STATE OF MICHIGAN

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of	)	
Consumers Energy Company for authority	)	Case No. U-20322
to increase its rates for the distribution of	)	
natural gas and for other relief.	)	

NOTICE OF PROPOSAL FOR DECISION

The attached Proposal for Decision is being issued and served on all parties of record in the above matter on August 1, 2019.

Exceptions, if any, must be filed with the Michigan Public Service Commission, 7109 West Saginaw, Lansing, Michigan 48917, and served on all other parties of record on or before August 16, 2019, or within such further period as may be authorized for filing exceptions. If exceptions are filed, replies thereto may be filed on or before August 26, 2016.

At the expiration of the period for filing exceptions, an Order of the Commission will be issued in conformity with the attached Proposal for Decision and will become effective unless exceptions are filed seasonably or unless the Proposal for Decision is reviewed by action of the Commission. To be seasonably filed, exceptions must reach the Commission on or before the date they are due.

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES
For the Michigan Public Service Commission

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August 1, 2019
Lansing, Michigan

Jonathan F. Thoits
Administrative Law Judge

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

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES

FOR 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-20322

PROPOSAL FOR DECISION

I.

PROCEDURAL HISTORY

On November 30, 2018, Consumers Energy Company (Company) filed a natural gas rate application requesting a $229 million revenue increase, and other relief.[1]

The Company, Staff, and potential intervenors attended the January 2, 2018 prehearing conference. The Department of the Attorney General (Attorney General) intervened by right and intervention was granted to the Association of Businesses Advocating Tariff Equity (ABATE), the Retail Energy Supply Association (RESA), the Lansing Board of Water and Light (LBWL), Michigan State University (MSU)(jointly, LBWL-MSU), Energy Michigan, Inc. (Energy Michigan), and the Residential Customer Group (RCG). The parties agreed to a schedule complying with the time limits of MCL

[1] This revenue increase amount has since been revised downward by the Company to $204 million. Company's Initial Brief, p. 3; Appendix A.

460.6a.[2] The parties also stipulated to entry of the Company's Proposed Protective Order, which was entered on January 2, 2019, pursuant to which certain testimony and exhibits relied upon by the parties were deemed Confidential Information and entered under a separate record.

On March 1, 2019, the Company filed, and on March 4, 2019, the Company re-filed its Motion To Require Substantiation Regarding Representation, Substitution of Counsel, or Revocation of Intervention. After hearings, the motion was denied pursuant to a Ruling issued April 25, 2019.

In keeping with the schedule established at the prehearing, Staff and intervenors Attorney General, ABATE, RESA, LBWL-MSU, and Energy Michigan, and RCG filed direct testimony and supporting exhibits on April 5, 2019. The Company, Staff, ABATE, and LBWL-MSU collectively filed rebuttal testimony on April 29, 2019. On May 10, 2019, the Company filed revised rebuttal testimony of Jason R. Corker.

Evidentiary hearings were held on May 13, 14, 15, 17, and 22, 2019. Eleven witnesses appeared and were cross-examined on their testimony, while the testimony of the remaining 40 witnesses was bound into the record.

During the hearing, the Company offered the testimony of the following employees:

1. Paul M. Wolven, Director of System Integrity (Direct and Rebuttal);
2. Jeffrey R. Parker, Director of Gas Customer Deliverability – West (Direct and Rebuttal);
3. Lora B. Christopher, Manager of Health Care & Retirement (Direct and Rebuttal);

[2] Section 6a(5) of Public Act 286 requires the Commission to issue its final order within 10 months following receipt of a complete rate case filing, lest the application be considered approved. MCL 460.6a(5).

4. Jason R. Coker, Principal Rate Analyst in the Revenue Requirement and Analysis Section of the Rates and Regulation Department (Direct and Rebuttal);

5. Timothy K. Joyce, Manager of Gas Asset Strategy in the Gas Engineering and Supply Department (Direct and Rebuttal);

6. Bruce K. Straub, Director of Fleet Services (Direct and Rebuttal);

7. Srikanth Maddipati, Treasurer and Vice President of Investor Relations (Direct and Rebuttal);

8. Marc R. Bleckman, Executive Director of Financial Forecasting and Planning (Direct and Rebuttal);

9. Josnelly C. Aponte, Principal Rate Analyst - Lead in the Rate Analyst and Administration Section of the rates and Regulation Department (Rebuttal);

10. Lori M. Harvey, Executive Director of Gas Management Services in the Energy Supply Operations Department (Rebuttal);

11. Chad L. Alley, Senior Engineer Lead II in the Gas Asset Management (GAM) Department (Direct and Rebuttal);

12. Laura M. Collins, Principal Rate Analyst – Lead in the Pricing Section of the Rates and Regulation Department (Direct and Rebuttal);

13. Amy M. Conrad, Director of Executive and Incentive Compensation (Direct and Rebuttal);

14. Charles C. Crews, Vice President of Gas Operations (Direct and Rebuttal);

15. Emily A. Davis, Senior Rate Analyst II in the Cost Analysis section of the Rates and Regulation Department (Direct and Rebuttal);

16. Lisa M. Delacy, Executive Director of the Gas Automated Meter Reading (AMR) Program in the Enterprise Project Management and Environmental Services Department (Direct);

17. Daniel L. Harry, Director of General Accounting (Direct and Rebuttal);

18. Eric J. Keaton, Principal Rate Analyst in the Planning, Budget & Analysis Department (Direct);

19. Karen J. Miles, Senior Rate Analyst I in the Rates and Regulation Department (Direct);

20. Hubert W. Miller, III, Regulatory Reporting Manager of the Clean Energy Products Department (Direct and Rebuttal);

21. Deborah S. Pelmear, Principal Financial Analyst (Direct);

22. Heather M. Prentice, Director of Environmental Compliance, Risk Management & Governance in the Environmental and Laboratory Services Department (Direct);

23. Latina D. Saba, Facilities manager of Transformation, Engineering, and Operations Support (Direct and Rebuttal);

24. Daniel G. Shirkey, Utility Metrics Director in the Quality Lean Office Department (Direct and Rebuttal);

25. Brian J. VanBlarcum, Senior Tax Manager in the Corporate Tax Department (Direct and Rebuttal);

26. Christopher J. Varvatos, Executive Director of Business technology for Transmission, Engineering & Operations Support (Direct and Rebuttal);

27. Michael A. Torrey, Vice President, Rates and Regulation (Direct and Rebuttal);

28. Sarah H. Bowers, Executive Director of Gas Management (Direct and Rebuttal).

Through these witnesses, the Company entered into evidence Exhibits A-1 through A-155, inclusive.

Also, during the hearing, the Attorney General provided the direct testimony of Sebastian Coppola, an independent business consultant, and Exhibits AG-1 through AG-55, together with AG-57 through AG-63. ABATE provided the direct and rebuttal testimony of Billie S. LaConte and Jeffry Pollock, both energy advisors and consultants in the field of public utility regulation and Exhibits AB-1 through AB-13. RESA provided the direct testimony of Joseph Oliker, associate general counsel with Interstate Gas Supply, Inc. and Exhibits RES-1, RES-2, and RES-3. LBWL-MSU provided the direct testimony of Timothy S. Lyons, a consultant in utility regulation cases and Exhibits LBW-

1 through LBW-12, and LBW-R1. Energy Michigan provided the direct testimony of Paul Wilkin, a gas transportation consultant, and Exhibit EM-1.

Finally, Staff offered testimony from the following witnesses:

1. Nicholas M. Revere, Manager of the Rates and Tariff Section of the Regulated Energy Division (Direct and Rebuttal);

2. Cynthia L. Creisher, Public Utilities Engineer in the Gas Operations Section of the Energy Operations Division (Direct and Rebuttal);

3. Michelle L. Edelyn, auditor in the Revenue Requirements section of the Regulated Energy Division (Direct);

4. Lauren Fromm, Public Utilities Engineer in the Smart Grid Section of the Energy Operations Division (Direct);

5. David W. Isakson, Department Analyst in the Rates and Tariff Section of the Regulated Energy Division (Direct and Rebuttal);

6. James E. LaPan, Public Utility Engineer (Direct);

7. Theresa L. McMillan-Sepkoski, Audit Specialist in the Revenue Requirements Section of the Regulated Energy Division (Direct);

8. Kirk D. Megginson, Financial Specialist in the Revenue Requirements Section of the Regulated Energy Division (Direct);

9. Nathan J. Miller, Supervisor in the Gas Operations Section of the Energy Operations Division (Direct);

10. Robert F. Nichols II, Manager of the Revenue Requirements Section of the Financial Analysis and Audit Division (Direct);

11. Shannon Rueckert, auditor in the Revenue Requirements section (Direct);

12. Spencer M. Ruggles, Department Analyst in the Rates & tariff Section of the Regulated Energy Division (Direct and Rebuttal);

13. Kevin P. Spence, Public Utilities Engineer in the Gas Operations Section of the Energy Operations Division (Direct);

14. Fawzon B. Tiwana, Economic Analyst in the Energy Waste Reduction Section (Direct);

15. Joseph E. Ufolla, financial analyst in the Revenue Requirements Section of the Regulated Energy Division (Direct).

Through these witnesses, Staff entered Exhibits S-1 through S-6, S-9.0 through S-9.29, S-10.0 through S-10.1, S-11.0 through S-11.4, S-12 through S-12.1, S-13 through S-13.1, S-16.1 through S-16.3, S-18.1, S-19.1 through S-19.2, S-20.1 through S-20.4, S-21.1 through S-21.3, and S-22.

On May 29, 2019, the Company filed a motion to correct the transcript as to a portion of the cross-examination testimony of Company witness Sarah Hollis Bowers. No party filed a response to the motion, which was granted pursuant to a Ruling Granting Motion To Order Correct Transcript dated June 12, 2019**.**

In accordance with the established schedule, the Company, Staff, the Attorney General, ABATE, RESA, RCG, Energy Michigan, MSU, and LBWL filed initial briefs on June 7, 2019. All parties except RESA also filed reply briefs on June 25.

In order to ensure compliance with the statutorily imposed timeframe for deciding this case, MCL 460.6a(5), the evidence and arguments necessary for a reasoned analysis of the disputed issues are expressly addressed in the Proposal for Decision. However, all the evidence presented in this case was considered, along with the arguments made by the parties based on the evidence.[3]

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[3] The January 4, 2019 scheduling memo in this case provided that "[a]ny reply brief shall be confined to rebuttal of the arguments in a party's initial brief." On June 17, 2019, this ALJ sent an email to counsel for all parties in this matter repeating this limitation for the reply briefs, which were due to be filed by June 25, 2019. On that date, the Company filed its reply brief which is 163 pages in length. A review of the Company's brief indicates that the Company did not confine its reply brief to rebuttal of arguments in another party's initial brief. Rather, much of the Company's reply brief is merely a restatement – often verbatim - of the same arguments and evidentiary references included in the Company's initial brief and without any new or different argument(s). *See, e.g.*, pages 15-50, and pages 75-107. Accordingly, various

II.

THE COMPANY'S APPLICATION

The Company is an investor-owned utility that provides natural gas service to approximately 1.8 million retail customers in Michigan. The Company's natural gas system is an integrated and interconnected system and is operated as a single utility system in which the same rates and tariffs are applicable. The Company's retail natural gas business, including its retail transportation, storage, and distribution business, is subject to the jurisdiction of the Commission pursuant to various statutory provisions of 1909 PA 300, as amended, MCL 462.2 et seq.; 1919 PA 419, as amended, MCL 460.54 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq.; and 1982 PA 304, as amended, MCL 460.6h(1) et seq. Pursuant to these statutory provisions, the Commission has the power and jurisdiction to regulate Consumers Energy's retail natural gas sales, transportation, storage, and distribution rates. Under this authority, the Company's application seeks Commission approval to increase its natural gas rates sufficient to produce additional revenues in the annual amount of approximately $229 million. Subsequently, Consumers reduced the increase it is seeking in this proceeding to $204 million.[4]

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portions of the Company's Reply Brief were not considered. In the future, the entirety of any non-conforming reply brief will be disregarded. *See*, *Fisher v City of Ann Arbor*, unpublished per curiam opinion of the Court of Appeals, issued January 30, 2014 (Docket No. 313634), p. 3 ("We also decline to address the issue raised by petitioner in her supplemental brief because the brief does not conform to the requirements of MCR 7.212(G). MCR 7.212(I)").

[4] Company brief at p. 3.

According to the Company, the need for the requested rate relief is due to: (i) ongoing investments in gas utility assets in order to provide safe, reliable, and efficient service to customers; (ii) ongoing investments in enhanced technology to provide improved operational efficiencies and increased customer satisfaction; (iii) increased Operation and Maintenance ("O&M") expenses necessary to, among other things, support long-term investments and improve customer interactions; (iv) increased financing costs associated with a higher return on equity necessary to attract capital for the Company's large capital investment program, partially offset by more favorable long-term debt cost rates; and (v) increased costs related to manufactured gas plant environmental response activities.[5]

In addition, the Application requests, among other things, that the Commission: (1) increase the utility's authorized return on common equity from 10.00%[6] to 10.75%; (2) approve the proposed Gas Revenue Decoupling Mechanism (RDM); (3) authorize the Company to implement an Investment Recovery Mechanism (IRM) to adjust rates to reflect incremental investments related to specific transmission and distribution programs; and (4) grant various accounting authorizations and approve modifications to the rates, rules, and regulations as described in the Company's direct testimony and exhibits.[7]

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[5] Company's November 30, 2018 application ("Application"), p. 3, paragraph 7.

[6] The utility's current 10.00% return on common equity was authorized by the Commission's final order issued August 28, 2018 in Case No. U-18424.

[7] Application, p. 10-11. In rebuttal testimony, the Company withdrew its request for an IRM. Company Brief, p. 193.

III.

TEST YEAR

A test year is the starting point for establishing just and reasonable rates for both the regulated utility and its customers.[8] A test year is used by the Commission to establish representative levels of revenues, expenses, rate base, and capital structure for use in the rate-setting formula.[9] The selection of an appropriate test year has two components: determining a 12-month period to be used for setting the utility's rates, and determining how the Commission should establish values for the various revenue, expense, rate base, and capital structure components used in the rate-setting formula.[10] The Commission may use different methods in establishing values for these components, provided that the result is a determination of just and reasonable rates for the company and its customers.[11]

Section 6a(1) of Act 286, MCL 460.6a(1), provides that a utility may use projected costs and revenues for a future consecutive 12-month period to develop its requested rates and charges. In a case where a utility decides to base its filing on a fully projected test year, the utility bears the burden to substantiate its projections.[12] If the utility cannot or will not provide sufficient support for a particular revenue or expense item (particularly for an item that substantially deviates from the historical data) the Staff, intervenors, or the Commission may choose an alternative method for determining the projection.[13]

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[8] MPSC Case Nos. U-15768 and U-15751, January 11, 2010 Opinion and Order, p. 9.
[9] *Id.*
[10] *Id.*
[11] *Id.*
[12] *Id*.
[13] *Id*.

In this proceeding, the Company proposed using the 12-month period ending September 30, 2020 as the projected test year and 2017 as the historical year.[14] Staff, ABATE and RCG each address the test year issue.

Staff agrees with the Company's selection of a projected test year ending September 30, 2020.[15] However, in the context of its concerns about the Cost of Service Study (COSS) model and how it might be improved, Staff addresses what should be considered as an appropriate test year. Specifically, in order to "most accurately allocate costs", Staff recommends that the Company "do away with its reliance on historic composition of costs in the COSS where actual spending can be tied directly to COSS accounts", and that in future rate cases the Company submit a COSS "which shows projected test-year spending in the exact as possible accounts or COSS categories to which it will be recorded."[16] In this regard, Staff asserts that "another alternative solution" for the Commission to approve would be a transition "from approving future test-year spending plans to historic test-years."

> The Company claims that the true problem with redesigning the revenue requirement is that the many projects/programs and area of responsibilities within the Company would need to categorize budgets into numerous FERC accounts. However, every year the Company already compiles the many project and program costs from across its entire rate-regulated operation into its annual report. Clearly, it is possible for the Company to arrange historic cost and revenue data into the FERC accounts necessary for the Company to perform a more appropriate COSS than relying on a future, projected test-year. Should the Commission require that the Company file rate cases that rely on historic test-years then Staff's proposal to make adjustments to the exact as possible accounts in the COSS would be satisfied, and customers would be allocated costs in the most efficient way possible. Further, the Company would not need to incur the costs of

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[14] Consumers Energy's Application, p. 2; 2 Tr 178, 519.
[15] Staff brief, p. 3.
[16] Staff Brief, p. 104-105.

> revamping its compilation of total revenue requirement, because it already performs such a compilation every year for its annual report.
>
> . . . .
>
> The Company claims that relying on historic test years for ratemaking would result in regulatory lag, make planning more difficult, and fail to match the incurrence of cost to the time in which they are recovered. What the Company fails to note is that any cost recovery outside of a test year will fail to match costs to their recovery. Further, using a projected test year necessarily means that costs and recovery will not match, because the costs were unknown during rate making. The Company admits as much when Vice President of Rates and Regulation Michael Torrey said in his rebuttal testimony, "[p]ast expenditures and historic financial trends are vastly different from those facing the Company in the future." Simply put, costs that are already incurred are known, and costs in the future are unknown. Should the Commission decided to instead rely on historic test years for ratemaking, not only would a great deal of uncertainty be eliminated from the process but performing the COSS would also more accurately match costs to their causation.[17]

Staff notes that ABATE supports the use of historic test years and argues that ABATE's proposal to set rates that rely on a historic test year would enhance the cost of service study.

> For the purpose of accurately assigning costs through the cost of service study (COSS), Staff agrees that reliance on a historic test year would greatly improve the model. The Company agrees with Staff that reflecting test-year spending in the exact accounts or COSS categories to which the costs will be eventually recorded would result in a more precise COSS. Consumers contends, though, that the main problem with implementing Staff's proposal to match the COSS directly with test-year spending is that test-year spending is based on projections that may not match what actually occurs or be made with the appropriate information to assign projected costs to the appropriate accounts. Switching to a historic test-year would solve this problem, and likely solve this problem at a much lower cost than fully redeveloping the Company's operational planning system.[18]

Staff points to the Company's proposed residential customer charge as a "prime example" of a problem that could be solved by converting to a historic test-year for the COSS.

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[17] Staff Brief, p. 106-107. Citations omitted.
[18] Staff Reply Brief, p. 14. Citations omitted.

> The Company claims that its proposed customer charge "would capture the actual fixed costs of serving its residential customers as reflected in the COSS." Setting aside the claim of fixed costs and assuming the Company is referring to costs properly included as part of the customer charge, the claim is untrue because the Company's projected test-year costs to be included in the customer charge are a result of multiplying total capital and O&M cost categories by the historic composition those categories from the Company's annual report. If the annual report shows that 20% of total O&M expense was related to customer accounting (which belongs in the customer charge), then the Company multiplies the projected test-year **total** O&M expense by 20% to arrive at test-year customer accounting expense. This method does not match the Company's operational plan for spending on customer accounting to what is ultimately allocated on customers and included in the customer charge. This method ignores whether customer accounting expense in the projected test year is *actually* 20% of the total O&M expense, and also will misconstrue any adjustment to that customer accounting expense approved by the Commission. Nearly every account included in the calculation of the customer charge, and the COSS at large, is tainted by this mismatch between projected spending and cost allocation. With a historic test-year, the customer charge could be calculated as Staff proposes by only including the actual spending in the appropriate accounts in the charge. Absent such a change, Staff's proposal to rely only on historical costs appropriate for inclusion in the customer charge, rather than projected, should be approved.[19]

Staff concludes that the Commission should consider "approving rates based on a historic test-year rather than a projected future test-year to both eliminate the uncertainty of inappropriate allocation and over-recovery of costs and to improve the accuracy of the COSS."[20]

In reply to Staff's assertion that there could be a benefit to using a historic test year for COSS purposes, the Company argues that "the Legislature has made the policy decision to provide utilities the ability to choose to 'use projected costs and revenues for a future consecutive 12-month period in developing its requested rates and charges.'

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[19] Staff Reply Brief, p. 14-15. Emphases in original.
[20] *Id*.

MCL 460.6a(1).”[21] The Company adds that Mr. Torrey identified compelling reasons in support of this policy decision, including that a projected test year “better reflects future expectations and investments, as opposed to a historic test year that is stuck looking at past expenses.”[22]

As Staff has indicated, it “agrees with the Company’s selection of a projected test year ending September 30, 2020”, and despite its discussion of the benefits of using a historical test year, Staff “is not opposed to the ALJ and the Commission adopting the Company’s projected test year ending September 30, 2020”.[23] However, Staff’s discussion and recommendation that the Commission consider approving rates based on a historic year in order to improve the COSS model is a good one, and this PFD recommends that the Staff and other parties introduce evidence and legal authority on this issue in a subsequent case in order to give the Commission more to evaluate and consider on this issue.[24]

ABATE also offers that use of a historical test year should be considered. ABATE argues that the Commission has the statutory authority to set the Company’s rates based on a historical test year.

> If a utility fails to provide sufficient support for a particular revenue or expense item, the Commission may choose an alternative method for determining the projection. This is particularly true for an item that “substantially deviates from the historical data. In those cases, the Commission may use different methods in establishing

[21] Company Reply Brief, p. 14.
[22] *Id*.
[23] Staff Brief, p. 3.
[24] While the Company and ABATE in this case offered some references to the statute and Commission precedent, a more comprehensive discussion of the applicable legal authorities should be undertaken.

values for the future test year components, "provided that the end result is a determination of just and reasonable rates for the utility and its customers."[25]

ABATE argues that the Company's use of projected test years to justify its annual rate increases "has produced overstated costs and resulted in rampant overearning", noting that "this is the second consecutive rate case where the Company reported a revenue sufficiency for the historical year while filing for a rate increase for the projected test year."[26] ABATE argues that this consistent over-earning is a clear indication that the projected revenue requirements approved by the Commission have been excessive and not reflective of the actual costs that the Company will experience for the projected test year.[27] Citing testimony from Attorney General witness Coppola, ABATE asserts that since the Company began using a projected test year, "its *earned* ROE has exceeded its *authorized* ROE in six out of the last eight years."[28] ABATE adds that in four of the past five years the Company has earned a return "significantly higher than the allowed ROE."[29] ABATE argues that the Company "projected a revenue deficiency" of $90.5 million for the year ending December 31, 2017, while actual results show that the Company had a revenue sufficiency of $33.5 million for that same year.[30] ABATE also points to various examples of Company forecasted capital expenditures greatly exceeding the actual

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[25] ABATE Brief, p. 46, citing *In re Detroit Edison Application for Rate Increase*, MPSC Case No. U-15768, 1/11/2010 Order, p 9; *In re Upper Peninsula Power Application for Rate Increase*, MPSC Case No. U-17895, 9/8/2016 Order, p 3.
[26] ABATE Brief, p. 47.
[27] Id.
[28] Id.
[29] Id.
[30] ABATE Brief, p. 48, Emphasis in original, citations omitted.

historical costs.[31] Finally, ABATE references the Commission's July 31, 2017 Order in Case. No. U-18124 which found that the Company had not sufficiently supported its projected expenditure increase, whereby the Commission accepted Staff's historical five-year average as a "more accurate projection" of the Company's test year expenses.[32]

In reply to ABATE, the Company argues that "neither the Commission nor MCL 460.6a(1) envision that the Commission may prohibit a utility from using a projected test year", and that instead, the evidence for individual projections is examined and weighed in determining the reasonableness and prudence of the projections, "with historical data controlling only where it is clearly demonstrated to be 'a more fair and reasonable reflection of the utility's cost of service, relative to projected data.'"[33] The Company also argues that ABATE's contention that the Company's use of projected test years has resulted in "consistent over-earning" is incorrect, noting that Ms. LaConte incorrectly used weather normalized ROE's instead of earned ROE's, and that when considering the correct earned ROEs, the Company's gas business "has under earned its authorized ROE in four of the last eight years and has not achieved its authorized ROE since 2015."[34]

Contrary to Staff, ABATE's focus regarding the test year issue appears to be on the Commission's use of historical data to determine appropriate income and expense projections. Noting that the Commission has the right to choose an alternative method for determining test year projections, ABATE "urges the Commission to exercise that right in

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[31] As discussed, *infra*, ABATE asserts that these differences between the historical and projected costs be disallowed.
[32] ABATE Brief, p. 53.
[33] Company Reply Brief, p.12.
[34] Id. Citations omitted.

this case and in any future proceeding where the Commission suspects that the utility has over-projected its costs or will be unlikely to spend the full amount authorized by the Commission."[35] Indeed, as discussed, *infra*., ABATE points to historical data in support of its recommended disallowances of various projected expenditures under the Rate Base analysis in this case. As such, ABATE's arguments do not support the Commission not accepting the Company's proposed projected test year.

