemented technology. *Id.* To address this increasing need for enhancements, the Company projected these costs by considering historical demand and spend and determining incremental enhancement demand for 2025 and 2026 based on the known worklist. 4 TR 717-718.

To ensure projected costs for enhancements are reasonable, the Company calculated a three-year historical average plus known incremental work and compared the resulting amount with the test year projected expenditure. 4 TR 793. The three-year historical average was \$4,848,979, and known incremental work was \$3,117,727, for a total of \$7,966,706, which is less than the projected test year amount of \$7,416,712. 4 TR 718. The Company also compared the total cumulative worklist amount, which was \$7,577,721, to the projected test year costs to validate that projections are in line with projected demand. *Id.* Again, the worklist amount is less than the amount projected in the test year.

As shown, the Company's projections for Enhancements are reasonably based on historical demand and actual expenditures, known incremental work, and the current worklist, and more accurately reflect the funding needed to perform the necessary enhancements than using a three-year average. The Commission should approve the Company's cost projections in this case that reflect the increasing demand and importance of this work. 4 TR 718.

If the Commission agrees with the PFD that Enhancements should be projected based on a three-year average, which it should not, the resulting disallowance should be reduced by the amount of any disallowance in individual Enhancements projects. In addition to recommending a capital expenditure reduction of \$2,209,214 for the 10 months ending October 31, 2025 and \$2,160,254 in the test year based on a three-year average of actual costs, the PFD also recommended capital expenditure reductions to individual Enhancements projects in the Product

Family Enhancements-Customer area as follows: Web Chat AI enhancements in the amount of \$180,565 in the test year, Mobile Application enhancements in the amount of \$498,727 in the bridge period and \$649,770 in the test year, and Low to Moderate Income (“LMI”) Customer Support enhancements in the amount of \$200,628 in the bridge period and \$40,126 in the test year. PFD, pages 180, 184, 193. See Section II.A.4.a of these Exceptions for discussion of the recommended reductions to individual Enhancements projects.

The Product Family Enhancements-Customer expenditures include the Web Chat AI, Mobile Application, and LMI Customer Support enhancements and are part of the total projected Enhancements expenditures. See 4 TR 720, 763, 794. Thus, requiring a reduction to total Enhancements expenditures based on a three-year average and requiring individual Enhancements project reductions would result in total projected Enhancements expenditures that are less than the three-year average. Accordingly, if the Commission determines that total projected Enhancements capital expenditures should be based on a three-year average, the Commission should reduce the total disallowances of \$2,209,214 in the bridge period and \$2,160,254 in the test year by the amount of any individual Web Chat AI, Mobile Application, or LMI Customer Support reductions that are also approved by the Commission.

e. **Asset Refresh Program**

i. **ARP – Local Area Network**

The Asset Refresh Program (“ARP”) – Local Area Network (“LAN”) project upgrades the entire LAN and a significant portion of the Wireless LAN (“WLAN”). 4 TR 683. The LAN and WLAN hardware needs to be routinely refreshed to maintain manufacturer support needed for equipment bug fixes, security vulnerability patches, and enhancements. *Id.* Also, aging equipment is unable to accommodate the increasing demand for wireless devices necessary to perform day-to-day operations, which include devices such as rugged field devices, cell phones, barcode

scanners, tablets, and other mobile devices. *Id.* Aging equipment is also at risk of higher failure rates, increasing the risk of unplanned outages that disrupt access services such as email, SAP, the internet, and phones. *Id.* The ARP-LAN project increases network reliability, adds new functionality, improves network performance, ensures equipment is vendor supported, provides consistent wireless coverage, increases user productivity, and improves support for wireless and field devices. 4 TR 684.

The PFD adopted MNSC's recommended reduction in expenditures of \$46,593 in the bridge period and \$81,719 in the test year based on projecting the ARP-LAN expenditures using historical unit costs. PFD, pages 153-155. The Commission should reject the PFD's recommendation because it fails to account for the actual equipment that is planned to be replaced in the bridge period and test year.

Company witness Baker explained that the type of switch that requires replacement determines the unit cost, and the Company's cost projections were based on the specific requirements. 4 TR 788. The PFD stated that it is not possible to compare proposed LAN switch purchases with historical costs based on the naming convention used in the Company's exhibit. PFD, page 155. As an example, the PFD notes that Exhibit A-22 (SHB-7), page 6, shows the average unit cost for LAN Switch A is projected at \$20,512 in 2025 and 2026, while it was only \$6,415 in 2023 and 2024. *Id.*, note 682. But the Company fully explained – both in response to Staff audit and during rebuttal – that the actual models associated with the switch designations (such as LAN Switch A, LAN Switch B, LAN Switch C) may change from year to year and result in variations in unit pricing. 4 TR 788. For example, a Juniper EX4100 switch has a unit cost of \$8,132, compared to a Juniper EX4400, which has a unit cost of \$20,512. *Id.*

The PFD suggests that the Company should have provided “specific documentation to support the higher costs in the projected test year.” PFD, page 155. It is unclear what “specific documentation” would have been sufficient for the PFD. The Company supported its ARP cost projections with Exhibit A-22 (SHB-7), which identified the specific ARP equipment being replaced as well as historical and projected average unit costs. If the parties had questions related to those designations, they were free to use the discovery process to make those inquiries such as Staff did in audit. See Exhibit A-112 (SHB-15). The PFD noted that CUB criticized the Company for failing to provide bids sought or vendor quotes. PFD, page 154. But just in the ARP area alone, there are thousands of units and hundreds of line items identified in Exhibit A-22 (SHB-7). The Company should not be penalized for failing to file “bids sought or vendor quotes” for the thousands of planned ARP equipment purchases - the Commission has never required that the Company’s evidentiary presentation include such extensive documentation. And it is unlikely that either the parties to the case or the Commission would find value in such an unreasonable expansion of the evidentiary record.

The Company presented the ARP-LAN average unit costs, explained the reason for the change in unit costs, and showed that the Company’s cost projections were based on the type of LAN switch that required replacement. 4 TR 788. The methodology adopted by the PFD, which simply takes total historical costs and divides them by the total number of historical switches, does not accurately project these types of costs. The Commission should reject the PFD’s recommended reduction based on historical unit costs because it ignores the difference in model pricing that exists in these switches. *Id.*

f. IT/Digital Foundation

i. Operational Technology Datacenter Migration

The Operational Technology (“OT”) environment includes systems that support the control and monitoring of the electric grid, electric generation, gas compression, and natural gas pipelines. 4 TR 723. The Company’s current datacenter for the OT environment is not a preferred location to house servers and systems critical to the control of the electric grid or gas pipeline because it is close to a railway system. 4 TR 723-724. The current location of the data center in the basement of the Parnall building also includes risk because there have been instances of water filtration in the basement and because it is near the main water piping for the building. In addition, the climate conditioners at the current OT data center are aging and have had faults resulting in unplanned shutdowns. 4 TR 723-724. Rising temperatures in the data center could cause damage, failure of equipment, and disruption to the monitoring of the critical OT systems. Exhibit AG-31, page 1. The OT Datacenter Migration project mitigates the legacy physical and location risks at the current Parnall location, migrates the OT infrastructure to a modern, highly secure environment with redundancy in climate conditions, and results in better data center facilities support with guaranteed redundant power. 4 TR 724.

The PFD adopted the Attorney General’s proposed disallowance of the Datacenter Migration funding in the amount of \$1,441,000 in capital and \$716,000 in O&M for the test year. PFD, pages 165-168. The PFD stated that it is not clear that relocating the data center is a reasonable option compared with remediating the problems in the Company’s current building. PFD, page 168. The Commission should reject the recommended disallowance because relocating the data center is the most reasonable option to address the several risks associated with the current location.

Consumers Energy performed an analysis of alternatives to expand capabilities and address constraints and risks, including remaining at the current Parnall location. 4 TR 724. The option to remain at the Parnall location was not selected because the co-location vendor is able to provide the building, cooling, power, and physical security that is not present at the current Parnall location. *Id.* The current data center would require extensive work to modernize, which still would not address all the present risks such as its proximity to water pipes. Exhibit AG-31, page 1. If the main water piping burst at the Parnall facility, the data center equipment would become wet, causing damage and failure, and could disrupt the monitoring of the critical OT systems, such as SCADA. *Id.*

The Commission should approve the funding for this project to remove the risks of the current data center location and ensure that the systems critical for safe and reliable natural gas and electric delivery are co-located to an enhanced data center facility. 4 TR 723.

III. CAPITAL STRUCTURE AND RATE OF RETURN

It is essential that Consumers Energy receives an authorized rate of return for ratemaking purposes that will support the Company's access to financing and favorable financing rates to fund quality utility service for its customers. Consumers Energy requests that the Commission adopt the Company's proposed cost of capital of 6.22% with an authorized ROE of 10.25% and an equity ratio of 50.75%, given the risk profile for Consumers Energy's gas business, current market conditions, and the need to support credit and attract capital. This recommendation also accounts for the trends in other utilities' authorized equity ratios and ROEs.

The PFD recommended a 5.97% authorized rate of return, which is not sufficiently supportive to attract the investment that is necessary for the Company and its customers. For the reasons discussed below, the PFD's recommended rate of return should be rejected.

Many years ago, the United States Supreme Court established the minimum criteria that must be met by a regulator in order to satisfy the constitutional threshold for sufficient rates in two landmark cases: *Bluefield Water Works and Improvement Co v Public Service Commission of West Virginia*, 262 US 679, 693; 43 S Ct 675; 67 L Ed 1176 (1923) and *Federal Power Commission v Hope Natural Gas Co*, 320 US 591; 64 S Ct 281; 88 L Ed 333 (1944). The Supreme Court stated in *Bluefield*:

A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties [262 US at 692.]

Similarly, the Supreme Court stated in *Hope*:

By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital. [320 US at 603.]

The Supreme Court has acknowledged that the ratemaking process “involves a balancing of the investor and the consumer interests.” *Hope*, 320 US at 603. The Supreme Court has also clearly stated:

A commission or other legislative body, in its discretion, may determine to be reasonable and just a rate that is substantially higher than one merely sufficient to justify a judicial finding in a confiscation case that it is high enough to yield a just and reasonable return on the value of the property used to perform the service covered by the rate. The mere fact that a rate is nonconfiscatory does not indicate that it must be deemed to be just and reasonable. It is well known that rates substantially higher than the line between validity and unconstitutionality properly may be deemed to be just and reasonable, and not excessive or extortionate. [*Banton v Belt Line Ry Corp*, 268 US 413, 422–23; 45 S Ct 534; 69 L Ed 1020 (1925).]

The Michigan Supreme Court similarly found that “a rate may be made by a legislative body, or by a legislative agency, materially higher than is required to meet the constitutional test, and still be regarded as reasonable.” *Michigan Bell Tel Co v Michigan Pub Serv Comm*, 332 Mich 7, 43; 50 NW2d 826 (1952).

The PFD in this case did not properly balance the interests of customers and investors. Furthermore, the PFD fails to recognize that this is a time when the setting of “just and reasonable” rates requires an increase in Consumers Energy’s equity ratio and ROE in order to attract the proper investment and keep pace with the trend of increasing authorized utility equity ratios and ROEs nationwide. The ALJ’s reasoning in support of the PFD’s recommended authorized equity ratio and ROE is unsound. Rather than seeking a balance between customer and investor interests, the PFD unreasonably dismisses the validity of solid analysis expressed from the investors’ perspective in the Company’s testimony and briefs. The record in this proceeding does not demonstrate that the Company’s request would be a burden on customers. To the contrary, the record shows that the Company’s requested rate of return is not “so high as to place an unnecessary burden on ratepayers, yet [is] high enough to ensure investor confidence in the financial soundness of the enterprise.” December 23, 2008 Order in Case No. U-15244, page 12.

One of the most significant errors in the ALJ’s reasoning is the failure to recognize that the equity ratio and ROE used in the ratemaking process are essentially just inputs into a complex calculation that is designed to produce the value that actually matters for ratemaking purposes: the overall rate of return used to determine the final revenue requirement. The equity ratio and ROE used by the Commission in setting rates have independent value for the message they communicate to investors. Also, they are correlated such that a decrease in one offsets an increase to the other in the rate of return and vice versa. Further, a decrease in one is compounded with a decrease to

the other. True, when courts evaluate whether the ratemaking process has resulted in constitutionally sufficient rates, the courts seldom evaluate inputs like the equity ratio or ROE in isolation or independently. Instead, the courts' frame of reference for ensuring that the rates established by commissions are "commensurate with returns on investments in other enterprises having corresponding risks" will be to look at the *overall* return allowed in the case and the *overall* return of comparable utilities (relative to time and risks). More than a hundred years of regulatory case law⁵ focuses attention there because it is the overall rate of return, not the individual components of the calculation, that ultimately applies to a utility's rate base to determine the rates the Commission intends to allow the utility. The U.S. Supreme Court in *Hope* was clear that the courts are concerned with the "total effect" of a rate order and that "it is the result reached not the method employed which is controlling." *Hope*, 320 US at 602.

The Company demonstrated the importance of considering the relationship between the ROE and the equity ratio used to calculate the overall rate of return in this case. The Company summarized its presentation on this topic on pages 45 to 46 of its Reply Brief. See also, 4 TR 809-810, 812, 817-818, 851-852, 900. The PFD did not reject the existence of that relationship. The importance of the relationship between ROE and equity ratio is consistent with the body of ratemaking case law, specifically the U.S. Supreme Court cases mentioned above. With respect to the determination of the minimal return needed to meet constitutional requirements, the ROE and the equity ratio must be set such that the overall rate of return will be one that compensates the utility for risk comparable to other similar companies, ensures the utility's financial soundness,

⁵ For just a small sample of the multitude of landmark cases bearing out this claim, see, e.g., *State of Missouri ex rel Sw Bell Tel Co v Pub Serv Comm of Missouri*, 262 US 276, 288; 43 S Ct 544; 67 L Ed 981 (1923); *Bluefield, supra*, 262 US at 692; *Bd of Pub Util Com'rs v New York Tel Co*, 271 US 23, 28-31; 46 S Ct 363; 70 L Ed 808 (1926); *Wabash Valley Elec Co v Young*, 287 US 488, 501; 53 S Ct 234; 77 L Ed 447 (1933); *W Ohio Gas Co v Pub Utilities Comm of Ohio*, 294 US 63, 75; 55 S Ct 316; 79 L Ed 761 (1935); *Fed Power Comm v Nat. Gas Pipeline Co of Am*, 315 US 575, 596; 62 S Ct 736; 86 L Ed 1037 (1942); *Hope, supra*, 320 US at 604-605; *Duquesne Light Co v Barasch*, 488 US 299, 310; 109 S Ct 609; 102 L Ed 2d 646 (1989).

and maintains the utility's credit and ability to attract capital. While not denying the relationship between ROE and equity ratio, the PFD failed to correctly apply these foundational legal requirements consistently throughout the ALJ's analysis. That concern alone should cause the Commission to approach the PFD's equity ratio and ROE and recommendations with skepticism. The PFD's recommendations cannot be sound when the PFD fails to recommend an equity ratio and ROE that taken together do not compensate the utility for risk comparable to other similar businesses and maintains the utility's credit (and ability to attract capital) to achieve a just and reasonable overall return.

In the remainder of this section of Consumers Energy's Exceptions, the Company discusses numerous other analytical missteps in the PFD that have led to an unreasonably low overall return recommendation. The PFD's equity ratio and ROE recommendations are too low when considering both as contributors to the Company's overall rate of return. The Commission should approve the Company's overall rate of return of 6.22%, which was premised in part on an ROE of 10.25% and a 50.75% equity ratio. The evidence in this case shows that an overall return of 6.22% is modest, but it is vitally important to maintain the Company's credit and access needed capital on favorable terms.

A. Test Year Capital Structure – Equity Ratio

The PFD's recommendation to utilize a 50.0% equity ratio for ratemaking purposes in this case should be rejected. The recommendation was based on numerous analytical errors that are discussed in more detail below. The PFD's recommendation, if taken with its recommendation to lower the Company's ROE, will contribute to further deterioration of the Company's credit metrics, rather than maintaining the Company's credit, which is one of the proper constitutional goals that should be driving the Commission's decision. The Commission should adopt Consumers Energy's recommended equity balance and the resulting equity ratio of 50.75%.

In briefing, the Company thoroughly covered the validations for its request to deviate from the Commission's previously stated preference for a strictly balanced equity ratio and therefore, to avoid unnecessary repetition, limits its arguments in the following three subsections. Please see Consumers Energy's Reply Brief at pages 60 through 64 for additional responsive argument in favor of a 50.75% equity ratio.

1. The PFD Failed to Appropriately Consider Peer Utility Equity Ratios and Equity Ratios of ROE Proxy Utilities

Consumers Energy's equity ratio has trended down to 50%, which was the Commission's stated goal in its July 31, 2017 Order in Case No. U-18124 for the Company's gas operations. See MPSC Case No. U-18124, July 31, 2017 Order, pages 45-46. In that gas rate case, the Commission set the Company's equity ratio to 53.10%. *Id.* at 46. With the comment that "ROEs are trending downward," the Commission lowered the Company's ROE in that case to 10.10%.

On page 224 of the PFD in this proceeding, in rejecting the Company's requested 50.75% equity ratio, the ALJ found that "many aspects of the company's argument and evidentiary presentation on this topic are substantially similar to those presented in previous rate cases." The PFD went on to mention the Company's concerns as to "financial market volatility, inflationary pressures fueled by the Trump administration's trade policies, the potential threat of an impending recession, and geopolitical tensions as new circumstances that warrant a higher equity ratio." *Id.*

In addition to the broader circumstances that justify a slightly higher than 50% equity ratio in this case, the utility industry trend in authorized equity ratios and ROEs is upward. Consumers Energy presented a Wells Fargo report (Exhibit A-34 (MRB-12)) that showed median approved equity ratios. The median equity ratio increased 130 basis points from 2019 to 2023, while the Company's decreased 262 basis points to the present. 4 TR 808; Exhibit A-34 (MRB-12). From that report, the PFD reaches back over 25 years to state that "in almost every year" the median was

“close to or below 50%.” However, the PFD acknowledged in 2022 and 2023 that the median exceeded 51%. PFD, page 229. The PFD also acknowledged the possibility of “a recent upward trend in approved” equity ratios but concluded that “it does not demonstrate that a balanced equity ratio is unreasonable, let alone an outlier” and accorded the Wells Fargo report “only slight support” for the Company’s request for a 50.75% equity ratio. PFD, page 229. Respectfully, Consumers Energy disagrees and believes a more reasonable equity ratio is 50.75%. The Company’s request is certainly not an outlier and on the low end when compared to other authorized equity ratios, for example, a 2023 median that exceeds 51.00%.

For comparison, in Exhibit A-32 (MRB-10), Consumers Energy presented equity ratios of a peer⁶ group of utilities that demonstrated an average equity ratio of 54.05%. See 4 TR 806-809. As a basis for its 50% equity ratio recommendation, the PFD extracts from the exhibit that “three of the company’s 30 listed peers in that exhibit, have balanced or nearly balanced equity ratios.” PFD, page 230. That is not a fair or reasonable way to weigh the evidence. It is more reasonable to give weight to the 26 peers that have equity ratios higher than the Company’s current authorized 50% equity ratio. The PFD acknowledged concerns raised by the Attorney General regarding Exhibit A-32 (MRB-10). PFD, page 230. The Company thoroughly rebutted these arguments in its Reply Brief. See Consumers Energy’s Reply Brief, pages 61-64. Importantly, the Attorney General and the PFD (Staff as well) misunderstood that the makeup of a proper equity ratio peer group does not need to be and likely is not going to be the same as for a proper ROE proxy group because the respective groups are comparing different things and therefore have different selection criteria. See *Id.* at 62. Company witness Marc R. Bleckman chose his peer group to ensure that he had access to actual regulatory authorized equity ratios. 4 TR 806-808. The purpose of the

⁶ Mr. Bleckman testified that it is appropriate to consider peer utility equity ratio averages and trends in determining the equity ratio for the Company in this case. 4 TR 857.

analysis was to show the Commission how other utility regulatory commissions view the required equity ratios for comparable utilities in their jurisdictions. See 4 TR 855-856. To provide a valid comparator, the peer group for an equity ratio analysis needs to reflect the authorized equity ratios as a percentage of permanent capital approved by the utility's regulatory commission. 4 TR 856. But regulated subsidiaries are not necessarily publicly traded companies. For comparison, Company witness Ann E. Bulkley used companies that are "both publicly traded and comparable to the Company in certain fundamental business and financial respects to serve as its 'proxy' for purposes of estimating the cost of equity." 4 TR 908 (emphasis added). For example, she used criteria including payments of quarterly cash dividends, ratings from S&P and/or Moody's, earnings growth forecasts, percentages of total operating income from regulated operations, percentages of regulated operating income from gas distribution operations, and merger or transaction information to select her ROE proxy group. 4 TR 908-909. The aforementioned criteria are of course attributes relevant to an ROE comparison between utilities. Based on different utilities appearing in Mr. Bleckman's peer equity ratio group versus Ms. Bulkley's ROE proxy group, the PFD confused the Company's analyses. Consequently, the PFD mischaracterized the Company's argument to mean Mr. Bleckman's equity ratio peer group "selection was appropriate because it adhered to the established selection criteria that the company itself selected." See PFD, page 230. Mr. Bleckman thoroughly explained and defended his selection criteria in direct and rebuttal testimony. See 4 TR 806-808, 855, 872-875. He compared attributes relevant to an equity ratio comparison between utilities. Finally, while the PFD may be correct that there are difficulties in "presenting apples-to-apples comparisons depending upon the practices of the utility in question and whether it employed short-term debt as a form of permanent financing" (PFD, page 231), Consumers Energy stands behind Mr. Beckman's peer group equity

ratio analysis. The important thing for purposes of setting a proper equity ratio is that his analysis is reasonable and, in fact, more reasonable than the equity ratio comparisons that were provided by the other parties in this proceeding. Company witness Bleckman demonstrated this in his testimony. 4 TR 855-857, 870-875, 884-886, 888-889. The Commission should give significant weight to Mr. Bleckman's analysis that was derived from his Exhibit A-32 (MRB-10).

If the Commission were to consider the equity ratios of ROE proxy group utilities, the showing is the same in that the Commission should raise the Company's equity ratio. For example, Staff offered and entered into the record a 53.62% calculated equity ratio average for its ROE proxy group. Exhibit S-4, Schedule D-5, page 2. While Mr. Bleckman pointed out that Staff's calculation is understated⁷ for setting a permanent equity ratio, it does suggest the Company's current and proposed equity ratios are comparatively low. 4 TR 856. Because Staff did not present an equity ratio peer group, its understated ROE proxy group equity ratio is the only peer equity ratio average that Staff submitted into the record for an equity ratio comparison. It is also the only quantitative evidence that Staff provided regarding an appropriate equity ratio for the Company. Staff claimed that its choice to exclude "its proxy group's average equity ratio or ROE in its analysis" means it does not need to be considered as part of Staff's recommendation. Staff's Initial Brief, page 62. But it is record evidence and available for the Commission's consideration. Additionally, the Commission must base its decisions on substantial evidence in the record, and Staff's proxy group average equity ratio provides an understated but still relevant comparison. For its part, the Association of Businesses Advocating Tariff Equity ("ABATE") used the Company's ROE proxy group to calculate an average equity ratio of 50.40% if excluding short-term debt. ABATE's Initial Brief, page 16. ABATE stated that the Company's "proposed equity ratio of

⁷ Authorized equity ratios as a percentage of total capitalization can under-report a comparable equity ratio because additional capital components can be included. 4 TR 856.

50.75% therefore exceeds that of the proxy group's comparable average equity ratio." *Id.* Even with its flaws, ABATE's comparison ultimately supports an increase in the Company's equity ratio above the strictly balanced recommendation of the PFD. In fact, using an approximately apples-to-apples (excluding short-term debt) comparison, the Commission could find that all of the quantitative (peer group) analyses presented in this case support an increase in the Company's current and strictly balanced equity ratio. Given all the different equity ratio comparators discussed by the parties, which all support an equity ratio above 50.00%, it was not reasonable for the ALJ to recommend holding Consumers Energy's equity ratio at exactly 50.00%.

In further support of an increase to the Company's equity ratio, the average equity ratio shown in ABATE witness Christopher C. Walters' Table CCW-2 has increased 246 basis points to 52.25% from 2015 to 2024. 4 TR 884. The trend is upward, and the Company's recommended 50.75% is below industry averages for the past nine years and all years listed in the table. *Id.* This is despite Mr. Walters' table understating the average equity ratios due to the potential inclusion of items such as short-term debt and customer deposits. 4 TR 884-885. For comparison, if Staff, the Attorney General, and ABATE expressed the Company's proposed equity ratio as a percentage of total capitalization, it would drop to 42.58%. 4 TR 885. In contrast, Mr. Bleckman's calculated average peer equity ratio was consistent with the Commission's Order in Case No. U-20963. 4 TR 871. Again, the average for the peer group was 54.05%. Having recognized that the peer group average provides a valuable comparison, Mr. Bleckman kept his 50.75% equity ratio recommendation to be consistent with a 6.22% proposed cost of capital (given the 10.25% authorized ROE recommendation from Ms. Bulkley). The Commission should approve this 6.22% cost of capital.

In denying an increase to the Company's equity ratio, the PFD cites principally to the Commission's 2017 Orders in Case Nos. U-17990 (a Consumers Energy electric rate case) and U-18124 (a Consumers Energy gas rate case), wherein the Commission indicated its desire to move Consumers Energy's capital structure toward a 50%-50% debt-equity ratio over the next five years. The PFD further notes that the Commission has "reiterated the objective of reaching" an approximately 50% equity ratio. PFD, page 223. As explained below, the Commission should reject the PFD's recommendation.

2. Given the Evidence and Analysis Presented on Peer Utility Equity Ratios and Equity Ratios of ROE Proxy Utilities, While Considering the Commission's Stated 50% Equity Ratio Goal for Utilities, the PFD's Equity Ratio Recommendation is Too Low

Consumers Energy does not dispute that the Commission reaffirmed its viewpoint that the Company maintain a capital structure balanced approximately evenly between debt and equity in recent past cases. However, for example in Case No. U-20963, the Commission also reiterated its philosophy, which was originally stated in Case No. U-17990, that "the Commission has also sought to maintain some degree of flexibility to accommodate the specific circumstances connected with a utility's investment plans and elements of its balance sheet." MPSC Case No. U-20963, December 22, 2021 Order, page 200. The Commission wrote that it continues to invite the Company to offer evidence and argument supporting the need for an equity ratio above 50% and that it "will continue to consider all evidence and circumstances in each rate case to determine the appropriate capital structure." *Id.* Similarly, in Case No. U-20332, the Commission stated that it "[in Case No. U-17990] did not set a prescriptive, year-to-year tempo for the company to achieve; rather, it allowed for flexibility." MPSC Case No. U-20332, September 26, 2019 Order, page 61.

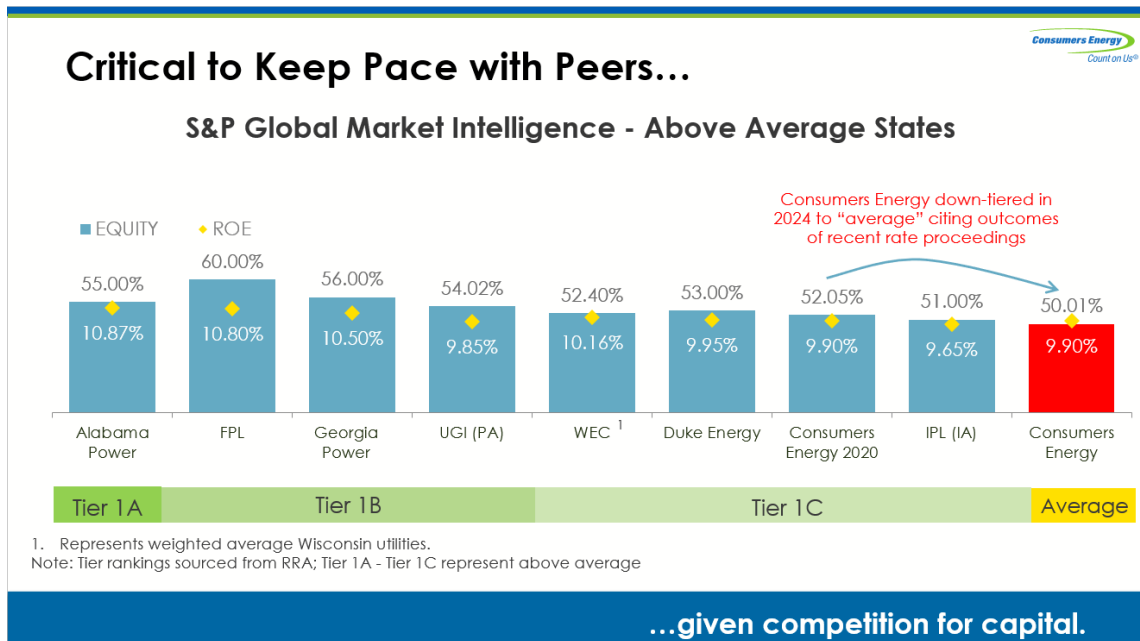
“Fixing and regulating rates is a legislative function, not a judicial one.” *Pennwalt Corp v Pub Serv Com’n*, 166 Mich App 1, 8; 420 NW2d 156 (1988). Previous Commission orders do not constitute binding precedent and do not have the preclusive effect of the legal doctrines of *res judicata* or collateral estoppel. *Id.* at 9. The Commission itself has noted that “it is doubtful whether the present Commission can bind a future Commission.” MPSC Case No. U-5609, May 1, 1978 Opinion and Order, page 8. The setting of the appropriate ratemaking equity ratio to ensure the Company’s financial soundness and maintain its credit and ability to attract capital is a finding of facts in each rate case, which is informed by the facts supported in the record. It is not a precedentially compelled outcome.

The Commission’s Order in Case No. U-17990 may have been a reasonable policy decision in its context approximately eight years ago, but the context has changed. Since the Commission’s February 28, 2017 Order in Case No. U-17990 was issued, the Company’s rate of return has sharply declined as a result of recent rate cases. 4 TR 812. A reduction in rate of return lowers the Company’s Funds from Operation (“FFO”) to Debt ratio, which affects credit ratings. *Id.* Consumers Energy needs to maintain strong credit ratings because the Company’s credit rating has been downgraded once already since the Commission’s decision in Case No. U-17735. Over the last several years, the Company’s credit metrics have also deteriorated as a result of numerous external economic factors coupled with numerous reductions in the Company’s equity ratio that have already been adopted. 4 TR 812.

Currently, and as discussed further below, there are difficulties in the overall market and specifically the utility industry, which includes the Company. For example, there are “headwinds to credit quality” as observed by S&P, including increased cash flow deficits that are funded to a higher extent with debt versus equity, higher interest rates, and a narrowing spread between U.S.

Treasuries and authorized ROEs. 4 TR 817-118; Exhibit A-107 (MRB-16). The credit rating agency, Fitch, also noted higher interest rates being a headwind. 4 TR 818. In addition, the Trump administration policies coincide with volatility and uncertainty that is likely to continue through the test year. 4 TR 851-852. In sum, the Commission should consider the Company’s equity ratio with its ROE in the context of the current market conditions, including the utility industry, and the Company’s regulatory environment. See Consumers Energy’s Reply Brief, pages 46-60.

Perhaps most importantly, as discussed above, peer utility equity ratios and equity ratios of ROE proxy utilities have trended up. In recent rate case filings, the Company has included the chart below, noting that the recent decline in the Company’s weighted rate of return with a comparison to a sample of other utilities (4 TR 816):



Unyielding adherence to the trajectory set by three different Commissioners, eight years ago, without regard to the change in circumstances is not sound policy. What’s more, even those three Commissioners knew that the policy they chose for the time should not be clad in iron for years on. In foresight, they wisely made sure to include language to clarify that the course could

be changed and adapted if circumstances changed, and that commitment has been reaffirmed in subsequent Commission decisions. The analysis is not as simple as merely citing the Commission's general preference from several past orders, especially in light of the peer equity ratios discussed in the previous subsection. Respectfully, the Commission should deviate from its past decisions finding a 50.00% equity ratio to be appropriate under then existing conditions, and raise the Company's equity ratio. A 50.75% equity ratio is reasonable given the record in this proceeding.