RCG argues that the Commission should adopt an historical test year, adjusted for known changes, and not a projected test year.[36] RCG reasons that a reasonable interpretation of the operative provision of MCL 460.6a(1)("A utility may use projected costs and revenues for a future consecutive 12-month period in developing its requested rates and charges.") is that a projected test year must be for the 12 consecutive months immediately following the utility's rate filing application.[37] RCG argues that the Company's use of a projected test year is based upon a "tortured interpretation" of MCL 460.6a, which means that the utility can project any future 12-month period "disconnected from either a historical period, or the date of the rate case filing, or anything else".[38] RCG adds that the Company's projected test year "drastically exaggerates" the Company's rate request and asserted revenue deficiency, and that if the Commission were to adopt an historical test year in this case, "it will serve to provide more confidence that rates are set at just and

[35] ABATE Brief, p. 46.
[36] RCG Initial Brief, p. 1.
[37] *Id*.
[38] *Id*., p. 6.

reasonable levels, particularly given the repeated issuance of orders based on projected test years over the past several years."[39]

The Company counters that the statute expressly provides a utility the right to have its rates based on a projected test year, and that applicable statutory interpretation principles indicate that the statute does not require that the 12-month period immediately follow the rate case filing.[40] The Company adds that the Commission recently considered and rejected this same argument RCG made in the DTE Electric rate case in Case No. U-20162:

> "The statute contains no limitation on the future consecutive 12-month period and no requirement to use an historical test year. The test year may be in the future, and the 12 months must be consecutive; those are the requirements of the statute. RCG offers no evidence whatsoever to demonstrate any relationship between the date of the rate case filing and the test year used by the applicant and the Commission can find none in the language of MCL 460.6a(1)."[41]

As the Commission has previously rejected RCG's argument, it should be rejected here.

Thus, this PFD recommends that the Commission adopt the 12-month period ending September 30, 2020 as the projected test year. However, Staff's, ABATE's, and the RCG's arguments on this issue are well-taken in part. Specifically, this PFD agrees that MCL 460.6a, as interpreted by the Commission in Case No. U-15985, permits other

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[39] *Id*., p. 3, 5.
[40] Company Initial Brief, p. 9, 10. While the Company asserts that statutory interpretation principles support its reading of the statute, the Company does not offer any statutory interpretation argument which addresses the ultimate question of whether the word "consecutive" modifies the word "month" in the term "12-month", or whether it modifies the word "period" in the term "12-month period".
[41] MPSC Case No. U-20162, May 2, 2019, Order, p. 4.

parties to propose appropriate costs and revenues on a basis other than the Company's projections. In that regard, it remains incumbent on the party proposing a different test period to provide the revenue and expense amounts corresponding to that period, as well as evidence to show that the alternative test period is more just and reasonable than the Company's proposal or any proposal by any other party.

IV.

RATE BASE

"Rate base consists of total utility plant (i.e. the capital invested in all plant in service, plant held for future use, and construction work in progress (CWIP), less the company's depreciation reserve (consisting of its accumulated depreciation, amortization, and depletion), plus the utility's working capital requirements."[42] In this case, the Company projects its rate base for the test year at $6.501 billion, consisting of $5.716 billion in net plant, $774.316 million in working capital requirements, $49.655 million in net unamortized Manufactured Gas Plant (MGP) expense, with a reduction of $39.193 million in retainers and customer advances.[43]

The components of the rate base projected by the Company, and reductions proposed by Staff and the Intervenors are as follows:

[42] MPSC Case No. U-17735, November 19, 2015 Order, p. 7.
[43] Company's Brief, p. 5; Appendix B, p. 1.

A. Net Utility Plant

1. Gas Transmission And Distribution Capital Expenditures

The Company is requesting rate recovery of its Gas Transmission and Distribution capital expenditures for the years 2018, the nine months ending September 30, 2019, and the projected test year ending September 30, 2020 in the amounts of $621,254,000; $567,207,000; and $711,653,000, respectively.[44] The Gas Transmission and Distribution capital expenditures are divided among six major expense categories, referred to as programs, as follows: (i) New Business; (ii) Asset Relocation; (iii) Regulatory Compliance; (iv) Material Condition; (v) Capacity/Deliverability; and (vi) Gas Operations Other.[45]

As discussed below, Staff and the Attorney General take issue with the Company's test year gas transmission and distribution projections related to the new business, regulatory compliance, material condition, and capacity/deliverability programs.

a. New Business Program

The New Business Program capital expenditures, net of customer contributions, projected for the year 2018, the nine months ending September 30, 2019, and the projected test year are $77,600,000; $55,562,000; and $91,959,000, respectively.[46] For the Large New Business Projects category of the New Business Program, the Company projected expenditures in the amount of $35,559,000 for the projected test year.[47] This

[44] Exhibit A-12 (corrected), Schedule B-5.
[45] Company Brief, p. 6.
[46] 5 Tr 612; Exhibit A-102.
[47] Exhibit A-102

program includes new customer connection projects where the estimated infrastructure cost exceeds $500,000 and the projects may require special tracking and project management.

The Attorney General disagreed with the expenditures to provide additional gas delivery capacity to the LBWL project, with Company projections of $326,000 in the nine months ending September period and $32 million in the 12 months ending September 2020.[48] Attorney General witness Sebastian Coppola notes that the Company indicates that the customer will contribute the entire amount toward the $52 million project cost in four installments as project milestones are achieved, and that once the customer starts using gas in 2021, it will receive a refund over a five-year period up to $38.5 million, if it reaches the target usage calculated under the Company's Rule C8.[49] Thus, according to Mr. Coppola, as the Company's capital expenditures are fully covered by the LBWL payments to the Company, there are no capital expenditures for this project to be recovered at this time.[50] Mr. Coppola concludes that it is premature for the Company to recover any net costs it may ultimately incur for a project of this size, it is uncertain at this time what the project ultimate costs will be given the large amount of contingency costs, and it is also uncertain how much of the $52 million in deposit money that the Company is collecting from LBWL will ultimately be refunded given the uncertain gas usage during the five-year period following completion of the project.[51] As such, Mr. Coppola

[48] 7 Tr 1623.
[49] 7 Tr 1624.
[50] Id.
[51] Id.

recommends that the Commission remove the $32,303,000 that the Company has included in its forecasted capital expenditures shown in Exhibit A-102, adding that once the project is completed and it is better known how much of the deposit and contributions in aid of construction will be retained, the Company can propose recovery of the remaining net cost of the project.[52]

The Company counters that the Attorney General fails to recognize that there is an offset of $32,340,000 for the impact of those expenditures included in the rate base as customer advances.[53] Company witness Coker testified that once the customer starts using gas, the customer will receive an annual refund for each of the first five years of gas usage, with contributions recorded as customer advances to the extent they are refundable.[54] In addition, as amounts expected to be received from the LBWL that are not refundable will be recorded as contributions in aid of construction (CIAC), which directly offset capital expenditures, the capital spending included in this case has been reduced for CIAC.[55] Therefore, as capital expenditures funded by customer advances are included in rate base, but are offset by advances projected to be received from the customer, the rate base is adjusted for amounts funded by the LBWL.[56]

This PFD is persuaded by the Company's argument. As the Company points out, there is an offset of $32,340,000 for the impact of those expenditures included in the rate base as customer advances. As such, the asserted uncertainty as to the timing and

[52] 7 Tr 1624-1625.
[53] 5 Tr 804.
[54] 5 Tr 805.
[55] 5 Tr 805.
[56] Id.

amounts involved does not support the disallowance sought at this time. Accordingly, this PFD recommends the Commission not accept the Attorney General's proposed disallowance of $32,303,000.

The Attorney General also takes issue with the expenditures associated with three new businesses in Saint Johns. Regarding the Company's cost estimate of $10.5 million,[57] Mr. Coppola points out that the Company acknowledges that it "does not have a project proposal and approval document with estimated costs, timeline and other project details", and that this is a new business project requested by a group of potential new customers, which will be constructed "[i]f the customers are willing to pay the costs associated with the project in accordance with the Company's tariffs".[58] He adds that the Company has not provided "any evidence of the economics of the project as requested."[59]

The Company counters that the Attorney General fails to recognize that the Company is required to undertake these projects for its customers, and that in developing its projections for the expenditures related to these customers, the Company reviewed the associated investment costs, applied the tariff by calculating the potential customer revenue, and determined that the revenues offset the investment.[60] The Company adds that it initiated a contract with the customers to ensure recovery of the projected revenues on the project, and a contract has been executed into for one of the projects.[61] Moreover,

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[57] Exhibit A-102, p. 2 shows the project cost at more than $10.5 million over the 21-month period ending September 2020.
[58] 7 Tr 1625.
[59] 7 Tr 1626.
[60] 5 Tr 668.
[61] 7 Tr 2249.

as shown on Exhibit AG-6, the Company provided a construction timeframe for each of the Large New Business Projects.[62]

This PFD is persuaded by the Attorney General's argument. The Company has failed to provide appropriate support for these expenditures, given the uncertainty surrounding these projects. Accordingly, this PFD recommends the Commission adopt the Attorney General's proposed disallowance of $10,500,000.

Finally, the Attorney General takes issue with the Company's forecasted investment in new business meters and meter replacement. Using the historical cost for units purchased in 2016 through 2018 and applying inflation factors, Mr. Coppola projects the cost per installed unit at $274 in 2016, $327 in 2017, $362 in 2018, and forecasted costs of $369 for 2019 and $377 for the year 2020.[63] Conversely, Mr. Coppola calculates the Company as projecting the installed cost per unit is $407 and $417, respectively, for the 9 months ending September 2019 and 12 months ending September 2020.[64] Mr. Coppola concludes that the Company's higher costs are "excessive, unexplained and unsupported by the Company."[65]

In contrast, Company witness Parker explained that the Company's standard gas meter configuration and baseline unit cost has changed with the implementation of AMI in the Company's combination gas/electric service areas and AMR in the gas only service areas.[66]

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[62] Company brief, p. 10.
[63] 7 Tr 1627.
[64] 7 Tr 1628.
[65] Id.
[66] 5 Tr 670.

> During the implementation of AMI and AMR, there were more than 55,000 meters in service throughout the Company's gas service area that were not compatible with a gas communication module. The meters purchased to replace these obsolete meters were delivered to the Company with gas communication modules pre-installed, but the responsibility for the actual capital expenditures were shared with the AMR project. The New Business and Replacements meter purchase programs included the cost of the meter unit, while the AMI and AMR programs included the cost of the communication module. With the completion of the AMR program during the first half of 2019, the New Business and Replacements meter purchase program will incur the cost of the entire meter and communication module unit. Attorney General witness Coppola used the historical costs, which do not include the communication modules, as the basis for his calculation and inflated them by 2%. As a result, Mr. Coppola's recommendation would disallow reasonable costs associated with communication modules no longer funded by the AMI or AMR programs, which will be picked up in New Business and Replacement meters programs going forward.[67]

This PFD is persuaded by the Company's explanation. The Company has provided appropriate support for these expenditures. Accordingly, this PFD recommends the Commission reject the Attorney General's proposed disallowance for these expenditures.

b. <u>Regulatory Compliance Program</u>

The Regulatory Compliance Program includes projects that are required to comply with federal and state pipeline safety regulations and mandates. Additionally, under the Regulatory Compliance Program, meters are purchased for replacements associated with routine, relocation, and other replacement projects.[68] For the test year, the Company projects capital expenditures in the amount of $53,037,000 for this program.[69]

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[67] 5 Tr 670.
[68] 5 Tr 622.
[69] Exhibit A-41.

i. Pipeline Integrity Program Overview

The Pipeline Integrity Program includes projects that are required to comply with federal and state pipeline safety regulations and mandates.[70] The Company employs a priority-based pipeline inspection schedule, and the remediation costs resulting from the findings of the inspections are included in this program, which complies with federal Pipeline and Hazardous Materials Safety Administration (PHMSA) requirements.[71]

The capital expenditures for the Pipeline Integrity Transmission Program are projected to be $39,037,000 in 2018; $14,783,000 for the nine months ending September 30, 2019; and $18,366,000 for the 12 months ending September 30, 2020.[72] The Company has shifted some capital expenditures to O&M, and during the projected test year, the Company projects that 30% of the remediation digs will be a capital expenditure while 70% of the remediation digs will be an O&M expense.[73]

ii. Pipeline Integrity Practices

In Case No. U-18424, as part of a Settlement Agreement, the Company agreed to the implementation of certain reporting and practices related to its Pipeline Integrity Program.[74] The Company now asserts that certain practices agreed to by the parties impact the Company's ability to enhance pipeline safety,[75] and as such, the Company

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[70] 5 Tr 561.
[71] 5 Tr 538-539.
[72] Exhibit A-12, Schedule B-5.6, line 1.
[73] 5 Tr 562.
[74] 5 Tr 544-547.
[75] 5 Tr 576.

proposed two changes to the pipeline integrity work: (i) to change the minimum pipe cut-out, from 1.5 times the diameter on each side of the target anomaly to a standard eight foot minimum for all size pipe; and (ii) to be allowed to remove additional Low Frequency Electric Resistance Weld (LF-ERW) pipe when a defect is being remediated.[76]

Regarding the minimum cutout, the Company "is concerned that the 1.5 times the diameter cut-out requirement will not be sufficient length to complete proof testing and perform additional pipe assessments."[77] In reply, Staff does not believe that the Company only realized after the Settlement Agreement was signed that they would not be able to conduct the additional testing mentioned in this case.[78] Nevertheless, Staff witness Miller agreed to amend the language addressing the Company's proposal to change the minimum pipe cutout from 1.5 times the diameter on each side of the target anomaly to a standard eight foot minimum for all size pipe, to read as follows:

> The Company should not replace more than 1.5 times the diameter of the pipeline of additional pipe on each side of the extent of a target anomaly for pipeline replacement, or eight feet, whichever is more. In the case where there are adjacent anomalies to the target defect, the Company can only include those as part of the target defect removal in cases where the defect is either immediate or scheduled in accordance with 49 CFR Part 192 Subpart O (i.e., NOT the Company's TIMP), or have a calculated response time less than 20 years. The Company can treat both HCA and non-HCA pipelines the same regarding this requirement.[79]

[76] 5 Tr 576.
[77] 7 Tr 2164.
[78] 7 Tr 2165.
[79] 7 Tr 2166.

The Company agrees with the language proposed by Staff.[80] Accordingly, this PFD recommends that the Commission adopt this change to the Settlement Agreement.

Regarding joint removal, the Company witness Wolven testified that the Company believes that "removing a full joint of LF-ERW pipe in which an anomaly has already been identified is a prudent practice" because it increases the safety and reduces the risk on the transmission pipeline because the seam "may have additional anomalies."[81] In addition, removing any pre-1970's ERW pipe increases the safety of the Company's gas transmission system, and is especially prudent when construction crews are onsite and already removing an anomaly, as pre-1970's EWR pipe "is known to be more susceptible to manufacturing related defects.[82]

Staff disagrees with the Company's suggestion to remove entire pipeline segments when segments containing a LF-ERW seam are encountered, and instead recommends that hydrotesting be utilized to supplement in-line inspections where a LF-ERW seam threat exists.[83] Staff recommends that this approach be utilized when necessary because Staff does not agree with the Company's assertion that the mere presence of LF-ERW pipeline constitutes a threat to system integrity.[84] In rebuttal testimony, Mr. Wolven testified that the Company will not seek modification of the Settlement Agreement on this issue, and instead will conduct a study of its LF-ERW pipeline:

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[80] Company brief, p. 16.
[81] 5 Tr 560.
[82] Id.
[83] 7 Tr 2177.
[84] Id.

> In light of Mr. Miller's recommendation, in order to review and gather further information, the Company will agree to not continue to seek modification to Condition I of the Settlement Agreement in this proceeding. Instead, the Company will perform the study of transmission pipelines containing a LF-ERW or other susceptible seams to determine the severity of the integrity threat due to seam manufacturing issues.
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> . . . .
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> The study will include the review of the manufacturer and vintage of transmission pipelines containing a LF-ERW or other susceptible seams. Also, the Company will review the material testing and proof testing it has performed on these pipelines and may apply the results of this testing to analogous pipelines (for example, same material properties). It will consider whether or not the pipelines have a valid Subpart J pressure test. The Company will review the additional white papers cited in Mr. Miller's direct testimony to identify additional information to include in the study.[85]

Accordingly, this PFD recommends that the Commission not modify Condition I of the U-18424 Settlement Agreement.

iii. Contractor Contracts

In March of 2018, the Company entered into a new Pipeline Integrity Remediation Contract with its contractor, which three-year agreement expires at the end of 2020. Staff witness Miller argued that the Company should reevaluate its contract as it relates to transmission integrity management remediation digs to ensure that small, localized remediation digs are not costing the Company the same as an excavation spanning an entire 40 to 42 foot segment of pipe, and suggested that the Company should create an additional unit cost that is reflective of an excavation of less than 20 feet.[86] The Company counters that it currently has the contract in place to establish a core team of contractor

[85] 5 Tr 580-581.
[86] 7 Tr 2195.

crews that are familiar with the Company's pipeline system and processes to ensure high quality performance.[87] The Company adds that if the Company attempted to negotiate an amendment to its current contract to include a unit price for excavations less than 20 feet, this would allow for negotiations of all aspects within the contract and could result in changes that overall could result in higher costs.[88] The Company points out that starting in 2021, the Company will have a new contract in place for its pipeline remediation work, and in such contract the Company "will evaluate the potential of adding a unit price for excavations less than 20 feet."[89] This PFD finds the Company's position persuasive. Accordingly, this PFD recommends that the Commission not ask the Company to re-negotiate its existing contract terms and instead encourage the Company to consider including such a provision in its next pipeline remediation contract.

iv. Excavation Practice

Under the Company's Pipeline Integrity Program, the Company's business practice is to fully excavate the entire pipe segment from girth weld to girth weld, which allows the Company to verify the girth weld on either side of the anomaly in order to ensure the Company is performing remediation on the correct joint of pipe and remediating the correct anomaly.[90] Mr. Miller recommended that the Company no longer expose an entire segment of pipe as a standard practice when performing transmission

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[87] 5 Tr 581.
[88] 5 Tr 582.
[89] 5 Tr 581.
[90] 5 Tr 559.

integrity management remediation digs, but reserve that practice only for instances where the targeted anomaly does not match what is discovered in the ditch.[91]

The Company disagrees with this recommendation. While the Company acknowledges that it is not required by any regulatory body to expose both girth welds during excavation, it notes that these, and other similar business decisions, are not currently prescribed by regulations.[92] Moreover, the Company asserts that exposing both girth welds is prudent and the best practice, as the Company can confirm the correct joint of pipe is being assessed through measurements from anomaly to girth welds and confirm the seam weld position on the adjacent joints.[93]

This PFD finds that the Company's approach is reasonable and potentially a more cost-effective practice, and thus recommends that the Commission not adopt Staff's recommendation.

v. Carryover Costs

The Company's Pipeline Integrity costs consist of several different components as set forth in the Company's Transmission Workplan for the years 2019 and 2020, and include carryover costs for projects that commenced in the prior year that continued into the following year.[94] The Attorney General proposed an adjustment to the Company's projected Pipeline Integrity expenditures, arguing that the Company's reasonably

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[91] 7 Tr 2195.
[92] 5 Tr 582.
[93] 5 Tr 580.
[94] Exhibit AG-20.

projected carryover costs are ballpark numbers included as placeholders of costs that the Company may not incur.[95] Mr. Coppola notes that when the Company was asked to explain what was included in the carryover amounts, and to identify the specific projects carried over or explain the basis for the carryover amounts, the Company replied that "the specific projects are unknown until the inspection results are received and the site conditions are evaluated."[96] Mr. Coppola asserts that the Company's response shows that "there are no specific projects or quantifiable basis to support the carryover amounts from one year to the next."[97] Mr. Coppola concludes that because the Commission has made it clear in prior rate case orders that placeholder amounts are not acceptable for inclusion in projected rate base, the carryover amounts should be removed from the capital expenditures forecasted by the Company in this rate case.[98] Similarly, with regard to the O&M carryover amounts, Mr. Coppola argues that the Company "included what appears to be a rough "ballpark" amount of $5 million in both years 2019 and 2020 with no specific basis or support."[99] Thus, Mr. Coppola asserts that the Commission should disallow capital expenditures of $4,457,347 for the 9 months ending September 2019 and $6,023,283 for the 12 months ending September 2020, together with $5 million of O&M expense for the projected test year.[100]

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[95] 7 Tr 1646.
[96] 7 Tr 1645.
[97] 7 Tr 1646.
[98] Id.
[99] 7 Tr 1646-1647.
[100] 7 Tr 1647.

ABATE similarly challenges projected carryover costs on the same grounds as the Attorney General. ABATE notes that the Company forecasted capital expenditures for 2019 and 2020 include certain carryover amounts from prior years.[101] Like the Attorney General, ABATE notes that when the Company was asked to specify what was included in the carryover amounts, and to identify the specific projects carried over or explain the basis for the carryover amounts, the Company was indeterminate.[102] ABATE argues that the Company's response "should give the Commission pause", asserting that if the Company is unaware of the specific projects, "it follows that there is no quantifiable basis to support the carryover amounts from one year to the next."[103]

The Company counters the Attorney General by asserting that carryover remediation is remediation work that is performed the year following the in-line inspection (ILI), based on the results of the inspection and an evaluation of the site condition.[104] Mr. Wolven testified that the carryover remediation amounts are included to cover difficult digs that require significant planning and design work, which is carried over due to a number of different factors including the inability to take a pipeline outage, permitting requirements, construction complexities, site restoration, and engineering complexities.[105] The Company argues that its carryover cost projections were based on

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[101] ABATE Brief, p. 51.
[102] Id.
[103] Id.
[104] 5 Tr 583.
[105] 5 Tr 583; Exhibit AG-21.

the projected ILIs to be completed and the historical amounts spent in previous years.[106]

The Company does not appear to address ABATE's arguments on these projections.