3. The PFD Inappropriately Dismissed Trends in the Company's FFO-to-Debt Ratio, Market Conditions, the Nationwide Utility Industry, and the Regulatory Environment

In his direct testimony, Company witness Bleckman explained that it is important and financially prudent for businesses to maintain their credit metrics with at least some cushion above credit downgrade levels. 4 TR 818. He explained that failure to do so would make the business vulnerable to unforeseen events, including market volatility or market disruptions. *Id.* The PFD was "not persuaded that there are significant changes in the company's economic circumstances since the Commission's last rate case order that would warrant increasing the company's equity layer." PFD, page 224. Specifically, on page 224 of the PFD in this case, in rejecting the Company's requested 50.75% equity ratio, the ALJ found that "many aspects of the company's argument and evidentiary presentation on this topic are substantially similar to those presented in previous rate cases." , page at 224). The PFD erred by not assigning enough weight to the circumstances that support an increase in the Company's equity ratio.

Consumers Energy's equity ratio has trended down to 50%, which was the Commission's stated goal in its July 31, 2017 Order in Case No. U-18124. See Order pages 45-46. In that gas rate case, the Commission set the Company's equity ratio to 53.10%. *Id.* at 46. In the same case,

commenting that “ROEs are trending downward,” the Commission lowered the Company’s ROE to 10.10%. The ALJ went on to mention the Company’s concerns as to “financial market volatility, inflationary pressures fueled by the Trump administration’s trade policies, the potential threat of an impending recession, and geopolitical tensions as new circumstances that warrant a higher equity ratio.” *Id.*

But the PFD did not fully address the additional and changed circumstances. Consumers Energy’s Reply Brief thoroughly addressed these circumstances in response to the other parties, so the majority of those arguments will not be repeated here. See Consumers Energy’s Reply Brief, pages 46-60. However, the trends are worth particular attention because the PFD does not adequately address them.

As discussed further below in the subsection addressing the Company’s ROE,⁸ in addition to the broader circumstances that justify a slightly higher than 50% equity ratio, the utility industry trend in authorized ROEs is upward, along with authorized equity ratios. The upward trend in authorized equity ratios and ROEs nationwide in the utility industry is therefore a “significant” change in circumstances given the reasons offered by the Commission for reducing Consumers Energy’s ROE and equity ratio in Case No. U-18124 and the opposite trend in the Company’s authorized equity ratio and ROE existing now. The PFD’s recommendation should have put more weight on the upward trend in authorized equity ratios and ROEs.

The PFD acknowledged a report authored by Regulatory Research Associates (“RRA”) that downgraded Michigan’s regulatory environment rating and stated “[w]hile approved ROEs for [Commission regulated utilities] remain above the prevailing industry averages, they compare

⁸ As also discussed further below, the ALJ compared the Company’s authorized and projected ROE with a peer group made from nationwide authorized ROEs. Consumers Energy takes exception to the PFDs analysis focusing on authorized ROEs without similarly weighting authorized equity ratios.

less favorably to these averages, which have risen, albeit modestly, in recent periods.” See PFD, page 225; Exhibit A-36, page (MRB-14), page(MRB-14), page 7. But the PFD took an overly optimistic view of the report. Whether considered for the proposition that the state’s regulatory environment has tightened or only that authorized ROEs have trended up while the Company’s ROE and equity ratio have not, the report is not favorable in regard to the Company’s credit quality and credit metrics.

The PFD also presents an unduly optimistic interpretation of a 2024 ratings report from S&P, mentioning the report’s indication of “a stable outlook for the company” and positive regulatory environment. PFD, page 226; See Exhibit A-116 (MRB-19), page 1. The PFD offered a similar view of a May 2024 credit opinion from Moody’s stating that it “expected the company’s financial metrics to remain stable.” PFD, page 227; See Exhibit A-117 (MRB-20). From these reports, the ALJ incorrectly concludes that the Company’s credit concerns were valid, but understated. PFD, page, 226. Company witness Bleckman offered these reports to demonstrate their expressed concerns with the Company’s regulatory environment and overall credit outlook. As the Company stated in its Reply Brief, these types of comments from the credit reporting agencies are outcome dependent. See Consumers Energy’s Reply Brief, page 47. Even when read optimistically there is no indication that any stability assumed in those reports reflects the PFD’s recommendation for a 50% equity ratio and 9.75% ROE. Those reports assumed, at the very least, that the Company’s overall return reflecting its ROE and equity ratio would remain stable – not decline further. The PFD’s recommendation is thus a continuation of the downward trend for the Company’s rate of return that impacts the FFO-to-Debt ratio and places the Company’s credit at unreasonable risk. See 4 TR 810, 812.

The Company seeks an authorized weighted rate of return at a level set prior to the Moody's downgrade but in an elevated interest rate environment. 4 TR 850-851. Again, the nationwide trend for authorized equity ratios and ROEs is upward. Taken with the possibility of unforeseen events materializing during the test year, Mr. Bleckman's concerns about the Company's need for financial cushion above credit downgrade levels are well founded. In sum, the PFD erred by assuming, without a proper basis, the ALJ's recommended equity ratio and ROE would fit within the expectations of the credit ratings agencies. There is no indication of that expectation, especially given the trend for authorized equity ratios and ROEs in the nationwide utility industry is upward.

The PFD looks to a nationwide data set of utilities for a controlling or near controlling comparison when it comes to recommending an ROE but does not appear to account for the trend of increasing equity ratios. For its equity ratio recommendation, the PFD looks to neither the comparison to other utilities at a peer level nor the trend nationwide. The more reasonable interpretation is that as authorized equity ratios and ROEs trend upward, Consumers Energy's (equity ratio plus ROE) should not further decline. Utilities compete for capital with other investments of similar risk, including (but not limited to), other gas utilities. 4 TR 900. With the current trends, a 6.22% cost of capital from a 50.75% equity ratio and 10.25% ROE is reasonable. Respectfully, the Commission should reject the ALJ's low recommendation.

With respect to the Company's concerns with the risk of a credit downgrade, the PFD recognized that a credit downgrade is a negative event but inappropriately downplayed "the severity of its consequences." See PFD, page 228. However, the impact of a credit downgrade could be significant to customers if the Company is hampered in "rais[ing] the money necessary for the proper discharge of its public duties." *Bluefield*, supra, 262 US at 693. When requesting a particular equity ratio (and investor-attractive but balanced ROE), the Company has to focus on

both the short term and the long term. The Company's ability to deliver on long-term investments to the infrastructure that provides safe, reliable, and customer focused utility service relies on its ability to raise money from the capital markets. 4 TR 814. The financing rates for these investments are at least partially offset by lower financing rates that generally come with a higher credit rating. *Id.* That is not to say there are no costs associated with infrastructure investments, but that the customer savings from improved credit ratings and lower interest costs can at least offset some of that burden. *Id.* While it may seem attractive for the benefit of customers in the near-term to downsize the Company's weighted rate of return, the potential resulting credit rating downgrade could lead to the Company's customers paying higher financing costs over the long term, and it could put at risk the Company's ability to execute on its critical investment plan on behalf of customers. 4 TR 853-854. The Commission should reject this undue risk.

Despite the importance of stable credit for a utility, the PFD determined that the Company offered "no convincing evidence that Moody's previous downgrade of the company in 2021 had any momentous adverse effect on the company's ability to attract capital or access credit. PFD, page 228. The PFD concluded that "even if the company's credit rating was to be downgraded . . . the company would still enjoy an investment grade credit rating that ensures access to credit at favorable rates." PFD, page 229. First, Mr. Bleckman testified that credit is not always available at favorable rates. 4 TR 814-815. Second, the ALJ's proposed finding is inconsistent with the Supreme Court's holding in *Hope*. The Supreme Court stated:

By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital. [320 US at 603, *emphasis added*.]

The U.S. Supreme Court did not say that the return should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit or attract capital. The return should maintain a utility's credit and attract capital. Mr. Bleckman testified regarding the balance between authorized equity ratio and ROE. 4 TR 809. His testimony suggested that a return would need to be raised to offset an inadequate input to a utility's credit metrics, for example, its equity ratio. *Id.*

Regarding access to capital, Mr. Bleckman raised the possibility that market conditions can include shocks to the financial markets. 4 TR 814. This is an important consideration and is not fully addressed by the PFD or the other parties. For example, in their Initial Briefs, Staff and ABATE did not acknowledge that spikes in interest rates can cause an increase in the cost of capital or even, under extreme market events, inaccessibility to capital. 4 TR 814-815. Customers are not well served in the possible event that their utility has difficulty accessing capital. *Id.* Whether it is refinancing higher interest rate debt or preserving the Company's credit ratings to secure lower interest costs, the Company has to be mindful of market conditions in relation to the overall cost of capital included in customer rates. *Id.* A 50.75% equity ratio and 10.25% ROE balance goals for the Company, the outcomes for customers, and the current capital market conditions.

It is prudent for Consumers Energy to maintain a reasonable financial cushion above the threshold, placing the Company at risk of credit downgrade. The PFD does not appear to find, as a matter of policy reflected in the ALJ's recommendations, that such a cushion should not be maintained. However, the ALJ's rationale for dismissing the Company's concerns about the degradation in its credit metrics is not as reasonable as the Company's rationale for a reasonable financial cushion. The Commission should reject the PFD's characterization of low risk surrounding the Company's generally favorable credit.

More importantly, the PFD's recommendation that the Company would still have access to capital if it experienced another credit downgrade misses the point that Consumers Energy will have better access to capital and will be able to access it at lower rates with a higher credit rating. The goal should be to improve the Company's credit quality at all of the credit reporting agencies, not continuously degrade its credit to achieve the lowest rates possible in the short term. Again, the U.S. Supreme Court's standards on a constitutionally sufficient rate of return require the regulator to pursue a path to "maintain" the utility's credit, not deteriorate it.

Thus, when the PFD points to some favorable language in the Company's recent credit reports, indicating that the Company's credit metrics have not deteriorated, the Commission should recognize two things: (i) those favorable reviews reflect the Company's attempts to financially manage the situation to offset the harm from the most recent ratemaking equity ratio decisions, and (ii) it reflects the Company's financial position at a *current state* where the ratemaking equity ratio is 50.00% with an ROE of 9.90%. The credit reports that the PFD relies upon have not analyzed the Company's credit, assuming a 50.00% equity ratio and further reduction to a 9.75% ROE as recommended by the PFD. There is nothing to support the PFD's assumption that stable credit health under current conditions necessarily means that there will be stable credit health if the things that harm credit health are exacerbated.

4. Conclusion on Equity Ratio

The PFD's recommendation to utilize a 50.00% equity ratio for ratemaking purposes in this case was based on numerous analytical errors. The PFD's recommendation will contribute to further deterioration of the Company's credit metrics, rather than maintaining the Company's credit, which is one of the proper constitutional goals that should be driving the decision. The Commission should reject the PFD's recommendation and adopt Consumers Energy's recommended equity balance and the resulting equity ratio of 50.75%.

B. Return On Common Equity

The authorized ROE is a key consideration for investors. In selecting an ROE in this case, the Commission should recognize that its decision will send a clear message to the investment community. An outcome viewed as non-constructive by investors would have negative ramifications not only for Consumers Energy, but also for the Company's customers and the state of Michigan.

Company witnesses Bulkley and Bleckman provided testimony supporting an increase in the Company's ROE. Each of the reasons cited in the PFD in support of the proposed reduction in the Company's ROE from the current 9.90% to 9.75% rely on arguments by other parties that were specifically refuted by the Company in this case. The Company takes exception to the PFD's ROE recommendations in the following three subsections.

1. The ALJ Erred by Placing Undue Reliance on Recent ROE Decisions by Regulatory Agencies for Utilities that are Not Proxies for Consumers Energy

In its September 8, 2016 Order in Case No. U-17895, the Commission stated it is not inclined "to give significant weight to ROE determinations resulting from evidentiary records that are not a part of this proceeding and that are exclusively related to geographically and structurally different utilities." MPSC Case No. U-17895, September 8, 2016 Order, page 20. In its December 9, 2021 Order in Case No. U-20940, the Commission quoted this finding but clarified that it "considers other ROEs" and noted the trend in authorized ROEs for gas utilities in other states. MPSC Case No. U-20940, December 9, 2021 Order, page 89. Nevertheless, the ALJ in this case cited to the Commission's order in Case No. U-20940 as support for the ALJ's recommendation that adopts a range from a list of "approved ROEs for gas utilities nationwide in

2023 and 2024” as compiled by RRA.⁹ PFD, page 295. The ALJ concluded “that the 10.25% ROE requested by the company, while within the range, is at its very upper limit and is not particularly well aligned with returns received by other utilities having corresponding risks” as demonstrated by that range. PFD, page 296. There are three problems with this conclusion. First, it is contrary to the Supreme Court’s holdings in *Bluefield* and *Hope*. Second, contrary to the Commission’s prior direction, it gives “significant weight to ROE determinations resulting from evidentiary records that are not a part of this proceeding and that are exclusively related to geographically and structurally different utilities.” MPSC Case No. U-17895, September 8, 2016 Order, page 20. Third, it does not address¹⁰ the explicit testimony of Company witness Bulkley on this type of data, notably, the upward trend of authorized ROEs.

The PFD’s comparison to recently authorized utilities’ ROEs throughout the United States is inconsistent with the legal framework set forth by the United States Supreme Court for establishing a constitutionally sufficient ROE. In *Bluefield*, the United States Supreme Court held:

A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. [Bluefield Waterworks, 262 US at 692-693. (Emphasis added.)]

⁹ This list was contained in Exhibit AG-48.

¹⁰ The Company acknowledges the statement in the PFD that “[a]ll the parties’ testimony and briefing addressing ROE has been reviewed and considered even if not expressly summarized in the sections above” but notes that the PFD does not respond to the trend in authorized ROEs nor the Commission’s reference to those trends in its Order in Case No. U-17895.

Bluefield thus has two prongs that are relevant to this case. The first is that the “utility is entitled to such rates as will permit it to earn a return . . . equal to that generally being made at the same time . . . on investments in other business undertakings which are attended by corresponding, risks and uncertainties.” *Id.* That prong is relevant to Consumers Energy’s requested ROE. The second is that the “return . . . should be adequate, under efficient and economical management, to maintain and support [the utility’s] credit.” *Id.* The second prong is relevant to ROE as well (and is also relevant to the Company’s requested equity ratio). The PFD erred under the first prong when the ALJ used a range of authorized ROEs, which were not “made at the same time” as the test year in this case, and assumed without any support that the utilities in this list have comparable risk to Consumers Energy.

Recently authorized ROE ranges or averages offered by the other parties to this proceeding are not comparable in terms of time or necessarily corresponding risks and uncertainties as required by the Court’s holding in *Bluefield*. Rather than comparing recently authorized ROEs for utilities “at the same time” as directed by the Supreme Court, the PFD relies on an incomplete data set showing the recently authorized ROEs of utilities nationally for 2022 and 2023 for this rate case with a 2026 test year. By looking into the past and limiting the PFD’s range of recommendations for a forward-looking ROE, the PFD’s reliance on data comparing Consumers Energy’s requested ROE to other recently authorized ROEs nationally is at odds with the Court’s direction for determining a constitutionally sufficient ROE. When the ALJ adjusted the parties’ model results or significantly reduced the weight that the ALJ assigned to unadjusted results, the PFD does more than look at the data for general comparison. The PFD incorrectly applied the legal standard.