This PFD finds the Attorney General's and ABATE's arguments persuasive and consistent with prior Commission rulings. Accordingly, this PFD recommends that the Commission disallow capital expenditures of $4,457,347 for the nine months ending September 2019 and $6,023,283 for the 12 months ending September 2020, and $5 million of O&M expense for the projected test year.

vi. Material Condition Program

The Company indicates that its Material Condition Program addresses leaks and deterioration issues which reduce natural gas emissions to the atmosphere, improve system integrity, and reduce service interruptions that impact customers.[107] In total, for this program in the projected test year, the Company projects spending in the amount of $172,659,000.[108] The expenditures in this program include EIRP pipe replacement projects (transmission and distribution), the VSR Program, and additional system enhancements.[109]

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[106] Id.
[107] 5 Tr 623; 6 TR 1034.
[108] Exhibit A-41.
[109] 5 Tr 623.

Enhanced Infrastructure Replacement Program

In 2012, the Enhanced Infrastructure Replacement Program (EIRP) was implemented to ensure continued customer safety and reliable system operation by replacing the Company's lowest performing mains with lower maintenance plastic and steel main, and replace or tie-over services to the new main.[110] The EIRP also includes the replacement of approximately 70 miles of LF-ERW piping located in gas storage fields.[111]

Staff supports the Company's acceleration of replacement of high risk main and believes the Company has demonstrated its commitment to the EIRP with spending and commensurate performance in accordance with Commission-approved expenditure levels and Staff's expectations.[112] Thus, given the increased level of expenditure proposed in this case and the corresponding proposed increase in miles to be replaced, Staff urges the Commission to direct the Company to achieve an average target mileage performance metric of 104 miles for the EIRP-Distribution program.[113]

The Company agrees that a performance metric should be adopted but asserts that the target created needs to be flexible to account for the volume of TOD and transmission pipeline work performed in any given year, as the replacement of high-

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[110] 5 Tr 623-624.
[111] 6 Tr 1034.

[112] 7 Tr 1983.
[113] 7 Tr 1984.

pressure TOD main is more expensive to install than common gas distribution main.[114] The Company also argues that the mileage targets should be based on installed miles of main rather than retired miles of main.[115] In that regard, the Company proposes a target for gas distribution main installed for the 2020 EIRP of 72 miles.[116] Also, the Company asserts that it is willing to meet with Staff to align on an appropriate metric.[117]

Regarding relying on installed miles instead of retired miles, the Company notes that some communities are now requiring replaced gas main to be placed on both sides of the road, which increases the cost of replacement without increasing the mileage retired.[118] In addition, the Company asserts that the primary main replacement cost driver is generally the length of main installed, not retired, as the Company generally abandons retired gas main in place, which minimizes the disturbance to the road right-of-way that it would require to remove these facilities, in turn resulting in a cost savings when compared to what it would cost to remove those facilities.[119]

The Staff disagrees that a target mileage of miles installed is more appropriate than miles retired.

> Staff maintains that the goal of the EIRP is accelerated main replacement and as such, the success of this program should not be measured by the number of miles installed. Further, Staff acknowledges the impact of certain TOD projects on the amount of overall distribution main that can be retired with EIRP funding. Staff recommends that the ALJ and Commission direct

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[114] 5 Tr 653. “TOD” refers to Transmission Operated by Distribution.
[115] Id.
[116] 5 Tr 654.
[117] 5 Tr 655.
[118] 5 Tr 653-654.
[119] 5 Tr 654.

> the Company to achieve a target mileage of miles replaced for non-TOD projects that is based on Staff's average calculated cost per mile replaced of $913,389. Given that the scope of TOD projects in the EIRP will fluctuate from year to year, Staff acknowledges that the mileage target will vary as well. Staff recommends that the ALJ and the Commission find that the Company should clearly delineate the TOD and non-TOD projects in its annual EIRP planning and performance reports.[120]

This PFD finds the Company's reasoning in support of miles installed to be more persuasive and recommends that the Commission adopt a target for gas distribution main installed for the 2020 EIRP of 72 miles. The Commission should also adopt Staff's recommendation that the Company clearly delineate the TOD and non-TOD projects in its annual EIRP planning and performance reports.

The Attorney General also takes issue with the Company's projected expenditure levels for 2019 and 2020, asserting that the Commission should disallow $6,582,000 of capital expenditures for the nine months ending September 2019 and $14,080,000 for the 12 months ending September 2020.[121] Mr. Coppola argues that the number of miles of mains retired for most categories of pipe type has declined despite the increasing amount of capital spending on the EIRP and other related programs.[122] Mr. Coppola asserts that the problem "may lie in the escalating cost per mile of main replaced under the EIRP since inception of the program".[123] He notes that the Company's explanation for the increase in cost - a variety of factors including the mix of projects, location differences, and increasing

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[120] Staff brief, p. 20.
[121] 7 Tr 1632-1633.
[122] 7 Tr 1629.
[123] 7 Tr 1630.

costs of local permits – does not explain the long-term trend of cost increase.[124] Mr. Coppola argues that the Commission should not authorize any further increases in capital spending on the EIRP until the Company shows that it can bring the cost per mile down to more reasonable levels, ideally below the $1 million per replacement mile experienced before 2017, and that the Company has not provided any engineering studies to show that replacing an additional 18 to 20 miles of mains, as proposed by Company witness Parker, is warranted.[125] He adds that the targeted completion date of 2036 seems to be an "artificial and arbitrary deadline", which is not supported by any engineering studies about the current deteriorating rate of the pipelines and its remaining life.[126]

The Company counters that Mr. Coppola's assertion that the number of miles of mains retired for most categories of pipe type is inaccurate, as Exhibit AG-10 shows that the vintage main retired in the EIRP is consistent with the miles of main retired when considering the amount spent.[127] Further, the Company notes that the Attorney General's assertion that there is no support that mains are deteriorating at a faster rate is inapplicable; since the Company is targeting replacement of the highest risk facilities each year, the Company would expect to see a reduction in leaks and risk, not an increase in the main deterioration rate as Mr. Coppola suggests. However, the evidence produced by the Company shows an increase in the leak rate on gas mains since 2012.[128]

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[124] Id.
[125] 7 Tr 1631.
[126] Id.
[127] Company brief, p. 24.
[128] 5 Tr 676.

This PFD agrees with the Company that its proposed EIRP cost projections are reasonable. The Attorney General has not shown that the proposed costs are inconsistent with the EIRP as adopted. Therefore, this PFD recommends that the Commission reject the Attorney General's proposed disallowance for this program.

Vintage Service Replacements Program

The Company's Vintage Service Replacements (VSR) program was approved through the August 28, 2018 Order Approving Settlement Agreement in Case No. U-18424.[129] The VSR program includes the replacement of vintage service lines without active leaks and that are not otherwise associated with planned main replacement projects.[130] The Company's projected costs for the VSR Program are $53,524,000 in 2018; $29,169,000 for the nine months ending September 30, 2019; and $41,059,000 in the 12-months ending September 30, 2020.[131]

While Staff finds that the Company has taken into consideration concerns expressed in Staff's positions in Case No. U-18424 and has presented a plan that includes a quantitative analysis of the Company's vintage service lines in order to develop a risk-based approach to selecting replacement projects, Staff does not support the Company's proposed capital expenditures for this program.[132]

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[129] 7 Tr 1984.
[130] 7 Tr 1985.
[131] 5 Tr 636; Exhibit A-105.
[132] 7 Tr 1985-1986.

Staff notes that the Company's proposed VSR program costs in this case are based on estimated costs per vintage service line replacement of $6,476 for 2019 and $6,606 for 2020, while in Case No. U-18424, the Company projected cost per vintage service line replacement of $4,933 in 2017, and $3,875 for 2018 and 2019.[133] Staff points out that Staff previously supported the Company's projected service line replacement unit cost in Case No. U-18424 based upon the Company's representations of future cost decreases included in discovery responses, as follows:

> The 2017 unit cost is reflective of the actual unit cost experienced through August of 2017. The Company has set an aggressive goal to improve performance going forward in the program. The projection is based upon measures the Company is taking to improve efficiency in the VSR in 2018 and beyond. The Company was able to determine several lessons learned from our efforts in 2017 and have implemented changes to the way we select services for replacement. The Company has also identified some operational changes to implement in 2018 in an attempt to drive down the cost per service. As the program continues, we will continue to review our operations and engineering processes to improve efficiency.[134]

Moreover, Staff's concerns in Case No. U-18424 regarding higher unit costs for service line replacements, as compared to other programs involving service line replacements, were allayed by the Company's explanation that the cost per service replacement is higher in the VSR program than the average service replacement cost because "the Company is not replacing every service on the street, as is typically done as part of those programs", because "VSR projects involve replacing one or two services, then skipping a house or two, then replacing a couple more services, etc., which is less

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[133] 7 Tr 1986.
[134] 7 Tr 1986.

efficient than replacing a gas main and every service along the main."[135] As such, Staff is concerned that the Company in this case has "reversed its position" and now anticipates a significant and marked increase beyond 30% from the unit costs experienced in 2017 despite its assertions in the previous rate case to the contrary.[136]

Staff analyzed the costs of 5 individual service line projects, finding that project costs varied from approximately $143,000 up to $3.5 million with average unit costs varying from $8,592 to $47,886.[137] Staff's analysis involved a comparison of the costs for certain service line replacement locations against the Company's service line cards accessed from its Service Information Management Systems (SIMS cards) and satellite and street-view imagery of the service locations.[138] Staff also considered whether the project involved a long-side or short-side service, meaning whether the main was on the same or opposite side of the end-use facility, in addition to other impediments that might complicate the project.[139]

In considering the Division Street project, Staff's analysis showed that the majority of these replacements were short-side replacements with the main approximately 15 feet from the center of the road right-of-way.[140] As such, Ms. Creisher does not find "any

[135] 7 Tr 1987.
[136] Id.
[137] 7 Tr 1988; Exhibits S-9.6, S-9.7, S-9.14, S-9.17 Confidential S-9.9, and Confidential S-9.10
[138] Id.
[139] 7 Tr 1988-1989.
[140] 7 Tr 1990.

significant impediments" to installation of the service lines that substantiate an average service line installation cost of $47,886.[141]

Regarding the Inglewood Drive project, Staff's review found that none of the service replacements required long-side services and that all service lines were relatively short in length and of similar construction.[142] Further, the SIMS cards for five individual service line projects indicate that the vintage service lines were abandoned with installation of a replacement.[143] Thus, according to Ms. Creisher, that there were no significant impediments to replacement that substantiate an average service line project cost of $8,753.[144]

Regarding the Company's Brenthaven Drive project, while several of the replacements in this project involved excavation, repair of asphalt driveway and pavement repair, Ms. Creisher noted that the "marked increase" in costs for the highest cost individual repair compared to the lowest cost service repairs in this project is "disproportionate and unreasonably high."[145] Staff points to its comparison of cost information regarding an active leak at 3107 Wildwood Avenue in Jackson, which comparison indicates a "significant amount of disparity" between the complexity of the

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[141] 7 Tr 1990.
[142] 7 Tr 1991.
[143] 7 Tr 1991.
[144] 7 Tr 1991.
[145] 7 Tr 1994.

highest cost Brenthaven Drive projects and the 3017 Wildwood Avenue leak repair, given that they have reasonably similar total project costs."[146]

Regarding the Company's Rives Junction Road project, Staff notes that the three properties in this project that it reviewed consisted of both long-side and short-side replacements which both included a main approximately 20 feet from the center of the road right-of-way, and that the gas distribution main must have been sufficiently out of the roadway so as to not be a significant impediment to replacement.[147] For one of the replacements in this project, the Company incurred $8,840 for traffic control expenses, whereas in the Wildwood replacement, the Company incurred only $957 in traffic control expenses.[148] Staff asserts that this disparity in traffic control expenditures is drastic, with the reason for this disparity is unclear and lacking in justification.[149] Further, Staff notes that the Company included $14,757 related to capitalized engineering and supervision for these projects without apparent necessity or requirement.[150]

Regarding the Pinecrest Drive project, while Staff recognizes additional costs for soft excavation of facilities, it "remains alarmed" at the total cost of a single service line replacement of $87,815.[151] Further, as with the Rives Junction project, Staff notes similar significant costs related to engineering and supervision. Additionally, one replacement

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[146] 7 Tr 1994.
[147] 7 Tr 1995; Staff brief, p.23.
[148] Exhibit S-9.17; S-9.14.
[149] Staff Brief, p. 24.
[150] 7 Tr 1996.
[151] 7 Tr 1997.

includes $41,523 for "Indirect Capital NL" without explanation as to what is included in this cost that accounts for nearly 50% of the total project cost.[152] As such, Staff finds the total costs of this project "disconcerting".[153]

Finally, Staff examined the unit costs for service line replacements for DTE and Northern States Power Company (NSP) to compare the Company's costs with those of other utilities undertaking similar projects. In that regard, Staff notes that in MPSC Case No. U-18999 DTE proposed projected unit costs of $1,775 and $2,500 related to a meter move-out program to relocate inside meters to the outside of the end use facilities, with DTE's $2,500 projection based on its average cost per service line renewal.[154] Staff also examined NSP's Distribution Integrity Management Plan (DIMP) projects where NSP proposed $2,900 estimated cost per service and where it experienced an actual average unit cost of $2,182 in 2018.[155] While noting that there is not a direct correlation between the experiences of these three company's due to differences in service territory, company operations, and other characteristics, Staff argues that the magnitude of the cost difference for similar work demonstrates the unreasonableness of costs incurred by the Company.[156]

The Company counters Staff's assertions by pointing out that the unit cost of $3,875 projected in Case No. U-18424 represented an "aggressive" unit cost target or

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[152] Staff brief, p. 24.
[153] Id.
[154] 7 Tr 1998.
[155] 7 Tr 1999.
[156] Staff brief, p. 25.

"goal" derived from the average unit cost experienced by the Company during the months of May 2017 through August 2017 of $4,933, less estimated unit cost reductions anticipated as a result of operational changes.[157] The Company acknowledges that it was unable to meet the aggressive target that it set, and notes that, since August of 2017, the Company has gained additional experience with VSRs and has experienced increases in various contractor support costs associated with the location of underground utility infrastructure, as well as welding, hydro-vac, traffic control, and property restoration costs.[158] Company witness Parker testified that in 2017, the Company experienced $7,900,000 in contracted service expense, while a year later, these costs jumped to $15,100,000.[159] He adds that while the increase in contracted services costs are not unique to the VSR Program, its costs are not directly allocated to each individual service order like they are for other programs, resulting in a higher unit cost in the VSR Program.[160] Additionally, since projecting a unit cost of $3,875 for the VSR Program, the Company revised the accounting for the depreciation of vehicles and equipment used by Company operating, maintenance, and construction crews so that those costs are transferred to the Company's workorders, effectively increasing the unit costs in the VSR

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[157] 5 Tr 655; 7 Tr 1986.
[158] 5 Tr 656.
[159] 5 Tr 657.
[160] 5 Tr 657.

program.[161] As a result, the initial 2017 unit cost estimates for VSR no longer provide a reasonable estimate of current and future program costs.[162]

Replying to Staff's analysis of specific projects discussed above, the Company asserts that cost differences between individual service replacement orders can occur for a number of different reasons that cannot reasonably be discerned from the review of the Company's SIMS records and satellite roadway images.[163] Mr. Parker adds that, due to the way the Company collects and distributes costs through the SAP work management system, looking at any individual order or even a small sample may not accurately represent the program's per unit costs.[164] As to the specific projects Staff reviewed, the Company asserts that the information Staff reviewed occasionally understated the number of applicable service orders, included variations in crew time charges for some orders, involved different underground site conditions and other construction challenges, and different internal accounting allocations.[165]

The Attorney General proposed adjustments to the Company's VSR Program expenditures as well. Mr. Coppola based his adjustments on the program's historical costs and the number of services replaced.[166] Using historical information, Mr. Coppla determined that the average cost per service line replaced under the VSR Program was

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[161] 5 Tr 568.
[162] Id.
[163] 5 Tr 568.
[164] Id.
[165] 5 Tr 655-665.
[166] 7 Tr 1634.

$5,372 in 2017 and this cost increased to $6,037 in 2018.[167] Using the Company's projected number of services to be replaced and the average cost per service, Mr. Coppola concludes that the Company's forecasted expenditures for the test year are "excessive and unreasonable", noting that the reasons for the cost increases offered by the Company - difficulty in locating sewer laterals, traffic control, hydraulic excavation and material handling – "do not seem to be out of the ordinary items that any construction project would not encounter."[168] Accordingly, the Attorney General recommends that the Commission remove $1,684,000 from the Company's forecasted capital expenditures for the test year.[169]

Mr. Parker counters that the Company's projections are based on the actual costs per service observed in 2018 plus an increase to account for the rate of cost increase that has been experienced over the past two years, which is beyond the 2% inflation rate proposed by Mr. Coppola.[170] He adds that the most significant aspects of the increase in service replacement costs were those related to outside services required for service replacement; sewer lateral locating and staking, traffic control, hydraulic excavation (to prevent damage to or causing leaks on the existing vintage facilities), etc.[171] Mr. Parker asserts that the cost projections for 2019 and 2020 were increased to reflect the increased

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[167] *Id*.
[168] 7 Tr 1635
[169] Id.; Exhibit AG-14.
[170] 5 Tr 671.
[171] *Id*.

costs experienced in 2018.[172] As such, the Company believes the projected VSR costs are the most accurate prediction of costs to be incurred by the program.[173]

This PFD finds that the Staff's and the Attorney General's arguments are persuasive. As Staff asserts, the Company has not fully explained why the costs associated with contracted support services for the VSR "doubled" between 2017 and 2018. In addition, the Company does not offer any rationale for the significant disparity between its projected costs and those disclosed by DTE and NSP in their most recent gas rate cases. While the Attorney General seeks a smaller disallowance than Staff, Staff's proposed disallowance is supported by the evidence. Accordingly, the PFD recommends that the Commission approve a capital expenditure level of $24,2018,750 for both 2019 and 2020, which is based on an adjusted vintage service line unit cost of $3,875 projected by the Company in its last gas rate case and which result in a projected capital expenditure of $17,454,000 for the 9 months ending September 30, 2019 and $24,219,000 for the test year ending September 30, 2020.

Finally, this PFD notes that Staff previously proposed that the Company align the timeline of the VSR program with that of the EIRP, and the Company agrees.[174] Accordingly, the Commission should adopt this change.

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[172] *Id*.
[173] *Id*.
[174] 5 Tr 635.

vii. Capacity/Deliverability Program

The capital expenditures related to the Capacity/Deliverability Program reflect necessary increases in transmission and distribution pipeline capacity.[175] Deliverability expenditures include city gate and regulation station rebuilds and improvements, as well as expenditures for the TED-I projects. For the Capacity/Deliverability Program, including Major Projects, the Company projects expenditures for the test year in the amount of $316,639,000.[176]

TED-I Program

TED-I pipeline projects focus on maintaining integrity and deliverability, including transmission pipeline replacements of higher relative risk pipe to ensure integrity and safe operation.[177] The major TED-I projects included in this filing are Saginaw Trail Pipeline, Mid-Michigan Pipeline, and the South Oakland Macomb Network.[178] Staff supported recovery of these projects, with an adjustment made for contingency.[179] In rebuttal, Consumers Energy updated the originally filed capital expenditures for the TED-I major projects to address the contingency cost adjustment.

The Attorney General took issue with the Company's expenditures related to the Saginaw Trail and Mid-Michigan pipelines.

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[175] 5 Tr 647; 6 TR 1035.
[176] Exhibit A-12; Exhibit A-41.
[177] 8 Tr 2305.
[178] 8 Tr 2296.
[179] 7 Tr 2241-2244.

Saginaw Trail Pipeline

Mr. Coppola asserts that, in reply to the Attorney General's discovery request seeking project cost approval and an implementation timeline, when those costs were planned to be incurred, and the status of implementation, the Company provided a copy of a presentation made to the Finance Committee of the Board of Directors in November 2016, nearly two and half years ago.[180] Mr. Coppola asserts that this information "is not helpful in making a current assessment of the status of the implementation of the project, and whether the large capital expenditures forecasted for 2019 and 2020 will likely be incurred as forecasted."[181] He adds that the Company indicates that the construction window for the section of the pipeline to be installed in 2020 will be between May 1 and November 1, 2020, with the November date being past the end of the forecasted test year.[182] As such, Mr. Coppola asserts that without more detailed implementation plans, "it is not possible to determine if the forecasted capital expenditures can reasonably be incurred before the end of September 2020, and whether this segment will be in service and useful as of that date."[183]

The Company counters that Exhibits A-29 and A-30 provide the projected cash flow by project, by month, and by cost element based on the Company's implementation

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[180] 7 Tr 1636-1637.
[181] 7 Tr 1637.
[182] 7 Tr 1637.
[183] 7 Tr 1636-1637.

plan.[184] Additionally, the Company points out that Exhibit A-128 provides a detailed milestone of the project's timeline.

This PFD finds the Company's response persuasive, as the Company has provided adequate information to support this project. Accordingly, the PFD recommends that the Commission not accept the disallowance proposed by the Attorney General.

Mid-Michigan Pipeline

Attorney General witness Coppola takes issue with the Company's projected expenditures related to the Mid-Michigan Pipeline project. Mr. Coppola asserts that

> In response to [a] discovery request, the Company disclosed that it is preparing an Act 9 application to obtain Commission approval to build the pipeline. The Company stated that it anticipates making the Act 9 filing in mid-summer 2019. In the prior gas rate case, Case No. U-18424, the Company stated that it was going to file the Act 9 application in the third or fourth quarter of 2018. It is now apparent that the project has already been delayed at least 6 months and maybe longer. From Ms. Bowers' testimony, it appears that the Company has done some engineering work which will continue into 2019, and plans to acquire land or land rights in the first half of 2020. Procurement of materials and other expenditures are planned for 2020 and into 2021.
>
> With no Act 9 application yet made and no certificate of public necessity and convenience issued, this is a case of the Company attempting to include capital expenditures into rate base before the project has been approved and is certain to be done. Although the Company seems to have a high-degree of confidence that its Act 9 application will be approved, official approval has not yet been given. In fact, the Company has not yet filed an application and has already delayed filing the application once. In other words, the request to include capital expenditures in rate base is extremely premature, irrespective of the fact that some costs will be incurred before the Act 9 application is approved. Those costs should only be recovered if the project is approved. The purpose of going through the Act 9 proceeding is to ensure that the project is necessary and in the public

[184] 8 Tr 2333.

> interest. The proceeding should not be preempted by assuming that approval will be forthcoming before an application is even filed. Similarly, customers should not pay for costs for a project that the Commission has not yet approved.[185]

The Company disagrees with the Attorney General's position, and notes that the Company's requested expenditures for the Mid-Michigan Pipeline project are the dollars associated with undertaking the necessary and prudent planning and project scoping in preparation for an Act 9 filing and engineering.[186]

This PFD finds the Attorney General's argument persuasive and the Company's position unsupported. As the Company acknowledges, the project already has been delayed and the Act 9 application has yet to have been made. Accordingly, this PFD recommends the Attorney General's proposed disallowance of the capital expenditures of $8,522,000 for this project be adopted by the Commission.

City Gates and Regulator Stations

Mr. Miller proposed that the Company develop a risk ranking to prioritize Transmission and Storage City Gate investments.[187] The Company agreed to develop a quantifiable risk ranking for City Gate and Regulator Station investments by the end of 2019.[188] Accordingly, this PFD recommends that the Commission accept the Company's agreement.