Under principles set forth in the *Hope* and *Bluefield* decisions, it is necessary to determine a return that will reflect the investor-perceived risk of the utility being examined as compared with

alternative investments and compensate investors for that risk. 4 TR 896. Ms. Bulkley explained that “the cost of equity is market-based and, therefore, must be estimated based on observable market data when establishing the ROE.” 4 TR 909 (emphasis added). “The required cost of equity is estimated by using analytical techniques that rely on market-based data to quantify investor expectations regarding equity returns, adjusted for certain incremental costs and risks.” 4 TR 910. Ms. Bulkley went on to say that the “key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors’ views of the financial markets in general, as well as the subject company (in the context of the proxy group), in particular.” *Id.* When the common stock of a public utility is not publicly traded, as with Consumers Energy, indirect or proxy approaches must be used to calculate an appropriate return on common equity. 4 TR 908. Since no one method of comparison perfectly simulates the operation of the market, multiple models combined with an assessment of the marketplace, are typically used in evaluating the market-required cost rate for common equity. 4 TR 910. The application of multiple methods, combined with overall qualitative assessment of the marketplace, provides a more comprehensive evaluation of cost of capital and is most appropriate in evaluating the required cost rate for common equity capital. *Id.*

“An appropriate proxy group is necessary to determine a reasonable return by considering investments in other firms of comparable risk.” ABATE’s Initial Brief, page 17; 4 TR 2191. For the reasons stated in the Company’s briefs and Ms. Bulkley’s testimony, the Company’s proxy group provides the best comparison to the Company for purposes of establishing an ROE estimate. In particular, the Company’s proxy group has operating and risk characteristics that are substantially comparable to Consumers Energy and therefore provides a reasonable basis to estimate the cost of equity for the Company. 4 TR 908. In other words, Ms. Bulkley (and the

other parties' witnesses) attempted to create ROE proxy groups that are as close as possible to "other business undertakings which are attended by corresponding, risks and uncertainties" (*Bluefield*, 262 US at 692) to ensure their models results are as accurate as possible (and compliant with the Supreme Court's holdings). Finally, because ROE is a forward-looking concept (4 TR 894), it is important to consider the proxy group, along with the Company, subject to the current and projected market conditions (4 TR 901). Company witness Bulkley testified that "the ROE established in a rate proceeding is intended to be forward-looking ... [and] if investors do not expect current market conditions to be sustained in the future, it is possible that the cost of equity estimation models will not provide an accurate estimate of investors' required return during that rate period." 4 TR 901. In other words, it is incorrect to rely on an incomplete data set of ROEs that were authorized in previous years to limit the results of forward-looking ROE models. Analysts use multiple models to ensure that the results reflect the market conditions that are expected during the period that the utility's rates will be in effect. 4 TR 911. The results should match returns "equal to that generally being made at the same time," (*Bluefield*, 262 US at 692) which is in the future for forward-looking rate cases. The PFD's reliance on an incomplete data set of previously authorized ROEs, to assign or withdraw full weight to the Company's model results, is in error because it is inconsistent with rate setting principles set forth in the Supreme Court's *Bluefield* holding.

There is no evidence to show that the nationwide list of ROEs in Exhibit AG-48 represent "other enterprises" or those "which are attended by corresponding risk and uncertainties" when compared to Consumers Energy during the test year, in Michigan, and having the Company's particular set of risks and uncertainties. That is why instead of simply stating an estimate of the nationwide average or range of ROEs in this proceeding, the parties' expert witnesses provide

multiple ROE models based on carefully selected peer groups, which are meant to better represent the Company's "corresponding risks and uncertainties" than a simple nationwide sample. Furthermore, a list of nationwide authorized ROEs is not market based. Ms. Bulkley's models are forward looking to evaluate what market-based ROE might be expected for those proxy companies during the test year. She testified that "[i]t is important for the ROE authorized in this proceeding to take into consideration current and projected capital market conditions, as well as investors' expectations and requirements for both risks and returns." 4 TR 900. The PFD's analysis, and its resulting range for its recommendation, is not market based or forward looking.

Under *Bluefield* and *Hope*, it would not be appropriate to rely on a, "not necessarily complete, sample of reported ROEs authorized by regulators nationwide from 2023 and 2024 as collected by Regulatory Research Associates" (PFD, page 295) as a stand in for "returns on investments in other enterprises having corresponding risks." *Id.*; *Hope*, 320 US at 603. If that were the case, the Court could have simply mandated that ROEs for individual utilities be held to an average or range from other utilities. But it did not. Multiple models, which Ms. Bulkley used in this proceeding, are appropriate for estimating ROE in the context of setting utility rates. 4 TR 910. The PFD erred when it minimized the results from several of the quantitative results from Ms. Bulkley's models.

The Commission's finding in Case No. U-17895 to not give significant weight to previously authorized ROEs was consistent with the legal framework set forth by the United States Supreme Court for establishing a constitutionally sufficient ROE. The PFD's comparison to recently authorized utilities throughout the United States is inconsistent with the Commission's previous finding and the evidence in this record regarding trends in the utility industry. The Commission has considered the trend of nationwide authorized ROEs. MPSC Case No. U-20940,

December 9, 2021 Order, page 89. The trend of nationwide authorized ROEs is certainly a relevant consideration because it is evidence for the trend in the utility industry that faces the same market conditions as Consumers Energy. The Company specifically addressed this topic on pages 55 through 58 of its Reply Brief. Industry trends that reflect market conditions for utilities are fundamentally distinct from an average or range of authorized ROEs for individual utilities within the industry. An average or range of authorized ROEs does not fit the time and similar-risk prong from *Bluefield*. However, a comparison with the trends in authorized ROEs does fit because it accounts for the relative attractiveness of the subject company to other utilities over a comparative time. Ms. Bulkley testified that when “higher returns are available elsewhere for other investments of comparable risk over the same time-period, investors have an incentive to direct their capital to those alternative investments.” 4 TR 898-899, emphasis added.

The industry trend is a rise in state commission authorized gas utility ROEs over the past three years. Like Staff and the Attorney General, the ALJ pointed to a range of authorized ROEs nationally to conclude that its ROE recommendation is reasonable. PFD, page 294; See 4 TR 1983, 2560; Consumers Energy’s Initial Brief, page 57. There are two inaccuracies in this view of the underlying data. First, when compared with Company witness Bulkley’s proxy development, the ALJ (like Staff and the Attorney General) did not establish that the gas utilities making up his range are useful proxies for the Company.¹¹ See 4 TR 993-1000. For example, the PFD notes challenges in California and Florida as pointed to by the Attorney General’s arguments

¹¹ There is also an issue of notice. For example, if entries on a list compiled by RRA are considered a comparator for setting an authorized ROE, a party should go through a vetting on each entry to demonstrate whether or not it is a comparator. Of course, by using proxy groups parties are able to conduct a vetting of the screening criteria and individual entries. See 4 TR 993-1000. On the other hand, no party knew the PFD would rely heavily on a sample of nationwide authorized ROEs.

why those states (or any others) in the list¹² have higher ROEs, but there is no specific showing why those states would or would not be sufficient proxies for the Company. PFD, page 294; 4 TR 1983-1984. Second, because the ALJ did not quantify any comparison between those gas utilities as proxies for the Company, the PFD's conclusion that the range is representative is unsupported by the record. It is speculative to consider those utilities to be sufficient comparators for the Company (whether referred to as ROE peers or proxies). Additionally, the PFD mentions several times that the list is not comprehensive.¹³ See, e.g., PFD, page 295. No intervening witness demonstrated that it is a correct list either.

The trend is more meaningful than the range or average from the list of authorized ROEs. If both nationwide authorized ROEs and equity ratios are trending upward, when taken together, Consumers Energy's ROE and equity ratio should not continue trending downward. The PFD recommends a decrease in ROE and a continuation of a stale equity ratio. The fact that the Commission set DTE Gas's ROE to 9.90% in Case No. U-20940¹⁴ while noting "that the authorized ROEs for gas utilities in other states may have declined and, in some cases, are below 10.00%" (MPSC Case No. U-20940, December 9, 2021 Order, page 89), does not mean that differences in "corresponding risks and uncertainties" (*Bluefield*, 262 US at 692) between nationwide authorized ROEs and Consumers Energy's ROE for the test year in this case are in any way aligned. In Case No. U-20940, the Commission noted the downward trend that was

¹² In Exhibit A-33 (MRB-11), the Company provided authorized ROE data. On page 294 of the PFD, the ALJ notes Attorney General witness Sebastian Coppola's arguments against the information in the exhibit, mainly his claims that the utilities were "not apt comparators for the Company." PFD page 294. However, the same argument would apply to the utilities from Exhibit AG-48. Neither list went through vetting on the record similar to the witness' proxy groups.

¹³ The PFD removes the "highest and lowest values" in the data set as outliers. It is worth noting that because the list is not comprehensive anyway, there may be higher or lower values of equal relevance that are not accounted for; therefore, there is no way of knowing whether the excluded values are outliers.

¹⁴ On page 294, the PFD cites to Case No. U-20940. DTE Gas's most recent gas rate case is Case No. U-21291, decided November 7, 2024.

demonstrated on the record for that 2021 proceeding. But the record now, for a 2026 test year gas rate case, demonstrates an upward trend in authorized ROEs. See, MPSC Case No. U-20940, December 9, 2021 Order, page 92. The PFD’s misstated Supreme Court standards for the adequacy of utility returns is not a sufficient basis for the ALJ’s recommendation. In other words, the historical data alone does not provide a useful comparison to a past, current, or future authorized ROE—too low, high, or just right. See 4 TR 981. However, the trend of the data is useful because it confirms the industry trends observed by Ms. Bulkley that authorized ROEs are increasing. *Id.* The more reasonable conclusion is that as the industry experiences an increase in authorized ROEs, the Company’s ROE should in turn increase and certainly not decrease. The upward trend in authorized ROEs is a meaningful statement about the industry or the overall market, for example, that the increase may be due to a contemporaneous period of elevated interest rates.¹⁵ Borrowing is more expensive with elevated expected interest rates, which in turn raises the cost of capital, and a higher return on equity. 4 TR 980.

In this proceeding, the parties analyzed the trends in authorized ROEs. For its part, ABATE referenced portions of Mr. Walter’s testimony that showed a decrease in gas utility ROEs over the last 10 years. ABATE’s Initial Brief, page 11. However, reference to the 10-year time horizon is misleading because, as mentioned above, recent ROEs have been trending up. As Ms. Bulkley observed, ABATE’s witness did not sufficiently cover the increased uncertainty in the economy that impacts capital investments. 4 TR 975. ABATE did not adequately consider uncertainty in the current market and therefore joins Staff in missing that increased uncertainty means increased

¹⁵ Ms. Bulkley testified regarding the interest rate environment during the 2022, 2023, and 2024 time period utilized by Staff witness Megginson and concluded that is analysis fails to appropriately consider the interest rate environment over the time period. 4 TR 981.

risk, which increases the cost of equity. 4 TR 976. This is the more correct conclusion regarding current and anticipated market conditions.

There are also several evidentiary deficiencies with the PFD's reliance on recently authorized ROEs in other jurisdictions. First, by explaining the importance of ROE proxy group selection, Ms. Bulkley demonstrated that recently authorized ROEs across the nation would exclude information necessary to fully reflect a complete and accurate understanding of the overall ROEs authorized for the utilities that the Company will compete with for capital. 4 TR 907-909. No witness in this proceeding demonstrated that RRA data should be used as a direct proxy in setting an ROE. Similarly, ranges within that data should not be used to significantly discount the wealth of actual model results that use proxies that were vetted on the record. Potentially, that vetting could have demonstrated whether states have alternative regulatory frameworks, for example, where ROE is set for multiple years without the need for a general rate case or ROE is set through a process outside of the normal rate case. The PFD also did not point to any additional state-specific regulatory frameworks in the context of the ALJ's adjusted authorized ROE range. Results for comparable utilities may or may not be included in the RRA data.

Using the artificially limited range and the average result from Exhibit AG-48 to check and ratify the average results from the witnesses' quantitative analyses has a major methodological flaw. By limiting the results of the quantitative results to those that fit within the ALJ's set range from the RRA data, the ALJ artificially ensures that the average of the remaining results for the quantitative analyses will trend toward the average of the chosen range. In other words, the chosen and adjusted results are close in value to the average because the PFD limited them to be within the range that contained that average. Of the 11 results, as adjusted, none are equal to or above the Company's requested and supported 10.25% ROE. PFD, pages 297-298. The average of the

PFD's accepted results is 9.72%, which is almost equal to the average of approved nationwide ROEs in 2023. PFD, page 298. The PFD determined that "the average of the model results given full weight [(9.72%)] and the average of other authorized ROEs [(9.71% from Exhibit AG-48)] will be considered when evaluating an appropriate ROE for the company under the Supreme Court's standards in *Hope* and *Bluefield*." PFD, page 298. But those averages are both subject to a range of authorized ROEs from Exhibit AG-48.¹⁶ Therefore, the ALJ's method intentionally excludes results from some comparable (proxy) utilities from consideration because they do not fit within the ALJ's range from non-comparable utilities. As stated above, this method is not consistent with the Court's standard and therefore the Commission should reject the PFD's ROE recommendation.

The PFD's ROE reasoning is also contrary to the ALJ's recommendation for the Company's authorized equity ratio. In addition to ROE, investors have options within the industry; therefore, the Company must be able to maintain supportive credit metrics relative to other utilities. 4 TR 933. In a forward-looking test year, that means considering industry trends and their potential impact on the Company and its peers. Therefore, to the extent that the Commission does consider the RRA data beyond trends (which should be given only minimal weight), it remains important to consider not solely ROEs but then the ratemaking equity ratios being approved nationwide. See 4 TR 809. Company witness Bleckman sponsored Exhibit A-34 (MRB-12), which highlights that equity ratios for regulated utilities have also increased over the last several years. 4 TR 808. Mr. Bleckman noted federal tax changes in 2018 negatively impacted utility cash flow and credit metrics, and then utility commissions adopted higher equity ratios as a way to combat those

¹⁶ The result of this double consideration of the authorized ROEs from Exhibit AG-48 is a weighing of the accepted results that fit in the range. PFD, page 297. Practically, the range is dispositive for the PFD's ROE recommendation because only the results that fit in the range get the ALJ's full weighing.

impacts. *Id.* There was an increase in approved electric utility equity ratios by 130 basis points from 2019 to 2023. *Id.*, Exhibit A-34 (MRB-12). In contrast, Consumers Energy’s authorized equity ratio has decreased 262 basis points from 2019 to the present. 4 TR 808. More specifically, peer authorized equity ratios are significantly higher than 50% and are rising. 4 TR 809. Mr. Bleckman testified that a 50.75% equity ratio coupled with an ROE of 10.25% is the minimum amount that is appropriate to help preserve the Company’s current credit rating. *Id.* Given the upward industry trend, it was error for the PFD to recommend a 50% equity ratio while recommending a 15 basis point reduction in the Company’s ROE.

In the PFD’s conclusion, the ALJ recommended an “ROE for the company that is within the range of ROEs awarded to other utilities but that tends toward the average or lower end of that range.”¹⁷ PFD, page 301. The PFD misunderstands the Supreme Court’s holdings. PFD, pages 300-301. The PFD recommended a 9.75% ROE based on the “average of the accepted results of the parties’ models as determined [by the PFD] (9.72%) and is close to, but just a few basis points above the national average awarded ROE in 2024 (9.71%).” PFD, page 302. Because it relies on the nationwide average and the parties’ models as adjusted to fit into the predetermined range of the list of nationwide ROEs, the PFD ultimately and incorrectly bases its ROE recommendation on the RRA list of nationwide authorized ROEs as shown in Exhibit AG-48 instead of the quantitative models presented on the record in this proceeding.

While utilizing nationwide authorized ROEs, the PFD recommends reducing the Company’s last authorized ROE of 9.90% to a level (9.75%) that would potentially move Consumers Energy’s ROE closer to levels favored in states with different regulatory paradigms. For purposes of this proceeding, there is no way of knowing because the PFD cites to no analysis

¹⁷ Note, however, the PFD made no upper adjustment to its strictly balanced equity ratio recommendation to reflect authorized peer equity ratios.

to compare the states covered by the RRA authorized ROE data to Michigan. This type of arbitrary result would send a significantly negative signal to investors that are considering Michigan as a good place to invest in needed infrastructure.

Given the importance of investor perceptions of risk and investors' desire to see a consistent track record of constructive regulation (4 TR 815), it is unwise and improper to base an ROE determination in this case on a comparison to ROEs for non-comparable utilities in potentially negatively regarded regulatory environments. Including these utilities in a range for direct comparison (as opposed to vetted proxies input to longstanding ratemaking models) will have the effect of "averaging down" the Company's ROE below levels that would be attractive to investor capital. The Commission should disregard recommendations that limit or lower the Company's ROE based on a nationwide authorized ROE data set, range, or average. For the reasons stated above, that type of data is not a proper basis for ratemaking purposes.

2. The ALJ Erred by Incorrectly Limiting the Weight of the Company's Quantitative Models

Although, the PFD did not generally criticize the Company's methodology for its quantitative analyses, the PFD did limit their weight. That is inappropriate. Instead, if there is no meaningful problem with the methodology, there is no justification for limiting the weight of the analyses. The PFD deferred to the ALJ's adjusted range of 9.15% to 10.25% to assign full weight to the parties' respective model results within that range and to adjust results in consideration of that range. PFD, pages 257-258. The PFD also agreed with Staff and the Attorney General when considering the Company's Market Risk Premium ("MRP") "on the high end of what could be considered a reasonable result" but did not exclude results because of it. PFD, page 257. However, it is worth noting that Company witness Bulkley showed that in 53% of observations the market was at 12.04% or greater. 4 TR 919. Ms. Bulkley supported her analysis with solid

reasoning and extensive academic support. 4 TR 911-914, 1000-1016. Ultimately, the PFD failed to give sufficient consideration to the Company testimony explaining the assumptions used to make the Company's adjustments to the models, which reflect actual current economic circumstances. Instead, the PFD improperly applied the RRA data set from Exhibit AG-48 as discussed above to limit full consideration of the models. As a result, the Commission should not follow the ALJ's recommendation to decrease the Company's ratemaking ROE based on these improper limitations.

CAPM

Regarding the Capital Asset Pricing Model ("CAPM"), the PFD found "value in having a multitude of different inputs and methods being presented and examined such that there should be minimal interference with the parties' inputs so long as they are justified and reasonable." PFD, page 256. Specifically, the PFD found that the parties' risk-free rates and MRP inputs are reasonable. PFD, page 257. The PFD considered the Company's MRP "on the high end" but did not disqualify the results. *Id.* The PFD also found appropriate to consider both "a forward-looking implied MRP or a MRP derived from historical data." *Id.* Nevertheless, the PFD departed from those findings and adopted "the adjusted range of the dataset in Exhibit AG-48 as a representative (albeit not complete) sample of reported ROEs recently approved by regulatory bodies nationwide." *Id.* The result was that the PFD averaged Ms. Bulkley's six lowest CAPM results to derive a single CAPM estimate of 10.12%. While this figure suggests an increase in the Company's current ROE is warranted, it was in error to exclude Ms. Bulkley's other CAPM results from full consideration only on the basis of the RRA dataset listed in Exhibit AG-48.

Ms. Bulkley used three sources for her CAPM risk-free rates. 4 TR 917-918. She also used three beta coefficients (one reported by Bloomberg, one by Value Line, and one relying on

long-term average betas from the proxy group). 4 TR 918. From these two sets with three inputs each, Ms. Bulkley calculated nine results. The ALJ excluded all three of Ms. Bulkley's CAPM results that used *Value Line* betas as inputs for no other reason than they were outside the preselected range from the RRA dataset listed in Exhibit AG-48. The PFD offered no support for the conclusion that *Value Line* betas were less valid than other betas. If the CAPM results based on *Value Line* betas are included, the average of Ms. Bulkley's nine CAPM results is 10.51%.

An authorized ROE should be a forward-looking estimate of the cost of equity. 4 TR 1036. In her testimony, Ms. Bulkley thoroughly defended the underlying analysis for her expected market return of 11.92%. See 4 TR 1036-1042. In particular, inflation remains well above the 2% target and is expected to remain elevated over the near term, and Ms. Bulkley demonstrated the MRP is higher during periods of increased inflation. 4 TR 1040.

The CAPM relies on interest rates as an assumption in the model and therefore may more directly reflect the market conditions expected at the time customer rates are in effect. 4 TR 911. In its presentation in this proceeding, the Company emphasized the importance of the inverse relationship between interest rates and the MRP. The intervening parties did not properly incorporate this concept and consequently understated the MRP and their ROEs. Likewise, their criticisms of the Company's MRP are misplaced. See Consumers Energy's Reply Brief, pages 73-74. The PFD should have recognized the merits of the Company's MRP analysis.

The Commission should consider that Ms. Bulkley's CAPM, which accounts for the inverse relationship between interest rates and the MRP, is a better approximation than the other parties' CAPM results, and categorically better than the RRA data reflected in Exhibit AG-48 for the Company's authorized ROE in this case. It was error for the PFD to exclude or diminish

Ms. Bulkley's particular quantitative results only because they fall outside the predetermined range from the RRA data set reflected in Exhibit AG-48.

ECAPM

The PFD rejected consideration of the Company's Empirical CAPM ("ECAPM") evidence. PFD, page 263. Ms. Bulkley's testimony thoroughly reviewed the benefits of the ECAPM model. See 4 TR 1044-1052. Because the ECAPM model accounts for a flatter risk/return relationship than predicted by the CAPM, which in this case skewed the CAPM model results downward, Ms. Bulkley's ECAPM calculated higher than her CAPM result. In other words, the ECAPM correction is necessary to adjust for a known issue with CAPM. The PFD offers no explanation to justify ignoring the known weakness in the CAPM results by rejecting any consideration of ECAPM. Accordingly, there is a basis for the Commission to weigh Ms. Bulkley's ECAPM results for the reasons described in her rebuttal testimony. See 4 TR 1044-1052. At a minimum, it is an additional source of relevant evidence for the Commission's consideration.

The PFD entirely rejected the ECAPM because Consumers Energy did not "identify any order in which the Commission has ever explicitly recognized [the] approach." PFD, page 263. But, traditionally, the Commission has based its ROE decision in rate cases on the totality of the circumstances as reflected in the record before it. As it has in the past, the Commission should consider all relevant evidence. As Ms. Bulkley pointed out, it is important to use multiple models because the cost of equity is not directly observable. 4 TR 910. Likewise, despite lauding the use of multiple models, or inputs into models, elsewhere in the PFD, it is improper that the ALJ summarily dismissed the ECAPM. The ECAPM is valid for all the reasons presented in this

proceeding and it was error for the PFD to reject it. The average of Ms. Bulkley's nine ECAPM results is 10.83%. 4 TR 971.

DCF

For the Discounted Cash Flow ("DCF") model, the PFD found that "all parties provided adequate justification or reasoning for their model choices and inputs such that all DCF calculations will be considered." PFD, page 273. Then, the PFD adopted "the adjusted range of the dataset in Exhibit AG-48 as a representative (albeit not complete) sample of reported ROEs recently approved by regulatory bodies nationwide." *Id.* Therefore, the PFD gave full weight only to the average of Company witness Bulkley's minimum growth rate results. *Id.* The PFD gave no weight to Ms. Bulkley's maximum growth rate DCF result because the average "approaches the company's own estimate of a market-based return." PFD, page 274. The PFD points to no evidence admitted in this proceeding that disqualifies a party's result that "approaches" (or even exceeds) its estimated market return for equities. Ms. Bulkley did show that projected growth rates are not limited by investors' expectations of the growth of the domestic economy. 4 TR 1010-1012; see, also, Consumers Energy's Reply Brief, page 75. There is significant academic literature that supports the use of earnings growth rates and shows their use is consistent with a long-term growth rate that matches investors' expectations of the domestic economy as a whole. 4 TR 1010-1011.

Consumers Energy also respectfully takes exception to the PFD's "concerns about the accuracy of the company's evidentiary presentation." (PFD page 275) In her DCF model testimony, Company witness Bulkley's cited a study filed by the Rate Regulation Initiative of the Alberta Utilities Commission to support her conclusion "that electric and combination electric and natural gas utilities were approximately 5% more productive than the U.S. economy over the study

period.” 4 TR 1011. The ALJ expressed concern that value for the Total Factor Production growth rate for the United States quoted by Ms. Bulkley¹⁸ from the study does not actually appear in the cited study. PFD, page 275. The Company did not offer the study into the record as an exhibit in this proceeding. However, in reviewing Ms. Bulkley’s testimony to respond to the ALJ’s concern, the Company discovered that there was an unnoticed error in Ms. Bulkley’s citation to the source material in footnote 89 of her rebuttal testimony. Ms. Bulkley’s rebuttal inadvertently referred to the update to the Alberta Utilities Commission study instead of the initial study. The figure quoted by Ms. Bulkley in her rebuttal testimony is correct and can be found there. This minor error does not justify an adverse conclusion regarding the accuracy of the Company’s overall evidentiary presentation. The Commission should not draw such a conclusion, particularly because the factual basis of Ms. Bulkley’s testimony is accurate.

Ms. Bulkley provided extensive evidence on the DCF model. See 4 TR 911-914, 1000-1016. One of her main points was taken from Dr. Roger A. Morin that “based upon the wealth of empirical and academic literature that supports the superiority of analyst’s forecasts as a measure of investor expectations for the use of such forecasts in the DCF model, current earnings growth forecasts are the appropriate growth rates to use in a DCF analysis.” 4 TR 1012, quoting Roger A. Morin, *Modern Regulatory Finance*, Public Utilities Reports, Inc., 2021, page 486. This point is directly contrary to the PFD’s finding that limited full weight consideration of DCF values higher than 10.25%. For context, in 53% of observations, the market was at 12.04% or greater. 4 TR 919.

¹⁸ The figure is the 0.91% TFP growth for the U.S. economy from 1972 to 2009 which accurately stated from the study in Ms. Bulkley’s testimony.

BYRP

The PFD expressed concerns about the use of authorized ROEs “as part of the input data” in the Company’s presentation of Ms. Bulkley’s Bond Yield to Risk Premium (“BYRP”) methodology. PFD, page 282. This concern is at odds with the PFD’s method using a range of authorized ROEs to explicitly limit from consideration the outputs of the various ROE models. That method of using authorized ROEs is far more direct than using authorized ROEs as an input for models. While not “market data,” investors are aware of authorized ROEs and would consider them in their overall assessment of the value of a utility stock. 4 TR 1058. Investors would also consider other factors. As discussed at length above, the PFD uses authorized ROEs for far more than “a basis for comparison,” counter to the PFD’s statements. See PFD, page 282. As discussed above, limiting model results by a predetermined range of authorized ROEs essentially moots all input data that led to those results.

The PFD also stated that “it is not clear if the particular BYRP methodology utilizing authorized ROEs can be used anywhere other than in utility regulatory proceedings because most other businesses do not have regulatory-awarded ROEs.” PFD, page 283. . Company witness Bulkley testified that investors certainly consider the ROEs of particular utilities that they consider for investment purposes. 4 TR 1058. Investors are aware of authorized ROEs (for actual comparisons), and “unconstructive ROEs have resulted in sharp declines in utility stock prices,” in addition to notice from “equity analysts and rating agencies.” 4 TR 1058.

Even while noting that “the Commission recently suggested that it would generally not endorse or discourage any model to maximize flexibility and to review models and data on a case-by-case basis,” the PFD nevertheless stated “great caution” as to “the company’s BYRP results

that utilized authorized ROEs as an input.” PFD, page 284. . The PFD’s resistance to the Company’s analysis is unsupported.

Finally, the “PFD adopted the adjusted range of the dataset in Exhibit AG-48 as a representative (but not necessarily complete) sample of reported ROEs recently approved by regulatory bodies nationwide” and reduced the weight of the Company’s results due “to the questionable methodology used, and because the values exceed the upper bound of the adjusted range of ROEs recently awarded nationwide.” PFD, page 284. The PFD’s findings regarding Ms. Bulkley’s BYRP analysis are in error. Her regression analysis demonstrated a strong negative relationship between the risk premium and interest rates and provides additional insight into considerations relevant to investors. 4 TR 922. Ms. Bulkley’s BYRP analysis uses authorized ROEs along with other factors in her BYRP analysis. The results of Ms. Bulkley’s BYRP analysis are 10.55%, 10.41%, and 10.33%, and support the Company’s proposed ROE of 10.25%. 4 TR 971.

3. The ALJ Erred By Failing to Appropriately Consider the Impact of Market Conditions – Flotation Costs, Capital Expenditures, and the Regulatory Environment – on the Determination of An Appropriate ROE

Consumers Energy thoroughly covered an analysis of the regulatory environment, credit, and macroeconomic considerations (together “market conditions”) in response to the other parties. See Consumers Energy’s Reply Brief, pages 46-60, 67-69, 71-74. The ALJ erred in failing to appropriately consider the impact of market conditions on the determination of an ROE in this case.

Flotation costs are real “out-of-pocket expenditures” (4 TR 925) and are a relevant consideration, in particular given that ROE models utilize proxies. The PFD noted that Ms. Bulkley calculated “that the average impact of floatation costs on the proxy group was

0.14%,” but took issue that “she did not incorporate an explicit adjustment for floatation costs into her recommendation.” PFD, page 286. The PFD did not recognize that Ms. Bulkley included a consideration of flotation costs in her analysis as another factor in the determination of an appropriate ROE. See 4 TR 928. Given the PFD’s reliance on the nationwide list of authorized ROEs from Exhibit AG-48, Ms. Bulkley’s flotation analysis shows the importance of the proxy group development that all the parties undertook. While flotation costs were not a determining factor, Ms. Bulkley applied the calculated cost “to the proxy group in the DCF analysis to estimate the impact of the cost of equity associated with flotation costs.” 4 TR 928.

The PFD’s dismissal of flotation costs demonstrates the inconsistency in the ALJ’s analysis. One of the fundamental flaws with the data in the RRA database from Exhibit AG-48 is that it does not consider other factors, for another example, flotation costs. In this context, flotation costs are an additional factor for comparison of “corresponding risks and uncertainties” between utilities under the Supreme Court’s holding in *Bluefield*. 262 US at 692. The Company’s presentation on capital expenditures provides further evidence as to the importance of using a proxy group of utilities as opposed to the PFD’s use of a raw data set (including the range or average of the data set). Ms. Bulkley considered that most of the proxy group had capital tracking mechanisms while the Company does not. 4 TR 931-932, 1074; Exhibit A-14 (AEB-1), Schedule D-5, page 29. Ms. Bulkley’s analysis of both of these factors in turn gives weight to her proxy analysis, which provides a valid comparison between utilities with corresponding risks and uncertainties.

Along similar lines, the PFD recites Ms. Bulkley’s analysis of the regulatory environment, credit, and macroeconomic considerations but fails to recognize that she was comparing those factors for Consumers Energy with her proxy group for a more wholistic

analysis. The PFD disposes of all these market condition factors by noting “that it undertook a significant discussion of the company’s regulatory environment and credit outlook in the section regarding capital structure” and “merely reiterates that the company’s credit outlook is stable and that ratings agencies view Michigan’s regulatory environment in a generally positive light.” PFD, page 293. However, that recommendation fails to consider that the Company requested a higher equity ratio, which the PFD rejected, and the PFD recommended lowering the Company’s ROE.

There is a larger concern. By utilizing the incomplete RRA list of authorized ROEs from Exhibit AG-48 to assign weight to the parties’ ROE model results, the PFD improperly eliminates or at least reduces the comparison of “corresponding risks and uncertainties” between utilities (in this case vetted proxies). That comparison is necessary in setting a constitutionally sufficient authorized ROE. Likewise, other factors – Flotation Costs, Capital Expenditures, and the Regulatory Environment - are additional factors that affect the corresponding risks and uncertainties between utilities.¹⁹ When the PFD does not include or consider flotation costs “when setting the ROE” (PFD, page 286) and finds that the Company’s capital expenditure plans “do not justify any adjustment when considering a proper ROE,” once again, the PFD misjudges the importance of the proxy group analysis. Instead, the ALJ favors the adjusted range of RRA-authorized ROEs from Exhibit AG-48. Ms. Bulkley’s proxy group analysis ensures that ROE models’ results cover both relevant prongs of the *Bluefield* holding in this case: a “utility is entitled to such rates as will permit it to earn a return . . . equal

¹⁹ The PFD goes into a discussion attempting to fit the broad “stock market” into the Supreme Court’s *Bluefield* and *Hope* holdings. PFD, pages 300-301. The Company raises this point to take exception with the ALJ’s statement that “[t]o best honor these divergent directives, this PFD recommends generally targeting a ROE for the company that is within the range of ROEs awarded to other utilities but that tends toward the average or lower end of that range.” PFD, page 301. That conclusion and resulting recommendation is unsupported because the Supreme Court holdings are not inconsistent.

to that generally being made at the same time . . . on investments in other business undertakings which are attended by corresponding, risks and uncertainties” and that the “return . . . should be adequate, under efficient and economical management, to maintain and support [the utility’s] credit.” *Bluefield*, 262 US at 692-693. The Commission should not lower the Company’s ROE (and should raise it) because the analyses (utilizing proxies) to cover the like risk prong, and market conditions covering the credit maintenance prong do not support such action.

In contrast, the PFD incorrectly declines to find a threshold met to deviate from the Commission’s preferred strictly balanced equity ratio, and then therefore declines to see any justification for “any significant adjustment when considering proper ROE.” PFD, page 293. But the PFD’s ROE recommendation itself limits its consideration of the models based on the predetermined range from Exhibit AG-48. Therefore, the PFD fails to meet both relevant prongs of the legal standard, i.e., similar risk and maintaining the utility’s credit, in its ROE recommendation. Further, the ALJ incorrectly considers Consumers Energy, headquartered in Jackson, Michigan, “analogous” to a gas utility in New York City over one hundred years ago and an essentially risk-free investment. PFD, page 299. Utilities today, including Consumers Energy, are certainly not risk-free investments. 4 TR 1072.