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[185] 7 Tr 1639-1640.
[186] 8 Tr 2328.
[187] 7 Tr 2190.
[188] 6 Tr 1050.

2. Gas Compression And Storage Capital Expenditures

The Company requests rate recovery of its Gas Compression and Storage (GCS) capital expenditures as follows: (i) $125.9 million for 2017 (actual); (ii) $258.9 million for the bridge period (21 months ending September 30, 2019) (projected); and (iii) $135.9 million for the 12 months ending September 30, 2020 (i.e., projected for the test year).[189] Staff and Attorney General witnesses raised specific challenges to certain GCS capital expenditures.

a. Well Rehabilitation Capital Expenditures

Ms. Creisher proposed that the 2019 and 2020 capital expenditures related to the Well Rehabilitation program be adjusted based on the Company's actual performance of the program in 2017 and 2018, resulting in a projected capital expenditure of $7,880,000 for the nine months ending September 30, 2019, and $10,120,000 in the test year ending September 30, 2019.[190] Ms. Creisher's recommendation is based on her calculation of a unit cost of performing remediation work using the Company's Well Rehabilitation capital expenditures for 2017 and 2018 divided by the total number of wells logged in 2017 and 2018.[191] Ms. Creisher notes that the Company's actual performance in the Well Rehabilitation program in 2017 and 2018 demonstrates that the Company was able to exceed its projections in Case No. U-18124 in consideration of the number of wells

[189] 5 Tr 850-851.
[190] 7 Tr 2007; Exhibit S-9.1.
[191] 7 Tr 2007.

impacted and the capital expended.[192] She adds that the Company indicates projected expenditures of for 2019 and 2020 at nearly the exact same level of capital expenditure as originally projected for 2019 and 2020 in Case No. U-18124.[193] She concludes that while the Company "has impacted more wells than anticipated" in the first two years of the program and has also reduced the amount of well logging and remediation for the remainder of the 10-year program, the Company "has neglected to revise its projected capital expenditures based on the efficiencies experienced in the implementation of the program as well as the reduction in the amount of work to be completed."[194] As such, Staff asserts that the Company's original capital expenditure projections for program years 2019 and 2020 are not representative of the program's experienced costs.[195]

In rebuttal, the Company counters that, while it does not oppose using a unit cost approach to project annual expenditures for the remainder of the program, the calculation of a straight average as Staff has done "does not provide the complete picture."[196] The Company asserts that Ms. Creisher's proposed disallowance based on a straight average unit per well cost, using 2017 and 2018 costs and the number of wells that the Company rehabbed during those years, is flawed in two respects. First, Mr. Joyce indicates that the range of costs that the Company will incur to rehab wells vary widely, noting that the actual costs from the first two years of the program range between $133,465 and

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[192] 7 Tr 2005.
[193] 7 Tr 2006.
[194] 7 Tr 2006-2007.
[195] 7 Tr 2007.
[196] 5 Tr 875.

$383,374 per well.[197] Second, he asserts that the Company's scheduled rehabilitation work for 2019 and beyond "will not be in the same quantities as it was for the first two years of the program."[198] Also, he states that there is work scheduled in 2019 to complete the well rehabilitations from the first two years of the program, which will cause the unit cost per well to increase.[199] He adds that the unit cost will be updated each year and then used for estimating expenses for future rate case filings.[200]

The Attorney General also asserts that the Commission should disallow certain well rehabilitation costs. Like Ms. Creisher, Mr. Coppola based his proposed disallowance on his calculation of the per-unit cost of performing remediation work using the actual results from 2017 and 2018.[201] After applying an inflation factor, he calculated the cost of well rehabilitations for the nine months ending September 30, 2019 and the 12 months ending September 30, 2020.[202] He then compared his numbers with the amounts forecasted by the Company after removing contingency costs.[203] His calculation resulted in cost projections of $11,507,000 for the nine months ending September 2019, and of $11,922,000 for the 12 months ending September 2020.[204]

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[197] Id.
[198] Id.
[199] 5 Tr 876.
[200] Id.
[201] 7 Tr 1643.
[202] Id.
[203] 7 Tr 1643-1644.
[204] 7 Tr 1643-1644.

The Company counters that Mr. Coppola's calculations suffer from the same mistakes as Staff's calculation, together with an additional asserted mistake. That is, the Company asserts that Mr. Coppola compared his projected per-unit cost to the Company's cost projections for a larger category of costs that included not only well rehabilitation costs, but also other projects, which resulted in a proposed disallowance much larger than what Staff proposed.[205]

Finally, ABATE also challenges the Company's forecasted capital expenditures for Well Rehabilitation. Relying on testimony from Mr. Coppola and Attorney General exhibits, ABATE notes that the Company forecasted capital expenditures of $17.7 million for 2018, $16.7 million for the nine months ending September 2019, and $21.5 million for the 12 months ending September 2020, while in comparison, the Company had capital expenditures of $14.9 million in 2017 and $21.9 million in 2018.[206] ABATE argues that, after incorporating an inflation factor of 2.3%, the Company will only likely spend $11,507,000 to rehabilitate its wells for the nine months ending September 2019, which is "far less" than the $16,740,000 that the Company forecasted for well rehabilitation work during the same period.[207] Thus, ABATE asserts that the Commission should find that the excess amount lacks justification and remove it from the Company's forecasted capital expenditures.[208] Similarly, for the 12 months ending September 2020, ABATE notes that

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[205] Company Brief, p. 44-45, referencing Exhibits AG-19 and A-149.
[206] ABATE Brief, p. 50.
[207] *Id*.
[208] *Id*.

the Company projects spending $21,528,000 to rehabilitate additional wells, while "[b]ased on the record evidence", the Company should be able to make the same repairs for $11,922,000.[209] Noting that the difference between these two amounts represents approximately $9 million dollars, ABATE asserts that the Commission should require the Company to adequately justify this disparity before it authorizes the Company to collect the funds from its customers.[210]

The Company does not appear to address ABATE's arguments on these expenditures.

The Company's arguments opposing Staff's and the Attorney General's proposed disallowances are not persuasive. While the Company asserts that the future rehabilitation costs will vary widely, the Company makes no attempt to quantify such costs despite agreeing to using a "unit cost approach". Similarly, while the Company asserts that future rehabilitation work will differ in quantity from that for the first two years, the Company makes no attempt to quantify this difference. Thus, this PFD recommends that the Commission adopt Staff's proposed projected Well Rehabilitation program capital expenditures of $10,506,000 in 2019 and $9,938,000 in 2020, which results in capital expenditures of $7,880,000 for the nine-months ending September 30, 2019, and $10,120,000 for the test year ending September 30, 2020. Although the Attorney General followed a similar approach to determining adjusted projected expenditures and is

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[209] *Id*.
[210] *Id*.

proposing adjusted projected expenditures in amounts greater than Staff's adjusted projections, this PFD is recommending that the Commission adopt the Staff's adjusted amounts.

b. Storage Pipeline Capital Expenditures

Ms. Creisher also proposed that the Commission disallow $4.5 million of the Company's projected Storage Pipeline Replacement Program expense in the nine months ending September 30, 2019, and $6.0 million in the test year.[211] Ms. Creisher, noting that the Company offered no direct testimony on this program and the Company's discovery response led the Staff to conclude that these projects are not directly related to integrity of the Company's storage wells, concluded that it is not appropriate to include these expenditures in the Well Rehabilitation program capital expenditures.[212] She further testified that "Staff does not dissuade the Commission from determining that it is also unreasonable for the 2018 capital expenditure amounts to be considered for recovery at this time."[213] Finally, Ms. Creisher indicated that Staff does not support the inclusion of the Storage Pipeline Replacement program under any other programs presented in this case:

> As previously mentioned, the Company demonstrated a lack of transparency when it failed to provide any mention through testimony or exhibits filed in its direct case. Furthermore, upon inquiry through Staff Audit Request #229 (Exhibit S-9.26) the Company provided a vague description related to risk, safety, integrity, and deliverability without sufficient tangible support for such claims. The Company did provide limited information for

[211] 7 Tr 2009-2011; Exhibit S-9.1, line 6.
[212] 7 Tr 2010.
[213] Id.

> one project included in the Storage Pipeline Replacement program in Attachment 139 of the Company's Part III – Standard Filing Requirements Supplemental Data, which details the Company's 25 highest cost capital projects. . . . However, where the Standard Filing Requirements direct the Company to provide all studies performed by the Company or other parties related to the project, the Company cited none. No further information was provided regarding the 5 remaining Storage Pipeline Replacement projects for Overisel Lateral 1, Overisel 6 Lateral 8, or Overisel-Salem Lateral 1. It is Staff's position that the Company has insufficiently supported the reasonableness and necessity of the Storage Pipeline Replacement projects for recovery of capital expenditures, regardless of any other programs in this proceeding that may be more appropriate. Furthermore, in order to be considered reasonable and prudent for recovery in this rate case proceeding, the Company must demonstrate that it has appropriately assessed and prioritized the risk related to the Storage Pipeline Replacement projects against the Company's other storage and transmission assets.[214]

The Company replies that "[w]hile Staff is free to advocate for the separate reporting of storage pipeline replacement costs, such preference provides no basis for disallowance of costs."[215] The Company adds that no Staff witness cited any statutory or regulatory standard, or Commission order setting forth any reporting requirement that prohibited the Company from including Storage Pipeline Replacement Program costs with well rehabilitation costs.[216] The Company notes that it included its Storage Pipeline Replacement Program with its Well Rehabilitation Program "because the former is a risk-based program that is located across the Company's storage portfolio."[217] The Company adds that it does not oppose Ms. Creisher's recommendation that the Commission require the Company to develop a comprehensive Storage Pipeline Replacement Program that

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[214] 7 Tr 2010-2011.
[215] Company Brief, p. 40.
[216] Id.
[217] Id., referencing Exhibit S-9.26.

is based on threats and risk to infrastructure, and to provide a risk assessment report for all identified high-risk storage field pipelines.[218] However, "the fact that the Company did not report its storage pipeline projects as proposed by Ms. Creisher's testimony in no way justifies disallowance of the Company's reasonably and prudently incurred costs."[219]

This PFD finds that Staff's argument is persuasive as the Company has not sufficiently supported the reasonableness and necessity of the Storage Pipeline Replacement projects for recovery of capital expenditures. Thus, this PFD recommends that the Commission disallow these expenditures.

c. <u>Storage New Wells</u>

Mr. Coppola asserts that the Commission should reduce the Company's 2018 Storage New Wells capital expenditures by $1.5 million for 2018, reduce expenditures by $4.1 million for the nine months ending September 30, 2019, and reduce expenditures by $3.1 million for the 12 months ending September 30, 2020.[220] Mr. Coppola notes that the Company indicated that it had completed a new storage well in 2017 for a total cost of $3,670,000, and that it was not planning to drill any new wells in 2018, but performed engineering and purchased land for the drilling of 3 new wells in 2019 and 2020.[221] Mr. Coppola calculated proposed future projections using the Company's total cost for the well drilled in 2017 and adding inflationary cost increases, which resulted in a cost

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[218] Id.
[219] Id., p. 42.
[220] 7 Tr 1641-1642.
[221] 7 Tr 1641; Exhibit AG-16.

projection of $13,086,000 less than the Company's projection.[222] Mr. Coppola concludes that the Company "has not explained or provided any justification why drilling three new wells in 2019 and 2020 should cost more than twice the inflation adjusted cost incurred in 2017."[223]

ABATE also challenges the Company's Gas Storage projections. Relying on Mr. Coppola's testimony and exhibits, ABATE notes that the Company stated that it had completed a new storage well in 2017 for a total cost of $3,670,000, and also indicated that it was not planning to drill any new wells in 2018, but performed engineering and purchased land for the drilling of three new wells in 2019 and 2020.[224] ABATE notes that the Company has forecasted total costs of $24,840,000 from 2018 through September 2020 to engineer, purchase land and drill the three new wells in 2019 and 2020.[225] ABATE argues that the Company has not explained or provided any justification why drilling three new wells in 2019 and 2020 should cost more than twice the inflation adjusted cost incurred in 2017.[226] Thus, ABATE asserts that the Commission should remove $8,797,000 from the Company's forecasted capital expenditures, which represents the excess $13,086,000 net of $4,289,000 in previously disallowed contingency costs.[227]

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[222] 7 Tr 1641-1642.
[223] 7 Tr 1642.
[224] ABATE Brief, p. 49.
[225] Id., p. 50.
[226] Id.
[227] Id.

The Company responds to the Attorney General by noting that, while the analysis for the cost estimate for three new wells based on 2017 new well expense is "valid", Mr. Coppola has made an invalid assumption that the three new wells are the only capital projects included in the New Well projection.[228] Mr. Joyce points out that Exhibit A-149 outlines expenses for additional projects including seismic storage field mapping, wellsite data acquisition, and strategic land purchase, and that these additional projects were not accounted for in Mr. Coppola's analysis.[229] Mr. Joyce adds that the oversight of these additional projects accounts for nearly all of Mr. Coppola's reduction amounts, and that any remaining discrepancy can be attributed to costs associated with engineering and site preparation for new well work occurring beyond the test year.[230]

The Company does not appear to respond to ABATE's arguments.

This PFD finds that the Attorney General's and ABATE's arguments are unsupported by the record, as the Company has shown that the Attorney General's comparison analysis is incomplete as it does not address all relevant expenses. Accordingly, this PFD recommends that the Attorney General's proposed disallowances not be accepted by the Commission.

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[228] 5 Tr 884.
[229] *Id*.
[230] Id.

d. **Contingency Costs**

Staff witness Fromm proposed that the Commission disallow the contingency costs that the Company included in its capital expenditure projections, including the contingency expenditure for the Well Rehabilitation project (which Ms. Creisher separately recommended be disallowed).[231] Staff adds that if the Commission does not adopt Ms. Creisher's recommendation regarding that project, Staff recommends the Commission reject the full contingency expenditures ($8.502 million in 2018, $22.902 million in 16 months ended September 30, 2019 and $30.198 million in the test year).[232] Ms. Fromm testified:

> Staff recommends the Commission reject the projected contingency expenditures because they cannot be deemed reasonable nor prudent at this time. Contingency expenditures are those set aside for the occurrence of uncertain or unexpected events. Because the Company chooses to file a projected test year, these expenditures are at the time unknown either in amount or scope or both. The Company earns a return of and on projected capital expenditures and Staff believes it is inappropriate for the Company to receive recovery of expenditures that cannot be evaluated for their reasonableness or prudence at this time. Should the Company prove these expenditures were spent prudently in a future rate case, Staff believes they can be included for recovery at that time.[233]

Staff notes that the Commission has consistently adopted Staff's recommendation to reject contingency expenditures, including in the Company's most recent fully-contested gas rate case, Case No. U-18124 (7/31/2017 Order) and the Company's past fully-

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[231] 7 Tr 2046-2047.
[232] 7 Tr 2046.
[233] 7 Tr 2047-2048.

contested electric cases: U-18322 (3/29/2018 Order), U-17990 (2/28/2017 Order), and U-17735 (11/19/2015 Order).[234]

The Attorney General also proposes to disallow all of the $61,602,000 contingency costs included in the Company's forecasted capital expenditures, for the same reasons put forth by Staff. [235]

The Company counters that it made adjustments to its proposed revenue deficiency by removing contingency amounts which resulted in a decrease to projected utility plant of $37,310,000, a decrease to depreciation expense of $952,000, and a decrease to property tax of $492,000 to remove contingency in projected capital spending for the 9 months ending September 30, 2019 and the 12 months ending September 30, 2020.[236] However, the Company asserts that the Commission should not disallow any proposed contingency costs for 2018, as those costs are now known (and, thus, no longer a contingency), those costs exceeded the Company's 2018 projection, and no evidence was offered to show that these actual costs were unjust or unreasonable.[237] Specifically, for contingency costs relating to the Well Rehabilitation project, Mr. Joyce testified that the Company's actual Compression and Storage project investments for 2018 exceeded

[234] 7 Tr 2048.
[235] See Attorney General Brief, p. 13-15, referencing Exhibit AG-4 and Commission Orders in cases U-17990, U-18124, and U-18322.
[236] 5 Tr 808; Exhibits A-136, A-138.
[237] Company brief, p. 42

the Company's 2018 projection, such that "[t]here is no longer any uncertainty about the Company's 2018 actual investments in Compression and Storage assets during 2018."[238]

This PFD finds the Staff's position to be persuasive and consistent with applicable Commission precedent. Moreover, it appears to be inappropriate to allow for late adjustments of certain projected expenses without also allowing for any other late changes to the Company's projected expenses. Accordingly, this PFD recommends that the Commission accept the disallowances proposed by Staff and the Attorney General.

Ms. Creisher recommended that the Commission continue to require the Company to provide a compression and storage field performance report through completion of its 10-year Well Rehabilitation Program, and that the report identify the actual number of wells logged and rehabilitated in each program year, and include an allocation of expenditures between logging and rehabilitation activities.[239] The Company agrees with this recommendation.[240] Accordingly, this PFD recommends that the Commission accept Staff's recommendation.

3. Facilities Capital Expenditures

Gas Operations Support provides support to the Company by acquiring, constructing, and maintaining assets required to operate the functional areas of the business.[241]

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[238] 5 Tr 880.
[239] 7 TR 2008.
[240] 5 TR 878.
[241] 6 Tr 1419-1420.

Mr. Coppola recommended that the Commission disallow $6,213,000 of capital expenditures for 2020 relating to asset preservation, asserting that the Company did not provide “sufficient justification” for the increase of approximately $8 million in capital expenditures from 2018 to September 30, 2020.[242] Specifically, Mr. Coppola asserts that Company witness Saba does not even mention the increase in capital expenditures much less justify the increase in her direct testimony, and that the Company failed to provide requested documentation and analyses to support the increase in capital expenditures.[243] Mr. Coppola concludes that without the requested information, “it is not possible to validate the reasons provided by the Company, or determine if the projects are economically justified and the proposed expenditures are reasonable.”[244]

The Company counters that Ms. Saba explained in her rebuttal testimony that the Asset Preservation capital expenditures for the 12 months ending September 30, 2020, were increased by approximately $8 million over the 2018 amount as a result of the following construction projects: (i) a small service center in the Standish area, (ii) a new service center in Hastings, and (iii) a renovation to the service center in Kalamazoo.[245] Ms. Saba further explained the process used by the Company to evaluate whether to invest in facilities.[246] Ms. Saba testified that the Company’s Asset Preservation of facilities investments includes: 1) infrastructure investments, 2) upgrades and maintenance, and

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[242] 7 Tr 1647.
[243] 7 Tr 1648.
[244] Id.
[245] 6 Tr 1427-1428.
[246] 6 Tr 1428.

3) purchase, new construction, and renovations.[247] Finally, she offered that the Standish Service Center that will complete the Northeast Initiative as currently there is no building that exists in this service territory, the Hastings Service Center that will be new construction, and the Kalamazoo Service Center that will be a renovation.[248]

This PFD finds the Attorney General's argument persuasive, as the Company has not adequately supported its proposed expenditures for these facilities. Accordingly, this PFD recommends that the Commission accept the disallowances proposed by the Attorney General.

a. <u>Fleet Capital Expenditures</u>

The Company's total projected Fleet Services investment is $23,466,000 in 2018; $4,269,000 for the nine-month period leading up to the start of the test year in October 2019; and $19,340,000 for the test year ending September 30, 2020.[249] The Company's Fleet Services capital spending is projected to increase in the 2019-2020 test year, when compared to the 2017 historical year, because the Company is proposing to move to an optimal fleet life cycle between five and eight years versus the current fleet life cycle of 12 to 15 years.[250]

The Attorney General challenged the Company's Fleet Services expenditures. Mr. Coppola testified that the information provided by the Company "does not make a

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[247] 6 Tr 1429.
[248] 6 Tr 1429.
[249] 5 Tr 909; Exhibit A-12 (BKS-2), Schedule B-5.8.
[250] 5 Tr 912.

compelling case" that the level of capital spending on transportation equipment should double beginning in 2019.[251] He adds that no evidence has been presented that transportation equipment is deteriorating at a faster pace and that O&M costs are escalating significantly, and that the evidence shows a high unit availability rate of nearly 100%.[252] Finally, he asserts that the Company has not presented a cost/benefit analysis to justify the proposed increase in capital spending, while the cost/benefit analysis he prepared shows that it is "uneconomic to increase spending instead of continuing with the current rate of fleet unit replacement even with escalating O&M costs."[253]

The Company counters that given the significant growth in the number of out-of-lifecycle units in the Company's fleet and the concerns regarding increasing costs to maintain such an aged fleet, a recommendation to further reduce the Company's capital spending on fleet vehicles is "irresponsible".[254] The Company asserts that fleet spending included in the Company's budget over the past several years has been significantly lower than required to even maintain the current level of out-of-lifecycle units, much less begin bringing the number of out-of-lifecycle units down.[255] Mr. Straub testified that Fleet Services has been required to shift focus back and forth between the two sides of the business due to the highest priority operational needs emerging that year, and that the problem can only be addressed by committing sufficient funding to allow the Company to

[251] 7 Tr 1654.
[252] Id.
[253] 7 Tr 1655.
[254] Company Brief, p. 56.
[255] 5 Tr 928.

achieve an appropriate fleet lifecycle.[256] Further, Mr. Straub explained that that unit availability does not demonstrate that the Company's fleet is not in deteriorating condition, and that technology advancements in today's fleet units lead to more frequent repairs and associated costs.[257] Finally, Mr. Straub testified that Mr. Coppola's calculations of fleet cost increases is misleading, as the average rate of increase per year was 15% over the last 3 years.[258]

This PFD finds that the Attorney General's requested disallowance is not supported by the record. Rather, the Company demonstrated that the proposed expenditures are reasonable, prudent and necessary given the current circumstances and status of the Company's fleet services. Accordingly, this PFD recommends that the Commission not accept the proposed disallowance offered by the Attorney General.

4. Information Technology Capital Expenditures

The Company proposes 2018 bridge period capital expenditures of $34,160,000, and projected test year capital expenditures of $25,450,000.[259]

a. OSIsoft PI Historian Upgrade

Staff recommends the Commission reject $832,337 capital expenditures for the test year for the OSIsoft PI Historian Upgrade project because the vendor had not released the update that the Company was planning to initiate and, thus, the Staff had

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[256] 5 Tr 929.
[257] 5 Tr 929-930.
[258] 5 Tr 931.
[259] 6 Tr 1476.

"no way of validating the costs the Company has projected."[260] Even after the Company explained in rebuttal that the upgrade had been released, Staff still proposes that this expenditure be disallowed because the Company has not presented evidence that its projection of $832,337 is valid or prudent.[261] Staff adds that the upgrade in 2018 was projected to be $289,532, which shows that this vendor's upgrades vary in scope and cost.[262]

Noting in rebuttal that the upgrade was released after Staff's discovery request, the Company adds that it has been using this vendor for "well over ten years and has completed multiple upgrades during this time."[263] The Company's Mr. Varvatos asserts that "the Company's experience with previous upgrades provides the knowledge to estimate the effort needed and allow for the necessary and appropriate level of planning for maintaining the currency and stability of the Company's critical historian systems."[264]

This PFD finds the Company's position persuasive. The fact that the cost of the upgrades vary does not mean that the costs are unreasonable. Accordingly, this PFD recommends that the Commission not accept Staff's proposed disallowance for this project.

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[260] 7 Tr 2050.
[261] Staff Brief, p. 17-18.
[262] Id.
[263] 6 Tr 1524
[264] Id.

b. Asset Refresh Programs

Staff analyzed all ten of the Company's Asset Refresh Program (ARP) projects and recommended adjustments to the Workstation Asset Management (WAM), Field Device Asset Management (FDAM) and Servers projects. These projects are intended to provide replacement workstations and field devices on a four-year refresh cycle and servers on a five-year refresh cycle.[265] For its analysis, Staff obtained from the Company the types and number of assets that had been replaced in the years 2016 and 2017, the number planned for 2018 and the test year, and the unit cost of each asset for each of the Company's Asset Refresh Programs, and compared these amounts to the material cost the Company had requested. [266] The three programs, ARP – WAM, ARP – FDAM, and ARP – Servers represented projects where the requested materials cost exceeded the cost that could be justified on a per-unit basis.[267] As such, Staff recommended disallowing the differences, as follows: $107,864 for 2017, $549,925 for 2018, $397,629 for 9-month ended September 30, 2019, and $571,649 for the test year.[268] For each of these three projects, Ms. Fromm testified that, after analyzing information from the Company and obtaining a total unit cost for each year between 2017 and 2020, even with the increase in unit costs due to the refresh of monitors, the unit cost and number of units

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[265] Exhibit A-117, pp 1-2.
[266] Staff Brief, p. 11; Exhibit A-117.
[267] Id.
[268] Id.; Exhibit S-14.1.

provided amounted to less than what the Company was requesting for the materials portion of this project.[269]

The Company counters that Ms. Fromm's analysis "reflects a misapplication of the Company's response to Staff's audit request."[270] Specifically, Mr. Varatos testified that, in reply to Staff's request, the Company provided the units and unit costs of each asset replaced under this program and the number planned for replacement.[271] However, the ARP – WAM project also includes material costs for new purchases such as tablets, rugged devices and incremental workstations purchases which was not provided in the Company's response to Staff's request.[272] Also, beginning in 2018, the ARP – WAM project included the new purchases needed to support new Company hires and contractors.[273] Regarding Staff's proposed disallowances, Mr. Varatos offers that the difference between total material costs and the unit cost and number of units is primarily attributable to new purchases of desktops, laptops, rugged devices, tablets and monitors, other miscellaneous costs, including new purchases to support new Company hires and contractors.[274] He adds that these historical actual costs represent reasonable and prudent purchases of assets in use by the Company today and disallowance would require assessment of asset impairment and potential write-off to expense.[275]

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[269] 7 Tr 2050-2052; Exhibit A-117.
[270] Company Brief, p. 67.
[271] 6 Tr 1525-1531; Exhibit A-117.
[272] Id.
[273] Id.
[274] 6 Tr 1525-1527.
[275] Id.

The Company asserts that, based on the wording of Staff's audit requests, the Company "provided the portion of the materials cost required to replace existing units", and that "if Staff had asked for information on new assets, the Company would have provided it."[276] The Company concludes that Staff "did not", and thus, "the fact that Staff narrowly tailored its discovery request does not support any disallowance of costs."[277]

Staff counters that the additional data the Company provided "creates additional uncertainties", noting that the unit costs of the tablets vary drastically between the new and replaced purchases, and that the Company "does not explain why this discrepancy in cost exists, nor why it is so large."[278] Staff concludes:

> Although the Company's rebuttal testimony stating that Staff's analysis only includes part of the material costs sheds light on reasons for the discrepancies between the information supplied through audit and the material requests, it does not fully explain the discrepancies. In fact, the Company's rebuttal testimony raises more discrepancies in the data. Staff believes that the Company has not provided sufficient record evidence to justify the costs for these three projects in the Asset Refresh Program. While Staff understands that its initial analysis did not take into account assets that were new purchases, the unexplained discrepancies between the unit costs prohibits Staff from recommending the Commission accept these costs.[279]

This PFD finds that Staff's arguments are persuasive. Although Staff's audit requests may not have been clearly stated, the Company's additional information still includes unexplained discrepancies, and thus is not properly supportive of its projected

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[276] Company Brief, p. 68. Emphasis in original.
[277] Id.
[278] Staff Brief, p. 12-13.
[279] Id., p. 14-15.

expenditures. As such, this PFD recommends that the Commission accept the disallowances proposed by Staff.

5. Accumulated Provision For Depreciation (Depreciation Reserve)

In its initial filing in this case, the Company calculated a Depreciation Reserve amount of $3,415,938,000, and thereafter, in rebuttal, the Company made adjustments which adjustments decreased the Depreciation Reserve by $695,000 and resulted in a total amount of $3,415,243,000.[280] Staff recommends a depreciation reserve of $3,413,977,000, which is a $1,266,000 reduction from the Company's projected amount of $3,415,243,000.[281] All of the difference between the Company and the Staff's projection for depreciation reserve appears related to the difference in projected capital expenditures.[282]

6. Construction Work In Progress

In its filing in this case, the Company calculated a Construction Work in Progress ("CWIP") amount of $631,603,000.[283] No party opposed the Company's proposed CWIP amount. Therefore, the Commission should approve the CWIP amount of $631,603,000 for the test year in this case.

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[280] Exhibit A-12, Schedule B-3, line 18; 7 TR 2037; Exhibit S-2, Schedule B
[281] Staff Brief, p. 6.
[282] Company Brief, p. 75; Staff Brief, p. 6.
[283] Exhibit A-12, Schedule B-1a, page 2, line 4.

B. Working Capital

1. Working Capital Methodology And Calculation

The Company projected a working capital balance of $774,316,000 for the test year.[284] Staff also projected a test year working capital balance of $774,316,000.[285]

The Attorney General opposed the Company's working capital balance. Mr. Coppola proposed a reduction to working capital in the amount of $14.3 million to reflect a lower Cash Balance level of $8.5 million versus the Company's proposed amount of $22.8 million.[286] Mr. Coppla explained this proposed adjustment, as follows:

> The $22.8 million cash level proposed by the Company is unreasonable and simply reflects the historical average. In several of the Company's recent rate cases, the Company has advocated a cash balance level equal to 1% of revenues. Had the Company taken this position in this case, the result would be a $17 million cash balance level, which would have been lower, but still unacceptable. As explained by both the Attorney General and Staff in prior rate cases, it is not appropriate or advisable for the Company to propose large cash balances and include the cost of those high balances in working capital. For the Company to earn a return at the overall cost of capital on such a large cash balance is costly for customers and is unnecessary. The Company has multiple bank lines of credit and access to the commercial paper market. These sources of short term borrowing can be accessed when the Company needs funds to meet short term working capital requirements. Other utilities, such as DTE Electric and DTE Gas Company, use this approach and avoid carrying large cash balances.[287]

Mr. Coppola also notes that the Company has increased its credit lines by approximately $230 million since the time of its last gas rate case (Case No. U-18424), which provides the Company with additional access to cash when needed.[288] Mr. Coppola

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[284] Exhibit A-12 (JRC-44), Schedule B-4, line 22.
[285] Exhibit S-2, Schedule B-4.**?**
[286] 7 TR 1657; Exhibit AG-45.
[287] 7 Tr 1657-1658. Footnote deleted.
[288] 7 Tr 1658.

adds that it is unacceptable for customers to be burdened both with the cost of the large credit facilities in the form of bank fees, and also with the cost of large amounts of cash included in working capital.[289] Accordingly, Mr. Coppola recommends a cash balance level of $8.5 million, which equates to half a percent (0.5%) of the Company's total annual revenue.[290]

Mr. Bleckman countered that the level of cash is based on the historical average of actual cash balances held by the Company, and that Mr. Coppola "has failed to recognize the importance of having adequate liquidity on hand for utility operations, including appropriate protection against volatility or potential inaccessibility of capital markets."[291] Mr. Bleckman replied to Mr. Coppla's assertion that the Company in the past has advocated a cash balance equal to 1% of revenues, as follows:

> As explained on page 21 of Company witness Denato's direct testimony in Case No. U-18124, the Company continues to support the need for holding an average cash balance of approximately 2% of revenues. However, in Case No. U-18124, the Company planned on an average cash balance of 1% of revenues to be held in temporary cash investment accounts. In Case No. U-17735, the Commission indicated that cash held in temporary cash investment accounts were not properly included in the Company's working capital, even if the cash is appropriately needed for liquidity purposes. While the Company excluded those temporary cash investment accounts from the working capital test year projection in Case No. U-18124, the Company indicated its plans to continue reviewing its approach to cash holdings in subsequent cases and reserved the option of holding more of its cash needs in ordinary cash accounts in such future cases. I continue to support the need for holding an average cash balance of approximately 2% of revenues, not 1% as Mr. Coppola implies.[292]

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[289] Id.
[290] Id.; Exhibit AG-45
[291] 4 Tr 474.
[292] 4 Tr 474.

Mr. Bleckman adds that there are a number of legitimate business reasons that support the level of cash presented by the Company in this case, including seasonality in cash flows, issuance of new bonds prior to actual maturity dates, and the need for flexibility to meet investing activities should there be a delay in accessing long-term capital from capital markets.[293] Mr. Bleckman states that the Company's projected cash balance included in working capital for the test year in this case "is needed, reasonable, and has been supported by the Commission in recent orders."[294] that approximately 2% of gas revenues in this case would equate to an average cash balance of $38.5 million, which is significantly higher than the $22.8 million average cash balance included in the proposed working capital in this case.[295]

This PFD finds that Mr. Coppola's proposed cash balance is unreasonable and should not be a basis for the disallowance the Attorney General seeks. The Company has shown that its cash balance is reasonable and prudent. Accordingly, this PFD recommends that the Commission not accept the Attorney General's proposed disallowance.

2. <u>Calculation Of Costs Of Gas And Gas Stored Underground</u>

The 13-month average cost of gas stored underground is included as part of the Company's working capital. The cost of gas stored underground is directly impacted by the average GCR purchased and produced cost of gas, as well as by the methodology

[293] 4 Tr 474-475.
[294] 4 Tr 475
[295] 4 Tr 474.

and inputs used. In turn, the methodology and assumptions used in developing the cost of gas sold impacts the determination of Company Use Gas and Lost and Unaccounted For ("LAUF") O&M expense. The cost of gas sold also affects the projected operating revenue for sales and the cost of gas sold expense.

The Company's cost of gas consists of the fixed and indexed price gas supply, as well as firm transportation costs. Company witness Deborah S. Pelmear testified that "[t]he Company's cost of gas sold reflects locational pricing differences between NYMEX (Henry Hub) and other supply locations (basis), transportation costs, unused reservation charges, and the GCR accounting treatment of net system uses."[296] These costs are a combination of actual and projected gas cost expenditures as of the date the calculations are completed. Included in the Company's direct testimony was an average cost of gas projection in the amount of $2.815/Mcf for October 2019 through September 2020.[297]

C. <u>Unamortized Manufactured Gas Plant Balance</u>

The Company originally projected Net Unamortized Manufactured Gas Plant (MGP) at $51,211,00.[298] Staff presents Net Unamortized MGP of $49,655,000, which the Company adopted in rebuttal.[299] Thus, this PFD recommends that the Commission adopt the net unamortized MGP balance of $49,655,000.

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[296] 6 Tr 1378.
[297] 6 Tr 1378.
[298] Exhibit A-12, Schedule B-1, 7 Line 10, Column (c).
[299] 7 Tr 2039; Exhibit S-2; Exhibit A-135..

D. Total Rate Base

The aforementioned capital expenditure adjustments, once adjusted for the revised accumulated depreciation expense, result in a projected rate base of $6,433,503,000 as shown in Appendix B to this PFD.

V.

CAPITAL STRUCTURE AND RATE OF RETURN

The rate of return used to set rates is based on the weighted average costs of the sources of capital comprising the capital structure. The weighted cost for each component of the capital structure is determined by multiplying the percentage ratio for that component by the cost rate for that component. The weighted cost rates for each component are then added to determine the overall rate of return.

The Company seeks a rate of return of 6.23% to set rates in this case.[300] Staff recommends an overall rate of return of 5.73%, with the difference primarily attributable to a disagreement concerning the Company's common equity balance and proposed ROE.

A. Test Year Capital Structure

As the Commission has indicated,

> The appropriate capital structure of a utility is based on considerations of cost and risk, and in accordance with these considerations, the Commission has from time to time adjusted a company's capital structure to one that was more reasonable. While a company with more debt is a financially riskier enterprise, a company with more equity has a greater amount of capital invested in the most expensive type of capital. Not only is equity capital

[300] Exhibit A-124; Initial Brief, p. 84. This rate of return was updated in Mr. Bleckman's rebuttal testimony and exhibits from the original requested rate of return of 6.26%.

> more expensive than debt capital, but the return on equity adds a tax burden to total revenue requirements, whereas debt does not. Thus, the Commission seeks an appropriate balance between the risks and costs of investor and debt funding.[301]

The Company has proposed that the rate of return should be calculated using a projected the Company's capital structure for the 12-month period ending September 30, 2020.[302] The Company and Staff agree on the amounts outstanding to be used in the Company's proposed capital structure for long-term debt, short-term debt, preferred stock, deferred federal income taxes ("FITs"), and the Job Development Investment Tax Credit (JDITC).[303] Staff differs with the Company's recommendation for common equity balance and cost rates.

1. <u>Common Equity Balance</u>

In calculating the 13-month average common equity balance for the test year, Mr. Bleckman began with the common equity balance as of December 31, 2017, as shown in Exhibit A-14 Schedule D-1a, page 1, and then made an adjustment to reflect retained earnings from January 2018 through September 2020, and an adjustment to reflect the average of equity infusions from January 2018 through September 2020.[304] The Company's common equity balance was subsequently updated to reflect the actual balance as of January 31, 2019, and was, further, updated to reflect the impacts of the

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[301] MPSC Case No. U-17999, Order, February 28, 2017, p. 63.
[302] 4 Tr 458; Exhibit A-124.
[303] Exhibit A-124; Exhibit S-4, Schedule D-1.
[304] 4 Tr 397-398; Exhibit A-14, Schedule D-1a.

Company's Calculation C rebuttal filing in Case No. U-20309. The updated common equity balance is $7,866,577 and results in an equity ratio of 52.5%.[305]

The Company notes that the Commission's orders in the Company's electric and natural gas rate cases (Case Nos. U-17990 and U-18124) indicates the Commission's desire to see a "rebalancing" of the Company's equity ratio from the levels utilized in recent years, and it argues that in Case No. U-18322 the Company demonstrated its commitment to this rebalancing by requesting an equity ratio which was 46 basis points lower than that approved in Case No. U-18124.[306] The Company points to the Commission's March 29, 2018 Order in Case No. U-18322, where the Commission found that the Company was on track to rebalance its capital structure over the five-year timeframe previously set by the Commission.[307]

However, Mr. Bleckman argues that the Tax Cut and Jobs Act (TCJA), which became effective January 2018, brought "sweeping changes to the federal tax system and has significant impacts on United States utilities."[308] According to Mr. Bleckman, the TCJA will reduce electric utility base rates, reduce gas utility rate base and Investment Recovery Mechanism (IRM) rates, and will necessitate a one-time reduction to the Company's total deferred tax balances.[309] Mr. Bleckman adds that while these savings will be passed on directly to the Company's customers, the changes reduce future cash

[305] Exhibit A-125; Exhibit A-124.
[306] Company brief, p. 86-87.
[307] Company brief, p. 87.
[308] 4 Tr 404.
[309] 4 Tr 404-405.

inflows to the Company and reduce credit quality.[310] As such, Mr. Bleckman argues that while the Company continues to take actions to rebalance its equity ratio, “the glidepath pace of attaining an equity ratio of 50% by 2023 is no longer sound planning based on the new economics that the Company is facing as a result of the TCJA.”[311] He adds that because of the “credit quality challenges now facing the Company”, he expects that maintaining an equity ratio of 52.5% will be appropriate “for the foreseeable future.”[312]

Thus, the Company recommends reducing the 2017 actual equity ratio of 53.6% to 52.5%.[313] As Mr. Bleckman explained, the Company is making that recommendation because “the Company has heard and understands the input of the Commission and intervenors in previous rate cases and is attempting to strike the right balance for customers, the state of Michigan, and credit agencies by holding the equity ratio at our filed position of 52.5%.”[314]

Mr. Bleckman also offered additional rationale for why the 52.5% equity ratio requested in this case is the right balance for customers and the Company:

> [T]he Company is in the midst of a major infrastructure upgrade cycle throughout our service territory in Michigan. We will require billions of dollars in new capital funding to complete these needed upgrades for our customers. Our goal is to raise the necessary capital at the lowest overall cost to customers over the long term. While lowering the Company’s equity ratio beyond the 52.5% recommended in this case may appear to have a near-term cost savings impact, as debt financing is presently less expensive than equity, such a move may result in credit downgrade and lead to our customers paying higher financing costs over the long term. Given the negative credit impacts of federal tax reform on utilities, it is of great

[310] 4 Tr 405.
[311] 4 Tr 409.
[312] *Id*.
[313] 4 Tr 410.
[314] 4 Tr 410.

> importance for the regulatory response to be balanced and thoughtful, as noted in Moody's June 2018 credit outlook for the utility sector.[315]

Mr. Bleckman adds that the Company can make this reduction to its equity ratio while still maintaining its strong credit quality, but that any further reduction would be viewed negatively by the credit rating agencies, given the negative cash flow impacts of federal tax reform.[316] Regarding how the credit rating agencies view the Company's equity ratio, Mr. Bleckman testified:

> Certain credit rating agencies (e.g., Moody's Investors Service ("Moody's")) include securitization debt as additional debt when calculating equity ratios. Other credit rating agencies (e.g., Standard and Poor's ("S&P")) also include Power Purchase Agreements ("PPAs"), benefit obligations, and leases as additional debt when calculating equity ratios. When credit rating agencies increase debt in this way to include securitization debt, PPAs, benefit obligations, and leases, the equity ratio (the ratio of equity to debt) used to evaluate the Company's credit-worthiness is lowered. Thus, a 52.50% equity ratio calculated by the Company gets adjusted to a lower ratio by the credit rating agencies, which, in turn, diminishes the Company's credit strength.[317]

Mr. Bleckman adds that incorporating the projected equity infusions in 2019 and 2020 in the common equity balance enables the Company to maintain reasonable equity ratios after the upward adjustments to debt made by credit agencies for securitization debt, PPAs, benefit obligations, and leases.[318]

Staff, the Attorney General, and ABATE have concerns with the common equity component of the Company's capital structure, with Staff proposing a reduction to the Company's test year common equity infusions, the Attorney General seeking an

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[315] 4 Tr 410-411.
[316] 4 Tr 401.
[317] 4 Tr 402-403.
[318] 4 Tr 403.

adjustment to the Company's common equity and long-term debt balances to achieve a 50/50 debt-to-equity balance, and ABATE seeking to have the Company move closer to a 50/50 debt-to-equity ratio more quickly than proposed by the Company.

a. Staff

Staff recommends a common equity balance of $7.725 billion, which represents 52.05% of the permanent capital structure and overall permanent cost of capital of 41.78%.[319] Mr. Ufolla explained that the Staff's common equity balance differs from the Company's recommendation primarily due to Staff "not recognizing" $125 million of a projected $325 million equity infusion the Company planned in June 2019, reasoning as follows:

> The Company's largest equity infusion in the past five years (aside from January 2019) was $250 million in January 2017, followed by $200 million in June 2017. No other equity infusion in the last five years has been nearly as large as these, and therefore Staff considers it reasonable to reduce the June 2019 infusion to a level that is more in line with what the Company has done in the past. Additionally, in a past electric rate case, U-18322, the Company forecasted a $200 million equity infusion in January 2018 from its parent. However, the Company received a $100 million equity infusion in January 2018. Thus, forecasts have proven to be subject to change at the Company's discretion. With such a high infusion to start 2019, the Company has already added as much as it historically has in an average year, so continued infusions at a larger than usual amount seem unlikely.[320]

Staff notes the reasons offered by the Company for projecting higher equity infusions than in years past: 1) the projected equity infusions enables the Company to maintain reasonable equity ratios after the upward adjustments to debt made by credit

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[319] 6 Tr 1717.
[320] 7 Tr 2270-2271. (footnotes omitted).

agencies for securitization debt, PPAs, benefit obligations, and leases, 2) the equity infusions and resulting equity ratio will allow the Company to raise the necessary capital for its infrastructure upgrade cycle at the lowest overall cost to customers over the long term, 3) the average equity ratio for the Company's peer group was 55.8%, well above the 52.50% proposed by the Company; and 4) the Tax Cuts and Jobs Act of 2017 (TCJA) had significant impacts on the Company's cash flow, resulting in a weakening of the Company's financial credit metrics.[321] Staff rebuts these arguments, as follows.