In sum, market conditions, including flotation costs, capital expenditures, and the regulatory environment, support the Company’s requested 6.22% return, consisting of a 10.25% ROE and 50.75% equity ratio. The Commission should reasonably approve the Company’s request in this case.

4. ROE Conclusion

Consumers Energy provided substantial testimony and other record evidence through Company witnesses Bulkley and Bleckman, which undermine the ALJ’s conclusion that the

Company's ROE should be reduced to 9.75%. The Company put forth substantial evidence supporting a finding that the Company's ROE for ratemaking purposes should be set no lower than 10.25% and explaining why an ROE at that level is appropriate in light of the legally required criteria for determining a constitutionally sufficient return. Consumers Energy respectfully submits that the Commission should not reduce the return below the most recently authorized level of 9.90% and requests that the Commission should instead use an ROE of 10.25% in calculating the Company's revenue deficiency in this case.

C. Overall Rate Of Return – Conclusion

Consumers Energy requests that the Commission authorize an ROE in this case for the Company's gas business of not less than 10.25%. If the Commission authorizes a 10.25% ROE in combination with the capital structure at a 50.75% equity ratio as recommended by the Company, then the resulting after-tax cost of capital would be 6.22%. The Company's proposal is more reasonable than the other parties' because its models are more accurate, and the proposal more appropriately fits the current market conditions, in particular the recent utility industry trends, and the risks to Consumers Energy's credit strength given the recent trends in the Company's authorized ROE and equity ratio. The Commission should reject the PFD's cost of capital recommendation because it puts too much weight into the incomplete dataset from Exhibit AG-48, contrary to the Company's overall presentation of the evidence in this case.

IV. THROUGHPUT

The PFD properly rejected arguments from the Attorney General to adjust the Company's gas load forecast and from MNSC recommending that the Company's gas load forecast should be rejected entirely. Consumers Energy agrees with the PFD's recommendation in that regard. The PFD also included three recommendations related to the Company's presentation of its gas load forecasts in future cases. Although Consumers Energy does not necessarily oppose those

recommendations, the Company observes that the arguments in favor of them are not as clear as the PFD supposes and the benefits are questionable.

First, the PFD recommends directing the Company to utilize out-of-sample data to test its regression model in the next gas rate case. PFD, page 320. Consumers Energy already plans to include some additional out-of-sample testing in its next gas rate case to further demonstrate the accuracy of its regression modeling. However, the PFD was not specific about how it was recommending the Company should perform that out-of-sample testing, so this issue requires additional clarification. Out-of-sample testing refers to using the regression analysis to “predict” the outcome from one or more known periods that were not included within the data used in training the model to see how accurately the model predicts those known outcomes. That can be accomplished in three ways: the analyst can (i) use the model to predict the next future period and, when that period occurs, the analyst can review the prediction to evaluate whether the model is accurate; (ii) withhold some of the data from the data set used to train the model and see if the model accurately “predicts” the portion of the data withheld; and (iii) use the model to “predict” recent past periods that predate the data used to train the model.

The first method of out-of-sample testing is what Company witness Mustafa A. Sherwani’s graph on page 8 of his direct testimony does. 2 TR 272. The Company plans to continue including that analysis in its next gas rate case. In the Company’s next gas rate case, Consumers Energy also plans to use the third method. The Company plans to use the model to “predict” some of the recent past years that predate the data used to train the model. However, Consumers Energy does not plan to use the second method in its next gas rate case because the second method can actually reduce the accuracy of the model. Consumers Energy uses the most recent 11 years of actual data to train its model. 2 TR 280. If the Company performed out-of-sample testing that excludes one

or more years of data from within the most recent 11-year period, that means the model would necessarily be trained with less data, making it more susceptible to error. Consumers Energy submits that it is not necessary for the Commission to be prescriptive about the use of out-of-sample testing in the Company's next gas rate case – the Company plans to do more of it anyway – but if the Commission chooses to adopt the PFD's recommendation on out-of-sample testing, it should either leave the specific method to the Company's discretion or at least specify that the first and third methods of out-of-sample testing described above are sufficient.

Second, the PFD recommends that the Commission should direct the Company to “find a way to incorporate the impact on gas demand attributable to increasing electrification measures” in future cases requiring long-term forecasts. PFD, page 320. Mr. Sherwani testified that Consumers Energy already “plans to assess possible projected impacts of electrification in future gas rate cases.” 2 TR 279. However, at the time of filing this rate case, Mr. Sherwani explained that there was “no information available” to show the impact, if any, from electrification. 2 TR 279. Although Mr. Sherwani was speaking specifically about electrification impacts associated with enactment of Public Act 229 of 2023 in his rebuttal testimony, under cross-examination he further clarified that Consumers Energy's gas strategy team did (and continues to) assess possible impacts from electrification generally. 2 TR 300-301. The Company determined that it was premature to include any electrification impacts in this case because there is no data by which the Company can determine what impact electrification might have. The Company cannot incorporate data into a future analysis if that data does not exist. As Mr. Sherwani testified, Consumers Energy anticipates that there will be impacts from electrification in the future, which means there will eventually be data that enables the Company to incorporate such impacts into its gas load forecasting. See 2 TR 279. However, it is uncertain whether such data will exist and be available

to the Company by the time of the next gas rate case filing. Again, the Company submits that the directive the PFD recommends is unnecessary because the Company is actively assessing electrification activity and already plans to incorporate the impacts of electrification into its gas load forecasts when reliable data supporting those impacts is available. But, if the Commission chooses to adopt the PFD's recommendation, it should at least expressly acknowledge that the impacts of electrification might be zero in near-term cases if no reliable data is available.

Third, the PFD recommends that the Commission direct Consumers Energy to "include the forecasted yearly sales for each major customer class for the 10-year gas delivery planning horizon and include for each year a list of the amount of throughput expected on a peak demand day." PFD, page 321. The Company already includes a 5-year forecast of gas deliveries as part of its gas rate case submissions. Consumers Energy is not necessarily opposed to providing the additional five years recommended by the PFD, but the Company questions the value of the additional work needed to produce it. The farther forward from the current year a forecast looks, the less reliable the forecast becomes. MNSC inadvertently illustrated this point in its Initial Brief in this case. MNSC used non-record evidence from prior Consumers Energy gas cases, specifically, the Company's five-year forecast exhibit, in an effort to (incorrectly) suggest that Mr. Sherwani's graph on page 8 of his direct testimony (2 TR 272) does not use rate case forecasts to develop the forecast line. As Consumers Energy showed in its Reply Brief, part of MNSC's error was that it compared the forecast line in the graph to gas load forecasts that were two or three years in the future rather than using the nearest term forecasts in those cases. The farther-range forecasts that MNSC pointed to deviated more from the forecast line in the graph than the near-term forecasts because the econometric data used to create the second, third, fourth, and fifth year of the forecast can change materially by the time those years actually come to fruition. The

years in those forecasts have some value when needed for planning activities that will extend beyond a single year. But, the farther forward the forecast looks, the lower the reliability of the prediction. In Consumers Energy's experience, a five-year outlook is sufficient to meet most long-term planning needs while still retaining adequate forecast accuracy. Consumers Energy cannot vouch for the value of requiring 10 years. The Company submits that the PFD's recommendation is not necessary.

V. **ADJUSTED NET OPERATING INCOME**

A. **Other O&M Expense**

1. **Gas Engineering and Supply O&M Expense**

a. **Project Management and Quality Lean O&M Expense**

The Quality Lean Office is responsible for the Company's quality management system, and establishes and maintains standards, processes, procedures, and policies to support overall business efficiency and compliance with regulatory requirements. 3 TR 360. Key responsibilities of the employees in the Quality Lean Office include developing and implementing policies and procedures to support the reduction of waste and errors. Department employees are involved in improving Company-wide processes, helping to identify opportunities for improvement. *Id.* The purpose of the Quality Lean Office is to build the Company's lean capabilities by supporting the organization in using the CE Way and lean tools (such as value stream mapping, data analysis, waste elimination, problem solving, and standardized work development) to manage and improve performance. 3 TR 461. The Quality Lean Office provides learning and development on lean methodologies and tools and facilitates problem solving, giving organizations throughout the Company the insight to identify opportunities to improve efficiency and effectiveness. See Exhibit AG-57, page 3.

The Company projected a test year expense of \$1,132,000 for the Quality Lean Office, which includes the salaries and expenses for the Company employees that make up the Quality Lean Office and that seek to develop the Company's ability to operate more efficiently and effectively. The PFD adopted the Attorney General's recommendation to deny all Quality Lean Office salaries and expenses. PFD, page 327. The Commission should reject the PFD's recommended disallowance of the salaries and expenses of these Company employees.

The Quality Lean Office is a department whose purpose is to provide tools to other departments throughout the organization to identify ways to improve work processes to ensure regulatory compliance, provide better service to customers, and become more efficient. The Quality Lean Office includes personnel that provide support throughout the Company, like many other support organizations. For example, several areas within Corporate Services provide various kinds of support throughout the organization:

- Sustainability & External Affairs acts as a conduit between the Company and its employees, customers, and external stakeholders;
- Legal, Ethics, Regulatory, and Risk Management is responsible for things such as determining and managing regulatory filings, maintaining an ethical culture, supporting adherence to information governance principles, and supporting legal and regulatory matters;
- People and Culture and Learning and Development create and execute on the employee experience for all co-workers at Consumers Energy, including recruiting, hiring, training and development, succession planning, compensation, payroll, performance management, workforce relations, employee engagement, and benefits administration; and
- Finance and Shared Services prepares budgets, forecasts, financial studies, and accounting records. 4 TR 1195-1196

Like these organizations, Quality Lean Office personnel use their expertise to support Company goals and customer service. Instead of expertise in things such as communications or finances or human resources, Quality Lean Office personnel have expertise in helping other

departments develop improved capabilities to work more efficiently and effectively and to identify and solve problems, all while pursuing continuous improvement. The benefit provided is helping departments throughout the Company mature in the CE Way and in their tools for process improvement. Examples included in this case where the Company used the CE Way to achieve performance results include (1) \$3,600,000 in benefits through Employee Incentive Compensation Plan operational performance measures and (2) the EIRP plastic pipeline cost reduction of \$216,500 per mile compared with the 2023 actual cost per mile. 3 TR 461. These benefits alone are more than the costs of the Quality Lean Office.

The Quality Lean Office employees and expenses support quality management implementation in the planning and execution of work throughout the Company. 3 TR 362. The Commission should approve these salaries and expenses so that the Quality Lean Office maintains sufficient funding to continue to support overall business efficiency and continuous performance improvement. 3 TR 462

b. Gas Engineering Support

As discussed previously in these Exceptions, the PFD recommended the removal of AMD capital expenditures. The PFD also recommended disallowing \$1.969 million in associated AMD O&M expense. PFD, page 330. As discussed in Section II.A.1.f of these Exceptions, the Commission should reject the PFD's recommended removal of AMD capital expenditures, and for the same reasons should reject the removal of the associated O&M expense. Even if the Commission agreed with the recommended reduction for AMD O&M, which it should not, the \$1.969 million is the total O&M spend for the program from 2021 through 2026. See Exhibit AG-57, page 5. The amount of O&M that will be included in rates is the test year amount, not the total O&M spent over the last five years. The projected test year O&M amount is \$572,508. *Id.* Thus, the correct disallowance amount would be \$572,508, not \$1.969 million.

2. Regulatory Compliance O&M Expense

a. MAOP – Transmission

Included in the Company's Regulatory Compliance O&M expense are expenses related to the MAOP Transmission Program. The MAOP Transmission Program O&M expense is projected to be \$1,898,000 in 2024, \$2,361,000 in 2025, and \$2,370,000 for the test year ending October 31, 2026. Exhibit A-58 (MPG-1), page 1, line 1. This expense amount consists of four parts. First, there is an annual expense of \$489,000 related to the Aerial population density survey needed to comply with 49 CFR 192.609 and 49 CFR 192.611. 4 TR 1275. There is also an annual expense of \$50,000 for Third Party Coordination Surveys. *Id.* Next, the Company is pressure testing the launcher and receiver barrels at St. Clair compression station, Rochester valve site, Grand Blanc valve site, and Atlas valve site to re-establish MAOP. Lastly, the fourth part of the test year expense is related to the O&M portion of the Standardized Engineering Analysis costs. *Id.*

Attorney General witness Coppola proposed reductions related to the Company's Standardized Engineering Analysis expenses. Following his recommendation to allow for recovery of 50% of MAOP expense, Mr. Coppola recommended that \$561,000 of expense be removed from the Company's forecasted O&M expense. 4 TR 2010. Page 354 of the PFD adopted this recommendation indicating that "in Case No. U-21291, the Commission stated that, as far back as Case No. U-20940, the Commission determined that the 2019 revisions to federal pipeline safety regulations and the 2011 advisory bulletin are not new record keeping requirements." Consumers Energy disagrees that this order is applicable to Consumers Energy.

Case No. U-21291 was a DTE Gas proceeding. In that case, when discussing DTE Gas's MAOP records review, the Commission made findings regarding DTE Gas's recordkeeping. Based on the language in the order, it appears that the Commission had previously questioned DTE Gas's recordkeeping, as the utility was previously instructed that "in future rate cases, DTE Gas

must adequately justify that the required [MAOP] work is a direct result of the new requirements in the regulations and not a result of the company's historically poor record keeping practices. Id., pp. 123-124.” MPSC Case No. U-21291, November 7, 2024 Order, page 148. This is not the case for Consumers Energy.

The Company's Standardized Engineering Analysis expenses are directly related to PHMSA's new pipeline safety regulations that require pipeline operators to reconfirm MAOP and to remediate line segments for which the operator's records do not meet PHMSA's new requirements for “traceable, verifiable, and complete records.” 2 TR 46-47. Those new requirements became effective on July 1, 2020. 49 CFR 192.624 establishes compliance milestones. By July 3, 2028, the Company is required to complete all actions required by 49 CFR 192.624 on 50% of the pipeline mileage subject to MAOP reconfirmation requirements, and complete all actions required by 49 CFR 192.624 on 100% of the pipeline mileage subject to MAOP reconfirmation requirements by July 2, 2035. 2 TR 77. Accordingly, the Company is reviewing its pressure-test records to ensure they are “traceable, verifiable, and complete,” consistent with PHMSA's regulations, and to remediate pipeline segments that require it. See 49 CFR 192.624. This review is being undertaken through the Standardized Engineering Analysis and full recovery of the expenses associated with the analysis is reasonable and appropriate.

3. Information Technology O&M Expense

a. Asset Accounting Tax Upgrade

The Asset Accounting Tax Upgrade project will upgrade the Company's current accounting asset management tax software to the Software-as-a-Service (“SaaS”) version as required by the vendor, or will implement a replacement solution, to ensure continued support of a critical financial application and provide new functionality. 4 TR 699. Standard vendor support ends for the current on-premise software in 2025, which will create security and stability risk that

can result in performance problems. *Id.* For the Company to comply with regulated and financial accounting in the fixed asset sub-ledger, the Company must perform an upgrade and maintain vendor support. The upgrade will also provide improved functionality to enable more frequent financial reporting. *Id.*

The PFD recommended a 20% disallowance (or \$25,233) of the projected expense based on a concern that the Company is still evaluating alternative solutions. PFD, page 368. The Commission should reject this recommended reduction in the projected expense. While the Company will be evaluating the current vendor/project solution with market leaders to ensure that it is the best solution, the Company will need to move forward with upgrading or replacing the current accounting asset management tax software with standard vendor support ending in 2025. 4 TR 792. Moving to the SaaS version of the current software will reduce hardware and server support costs and avoid database and server upgrades. 4 TR 792.

The Commission should approve the Company's projected expense to fund this project that is critical to ensuring compliance with regulated and financial accounting for fixed assets. See 4 TR 792.