First, the Company states many other utilities have a ratio lower than 52.5%, including DTE Gas, for which the Commission authorized an equity ratio of 52% in its most recent rate case (Case No. U-18999) despite DTE Gas having a lower credit rating.[322] Mr. Ufolla asserts that this proves the ability of a gas utility to operate in good standing with an equity ratio of less than 52.5%.[323] In addition, contrary to the Company's assertions that a low equity ratio would have a negative effect on the Company's credit metrics and could lead to a downgrade by one of the three major credit rating agencies, none of the three rating agencies have shown signs of considering a downgrade for the Company.[324]

Second, when asked to identify what major infrastructure upgrades were going to be funded with the larger than usual equity infusions, Mr. Ufolla notes that the Company

[321] 7 Tr 2271.
[322] 7 Tr 2271.
[323] 7 Tr 2272.
[324] 7 Tr 2272.

did not identify any major infrastructure upgrades, suggesting that large equity infusions 50% higher than those made over the last five years are unwarranted. [325]

Third, Mr. Ufolla asserts that the fact that other utilities necessitate a higher equity ratio to operate does not justify that all utilities should be at the same ratio, as there are many different factors determine what a proper equity ratio may be for a given company.[326] For example, one factor is credit rating, and as the Company has a very strong credit rating, it would not require as high an equity ratio as a less creditworthy utility.[327]

Fourth, Mr. Ufolla points out that the TCJA did not lead to a downgrade of credit rating or even a downgrade in credit outlook for the Company or its parent, which suggests that the Company has strong enough metrics to maintain its credit rating.[328] In addition, although Moody's downgraded 25 utilities as a result of TCJA, none are in the jurisdiction of the MPSC, which suggests that the regulatory environment in Michigan is positive.[329]

Finally, Staff notes that the Commission has previously requested for the Company to move toward a 50/50 debt to equity ratio and Staff's recommended equity balance is also in line with this. Staff's 52.04% common equity balance supports the Commission's objective of a more balanced capital structure that is less costly to ratepayers, due to debt

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[325] 7 Tr 2273; Exhibit S-11.1.
[326] 7 Tr 2273.
[327] *Id*.
[328] *Id*.
[329] *Id*.

being less costly than common equity, and still reasonable for the Company to maintain its access to capital markets.[330]

In rebuttal, Mr. Bleckman argues that his projected common equity balance in this case takes into account equity infusions from CMS Energy "that are planned, needed, and consistent with the expected capital needs of Consumers Energy through the test year ending September 2020."[331] Moreover, the Company argues that while the planning for a lower equity infusion in Case No. U-18322 was appropriate under the facts and circumstances at the time, the TCJA made the previous strategy no longer viable.[332] Finally, the Company adds that Mr. Bleckman's proposed capital structure uses evidence and an analysis of that evidence – taking the actual capital structure balances and projecting the changes in the balances through the test year ending September 2020 -- while Staff's proposed reduction contains no substantive or analytical connection between that observation and its proposed reduction, and fails to take into account the financial credit metric impacts of the Company's Power Purchase Agreements ("PPAs"), benefits obligations, leases and securitization debt.[333]

b. <u>Attorney General</u>

The Attorney General recommends a capital structure of 50% common equity and 50% debt and preferred stock, which she proposes to achieve by increasing the long-term debt component by $375 million and reducing the common equity component by the

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[330] 7 Tr 2273-2274.
[331] 4 Tr 441.
[332] Company brief, p. 93.
[333] *Id*.

same amount.[334] According to Mr. Coppola, such an adjustment is warranted because of (1) the Commission's directive in the Company's electric rate case U-17990 that moving to a 50/50 capital structure is appropriate in the absence of evidence suggesting otherwise; (2) the Company's practice of funding a significant part of its equity contributions with funds from long term debt issued at the parent company level; (3) the Company's unsupported position that a higher equity cushion is needed to maintain its credit ratings on long-term debt; and (4) fact that the common equity ratio of the peer group, used to assess the cost of common equity in this case, averages slightly above 50%.[335]

Regarding the peer group, Mr. Coppola asserts that the peer group's average common equity percentage supports these companies' utility operations, as well as non-utility operations which represent about 20% of the peer group's business operations and which tend to be somewhat more risky.[336] He adds that the riskier non-utility businesses require a higher common equity cushion to maintain similar credit ratings, such that if adjustments were made for the higher equity capital required by the non-utility businesses, the equity capital for the utility portion of peer group's capital structure would be lower than 50%.[337]

Regarding the Company's initial proposal to reduce its common equity ratio each year until the 50% ratio is achieved in 2023, Mr. Coppola points out that the Company's

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[334] 7 Tr 1659: Exhibit AG-29.
[335] 7 Tr 1660.
[336] *Id*.; Exhibit AG 34
[337] *Id*.

position 18 months ago in October 2017 was to reduce its common equity ratio to 52.5% in 2018, 52.0% in 2019, 51.5% in 2020; and by a half of a percentage point in each year until the 50% ratio is achieved in 2023, and that the need for an equity ratio slightly higher than 50% will be "less critical" as the Company's significant capital investment program decelerates to more normal levels.[338] Mr. Coppola notes that Mr. Bleckman asserts that the TCJA, the financing required for the Company's planned infrastructure upgrades, the effect of PPAs and maintaining certain cash flow ratios to support the Company's credit ratings all support making the equity ratio 52.5% mandatory for the foreseeable future.[339] However, Mr. Coppola asserts that Mr. Bleckman does not address either the expiring Power PPAs nor the deceleration in capital expenditures, which were major considerations in Mr. Denato's proposal in Case No. U-18424.[340]

Mr. Coppola adds that the Company is now communicating to investors and securities analysts that because of the pass-through to customers of lower taxes from the TCJA, it has "headroom" to increase capital expenditures even higher than currently projected in this rate case, which clearly contradicts the Company's view that it needs a higher equity ratio as a result of the TCJA.[341]

In addition, Mr. Coppola argues that the additional debt to fund additional capital expenditures, which the Company has stated are now opportunistically possible due to the TCJA, is likely to be the real issue for rating agencies when assessing the Company's

[338] 7 Tr 1661.
[339] *Id*.
[340] *Id*.
[341] 7 Tr 1662.

credit ratios, as the agencies have frequently expressed concerns with the Company high level of capital expenditures which require more debt capital to finance them.[342] He adds that a better option to increasing the equity ratio would be for the Company to decrease capital expenditures and issue less debt if it concerned with its cash flow to debt coverage ratios.[343]

Moreover, Mr. Coppola asserts that PPAs should not be considered regarding the equity ratio as most of the Company's peer utilities buy power under PPAs and PPAs are not relevant to setting rates for natural gas distribution businesses.[344] Also, he notes that different peer company groups are used to establish the cost of common equity for each business, which dictates the exclusion of items that pertain singularly to one business or the other.[345]

Finally, Mr. Coppola asserts that Exhibit AG-37, which shows the cash flow coverage ratios with his proposed 50% equity ratio and 9.5% authorized ROE, shows that while the 2017 pro-forma cash flow coverage ratios are lower than the actual ratios reported by the Company for 2017, the pro-forma coverage ratios are still significantly above the minimum levels set by the rating agencies to maintain the current debt rating.[346] Thus, the Company has ample room between the pro-forma cash flow to debt coverage ratios and the minimum ratios set by S&P and Moody's.[347]

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[342] *Id*.
[343] *Id*.
[344] 7 Tr 1663.
[345] *Id*.
[346] 7 Tr 1664.
[347] *Id*.

In addition, Mr. Coppola testified that CMS Energy, the Company's parent, can make the Company's common equity ratio "whatever it wants", as CMS management can direct at any time how much in capital it wants to inject into the Company and "call it equity capital."[348] Moreover, Coppola noted that the average common equity ratio of the peer company group was 50.2%, and that it is critical to synchronize the capital structure of the Company to the peer group average as closely as possible in order to have consistency with the cost of equity capital derived from those peer group companies.[349] In addition, the lower peer group equity ratios also demonstrate that similar situated companies are able to operate and thrive with a lower equity ratio.[350]

In reply, Mr. Bleckman asserts that the Commission's Order in Case No. U-17990 gave the Company an option to provide a more detailed analysis explaining why the Company would not reasonably or prudently be able to meet rebalancing of the equity ratio within the five-year time period contemplated by the Commission, and in that regard the Company presented extensive quantitative evidence and rationale in testimony as to why it is necessary for the Company to maintain an equity ratio higher than 50% in this case.[351] Mr. Bleckman adds that the federal tax reform legislation "lends further justification to the 52.50% equity ratio proposed in this case and makes the equity ratio approved in this case critical to the financial health of the Company."[352]

[348] 7 Tr 1665.
[349] 7 Tr 1669-1670; Exhibit AG-34.
[350] 7 Tr 1670.
[351] 4 Tr 459.
[352] *Id*.

Regarding PPA's, Mr. Bleckman replies that while other utilities utilize PPAs to purchase power, maintaining an equity ratio higher than 50% enables the Company to maintain reasonable ratios after adjustments for PPAs, benefit obligations, leases and securitization debt are incorporated, as he asserts the Commission recognized in Case No. U-17735 and as Mr. Coppola's testified in Case No. U-20165.[353] Regarding a proxy group comparison, Mr. Denato testified that Mr. Coppola's proxy group equity ratio calculation used ratios at the parent holding company level and thus may be "distorted" by other, non-regulated balance sheet items.[354]

Regarding Mr. Coppola's testimony that the Company is communicating to investors and analysts that the TCJA has given the Company additional headroom to increase capital expenditures, Mr. Bleckman asserts that Mr. Coppola mischaracterizes the analyst report as well as statements made by the Company.[355]

c. <u>ABATE</u>

Ms. LaConte recommends an equity ratio of 51.5%.[356] She asserts that the Company's requested equity ratio of 52.5% is overstated and should be reduced.[357] She argues that the Company is using the TCJA as an excuse to request a higher equity ratio.[358] Ms. LaConte asserts that based on her recommended ROE and equity ratio, the Company's credit rating will not be adversely impacted and therefore, it should receive

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[353] 4 Tr 466.
[354] 4 Tr 472.
[355] 4 Tr 463.
[356] 7 Tr 1811.
[357] *Id*.
[358] *Id*.

an equity ratio that follows its recommended schedule as presented in testimony in its electric utility rate case, Case No. U-18322.[359] She argues that a higher common equity ratio will increase costs to ratepayers because equity is more expensive than debt.[360] Thus, reducing the proposed common equity ratio to 51.5% moves the Company closer to its Commission directed goal of a 50/50 debt-to-equity ratio.[361]

In reply to Ms. LaConte's testimony, Mr. Bleckman reiterates his counterarguments made in opposition to the testimony and arguments of Staff and the Attorney General. The Company argues that Ms. LaConte offers "no sound support" for her recommendation and fails to account for the potential detrimental impacts if it were to be adopted.[362]

This PFD finds that the Company's proposal to continue its common equity balance at 52.5% is not reasonable nor supported by the record. While the Company acknowledges the Commission's prior directives that the Company should return to a balanced capital structure, the Company asserts that its previous commitment to rebalance its capital structure is "no longer sound planning" based on the "new economics" that the Company is facing as a result of the TCJA, such that maintaining its currently authorized equity ratio of 52.5% will be appropriate "for the foreseeable future." However, the evidence presented in this case indicates that the effect of the TCJA does not justify deviating from moving towards a balanced capital structure. The Company

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[359] *Id*.
[360] 7 Tr 1813.
[361] 7 Tr 1814.
[362] Company Brief, p. 103.

offered evidence from credit reporting agencies and analysts that suggests that the TCJA will have negative credit impacts on utilities. However, the evidence indicates that the TCJA has not adversely affected the Company’s credit rating or outlook. Indeed, despite the ratings agencies having lowered their ratings for other utilities, these ratings agencies have not lowered their ratings for the Company. The Company relies heavily on the Funds From Operations (FFO)/Debt ratio and its adjusted extrapolation of those ratios as calculated by S&P and Moody’s rating agencies to show that the TCJA (and lower ROE and equity balance percentages) has adversely affected those ratios for the Company which may in turn adversely affect its credit rating. Again, however, other evidence submitted shows that while the TCJA will have some effect on the adjusted FFO/Debt ratios for the Company, the adjusted ratios do not approach the percentage levels at which the ratings agencies might consider a credit downgrade even with ROE and equity balance percentages well below those proposed by the Company (and recommended by this PFD). Indeed, still other evidence from stock analysts indicate that the Company has indicated that the effects of the TCJA will be advantageous to the Company by giving it more “headroom” to make capital improvements. While the Company suggests that this evidence is being mischaracterized, notably it does not deny it.

Moreover, the other factors upon which the Company relies in support of its proposed equity balance in this case are the same as those it has previously offered to the Commission in prior rate cases, in which the Commission ultimately reiterated its directive that the Company should move toward a balanced capital structure (and thereby implicitly rejected those factors as justifying deviating from its prior directives).

Recently, in another case involving DTE Electric Company, where many of the same arguments were presented, the Commission adopted the findings and conclusions of the ALJ and approved a permanent capital structure of 50/50 debt and equity.

> The Commission agrees with the ALJ that the risks identified by DTE Electric are not new to this utility, and that the economy of southeast Michigan has improved dramatically in the last decade, thereby lessening many of those same risks. In addition, the Commission agrees with the ALJ that the TCJA has been in effect for more than a year and there has been no noticeable effect on DTE Electric, and the company admitted that its credit rating is unchanged. While the Commission is aware that the utility will need to continue investing in its infrastructure to provide safe and reliable electric service to its customers, the Commission is confident that DTE Electric can attract the capital it needs to continue such investments with a balanced capital structure as it has had in the past. The Commission agrees Page 55 U-20162 with the ALJ that conditions have not changed to such a degree as to warrant a departure from a balanced equity ratio at this time.[363]

The evidence presented in this case supports a similar conclusion by the Commission that conditions have not changed to warrant a departure from the Commission's prior directives for the Company to move to a balanced capital structure.

Staff recommends a common equity balance of $7,725,058,000, which represents approximately 52.05% of the permanent capital structure and 41.78% of the ratemaking capital structure. This equity balance consists of Staff's initially filed 13-month average equity balance of $7,714,684 and takes into account the revised $10.4 million Calculation C adjustment presented by the Company pertaining to deferred income taxes. In order to arrive at Staff's recommended balance Staff reduced the June 2019 equity infusion by $125 million in order to better align the Company's projections with prior historical infusions, and the Commission's desire to see the Company move toward a 50/50 capital

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[363] MPSC Case No. U-20165, Order, May 2, 2019, p. 54-55.

structure. Staff's witness testified that its recommended 52.04% common equity balance supports the Commission's objective of a more balanced capital structure that is less costly to ratepayers, due to debt being less costly than common equity, and still reasonable for the Company to maintain its access to capital markets. This PFD agrees.

This PFD finds the Attorney General's and ABATE's proposed adjustments to the common equity balance should not be adopted. While both rely on the same evidence showing the Company's strong credit posture and the lack of a significant adverse impact from the TCJA, both recommendations represent a significant change from the current equity ratio of 52.5% previously authorized by the Commission in the Company's last gas rate case. The Commission's prior directive in Case No. U-17990 that the Company achieve a balanced capital structure over a five-year period suggest that the Commission prefers these changes to be more gradual than proposed by the Attorney General and ABATE.

Accordingly, this PFD recommends the Commission adopt Staff's proposed common equity balance of $7,725,058,000, which represents approximately 52.05% of the permanent capital structure and 41.78% of the ratemaking capital structure, as set forth in Appendix D to this PFD.

2. **Long-Term Debt Balance**

For the test year, the Company projects a long-term debt balance of $7.080 billion, a projection with which Staff concurs.[364] The Company's long-term debt balance projection is therefore adopted.

3. **Short-Term Debt Balance**

For the test year, the Company projects a short-term debt balance of $151 million, a projection with which Staff concurs.[365] The Company's short-term debt balance projection is therefore adopted.

4. **Deferred Federal Income Tax**

For the test year, the Company projects a $3.378 billion deferred tax balance, a projection with which Staff concurs.[366] The Company's deferred federal income tax balance projection is therefore adopted.

5. **Other Capital Structure Balances**

The Company and Staff both used projected balances for preferred stock and Job Development Investment Tax Credit (JDITC) corresponding to balances in the historical period, with components for JDITC based upon the allocation of long-term debt, preferred stock, and common equity.[367]

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[364] Staff Brief, p. 48.
[365] Staff Brief, p. 49.
[366] Id.
[367] Exhibit A-14, Schedules D1a; Exhibit S-4, Schedule D-1.

B. Cost Rates

1. Return on Common Equity

A utility's cost of common equity, generally referred to as the return on equity (ROE), is the return that investors expect in order to provide the utility with capital for use in its various operations. The cost of this capital essentially represents an opportunity cost; in order to induce investors to purchase common stock or bonds, there must be the prospect of receiving earnings sufficient to make the investment attractive when compared to other investment opportunities.

The criteria for establishing a fair rate of return for utilities like Consumers Energy evolved from the decisions issued by the United States Supreme Court in *Bluefield Water Works Co. v Public Service Commission of West Virginia*, 262 US 679 (1923) and *Federal Power Comm. v Hope Natural Gas Co*., 320 US 591 (1944). With these decisions, the Court determined that when establishing a fair rate of return for a public utility, consideration must be given to both customers and investors. As enunciated by the Commission in previous rate case final orders, the rate of return "should not be so high as to place an unnecessary burden on ratepayers, yet should be high enough to ensure investor confidence in the financial soundness of the enterprise."[368] The Commission has observed nonetheless that any determination of what is fair and reasonable "is not subject to mathematical computation with scientific exactitude but [rather] depends upon

[368] MPSC Case No. U-15244, December 23, 2008 MPSC Order, p. 12.

a comprehensive examination of all factors involved, having in mind the objective sought to be attained in its use."[369] Moreover, "[w]hat is reasonable depends upon a comprehensive examination of all factors involved, having in mind the objective sought to be attained in its use."[370] In addition, in its recent order in the Company's electric rate case, the Commission noted that "it is not realistic to make a significant change in ROE absent a radical change in underlying economic conditions."[371]

a. <u>Consumers Energy</u>

The Company is seeking an authorized ROE of 10.75%, which represents a 75-basis point increase above its currently authorized ROE of 10.00% set in the Company's last gas rate case, Case No. U-18424.

In his direct testimony, Mr. Maddipati explains that his recommendation of 10.75% is within his reasonable ROE range for the Company's gas business of 10.00% - 11.00%,[372] and is based upon consideration of the current state of the economy and capital markets; the need to continue to attract capital and maintain financial strength as the Company undertakes a large capital expenditure program designed to improve safety,

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[369] *Id*., citing *Meridian Twp. v City of East Lansing, Mich*., 342 Mich 734, 749 (1955).
[370] *Meridian Twp v City of East Lansing,* 342 Mich 734, 749; 71 NW2d 234 (1955).
[371] MPSC Case No. U-18322, March 29, 2018 Order, p. 44.
[372] Mr. Maddipati offers that his "reasonable ROE range" of 10.00 – 11.00% is based on his "qualitative and quantitative analyses". 4 Tr 105. However, he does not explain or otherwise support how he came up with his recommended "range". Generally, in statistics, the "range" of a set of data is the difference between the largest and smallest values. In this case, Mr. Maddipati's range does not appear to be based on or have any correlation to (i.e., an average or a median value) the results of the cost of equity calculations he performed under the various economic models he utilized. See Exhibit A-14, Schedule D-5, with ROE estimates from 9.72% to 12.81%. Indeed, of the nine ROE estimates calculated, only four fall within Mr. Maddipati's recommended "range". Thus, Mr. Maddipati's "reasonable ROE range" does not appear to lend any independent support for his recommended ROE.

reliability, and customer value; the risk profile of the Company's gas business compared to the proxy group; established principles for setting a fair ROE; and the results of various economic models used to calculate the cost of equity.[373] He adds that while a 75 basis point increase in the authorized ROE "may be considered significant", the increase is warranted given the impact of the TCJA, which has led to a "radical change in underlying economic conditions," especially "credit quality deterioration across the utility sector".[374] He also testified that the consistency, predictability, and promptness of regulatory outcomes coupled with a constructive and supportive authorized ROE are important parameters to enable a financially healthy utility.[375] He added that while the analyst and investor community generally view the regulatory environment in Michigan as "constructive and supportive," concerns that ROEs could decline, or that regulatory outcomes could become less predictable, may cause a reassessment of that view.[376]

Mr. Maddipati testified that he utilized multiple ROE estimating methods, as the results of the "standard quantitative models" often make assumptions "that do not fully reflect the returns that investors expect given current economic and financial conditions":

> Each of the standard quantitative models is based on the assumption that economic conditions are relatively stable and that current market inputs are reflective of their long-term outlook. That assumption may not be true in current market conditions mainly because of the unprecedented amount of intervention by central banks during the last several years as well as the impacts of the TCJA on both the economy and the credit quality of utilities. As a result, the standard quantitative models tend to understate the return that investors currently require to compensate them for risk. Furthermore, mechanical application of these models without consideration of the

[373] 4 Tr 105.
[374] 4 Tr 106.
[375] 4 Tr 108.
[376] 4 Tr 110.

> underlying assumptions may not meet the requirements in *Hope* and *Bluefield* as indicated in Federal Energy Regulatory Commission ("FERC") Opinion 551.[377]

As such, the application of multiple methods, combined with an 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.[378]

Mr. Maddipati offered that the TCJA has had a significant impact on utilities, such that while the tax savings will be passed on directly to the Company's customers, they also lower the amount of operating cash flow that the Company generates, which impacts the credit quality of the Company.[379] He adds that the FFO to Debt metrics calculated by Standard and Poor's and Moody's dropped from 23.5% and 26.9%, respectively, to 18.5% and 21.4%, respectively, when the impact of the TCJA is added.[380] He asserts that an FFO to Debt ratio below 20% on a long-term basis would put the Company at risk of a ratings downgrade, which would inevitably increase its debt financing costs to the detriment of customers.[381]

Mr. Maddipati testified that several of the inputs to his analysis included market observations that are impacted by the current state of the United States economy

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[377] 4 Tr 113-114.
[378] 4 Tr 113.
[379] 4 Tr 120.
[380] 4 Tr 122-123.
[381] 4 Tr 125.

including the Federal Reserve's influence in the interest rate markets and the impacts of tax reform on financial metrics.[382]

Mr. Maddipati indicated that he applied multiple financial methodologies using a proxy group of companies, each of which had to be classified as a gas utility in the S&P Global database, as well as: (i) have a market capitalization greater than $1 billion and less than $25 billion; (ii) be headquartered in the United States; (iii) currently not be a recent merger target or be engaged in significant restructuring; (iv) be currently paying common stock dividends; and (v) have bonds rated at or above a minimum investment grade of Baa3 by Moody's and BBB- by Standard & Poor's.[383] These criteria resulted in a proxy group of 14 companies.[384] Mr. Maddipati then used this group of proxy companies in performing various analyses based on the Capital Asset Pricing Model (CAPM), the Empirical CAPM (ECAPM), the Risk Premium analysis, the Discounted Cash Flow (DCF) analysis, and the Comparable Earnings analysis.[385]

Applying each of the five above-mentioned analyses to the proxy group that he selected produced the following average rate of return figures: the two CAPM analyses (Normalized and Projected Risk Premium) resulted in an average of 10.90%, the two ECAPM analyses (Normalized and Projected Risk Premium) produced an average of 11.35%, the two Risk Premium analyses (Normalized Premium and Projected Risk Premium) resulted in an average of 11.89%, the two DCF analyses (Analyst Consensus

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[382] 4 Tr 139.
[383] 4 Tr 148-149; Exhibit A-14, Schedule D-5.
[384] 4 Tr 149.
[385] 4 Tr 150-168; Exhibit A-14, Schedule D-5.

and Company Guidance) produced an average of 9.62%, and the Comparable Earnings analysis resulted in an average of 11.13%.[386] Mr. Maddipati concludes that his recommended 10.75% ROE is based on an equity ratio of 52.50%, the Company's significant infrastructure investment, anomalous market conditions and increased market conditions, and the TCJA.[387]

b. <u>Staff</u>

In contrast to the Company, Staff recommends adopting an ROE of 9.65%, which is at the upper end of Staff's ROE range of 9.00% and 10.00% provided by Mr. Megginson.[388]

Mr. Megginson notes that Standard & Poor's rates Consumers Energy's senior secured debt "A", which was raised from "A-" on December 4, 2014, while Moody's rates the Company's senior secured debt "Aa3", which was raised from "A1" in April 2017, and Fitch rates the Company's senior secured debt "A+", which was raised two notches from "A-" in March 2016.[389] These metrics suggest that the Company should have no problem accessing the capital markets for reasonably if not preferably priced borrowings in the future.[390] Staff believes that competitive pricing on the Company's borrowings promotes

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[386] Exhibit A-14, Schedule D-5.
[387] 4 Tr 173.
[388] 7 Tr 2125. Like Mr. Maddipati, Mr. Megginson does not explain or otherwise support how he came up with his recommended "range". Similarly, Mr. Megginson's range does not appear to be based on or have any correlation to the results of the cost of equity calculations he performed under the various economic models he utilized. See Exhibit S-4, Schedule D-5, p. 12 with ROE estimates from 7.64% to 10.84%. Of the 11 ROE estimates calculated, only five fall within Mr. Megginson's recommended "range". Thus, like Mr. Maddipatii, Mr. Megginson's "range" does not appear to lend any independent support for his recommended ROE.