4. Pension and Benefits Expense

a. LIBA

The Leaving it Better Award ("LIBA") is a tool that helps the Company retain talent, boost morale, and reinforce behaviors that advance the Company's goals and promote operational excellence, leading to better customer service. 4 TR 1365. As Company witness Kendra K. Grob, Senior Benefits Manager, described LIBA, it is "a way to show employees that they are valued for their work, increases the level of productivity at work, and reduces employee turnover, which supports improved service to customers." *Id.* LIBA serves as an almost-instant acknowledgment of exceptional work, recognizing individual employees who go above and beyond everyday

expectations to serve the Company and its customers while motivating employees to continue performing at high levels. *Id.*

Staff argued that LIBA expenses should be disallowed because the Company is already able to offer incentives through the employee incentive compensation program (“EICP”) or through promotions or raises, and the ALJ agreed, at least as far as promotions and raises are concerned. PFD, page 376. The ALJ rejected the Company’s argument that LIBA is fundamentally different from these incentives because it allows the Company to award employees for outstanding performance after the fact. The ALJ reasoned that the Company “can also promote or award a raise after the fact to recognize an outstanding employee.” *Id.*

Ms. Grob did not disagree that two ways the Company can promote excellence are to promote employees or raise their salaries, but she described LIBA as a complementary tool that encourages excellence in different ways. Studies confirm that award systems, like LIBA, are fundamentally different from promotions and merit raises. 4 TR 1368.²⁰ And when designed appropriately, awards offer another incentive to excel.²¹ This makes sense. An award involves public recognition, which Ms. Grob described as almost instant, whereas promotions and raises may or may not be public and take time to vet through the performance-review process.

An award is not only different from a promotion or a raise; it is also different from an EICP incentive. Ms. Grob distinguished LIBA from EICP incentives, noting that “the EICP is based on pre-determined performance criteria,” whereas LIBA gives the Company discretion to award

²⁰ Ms. Grob cited an article from the Strategic Management Journal, a scholarly publication focused on strategic business management, as an example of a study confirming that LIBA is different from promotions and raises. 4 TR 1368 (citing Jana Gallus & Bruno S. Frey, Awards: A strategic management perspective, 37 STRATEGIC MANAGEMENT JOURNAL 1527 (2016)).

²¹ Ms. Grob cited another article by Indeed, which is a job matching website and hiring platform, to support her conclusion that awards can provide further incentive to excel. 4 TR 1368 (citing Indeed Editorial Team, *Rewards and Incentives in the Workplace (Advantages and Examples)*, at <https://www.indeed.com/career-advice/career-development/rewards-incentives> (last visited May 12, 2025)).

employees for outstanding performance after the fact. 4 TR 1368. The ALJ appeared to reject this argument, but in fact, he did not find that *EICP* could fill the gap left by LIBA if it ends. Rather, the ALJ focused on *promotions and raises* as alternatives he believed could fulfill LIBA's function. Respectfully, however, the literature discussed above contradicts this conclusion.

The ALJ also concluded that LIBA awards should be paid for by the Company's shareholders instead of customers. It is not clear why the ALJ reached this conclusion. LIBA is uniquely structured to encourage outstanding performance that benefits customers by helping the Company retain talent, boost morale, and reinforce exceptional customer service, so there is no reason for LIBA costs to be borne by shareholders rather than being recovered through rates as a just and reasonable cost.

The Commission itself has recognized the potentially valuable benefits that LIBA provides. See MPSC Case No. U-21585, March 21, 2025 Order, page 342. Although the Commission did not approve the electric business's request to recover LIBA costs in Case No. U-21585, it also did not preclude the possibility it would approve such costs in other cases if the Company answered the Commission's questions about how LIBA was funded in the past. The Company has done so in this case. See 4 TR 1369.

The Company respectfully requests that the Commission approve its request to recover the gas business's LIBA O&M expenses and capital costs. The Company has supported its conclusions with expert testimony, scholarly publications, and advice from a hiring platform. In short, as the Commission instructed in Case No. U-21585, the Company has justified the program as a valuable tool to retain talent and improve customer service.

5. Incentive Compensation Expense

The Company takes exception to two issues from the PFD's recommendation for Consumers Energy's EICP expense for the test year. The Company appreciates and agrees with

the PFD's recommendation that the Commission approve the Company's full request for its non-officer portion of the EICP expense. However, in connection with the non-officer EICP, the PFD recommends that "going forward, Consumers [Energy] endeavor to find some way to separate electric-specific and gas-specific metrics into their respective rate cases." PFD, page 397. The ALJ expresses some concern that gas customers "may ultimately be subsidizing other parts of the company." PFD, page 398. That concern is unwarranted. The ALJ overlooks the fact that the Company uses an allocation factor to allocate the total EICP cost between its gas and electric utility so that each utility's customers are only paying the portion of the cost that corresponds to each utility's share of the overall program. 4 TR 1170. Furthermore, there is only one gas-specific and one electric-specific metric included in the Company's EICP, all the remaining metrics are applicable to both utilities. Because the program is balanced in this way, it is reasonable to conclude that the allocation factor sufficiently avoids any subsidization between the two utilities.

Next, the PFD recommends that the Commission disallow \$276,300 of Consumers Energy's projected O&M expense for its EICP in this case associated with the portion of EICP attributable to the Company's top five officers. PFD, page 397. The ALJ acknowledged that the Company "attempts to provide additional information to Staff" in this case to address the Commission's reasoning for disallowing the corresponding top-five officer EICP amount in the Company's last electric rate case, Case No. U-21585. PFD, page 398. Consumers Energy sought and obtained permission from the third-party owner of the proprietary market data, which allowed Staff to view the materials that helped to inform the Company's top-five officer EICP compensation decision at the Company's offices. However, relying on Staff's claims about their review of that data, the ALJ reasoned that "the inability to share key data and the redaction of employee names from even the limited viewing of the information on the company's premises

clearly hampered Staff's ability to independently compare the limited information provided with market data." PFD, page 398. However, the ALJ failed to give due consideration to the Company's rebuttal testimony responding to Staff's claims about the data they reviewed.

Although Staff witness Theresa McMillan-Sepkoski claimed that the materials did not include a "financial presentation of the compensation data that Staff needed to examine to make a valid comparison," 2 TR 2610, that was not accurate. Company witness Amy M. Conrad responded in rebuttal testimony that the "charts contain the percentages of base salary, total cash compensation and total direct compensation compared to market." 2 TR 1187. Furthermore, Ms. Conrad testified that, although the actual names of the people involved in the market comparison were redacted, "[t]he market data position titles were also contained on the charts." 2 TR 1187. Staff did not need to know, for example, whether the person in the comparison was named "John Smith" as long as Staff had sufficient data to tell that "John Smith" was Chief Operations Officer in the comparison company. Staff only needed information that would enable it to compare the officer position in the market materials with the comparable officer position at Consumers Energy. That information was present and available during Staff's review. The Company does not know why Staff failed to see the information, but it is unfair to resolve that failure against Consumers Energy, which went to extraordinary lengths to be able to provide access to the highly sensitive third-party data. It is unclear why Staff would need or want to see the officers' names, in addition to the respective titles of the five positions. Consumers Energy has been responsive to the Commission's reasons for disallowing the top-five officer portion of EICP in Case No. U-21585 and other recent cases. The data shows that the Company's EICP for its top-five officers is consistent with (and actually slightly below) the market. The Company's EICP for its top-five officers is reasonable and should be approved.

6. Customer Experience O&M Expense

a. Customer Interactions Expense

i. Customer Order Service Tracker

The Customer Order Service Tracker (“COST”) will implement a service order status tracker to provide both transparency to customers and oversight to internal teams supporting utility service orders that provide timely and accurate service order updates for customers as well as an interactive channel for use by dispatch, scheduling, and field crews. 4 TR 1088. The COST will give customers more visibility into when the Company’s crew will be onsite for work because the Company’s digital channels do not have features that give customers accurate updates from dispatch, scheduling, and field crews. The COST will give customers more visibility into when the Company’s crew will be onsite for work because the Company’s digital channels do not have features that give customers accurate updates from dispatch, scheduling, and field crews. *Id.* The lack of available information leads to a high volume of calls into call centers. *Id.* Additionally, the tracker will benefit Company dispatchers and give them better awareness of crew locations and routes. 4 TR 1088-1089.

The PFD modified CUB’s recommended reduction in expenditures of \$528,342 in Contact Center O&M and \$3,824,456 for Gas Operation O&M to a more modest \$176,114 in Contact Center O&M as well as \$1,062,349 in Gas Operations O&M. PFD, pages 408-409. Alternatively, the PFD recommended the Commission “direct the company to track and quantify the realized O&M savings from this project in its next rate case so that it can be used to offset other O&M expenses.” PFD, page 409. The Commission should accept the PFD’s alternative recommendation because it more accurately reflects the time frame in which savings from the project will be realized.

The PFD found it “reasonable to expect that 25% of the maximum projected savings will be realized during the test year” and thus recommended a total disallowance of “\$176,114 in Contact Center O&M (25% of \$704,456) and \$1,062,349 in Gas Operations O&M (25% of \$4,249,395)”. PFD, page 408-409. This calculation is not reasonable as the total is over \$1.2 million which is more than double the cost of the project. This is a significant amount because as the Company stated:

[T]he project is in the early stages, and that the savings are in fact estimated as part of the related cost/benefit analysis, and subsequently have not been accounted for in Operations other than IT implementation, and consequently should not be pulled from the present case. The Company’s test year forecast for the COST project should be approved, excluding O&M savings that cannot be realized within the test year. During this period, the Company will complete the project, without yet benefiting from the anticipated savings. [4 TR 1137]

The Company is confident in the savings but as Company witness Jessica R. Byrom stated, the timing of the savings is misaligned with the completion of the project – the ALJ’s alternative for the Commission to order the Company analyze projected savings and include those in its next case would be more reasonable. A 25% deduction from Contact Center and Gas Operations O&M each would represent an arbitrary reduction when the Company does not believe savings will be realized within the test year and neither the Contact Center nor Gas Operations have accounted for the savings in building projections for this case. Therefore, the Company believes the ALJ’s alternative approach of having the Company evaluate savings to include in its next rate case would be more reasonable than the proposed disallowance.

7. Voluntary Separation Program

The PFD erred in recommending removal of \$7,989,000 in O&M expense for the projected test year related to the Company’s Voluntary Separation Program (“VSP”). This recommendation is based on the conclusion that the Company failed to provide “clear evidence that demonstrates

how the VSP cost savings are accounted for or reflected in rates.” PFD, page 380. This finding fails to recognize why this information was not provided.

The Company did not provide a calculation of the savings because these savings are actual amounts. The Company disclosed to the Attorney General the number of employees by area and the dollar value of the savings associated with their departure. While specific workpapers identifying these VSP savings for each witnesses’ exhibit were not created, all O&M witnesses included total projected O&M expenses based on the forecasted needs in their business areas. 4 TR 1597. Each witness, with their extensive knowledge and expertise, considered the VSP savings when developing their O&M expense projections for this case. The only exception to this was Company witness Matthew J. Foster who sponsors Corporate O&M expense. Mr. Foster forecasts Corporate O&M by inflating historical O&M expenses. Importantly, he removed VSP savings from the historical year before inflating the expenses, ensuring accuracy. 4 TR 1597. All VSP savings were considered in the development of this case and have been properly incorporated. Therefore, the PFD’s recommendation is not appropriate.

8. Inflation Rate

The PFD reasonably determined that it would be unreasonable to adopt the Gross Domestic Product (“GDP”) chained price index to represent inflation rates. PFD, page 416. It also determined that it would be inappropriate to apply productivity offsets across a wide range of O&M and labor expenses to reduce the effects of inflation. PFD, pages 416-417. On these points, the Company agrees. Consumers Energy takes exception to the PFD’s recommendation that “the Commission, consistent with its order in the company’s last electric case, should direct the company to present, in its next gas rate case, more detailed evidence to demonstrate that it is in fact offsetting inflation with productivity increases.” PFD, page 417. While the PFD maintains that course of action will allow the Company to specifically demonstrate how it offsets inflationary

increases with productivity gains (*Id.*), Consumer Energy is concerned with being able to isolate and quantify the precise impact of productivity gains as an offset to inflationary pressures, especially for productivity gains that have not been realized at the time of filing the rate case.

Productivity improvements often manifest in indirect ways—such as through process efficiencies, technological integration, or workforce optimization. This is not easily captured in traditional financial metrics or short-term reporting frameworks. While the Company incorporates known savings in its cost projections, Company witness Heidi J. Myers explained that “accurately measuring productivity gains that accumulate over time and pointing to a specific spending line item in the case that is impacted can be complex. Productivity as defined by the BLS, is outputs divided by inputs. Trying to identify each and every change in either outputs or inputs in the context of productivity as part of a regulatory filing would be overly burdensome.” 4 TR 1593. For this reason, the Company takes exception to this recommendation.

Additionally, the PFD adopted the Attorney General’s recommendation to require the Company to disclose, by operating unit and cost function, forecasted inflationary cost increases that are different from the Consumer Price Index (“CPI”) forecast inflation rates. PFD, page 416. While indicating that this requirement will highlight costs where the inflation rate differs to provide greater ability to scrutinize whether such increases are reasonable and justified (*Id.*), this fails to recognize that the Company’s expenses are not based on inflation. With the exception of Corporate expenses, the Company projects its O&M expenses and explains the development and reasonableness of its projected amounts in its witnesses’ testimonies. Inclusion of the Attorney General’s recommendation will not provide the comparison that the PFD appears to be trying to achieve. Accordingly, this recommendation should be rejected.

VI. COST OF SERVICE, RATE DESIGN, AND TARIFF ISSUES

A. Rate Design

1. Transmission-Only Transportation Service Rate

The Company's proposed Transmission-Only Transportation Service rates will give transportation customers more options to take service directly from the transmission system. Currently, this Transmission-Only Rate is offered as a single rate (a volumetric charge of \$0.4533 per Mcf), and the Company is proposing four rate options (small, large, extra-large, and extra, extra-large) that have both a volumetric and customer-charge component. The Company proposed these four rate options to match full-service transportation rate schedules. 4 TR 1797. The revenue from these customers will be included in other revenue and offset the Company's revenue requirement. 4 TR 1798.

Staff witness Nancy C. Rademacher opposed the Company's proposal because she was concerned that the "proposed Transmission Only Transportation Service rates do not reflect the breakeven points of the associated rate schedules." 4 TR 2585. Ms. Rademacher was further concerned that "the service provided to the Transmission-Only Transportation Service customers has not been shown to differ in a way that supports separate rates for the breakeven-based classes." 4 TR 2585.

In rebuttal testimony and in its brief, the Company responded that there is no cause for Staff's concern. Company witness S. Austin Smith testified that the proposed Transmission-Only Rate is "set according to the same breakeven point thresholds" used in other transportation rate schedules. 4 TR 1803. And service provided to Transmission-Only customers does differ, just like service to other transportation customers differs. This is why the Company used the same breakeven thresholds for Transmission-Only customers that it uses for other transportation customers. It will ensure internal consistency across all transportation rate classes.

The ALJ disagreed. He said that the Company did not demonstrate that separate rates, including breakeven thresholds, for Transmission-Only customers are justified. PFD, page 448. He noted that the Company relied on “one or two lines of testimony from Mr. Smith” that service to Transmission-Only customers does differ. *Id.* at 448–449. The testimony the Company relied on was the testimony most obviously refuting the claim that service to Transmission-Only Transportation customers does not differ in the same way as service to other transportation customers, but there was far more testimony on the subject.

In direct testimony, Mr. Smith explained how the rate schedules for Transmission-Only customers align with the rate schedules for other transportation customers. Service differs based on the size of the Transmission-Only Transportation customer just like service differs for other transportation customers based on their size.

The Company designed a Transmission-Only rate for small, large, extra-large, and extra extra-large service which follows the full-service transportation rate schedules. The transmission costs from the cost of service, as allocated to the transportation rate schedules, were divided by the corresponding transportation sales forecast to develop a per Mcf transmission cost, as shown on Workpaper WP-SAS-5. [4 TR 1797 (emphasis added).]

Mr. Smith then explained the Company’s proposal to change its rates and breakeven points for Transmission-Only customers consistent with its rates for other transportation customers.

Q. What change is the Company proposing to this design?

A. *Consistent with the rate design structures proposed for full transportation service customers, the Company is proposing customer charges and transportation charges to collect revenues from Transmission-Only customers. The customer charges for STT and XXLTT are set based on the COSS. The principal customer charges for LTT and XLTT are set to maintain the economic breakeven points. These rate changes maintain economic breakeven points between Rate STT and Rate LTT at 100,000 Mcf annually and a breakeven point between Rate LTT and Rate XLTT at 500,000 Mcf annually, as well as provide for recovery of the annual revenue*

requirement for Transmission-related costs. *Consistent with rate design proposed for full transportation service customers, and to maintain current approved breakeven points, the Company is proposing to shift proposed revenue between transmission-only rate schedules.* Approximately \$1.5 million has been shifted into Rates STT and LTT from Rate XLTT. *Furthermore, to mirror the proposal for XXLTT, the Company is proposing to maintain Rate XXLTT's minimum annual eligibility requirement of 4 Bcf.* These rate changes are shown in Exhibit A-16 (SAS-2), Schedule F-2.1. [4 TR 1797-1798 (emphasis added).]

After Ms. Rademacher expressed concern that the proposed Transmission-Only Transportation rates allegedly “do not reflect the breakeven points of the associated rate schedules,” Mr. Smith revisited the issue in rebuttal. He began by explaining how the Company’s proposal in the present case, which includes breakeven points for Transmission-Only customers, differed from its proposal in its last rate case, which did not include breakeven points for Transmission-Only customers.

Q. Staff witness Rademacher, on page 5, lines 1 and 2, of her direct testimony testified that the Company’s proposed Transmission-Only Transportation Service rates do not reflect the breakeven points of the associated rate schedules. Do you agree?

A. No. This appears to mirror the stance Staff witness Rademacher took in the last case, when the Company did fail to include Customer Charges and associated breakeven points with the four proposed rate schedules. But in the instant case, the rates are set according to the same breakeven point thresholds used by the Transportation class rate schedules. This is discussed on page 15, line 23, through page 16, line 3, of my direct testimony. [4 TR 1803.]

He then explained how service to Transmission-Only Transportation customers differs in a way that supports separate rates for the breakeven-based classes by again comparing Transmission-Only Transportation customers to other transportation customers:

Q. Staff witness Rademacher, on page 5, lines 3 through 8, of her direct testimony testified that the service provided to Transmission-Only Transportation Service customers has not been

shown to differ in a way that supports separate rates for the breakeven-based classes. Do you agree?

A. No, I do not agree. In the last gas rate case, Case No. U-21490, the Company did not fully align its Transmission-Only Transportation Service rate design with the breakeven methodology used for other transportation classes. *The Company has now developed and applied breakeven points for Transmission-Only customers consistent with how rates are designed for end-use transportation customers. This approach ensures internal consistency across all transportation rate classes and better reflects cost-causation principles.* The use of breakeven analysis in designing these rates helps determine appropriate fixed and variable components while supporting rate stability for customers. [*Id.* (emphasis added).]

Respectfully, therefore, there was far more than “one or two lines of testimony from Mr. Smith” that service to Transmission-Only customers differs just like service to other transportation customers differs. The Commission should reject the ALJ’s recommended finding on this issue and adopt the Company’s proposed rate design for Transmission-Only customers.

2. Customer Charges

Customer charges are intended to capture costs “directly associated with supplying service, such as metering, service laterals, and customer billing.” 4 TR 1804. Using the method the Commission first approved in Case No. U-4331, Company witness Smith calculated that a cost-based residential customer charge would be \$21.96 per month. 4 TR 1790. Because achieving a cost-based residential customer charge would require a nearly \$7.00 increase to the current customer charge, the Company moderated its proposed increase to \$20.00 per month. *Id.* Although it is a more gradual increase, it still moves the residential customer charge closer to the cost to serve these customers consistent with cost-causation principles. Plus, the increased customer charge is accompanied by a corresponding increase to the low-income monthly credit for Residential Income Assistance (“RIA”) customers, as the customer charge is completely offset

by the RIA credit, so increasing the customer charge would reduce the cost burden for these customers. 4 TR 1790-1791.²²

Using a different method that relied exclusively on historical costs, Staff calculated a \$19.00 residential customer charge while supporting the Company's proposed customer charge for Rate GS-1 even though its calculation could have supported a higher charge. 4 TR 2571; Exhibit S-6, Schedule F-1.1b. The Attorney General and MNSC, by contrast, opposed any increase to the residential or Rate GS-1 customer charges.²³ Attorney General witness Coppola and CUB witness Denzler recommended keeping the current charges. 4 TR 2035, 2480. Their proposals were not cost based, 4 TR 1804, and the Company explained in rebuttal testimony and its briefs why the ALJ and the Commission should reject their lower proposed customer charge, which would require a higher variable distribution charge. The ALJ rightly rejected the Attorney General and MNSC's arguments, agreeing with Staff and the Company that the customer charge should be based on cost-of-service principles. PFD, page 462.

Despite rejecting the Attorney General and MNSC's arguments, the ALJ proposed a customer charge that was lower than the Company's and Staff's proposed charge. Respectfully, the ALJ erred by (1) rejecting the method the Company used to calculate customer charges and (2) adjusting the customer charge – more than the Company already adjusted it – to advance gradualism:

1. The method that the ALJ rejected was not just the Company's proposed method; it was the Commission-approved method.
2. The adjustment the ALJ made to the customer charge verges on elevating gradualism above cost-based ratemaking that should be the chief guiding principle.

²² The Company also proposed to increase the customer charges for Rate GS-1, GS-2, and GS-3 as shown in Exhibit A-16 (SAS-2), Schedule F-2.1, page 1.

²³ MNSC did not specifically address the proposed GS-1 customer charge, but the Attorney General did. 4 TR 2036.

a. The Company Used the Commission-Approved Method to Set the Customer Charge

The Company calculated a residential customer charge using the methodology adopted by the Commission in its January 18, 1974 Order in Case No. U-4331. 4 TR 1790. This methodology limits the customer charge to only those costs associated directly with supplying service to a customer, such as costs related to metering, the service lateral, and customer billing. *Id.* Staff witness Kevin S. Krause noted that the Company's calculation of customer charges uses a combination of historical and projected costs, which is the method that has been approved by the Commission. 4 TR 2571. Mr. Krause explained that the Company split the test year capital and O&M into separate accounts or categories based on the historical composition of those accounts in relation to total historical capital and O&M. *Id.*

Staff proposed to only use historical amounts to calculate customer charges in this case, which Staff argued is preferable since the cost compositions change from year to year. 4 TR 2571. Using only historical costs instead of projected costs, Staff calculated a proposed residential customer charge of \$19.00. *Id.* The PFD adopted Staff's customer charge calculation methodology, agreeing with Staff's argument that applying historical ratios to projected costs could result in inappropriate costs being included in the customer charge.²⁴ PFD, page 462. The Commission should reject this change in methodology for calculating the customer charge.

The Company's methodology for calculating the customer charge is consistent with the method approved in the Company's previous gas rate cases, calculating the customer charge based on a combination of historical and projected expenses. 4 TR 1242. The Company's breakout of test year costs in the Cost-of-Service Study ("COSS") based on historical ratios is reasonable

²⁴ The PFD went on to limit the recommended residential customer charge to \$17.00 (PFD, page 462), which will be addressed separately below.

because rates are designed based on a forward-looking test year. Accordingly, customer costs, including the customer charge, should reflect projected test year costs. *Id.*

Staff's proposal to use only historical amounts to calculate customer charges fails to properly reflect test year costs, which is inconsistent with the authority granted to utilities by the Legislature to "use projected costs and revenues for a future consecutive 12-month period in developing [their] requested rates and charges." See MCL 460.6a(1). In this case, the Company used the same methods and inputs that were previously approved by the Commission to calculate customer costs, resulting in the recommended customer charge. 4 TR 1242. Staff recently made the same proposal to calculate the customer charge using only historical amounts in the Company's last electric rate case, Case No. U-21585. See MPSC Case No. U-21585, March 21, 2025 Order, pages 425-426. In that case, the ALJ recommended that Staff's proposal be denied, and the Commission found that the ALJ's recommendation should be adopted. *Id.* at 427.

Consistent with the Commission's finding in Case No. U-21585 and with the ability of the Company to use projected costs and revenues in developing rates and charges, the Commission should reject the PFD's recommended change in the methodology for calculating the customer charge.

b. Gradualism Principles Should Not Supersede Cost-Based Ratemaking Principles

Relying on the principle of gradualism, the ALJ recommended that "the Commission limit the increase in the residential customer charge to \$2.00, resulting in a charge of \$17.00 per month for residential customers, and limit the increase to GS-1 customers to \$3.00 resulting in a customer charge of \$21.00 per month, with any remaining disparity between the COSS and customer charges to be addressed in future rate cases." PFD, page 462. The ALJ reasoned that a 25-30% increase

to the customer charge could result in rate shock and that increasing the customer charge at a slower pace is “aligned with the principle of gradualism in rate design.” *Id.*

As an initial matter, the ALJ recognized the need to move the customer charge toward the actual cost of service, which the Company appreciates. The math, however, does not support the conclusion that the Company’s proposed customer charge will lead to rate shock. Although the customer charge is increasing by 25-30%, there is a corresponding decrease to the variable charge that must be considered when evaluating possible rate shock. When a larger portion of revenue is collected through the fixed customer charge, a smaller portion of the proposed revenue is collected through the variable distribution charge. Further, for customers receiving the RIA credit, the customer charge is completely offset by the credit. 4 TR 1791, 1805.

A higher customer charge and lower variable charge, therefore, means a lower monthly bill for the most vulnerable RIA customers – especially during the winter when customer use is highest. Company witness Smith compared a hypothetical bill for an RIA customer with a \$20.00 customer charge and lower volumetric charge against the bill for an RIA customer with a \$15.00 customer charge and higher volumetric charge, showing that the RIA customers with the higher customer charge would enjoy a lower overall bill. 4 TR 1805. Even without the RIA credit, customers (low-to-moderate income or otherwise) paying a \$20.00 customer charge and consuming 8 Mcf or more per month have lower bills than customers paying a \$15.00 customer charge. 4 TR 1806.

Even putting the math aside and viewing the customer charge in isolation, the more the customer charge is below its cost basis, the more the wrong customers will be charged. Someone is paying for services like metering, service laterals, and customer billing that the customer charge is designed to cover, and if it is not the customers who are benefiting from these services, then it is customers who are not benefiting who are nonetheless paying for them. This is the unbalanced

outcome the Company seeks to avoid. And the Commission has historically avoided this outcome as well, holding that “customer charges should be limited to the costs associated directly with supplying service to a customer.” MPSC Case No. U-17999, December 9, 2016 Order, page 66.

At the same time, the Company, like the ALJ, recognizes that there is value in moderating the increase. Achieving a cost-based charge would require a \$7.00 increase to the current customer charge, and the Company proposed a lower \$5.00 increase. 4 TR 1790. Moderating the impact is a secondary consideration though. Adhering to cost-causation principles when proposing the customer charge was the Company’s highest priority – just like it has been the Commission’s highest priority in the past when setting the customer charge. Reducing the customer charge further in the name of gradualism elevates gradualism principles above cost-based ratemaking principles contrary to longstanding practice.

The Commission’s longstanding practice of approving cost-based customer charges exists for a reason. In DTE Gas’s 2015–2016 gas rate case, the Commission adopted a “cost of service based customer charge” that excluded costs not directly tied to individual customers. Referring to orders from the 1970s where it approved cost-based customer charges, the Commission concluded that it “does not continue to follow this precedent simply because it is there, but because the reasoning relied upon in determining that customer charges should be limited to costs associated directly with supplying service to a customer remains as viable today as it was then.” MPSC Case No. U-17999, December 9, 2016 Order, page 66.

To adhere to cost-causation principles, the Company proposed a residential customer charge that moves it closer to its cost of service than any other party’s proposed residential customer charge. The Company also proposed a cost-based customer charge for Rate GS-1 that

Staff supported and only the Attorney General opposed. The Commission should adopt the Company's proposals.

VII. OTHER ISSUES

A. Natural Gas Delivery Plan

The Company's Natural Gas Delivery Plan ("NGDP") provides a comprehensive 10-year plan for Consumers Energy's gas system. The Company developed its NGDP in response to the Commission's September 26, 2019 Order in Case No. U-20322, which directed Consumers Energy to develop a plan addressing the long-term operational and investment needs for the supply and delivery of natural gas that includes comprehensive treatment of the Company's storage, transmission, compression, and distribution systems. The Company's NGDP complies with the Commission's requirements and provides a clear and transparent investment plan framework for the next decade for the Company's natural gas assets. This investment plan framework considers safe and reliable gas supply and how the Company plans to evolve its assets in accordance with the Gas Pipeline industry standard API RP 1173 Pipeline Safety Management Systems ("PSMS") framework. The Company's program in response to the PSMS is called the Gas Safety Management Systems. It also incorporates the suggestions discussed in the Commission's Statewide Energy Assessment ("SEA") final report, in Case No. U-20646, issued on September 11, 2019. The Commission's SEA includes recommendations that gas utilities develop safety management systems, use probabilistic risk models to prioritize investment across natural gas investment portfolios, limit risks associated with commodity supply, and enhance natural gas delivery through the development of demand response and remote gas shutoff systems.

In Case No. U-21291, a DTE Gas rate case, the Commission made the following ruling related to that utility's Gas Delivery Plan. The Commission stated that:

The Commission agrees with the ALJ's recommendation that DTE Gas provide an updated GDP that includes consideration of the energy transition. It is clear from the record in this case that the transition away from fossil fuels and the eventual trend of declining natural gas demand will have impacts on the future of the natural gas system and that these impacts were not sufficiently considered in the company's GDP as filed. Thus, DTE Gas shall file an updated GDP consistent with the ALJ's recommendation showing how it has considered various energy transition pathways and the associated costs and risks of each.

To lend further clarity to the ALJ's recommendation, the Commission adds that DTE Gas shall include in its updated GDP information pertaining to how the company intends to achieve emissions reductions as part of its corporate goals and the State's emissions reductions goals with an estimated timeline for achieving those goals and interim goals; alternatives to capital investment, such as pipeline repairs and NPAs; historical trends of natural gas demand, projected demand, and impacts of changing demand; and the projected impacts of the transition towards electrification and decarbonization, including the portion of its distribution system that DTE Gas anticipates will be most immediately impacted. DTE Gas shall take steps to meaningfully engage interested persons in the development of its updated GDP and shall file the plan in this docket no later than December 31, 2025. [MPSC Case No. U-21291, November 7, 2024 Order, pages 216-217.]

In this proceeding, the PFD recommended that the Commission direct the Company to update its NGDP to include the information required in Case No. U-21291. PFD, page 482. A review of DTE Gas's Gas Delivery Plan, which is Exhibit A-12, Schedule B5.6 in Case No. U-21291, shows why the PFD's recommendation is inappropriate. As seen in that exhibit, DTE Gas's Plan does not address clean energy goals in the same manner as Consumers Energy's. The Company's NGDP develops a strategic framework in response to decarbonization goals and future policy. 4 TR 569.

On its own initiative, Consumers Energy has made one of the primary objectives of the NGDP the "reduction of the Company's and its customers' contribution to climate change through gas system decarbonization. Gas system decarbonization will include options for reducing

methane emissions across the delivery system and investment in renewable natural gas to help customers offset emissions associated with natural gas use.” Exhibit A-42 (NPD-1), page 12. Consumers Energy has established its own climate goals and is committed to reducing fugitive methane and carbon emissions from the delivery system, while also better understanding the emissions from the natural gas upstream suppliers and end-use. This commitment is demonstrated in the Company’s Scope 1 net zero methane emissions goal by 2030 and Scope 3 customer net zero carbon emissions goal by 2050. These goals align with the MI Healthy Climate Plan. Exhibit A-42 (NPD-1), page 14. Thus, the PFD’s recommendations are unnecessary as the Company’s NGDP, and its appendices, already fully consider decarbonization.

VIII. CONCLUSION

For the reasons set forth in these Exceptions, Consumers Energy Company’s Initial and Reply Briefs, and the evidentiary record in this matter, Consumers Energy Company respectfully requests the Michigan Public Service Commission to authorize Consumers Energy Company to increase its retail gas rates so as to produce additional annual revenues in the amount of approximately \$217 million, and to grant other relief consistent with the positions set forth in Consumers Energy Company’s Exceptions, Initial Brief, and Reply Brief.

CONSUMERS ENERGY COMPANY



Dated: August 28, 2025

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for the)
distribution of natural gas and for other relief.)
_____)

Case No. U-21806

PROOF OF SERVICE

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Melissa K. Harris, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on August 28, 2025, she served an electronic copy of **Consumers Energy Company’s Exceptions to the Proposal for Decision**, pursuant to the Protective Order in this case, upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.



Melissa K. Harris

Subscribed and sworn to before me this 28th day of August, 2025.



Crystal L. Chacon, Notary Public
State of Michigan, County of Eaton
My Commission Expires: 05/25/30
Acting in the County of Jackson

ATTACHMENT 1 TO CASE NO. U-21806

Party	Email Address
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