[389] 7 Tr 2125-2126.
[390] 7 Tr 2126.

competitive value in its required return.[391] As such, Staff's recommended 9.65% ROE provides the Company with over 5.30% in spread value above its embedded long-term debt cost, which means that Staff's ROE is very fair compensation for the Company's equity.[392]

According to Mr. Megginson, his analysis began by using a "modified version" of the Company's proxy group, using the following criteria required to ensure that the proxy group was highly representative of the Company: 1) net plant greater than $2.0 billion but less than $15.0 billion to better compare in size and footprint to the Company's gas division; 2) no less than approximately 45% or more of its revenues derived from regulated natural gas service; 3) an investment grade rating within three notches from that of the Company from the two primary rating agencies, S&P and Moody's; 4) currently be paying dividends to shareholders; and 5) not currently involved in a merger or major corporate buyout.[393] Staff then removed four companies from the proxy group as being unsuitable, resulting in Staff's ten gas utilities proxy group.[394]

In conducting his analysis, Mr. Megginson employed several models including three of the same models relied upon by Mr. Maddipati. Specifically, he used the DCF analysis (which produced an average estimate of 9.59%), a historical CAPM full term analysis (which provided an average estimate of 8.04%), a projected CAPM treasury analysis (with an estimate of 7.64%), a historical Risk Premium analysis for A-rated

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[391] *Id*.
[392] *Id*.
[393] 7 Tr 2127-2128.
[394] 7 Tr 2128; Exhibit S-4, Schedule D-1, p. 1.

utilities (which produced an estimate of 8.02%), a historical Risk Premium analysis for Baa/BBB-rated utilities (which produced an estimate of 8.39%), and a comparison of recent gas ROE determinations from other state jurisdictions (that produced an average estimate for 2016 of 9.54%, an average estimate of 9.72% for 2017, and an average estimate for 2018 of 9.59%).[395]

Mr. Megginson disagreed with the ROE estimate calculations performed by Mr. Maddipati. Mr. Megginson asserts that the Company's ROE request is 75 basis points higher than the Company's currently authorized 10.00% ROE, which does not coincide with the Commission's request for prudence, does not coincide with the Company's solid credit rating and the current low interest rate environment, and is not proportionate with the Company's solid credit profile.[396] He adds that the risk-mitigating cost recovery mechanisms the Company requests in this case reduce the Company's risk of not earning its authorized ROE.[397]

Regarding the Company's DCF analysis, Mr. Megginson testified that Mr. Maddipati used just a single source for dividend growth rates, instead of multiple sources which provide a broader review of estimates.[398] Also, Mr. Maddipati used dividend per share growth metrics instead of the earnings per share, which the Company had relied upon in the past.[399] Mr. Megginson also disagrees with the Company's use of company's

[395] 7 Tr 2145.
[396] 7 Tr 2146.
[397] 7 Tr 2147-2148.
[398] 7 Tr 2132.
[399] 7 Tr 2132.

guidance expectations, which are inconsistent.[400] Finally, Mr. Megginson challenged the Company's inclusion of flotation costs, which represent costs the Company has not incurred.[401]

Regarding the Company's two CAPM analyses, Mr. Megginson offers that in the Company's "normalized" analysis, the Company uses an historical risk-free rate that does not correspond with a bond analyst's projection of future long-term Treasury rates and does not correlate with the forward-looking nature of this rate case.[402] Mr. Maddipati's use of a historical risk-free rate distorts the accuracy of future borrowing costs and thus an investor's reasonable required rate of return.[403]

Mr. Megginson testified that the Company's assertion that the Fed's actions have artificially suppressed interest rates and created anomalous market conditions is incorrect.

> The Fed's policies have been in place for several years now and at some point, stopped being artificial and started being normal. The Fed has steadily increased interest rates since 2015, and even more so increased them four times in 2018 alone. The Fed has plans to increase them potentially two more times in 2019. Thus, the Fed is managing interest rates and the economy as it sees fit and the Company's effort to input unconventional rates or use irregular timelines in its cost of equity models based on its argument that capital markets are currently anomalous is unwarranted.[404]

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[400] 7 Tr 2133.
[401] 7 Tr 2133-2134.
[402] 7 Tr 2138.
[403] 7 Tr 2139.
[404] 7 Tr 2139. (citations omitted)

Mr. Megginson also argues that the Company's "projected risk premium" CAPM analysis is improper as it uses improper data points and improper historical timelines.[405]

Mr. Megginson expressed concerns with the Company's ECAPM model, especially the use of a Value Line adjusted beta instead of a raw beta, and the fact that the ECAPM adjustment is unnecessary as the Staff's CAPM analysis already accounts for the shortcomings recognized by ECAPM.[406] Similarly, Mr. Megginson concluded that the Company's risk premium analysis has the same flaws as its CAPM analysis; namely, the use of unconventional, inflated and improper data points and timelines in the model, which result in "overinflated, unreasonable, and unsuitable ROE estimates."[407]

Mr. Megginson maintains that the Company's recommended ROE of 10.75% should be rejected for several reasons.

> First, the ROE request is 75 basis points higher than the Company's currently authorized 10.00% ROE, which does not coincide with the Commission's request for prudence. The request also does not coincide with Consumers Energy's solid credit rating and the current low interest rate environment. This low interest rate environment and solid credit rating entails lower debt costs for Consumers Energy, which should entail a more equitable return on equity for the benefit of the Company as well as its ratepayers.
>
> Second, the proxy group's average authorized ROE is 9.60%, five basis points below Staff's recommendation, yet its credit rating is well below that of Consumer Energy. Consumers Energy request for a substantially higher ROE, even with its more favorable credit rating, is not proportionate with its solid credit profile and should be rejected.
>
> Third, . . . the risk-mitigating cost recovery mechanisms the Company is requesting in this case. In the Company's last gas rate case, U-18424, the Commission adopted the Company's proposed revenue decoupling

[405] 7 Tr 2139-02140.
[406] 7 Tr 2140.
[407] 7 Tr 2144.

> mechanism that was developed in its previous gas case U-18142. (MPSC Case No. U-18124, July 31, 2017 Order, p 94.) The decoupling mechanism reduces Consumers Energy's risk in collecting its authorized revenue level and thus reduces the Company's risk of not earning its authorized ROE. . . . The Company also requests that the Commission approve a revised Infrastructure Recovery Mechanism (IRM). The Company's current IRM was approved as part of the Settlement Agreement in Case No. U-18424 and is currently collecting revenues, through a separate customer surcharge, for incremental capital spending through June 2021. The Company's new IRM proposal will seek to collect additional revenue starting October 1, 2020 for incremental spending through September 30, 2022. . . . the Company has continued to file rate cases on an annual basis even with an approved IRM in place. Ratepayers deserve consideration from annual rate increases either in the form of less filed rate cases and/or a fairer ROE.[408]

c. <u>Attorney General</u>

The Attorney General recommends an ROE of 9.50% be adopted in this case.[409] Mr. Coppola commenced his analysis by using a proxy group made up of the 10 gas utility companies followed by the Value Line Investment Survey, less 2 companies he eliminated due to foreign and propane investments, and relatively small size, respectively.[410] Using this revised proxy group, Mr. Coppola then performed his own DCF, CAPM, and Utility Risk Premium analyses, arriving at ROE estimate figures of 9.57% from the DCF method, 8.54% from the CAPM approach, and 9.09% from the Risk Premium analysis.[411]

In addition to conducting these analyses, Mr. Coppola reviewed the ROEs that other regulatory commissions have granted in 2017 and 2018. He noted that, since 1990,

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[408] 7 Tr 2146-2148. It is noted that in its rebuttal testimony the Company withdrew its request for an IRM. Company brief, p. 193.
[409] 7 Tr 1673.
[410] 7 Tr 1674.
[411] 7 Tr 1676, 1678-1679, 1680-1681; Exhibits AG-31, AG-32, AG-33.

return on equity rates approved by regulatory commissions have been on a steady decline from over 12.7% in 1990 to approximately 9.7% in 2017 and 9.5% in the first six months of 2018.[412] Mr. Coppola testified that this information shows that the capital markets have continued to provide debt capital at competitive interest rates to gas utilities with authorized ROEs well below 10%, and as such, dispels the Company's statements that an ROE rate below 10% and in line with the 9.5% proposed by the Attorney General would impair its ability to raise capital.[413] Indeed, Mr. Coppola testified that investors continue to migrate to utility stocks recognizing that the authorized ROE's are still above the true cost of equity.[414]

Mr. Coppola also considered the current circumstances in the capital markets, the improved Michigan economy, and any potential changes in the risk profile of the Company as a result of changes occurring in its gas business.[415]

Based on all components of his ROE analysis in this case and giving more weight to the DCF method as a more reliable approach to estimating the cost of equity, Mr. Coppola developed a weighted average cost of equity of 9.19%.[416] However, Mr. Coppola then increased this number to a recommended ROE of 9.50% as "a gradual transition to the true cost of equity" because (1) the industry peer group "may not incorporate the unique risks and circumstances that exist with CECo and how investors perceive those risks," (2) while the cost of common equity under the DCF approach is an

[412] 7 Tr 1692; Exhibit AG-36.
[413] 7 Tr 1692, 1697.
[414] 7 Tr 1697.
[415] 7 Tr 1673.
[416] 7 Tr 1695-1696; Exhibit AG-30.

accurate assessment of investors' expectations of higher interest rates, the higher interest rates assumed in this case may produce a different result should such higher interest rates become a reality, and (3) the Commission may be reluctant to set an ROE for the Company at the true cost of equity in the 9.0% area.[417] Mr. Coppola adds that regulatory commissions in 2017 and the first half of 2018 granted ROE rates which average close to 9.50% in the majority of the cases decided.[418]

Like Mr. Megginson, Mr. Coppola disagreed with Mr. Maddipati's ROE estimate calculations. Regarding the Company's DCF analysis, Mr. Coppola asserts that Mr. Maddipati includes several combination gas and electric companies within his gas proxy group.[419] In addition, Mr. Maddipati included an outlier (Southwest Gas Holdings) in his company growth rate guidance calculation which includes a doubtful growth rate, and had this outlier been excluded, Mr. Maddipati's result would have been in line with Mr. Coppola's DCF results and Mr. Maddipati's own "analyst based" DCF result.[420]

Regarding the CAPM, ECAPM and utility risk premium calculations, Mr. Coppola asserts that there is no such thing as a "normalized" CAPM, ECAPM or Risk Premium approach in academic literature describing these methods.[421] In addition, Mr. Maddipati applied a 4.99% risk-free rate based on an average of the 30-year U.S. Treasury rate, which is not reflective of conditions expected during the projected test period.[422] As to

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[417] Id.
[418] *Id*.; Exhibit AG-36.
[419] 7 Tr 1675.
[420] 7 Tr 1677-1678.
[421] 7 Tr 1682.
[422] 7 Tr 1682-1683.

the Company's CAPM and ECAPM estimate, Mr. Coppola testified that Mr. Maddipati used a higher peer group average beta due to the wrongful inclusion of three companies in his peer group.[423] In addition, Mr. Coppola asserts that Mr. Maddipati's use of an 11.5% risk premium is much higher than the historical market risk premium of 7.07%.[424] Also, Mr. Coppola asserts that the applicability of the ECAPM method as an alternative to the CAPM method is doubtful.[425] Finally, Mr. Coppola asserts that the Company's comparable earnings analysis is not an "academically sound approach" as it fails to take into account investors' expectations or stock market parameters, and includes substantial non-utility operations with higher earnings per share growth rates.[426]

d. ABATE

Ms. Laconte recommends an ROE of 9.22%, which is the average of her recommended range of 7.23% - 14.63%.[427] Ms. Laconte notes that the economic outlook for Michigan is positive and has improved since the Company filed its last gas rate case.[428] She asserts that the Company's FFO-to-Debt ratio using S&P's methodology (which includes the impact of the TCJA) is 18.1%, which falls within S&P's current benchmark range of 13%- 23%, and that the ratio is 21% using Moody's methodology, which falls within their projected range of 20%-24%.[429] As such, the Company's credit

[423] 7 Tr 1683.
[424] 7 Tr 1684.
[425] 7 Tr 1687-1688.
[426] 7 Tr 1690.
[427] 7 Tr 1758, 1778.
[428] 7 Tr 1759-1760.
[429] 7 Tr 1766.

rating would not be negatively affected by a lower authorized ROE or the impact of the TCJA.[430]

Ms. LaConte observed that the Company currently recovers a number of its costs through various surcharges and cost recovery factors including an investment recovery mechanism, which promote revenue stability and lead to lower financial risk for the Company.[431] In addition, Ms. LaConte notes that the relatively low expected volatility in the financial markets means that investors' realistic expectations concerning required returns are lower than in the recent past, which supports a substantial reduction in the Company's authorized ROE.[432] Ms. Laconte notes that the Company's requested ROE is over 115 basis points higher than the average authorized ROE for other natural gas distribution utilities during 2018, and adds that the trend in utility authorized ROEs indicates that utilities' current risks are lower than in the past due to the lower risk-free cost of capital and the implementation of cost recovery mechanisms.[433]

To estimate the Company's cost of common equity under various methodologies used by the Company, Ms. LaConte used similar criteria that the Company used when it created its proxy group.[434] Ms. Laconte's used a single stage DCF method with a constant growth rate (which resulted in an ROE range of 7.47%-14.63%), a multi-stage DCF method with varying growth rates (which produced a range of 7.23%-9.15%), a

[430] *Id*.
[431] 7 Tr 1768-1769**.**
[432] 7 Tr 1772.
[433] 7 Tr 1773, 1774.
[434] 7 Tr 1782.

CAPM method (which estimated ROE at 8.29%), and a risk premium analysis (which estimated the ROE at 9.10%).[435]

> Ms. LaConte testified that the Company's ROE analyses were faulty.
>
> Mr. Maddipati's recommended ROE of 10.75% does not recognize Consumers' reduced risk due to regulatory mechanisms it has in place that reduce regulatory lag and income variability. Further, his recommendation ignores positive market and economic conditions. Finally, his reasoning for increasing Consumers' ROE due to the impact of the TCJA is unfounded and should be rejected.
>
> Mr. Maddipati's proxy group includes companies that are not comparable in risk to Consumers. It includes companies that are not primarily gas utilities, and/or do not derive the majority of their revenues from regulated gas operations.
>
> Mr. Maddipati relies on nine methods to estimate an ROE for Consumers. His two CAPM methods are not reliable. His Normalized CAPM analysis relies on a historical risk-free rate when a forecast risk-free rate is available and his Projected Risk Premium CAPM relies on limited data to determine the MRP.
>
> The ECAPM is not a common method and produces over-stated ROEs by adjusting betas that have already been adjusted.
>
> The Risk Premium methods have issues that are similar to Mr. Maddipati's CAPM analyses. The Normalized Risk Premium method uses historical long-term government bond yields when projected bond yields are readily available. The Projected Risk Premium method uses an MRP estimate that is based on a short-term period (seven years) and results in an over-stated ROE.
>
> The DCF analyses use forecast dividend growth rates instead of earnings growth rates. Forecast earnings growth rates provide a better estimate of dividend growth rates because earnings are the main driver for dividend growth.
>
> The Comparable Earnings method is not a common method used to estimate the ROE for a regulated utility and does not estimate the required

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[435] 7 Tr 1786,1787, 1791, 1792; Exhibit AB-5, AB-6, AB-7, AB-8, AB-9, AB-10.

cost of equity but only provides a forecast ROE. Therefore, it should be rejected.[436]

e. <u>Rebuttal</u>

In his rebuttal testimony, Mr. Maddipati takes issue with the testimony of witnesses for Staff, the Attorney General and ABATE.

As to the Company's recommended ROE, Mr. Maddipati initially asserts that the impacts from the TCJA coupled with the Company's recommended equity ratio of 52.50% supports an ROE of 10.75%, 75 basis points above the Company's currently authorized ROE.[437] Mr. Maddipati adds that if the Commission believes a more modest increase in the ROE is reasonable, that outcome could be partially mitigated by a corresponding increase in the authorized equity ratio. [438]

Mr. Maddipati testified that the implied FFO to Debt ratios based on the recommendations of Staff, the Attorney General and ABATE (18.6%, 17.3% and 17.8%, respectively) are all drastically lower than the 20% threshold recommended by the Company.[439]

Mr. Maddipati asserts that "managing the credit and financial health" of a large public company is "complex" and requires "experience and judgment".[440] He adds that the Commission should note that "no other witness in this case" has been "responsible for consistently and effectively managing the credit of any public company", and yet,

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[436] 7 Tr 1809-1810.
[437] 4 Tr 179.
[438] *Id*.
[439] *Id*.
[440] 4 Tr 181-182.

"despite this lack of experience", the witnesses for Staff, the Attorney General and ABATE are asking the Commission "to trust their judgment that there is no need to address large changes to key financial metrics of the Company."[441]

Mr. Maddipati explained that, as a result of the TCJA, Moody's has downgraded the outlook of nine holding companies and utility companies in addition to the 24 utilities initially implicated, including placing DTE Gas on a "negative watch" with an ROE and equity ratio "meaningfully higher " than that proposed by any other witness in this case.[442] Mr. Maddipati indicates that Staff's Mr. Megginson "makes no mention" of how his recommended ROE and equity ratio incorporate the impact of the TCJA, that ABATE's Ms. Laconte "does not provide any response" to the negative actions taken by credit rating agencies, and that the Attorney General's Mr. Coppola minimizes the Company's claims in this regard as a "red herring" without providing any evidence to contradict the relationship between equity ratio and the ROE or the resulting FFO to Debt ratio.[443] He adds that the failure of these witnesses to "give proper consideration" to the impact of the TCJA in their ROE analyses "should give the Commission considerable pause".[444]

Mr. Maddipati also indicates that the application of inputs to the various financial models result in the differences between his quantitative analysis and those performed by Staff, the Attorney General, and ABATE. Mr. Maddipati asserts that the inputs used by the others have not been properly vetted and that his analyses have support from - while

[441] 4 Tr 182.
[442] 4 Tr 184.
[443] 4 Tr 187, 188, 193.
[444] 4 Tr 188.

those of the other witnesses do not - other cost of capital witnesses and regulatory commissions, and academic sources.[445]

Mr. Maddipati challenges the other witnesses' use of ROE's in other jurisdictions, noting that the Commission has indicated that it gives little weight to ROE's established in other unrelated proceedings, and that the Regulatory Research Associates (RRA) data that the other parties point to is incomplete and unreliable.[446]

f. **Recommended ROE**

In reviewing the different analyses presented by the witnesses, and mindful of the Commission's reliance on the principles enunciated in *Bluefield* and *Hope, supra,* that there is no precise mathematical formula to determine the appropriate return on equity, this PFD finds that the Company's recommended return of 10.75% is excessive and should be rejected for the following reasons.

First, the Company's contention that it needs to increase its return by 75 basis points overlooks the impact of the Company's solid credit rating and current low interest rate climate. As Mr. Megginson observed, the Company's requested ROE of 10.75% "does not coincide with Consumers Energy's solid credit rating and the current low interest rate environment."[447] As such, the Company "should have no problem accessing

[445] 4 Tr 201-202
[446] 4 Tr 209.
[447] 7 Tr 2146. Referencing the Company's Exhibit A-22, Schedule D-6, p. 1, Mr. Megginson notes that "Standard & Poor's (S&P) rates Consumers Energy's senior secured debt "A" (raised from "A-" on December 4, 2014), Moody's rates Consumers senior secured debt "Aa3" (raised from "A1" in April 2017), and Fitch rates Consumers senior secured debt "A+" (raised two notches from "A-" in March 2016)". 7 Tr 2125.

the capital markets for reasonably if not preferably priced borrowings in the future."[448] Similarly, Mr. Coppola testified that the Michigan economy is "robust" with low unemployment rates and stable interest rates "due to the lower corporate tax burden and the monetary policy of the Federal Reserve Bank", which "have placed the Company in a better position with respect to sales levels, interest rates and uncollectible sales amounts."[449] He added that the Company's access to the capital markets "is strong as witnessed by its issuance of new 30-year debt".[450] Mr. Coppola concludes that the Company "has had and should continue to have ample access to capital markets."[451] Likewise, Ms. Laconte testified that her recommended ROE of 9.22% "will not adversely impact" the Company's credit rating, "nor hinder its ability to attract capital at reasonable rates."[452] Indeed, Mr. Maddipati acknowledged that the investment community views Michigan's regulatory environment as "constructive and supportive" even though the Commission authorized an ROE of 10.00% in its last rate case.[453] Moreover, the Company asserts that it has experienced "successful capital attraction activities" over the past several years.[454]

The Company asserts that the TCJA will adversely affect the Company's credit rating. However, this assertion is disputed by the evidence. For example, Mr. Ufolla testified that the TCJA "did not lead to a downgrade of credit rating or even a downgrade

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[448] 7 Tr 2126.
[449] 7 Tr 1691.
[450] *Id*.
[451] *Id*.
[452] 7 Tr 1793.
[453] 4 Tr 110.
[454] Company brief, p. 115.

in credit outlook for Consumers or CMS Energy", which implies that the Company "has strong enough metrics to maintain its credit rating."[455] In addition, Mr. Bleckman acknowledges that the Company anticipates engaging in "a significant increase in the level of long-term debt financing compared to previous years" to accommodate the gas infrastructure investment planned over the next five years.[456]

Moreover, the evidence the Company offers in support of this argument appears to be incomplete and inconsistent. For example, the Company points out that Moody's revised the outlook of 24 utilities to negative because of the TCJA.[457] However, Mr. Maddipati acknowledges that the Company "was not one of the companies put on negative watch by Moody's".[458] Indeed, as noted by the Attorney General, at the same time that Moody's outlook for the regulated sector was moved from "stable" to "negative", Moody's issued a specific outlook for the Company as "stable", with Moody's outlook for the Company specifically indicating that "the utility's financial profile will remain healthy despite the negative cash flow impact from the passage of the federal tax reform."[459]

The Company asserts that the other ROE witnesses either disregarded the impacts of the TCJA or they dismissed its significance without any meaningful analysis of its impact.[460] This assertion is misplaced. The witnesses for Staff, the Attorney General and ABATE all considered the impact of the TCJA on the financial status of the Company,

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[455] 7 Tr 2273.
[456] 4 Tr 442-443.
[457] 4 Tr 121.
[458] *Id*.
[459] Attorney General Initial Brief, p. 18, fn 37; Exhibit AG-47, p. 2.
[460] 4 Tr 187-188.

albeit concluding that such impact was over-stated as shown by the Company's own evidence and the conclusions of the credit agencies.

The Company points to the effect of the TCJA on a credit metric known as FFO to debt ratio as evidence that the TCJA will adversely impact the Company's credit rating. Specifically, Mr. Maddipati asserts that a FFO/Debt ratio below 20% "would put the company at risk of a ratings downgrade".[461] This assertion appears to be overstated and inconsistent with the evidence. First, the 20% ratio is Mr. Maddipati's opinion of the minimum ratio he believes should be maintained[462]; it is not a specific metric recognized by the credit agencies as leading to a possible credit downgrade. Moreover, the Company acknowledges that its current ROE and equity balance authorized in its last rate case put its FFO/Debt ratio at 19.3%, which is below its purported minimum ratio.[463] In addition, in order to quantify the impact of the TCJA on the Company's FFO/Debt ratios, the Company calculated the pro forma metric impact of the TCJA as well as adjustments for a 50% equity ratio and a 10% ROE, resulting in a 18.5% (S&P) and a 21.4% (Moody's) adjusted ratio which is above the Company's purported 20% minimum ratio.[464] And while the Company's calculations show that the resultant ratios put this rating in the next lower category (dropping from the third to the fourth of six categories) for S&P and Moody's, there is no indication that such a drop will lead to a credit downgrade.

[461] 4 Tr 125.
[462] 4 Tr 273
[463] 4 Tr 125.
[464] 4 Tr 122-125.

Second, several of the model-based analyses performed by Mr. Maddipati appear to be based on flawed assumptions and application of inappropriate inputs. For example, as noted by Staff, the Attorney General, and ABATE, Mr. Maddipati's use of a historical risk-free rate of 5.07% in his "normalized" CAPM analysis does not correlate with the forward-looking nature of this rate case.[465] To avoid this distortion, Staff, the Attorney General, and ABATE relied on the forward-looking Treasury yields that correspond to a forward-looking cost of equity model in a forward-looking test year.[466] In addition, Mr. Coppola testified that "[t]here is no such thing as a 'normalized' CAPM, ECAPM or Risk Premium approach in academic literature describing these methods."[467]

In addition, Mr. Megginson, Mr. Coppola, and Ms. LaConte provided persuasive testimony that Mr. Maddipati's use of adjusted betas in his ECAPM model instead of raw betas is improper, thus producing a result that is higher than it should be.[468] Indeed, Mr. Megginson asserts that the ECAPM methodology or its ROE has never been considered by this Commission.[469]

Also, Mr. Maddipati's use of company-provided long-term guidance growth rates in his DCF analysis instead of the growth projections of professional analysts as relied upon by Staff, the Attorney General, and ABATE in their witnesses' analyses, is inherently biased and lacking impartiality.[470] Moreover, as Staff and ABATE point out, the

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[465] 6 Tr 1734; 7 Tr 2437-2439; 7 Tr 2183.
[466] *Id*.
[467] 7 Tr 1682.
[468] 6 Tr 1735-1739; 7 Tr 2441; 7 Tr 2187.
[469] 7 Tr 2143.
[470] 6 Tr 1728-1729; 7 Tr 2194.

Company's reliance on dividend growth instead of earnings growth renders its DCF analysis even more unreliable.[471] In addition, Mr. Coppola notes that the Company's DCF calculation using company dividend growth guidance includes an excessive growth rate for an outlier, Southern Gas Holdings, the exclusion of which would have reduced the Company's guidance based average ROE estimate to 9.65%.[472]

Additionally, Staff asserts that Mr. Maddipati's inclusion of a flotation cost adjustment, is unnecessary.[473] Indeed, the Commission previously rejected the application of such an adjustment for this utility.[474] This PFD agrees with Staff that the Company has not justified a change in the Commission's prior determination that flotation costs are not recoverable.

As a result of these issues, many of the Company's analyses based on the CAPM, ECAPM, and DCF models have likely produced results that were higher than they should have been.

Mr. Maddipati cautioned that the standard quantitative models are based on the assumption that economic conditions are relatively stable, that current market inputs are reflective of their long-term outlook, and that this assumption is not currently being met due to the recent unprecedented amount of intervention by central banks as well as the impacts of the TCJA.[475] As a result, the models tend to understate the return that investors

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[471] 6 Tr 1728; 7 Tr 2194.
[472] 7 Tr 1676-1677.
[473] 7 Tr 2133-2134.
[474] See MPSC Case No. U-14347, December 22, 2005 Order, p. 24. ("The Commission also finds that the exclusion of flotation costs is appropriate. The Commission is persuaded that these costs are not costs incurred by the regulated utility. Consequently, it is not appropriate to include these costs in the calculation of Consumers' return on equity.")
[475] 4 Tr 113-114.

currently require to compensate them for risk, such that a "mechanical application of these models without consideration to the underlying assumptions would not meet the requirements in *Hope* and *Bluefield* as indicated in FERC Opinion 551."[476] Accordingly, Mr. Maddipati made "appropriate adjustments" to the inputs used in various of his methodologies "to mitigate the impacts of these temporary economic conditions and uncertainty."[477]

However, the Company's assertion that the methodologies used and applied by Staff, the Attorney General and ABATE are unreliable is unpersuasive. Initially, this PFD finds that Mr. Maddipati's assertion that witnesses for Staff, the Attorney General, and ABATE engaged in a purely mechanical application of the DCF model is unsupported, since each of the witnesses gave careful thought to the selection of inputs, and formulation of the model, as well as the conclusions to draw from the results.

In addition, as Mr. Megginson testified, it is questionable whether "anomalous market conditions" exist today:

> The Fed's policies have been in place for several years now and at some point, stopped being artificial and started being normal. The Fed has steadily increased interest rates since 2015 and even more so, increased them four times in 2018 alone. The Fed has plans to increase them potentially two more times in 2019. Thus, the Fed is managing the economy as it sees fit and the Company's effort to input unconventional rates or use irregular timelines in its cost of equity models based on its argument that capital markets are currently anomalous is unwarranted.[478]

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[476] 4 Tr 114.
[477] Consumers Energy's Initial Brief, p. 121.
[478] 7 Tr 2139.

Similarly, the Company's reliance on FERC Opinion 551 and a related FERC remand order in docket no. EL11-66-001 in justifying its application of various adjustments to inputs used in its various quantitative models appears to be misplaced. In FERC Opinion 551, FERC reasserted principles first set forth in FERC Opinion 531 that it may consider whether market anomalies may affect the reliability of the DCF analysis.[479] However, rather than concluding that the presence of any such anomalies negate the applicability of the DCF methodology, FERC reiterated the propriety of the DCF model and cautioned that alternative methodologies (such as risk premium analysis and CAPM) may be considered only to provide a comparison to the DCF analysis in order to assess whether the authorized ROE should be moved from the mid-point of the DCF-analyzed ROE range.

> "As the Commission found in Opinion No. 531, in considering these other methodologies and the ROEs allowed by state commissions, we do not depart from our use of the DCF methodology; rather, due to the presence of unusual capital market conditions, we find it appropriate to look to other record evidence to inform the just and reasonable placement of the ROE within the zone of reasonableness [defined by the low and high estimates for the proxy group] produced by the DCF methodology."[480]

Subsequently, on April 14, 2017, the D.C. Circuit Court of Appeals vacated FERC Opinion 531.[481]

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[479] FERC Opinion 531, *Coakley v. Bangor Hydro-Elec. Co,* 147 FERC ¶ 61,234 (June 19, 2014). FERC Opinion 551, *Ass'n of Businesses Advocating Tariff Equity, et al., v. Midcontinent Indep. Sys. Operator, Inc., et al.,* 156 FERC ¶ 61,234 (Sept. 28, 2016).
[480] FERC Opinion 551 at par. 137.
[481] *See Emera Maine v Federal Energy Regulatory Comm'n*, 854 F.3d 9 (2017).

On remand, FERC issued its Order Directing Briefs, dated October 16, 2018 (FERC Remand Order)[482], wherein FERC proposed a new approach for determining a lawful ROE, changing from primarily relying on the DCF model to utilizing the results of the DCF, CAPM, Expected Earnings and Risk Premium models:

> In short, we intend to give equal weight to the results of the four financial models in the record, instead of primarily relying on the DCF model.
> . . .
>
> We begin with the Commission's proposed framework for determining whether an existing ROE remains just and reasonable (i.e., the first prong of the FPA section 206 analysis). Specifically, we propose (1) relying on the three financial models that produce zones of reasonableness—the DCF, CAPM, and Expected Earnings models—to establish a composite zone of reasonableness; and (2) relying on that composite zone of reasonableness as an evidentiary tool to identify a range of presumptively just and reasonable ROEs for utilities with a similar risk profile to the targeted utility.
> . . .
>
> We then turn to the Commission's proposed framework for establishing a new just and reasonable ROE, where the existing ROE has been shown to be unjust and unreasonable (i.e., the second prong of the FPA section 206 analysis). At that stage, we propose to rely on all four financial models in the record—i.e., the three listed above, plus the Risk Premium model—to produce four separate cost of equity estimates. We propose to then give them equal weight by averaging the four estimates to produce the just and reasonable ROE.[483]

However, FERC indicated that "whether the continuing low-interest rate capital market conditions should be considered 'anomalous' and whether those conditions distort the results of a DCF analysis" were "largely irrelevant" under its new approach for determining just and reasonable ROE's:

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[482] This Order is referred to as that in "Docket No. EL11-66-001" by Mr. Maddipati, and is Exhibit A-153. See 4 Tr 234; Company brief, p. 128.
[483] FERC Remand Order, Exhibit A-153, p. 13.

> There is thus no need to find that low-interest rate capital market conditions distort the results of a DCF analysis so as to justify adjusting the ROE for average risk utilities above the midpoint. To the contrary, our primary reason for proposing to average the results of a DCF analysis with the results of the CAPM, Expected Earnings, and Risk Premium analyses is that investors use those models, in addition to the DCF methodology, to inform their investment decisions. Under this approach, whether a change in the capital market conditions is anomalous or persistent is of less importance, because relying on multiple financial models makes it more likely that our decision will accurately reflect how investors are making their investment decisions. As discussed above, a key consideration in determining just and reasonable utility ROEs is determining what ROE a utility must offer in order to attract capital, i.e., induce investors to invest in the utility in light of its risk profile. For this purpose, we must look to the methods investors use to analyze and compare their investment opportunities in determining what ROE to award a utility consistent with the *Hope* and *Bluefield* capital attraction standards, and those methods include methods other than the DCF methodology.[484]

Third, although not dispositive, this PFD notes that in the Company's last contested gas rate case, the Company sought an ROE of 10.60%, which request was similarly based on certain qualitative factors which the Company asserts here, including investors' view of Michigan's positive regulatory environment, the current state of the economy and capital markets, and the company's need to attract capital to finance its capital expenditure program.[485] However, the ALJ recommended that the Commission set the Company's ROE at no higher than 10.00%, which the ALJ noted reflected the top of Staff's recommended ROE range, which acknowledged "both the volatility in United States and global markets and the likelihood of rising interest rates", and which would still allow the Company to provide "appropriate compensation for risk and assuring reasonable access to capital on reasonable terms and conditions, while also remaining

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[484] *Id*., p. 29-30.
[485] MPSC Case No. U-18124, 5 Tr 430-433.

cognizant of the burden on ratepayers."[486] Agreeing with the ALJ's analysis and findings that the Company's proposed ROE of 10.60% was "excessive", and with her observation "that some of the evidence supports an ROE below 10%", the Commission concluded that an ROE of 10.10% "will best achieve the goals of providing appropriate compensation for risk, ensuring the financial soundness of the business, and maintaining a strong ability to attract capital", and that it "appropriately balances the interests of the utility with the interests of its ratepayers, and will ensure investor interest and confidence while protecting customers from unnecessarily burdensome rates."[487]

Similarly, in its last rate case, the Company sought an ROE of 10.75%, which request was also based on many of the same factors which the Company asserts in this case, including the current state of the economy and capital markets, the need to attract capital to finance the capital expenditures program at the Company's gas business, and the potential adverse impact of the TCJA on the Company's credit.[488] The ALJ in that case recommended that the Commission set the Company's ROE at 10.00%, reasoning that that return "is based upon an objectively reasonable analysis which is consistent with past Commission decisions and the requirements of *Bluefield* and *Hope*", "acknowledges the volatility in United States and global markets and the likelihood of rising interest rates", and will still allow the Company to achieve the goals of providing appropriate compensation for risk and assuring reasonable access to capital on reasonable terms

[486] MPSC Case No. U-18124, May 18, 2017 PFD, p. 104-105.
[487] MPSC Case No. U-18124, July 31, 2017 Order, p. 52-53.
[488] MPSC Case No. U-18424, PFD, July 2, 2018, p. 179, 190. Citations omitted.

and conditions, while also remaining cognizant of the burden on ratepayers."[489] Thereafter, the Company agreed to the recommended 10.00% ROE pursuant to a settlement agreement approved by the Commission.[490] While a settlement agreement is not precedential, the Company has continued to raise capital and has not established an adverse impact as a result of this agreement.

Fourth, the authorized ROEs approved by other Commissions for gas utilities have generally declined in recent years, with the average authorized returns in the presentations compiled by the witnesses generally within the range of 9.50% to 9.72%.[491] Likewise, since November 2015, in Case Nos. U-17735, U-17999, U-18014, U-17990, U-18124, and U-18322, the Commission has issued orders for Consumers Energy and DTE adopting ROEs of 10.30%, 10.10%, 10.10%, 10.10%, 10.10% and 10.00%, respectively.[492] While the Company argues that the Commission has stated its disinclination "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", the Commission nonetheless acknowledges that it considers other ROEs. *See*, *e.g*., MPSC Case No. U-18999, Order, September 13, 2018, p. 52 ("Nonetheless, the Commission considers other ROEs and notes that the authorized ROEs for gas utilities in other states may have declined and, in

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[489] MPSC Case No. U-18424, PFD, July 2, 2018, p. 207-208.
[490] MPSC Case No. U-18424, Order, August 28, 2018, p. 207-208.
[491] 6 Tr 1741, Exhibit S-4, Schedule D-5. p. 12; 7 Tr 2446-2447, Exhibit AG-49; 7 Tr 2168, 2172, Exhibit AB-6.
[492] MPSC Case No. U-17735, November 19, 2015 Order; MPSC Case No. U-17999, December 9, 2016 Order; MPSC Case No. U-18014, January 31, 2017 Order; MPSC Case No. U-17990, February 28, 2017 Order; MPSC Case No. U-18124, July 31, 2017 Order; MPSC Case No. U-18322, March 29, 2018 Order.

some cases, are below 10.00%.") Indeed, in the most recent contested gas rate case for the Company, the Commission noted that an ROE of 10.10% "is consistent with its ROE determinations in recent years", and that "[n]ationally and in Michigan, ROEs are trending downward".[493] Therefore, such information, if considered here, further demonstrates that the Company's requested ROE of 10.75% is well above these recently authorized ROEs.

Moreover, the Company's requested ROE of 10.75% overlooks the RDM previously granted to the Company that have substantially reduced the Company's business risk going forward. Specifically, as Mr. Megginson testified, the RDM "reduces Consumers Energy's risk in collecting its authorized revenue level and thus reduces the Company's risk of not earning its authorized ROE."[494]

Finally, it is important to recall that in its recent order in the Company's electric rate case, the Commission noted that the parties should "consider the degree of financial adjustment" that they are asking the Commission to make in any case "because it is not realistic to make a significant change in ROE absent a radical change in underlying economic conditions."[495] Here, the Company is seeking a significant increase of 75 basis-points in its authorized ROE without having demonstrated that there is a "radical change" in the current economic conditions.[496] Although the Company asserts that the TCJA "has

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[493] MPSC Case No. 18124, July 31, 2017 Order, p. 52.
[494] 6 Tr 1743.
[495] MPSC Case No. U-18322, March 29, 2018 Order, p. 44.
[496] Consumers argued that, with the passage of the TCJA, there "has been" a "radical change in underlying economic conditions". Consumers Energy Reply Brief, p. 108. However, as discussed *supra*, Consumers has failed to show that the TCJA should properly be considered a "radical change" in economic conditions which might justify a "significant change" in an authorized ROE in accordance with the Commission's recent pronouncement.

led to a radical change in underlying economic conditions – most notably, in the form of credit quality deterioration across the utility sector"[497], the evidence does not support a conclusion that the TCJA constitutes a "radical change" in the current economic conditions so as to justify a dramatic 75 basis-points increase in its authorized ROE.

Notwithstanding this PFD's determination that the Company's requested ROE of 10.75% is excessive, consideration must be given to the Company's contention that setting the rate of return as recommended by Staff, the Attorney General, and ABATE, would send a significant negative message to investors that would undercut the positive investor perceptions of Michigan and the Michigan regulatory environment. According to Mr. Maddipati:

> The consistency, predictability, and promptness of regulatory outcomes coupled with a constructive and supportive authorized ROE are important parameters to enable a financially healthy utility.
>
> . . . . attractive ROEs are important and, in part, set the stage for consistent financial performance. This occurs because the equity provided by utility shareowners and the return allowed on that equity provide the financial resources and capital to: (i) support the debt financing raised by the utility; (ii) procure contracts with suppliers; and (iii) fund unplanned or unexpected expenses.
>
> . . . a cycle of good regulation, together with a reasonable ROE, enables a utility to attract capital and make investments that drive better service and maintain affordable rates.[498]

Staff, the Attorney General, and ABATE each are also proposing significant changes to the Company's authorized ROE, ranging between 35 and 78 basis points. This PFD finds that these proposed ROEs are supported by the record evidence in this

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[497] 4 Tr 106.
[498] 4 Tr 107-109.

case. However (and similarly with the Company's recommendation to raise its authorized ROE by 75 basis points), these proposed ROEs are likely to be considered by the Commission to be "unrealistic" absent a "radical change" in the current economic conditions, which these parties also have not shown.[499] Thus, although supported by the evidence in this case, this PFD finds that the ROEs of 9.22%, 9.65%, and 9.50% utilized or recommended by ABATE, Staff, and the Attorney General, respectively, may be considered by the Commission as harmful to the Company's credit ratings and send an adverse signal to investors, analysts, and credit rating agencies and, thus, should not be adopted.

Instead, this PFD finds that the Commission should set the Company's ROE at 9.80%. This return is slightly above Staff's recommended ROE of 9.65%, is based upon an objectively reasonable analysis which is consistent with past Commission decisions and the requirements of *Bluefield* and *Hope*, and acknowledges the volatility in United States and global markets and the likelihood of rising interest rates. This ROE is also slightly higher than the average ROE of 9.60% of Staff's proxy group and the national average of gas ROEs in 2018 (9.59%). This PFD concludes that such a ROE will allow the Company to achieve the goals of providing appropriate compensation for risk and assuring reasonable access to capital on reasonable terms and conditions, while also remaining cognizant of the burden on ratepayers.

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[499] MPSC Case No. U-18322, Order, March 29, 2018, p. 44.

Accordingly, this PFD recommends the Commission authorize a ROE of 9.80% for the Company.

VI.

THROUGHPUT

Mr. Keaton presented the Company's forecasted gas delivery and customer counts for the test year. According to Mr. Keaton, total deliveries are expected to remain at weather normalized levels of 304 billion cubic feet (Bcf) through the test period, with customer counts projected to increase 1.5% from the 2017 historical year through the test period.[500] Total deliveries are expected to increase by 0.04% per year over the next five years.[501]

No party took issue with the Company's throughput projection for the test year. The Commission should therefore adopt the company's forecasted gas deliveries.

VII.

ADJUSTED NET OPERATING INCOME

Adjusted Net Operating Income (NOI) represents the difference between the company's projected test year operating revenues at current rates and projected test year expenses. As a result, the first step in computing a company's NOI is to forecast its overall sales level, and then convert that figure into the appropriate amount of expected revenue to be received during the test year, adjusted for revenue received by other utility

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[500] 6 Tr 1299.
[501] 6 Tr 1298-1299; Exhibit A-15, Schedules E-1 and E-2.

operations. The second step is to determine the expenses that are expected to be incurred during the test year, and then subtract that amount from overall revenues.

A. Operating Revenue Forecast

1. Sales Revenue

The Company projected test year sales revenues of $1,513,094,000.[502] Staff agreed with this projection and the amount was not disputed by other parties.[503] The PFD therefore recommends the Commission adopt the Company's sales revenue projection of $1,513,094,000.

2. Transportation Revenue

The Company projected test year transportation revenues of $70,646,000.[504] Staff projected total transportation revenues of $82,510,000, an increase of $11,864,000, based on Staff's proposed transfer of $11,864,000 of Midland Cogeneration Venture LP (MCV) revenue from other gas revenue to transportation revenue.[505] Consistent with the discussion and recommendation on the treatment of revenues from the MCV Act 9 contracts, as set forth in Section X.C. of the PFD, this PFD finds that Staff's adjustment is unnecessary.

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502 Company Brief, p. 137; Exhibit A-13, Schedule C-1.
503 Staff Brief, p. 66 and Appendix C.
504 Company Brief, p 137-138.
505 Staff Brief, p 67 and Appendix C.

3. Miscellaneous (Other Gas) Revenue

The Company originally projected test year miscellaneous revenue of $114,426,000. Subsequently, the Company accepted some of Staff's proposed adjustments and revised its miscellaneous revenue amount to $114,518,000.[506]

As noted above, Staff proposed that $11,864,000 in revenues from the MCV Act 9 contracts be transferred from miscellaneous revenue to transportation revenue.[507] Again, in accordance with the discussion in Section X.C., the PFD finds that, rather than transferring MCV revenues from miscellaneous to transportation revenues, an additional $12,759,000 should be imputed to the MCV Act 9 contracts and included in miscellaneous revenue. For this reason, this PFD recommends that the Commission accept the Company's revised miscellaneous revenue projection of $114,518,000 and impute $12,759,000 in revenues from the MCV contracts, for a total miscellaneous revenue amount of $127,277,000.

B. Cost of Gas Sold

The Company projected a cost of gas sold expense for the test year of $633,882,000, based on an average cost of gas sold of $ 2.815 per Mcf.[508] Staff agreed with these amounts.[509] Therefore, this PFD recommends the Commission adopt the Company's projection. Staff also agreed with the Company's 13-month average storage

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[506] Company Brief, p 138.
[507] Staff Brief, p 67-68; Exhibit S-10.1.
[508] Company Brief, p 139.
[509] Staff Brief, p 68, Appendix C.

volume of 127,805 MMcf and the associated 13-month average cost of $347,595,424 or $2.720/Mcf.[510] This PFD recommends the Commission adopt these amounts.

C. Lost and Unaccounted for Gas and Company Use Gas

In rebuttal, based on a five-year average, the Company projected lost and unaccounted for (LAUF) gas and company use gas expense of $8,317,000 and $5,101,000, respectively; totaling $13,418,000. Staff agrees with these projections.[511]

The Attorney General proposed a $4,200,000 disallowance to the Company's proposed expense for LAUF gas and company use gas.[512] Mr. Coppola took issue with the Company's use of a five-year average to calculate this expense in this case, noting that the Company made an unusually large adjustment to the storage inventory in 2013-2014 that skewed the data upward.[513] Mr. Coppola also asserted there has been a significant decline in the amount of gas lost in the last three years. Therefore, Mr. Coppola argued that use of a three-year average was more reasonable and prudent in this case.[514] In the alternative, the Attorney General argued that if the Commission chooses to use a five-year average, it should remove the large inventory storage adjustment prior to making the expense calculation.[515]

The Company argued that the Commission has consistently recognized a five-year average for determining LAUF gas. Mr. Joyce testified:

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[510] 6 Tr 1378.
[511] Staff Brief, p 68, Appendix C.
[512] Attorney General Brief, p 91, See also Exhibit AG-39.
[513] 7 Tr 1709; Exhibit A-77.
[514] 7 Tr 1709.
[515] Attorney General Brief, p. 91-92.

> The Company has consistently utilized the use of a five-year average of Gas Losses to calculate the LAUF volumes to project LAUF test year recovery. This methodology has been utilized and approved in Consumers Energy's gas rate cases for over 10 years. This includes MPSC Case Nos. U-15506 (February 2008), U-15986 (May 2009), U-16418 (August 2010), U-16855 (September 2011), U-17643 (July 2014), U-17882 (July 2015), U-18124 (August 2016) and U-18424 (August 2017). There is very compelling precedent established over this period and Mr. Coppola now wishes to deviate from this past practice. This practice was established to recognize variations that can occur in LAUF and should continue to be approved by the Commission.[516]

Mr. Coppola's expense projection for LAUF gas and company use gas includes a reduction of $500,000 for Gas in Kind (GIK) volumes. He stated the Company used a GIK volume of 2,051 MMcf but failed to provide support for that amount.[517] Mr. Coppola testified that he used 2,237 MMcf GIK based on workpapers provided by Ms. Pelmear.[518]

Again, the Company pointed out that the Attorney General's calculations are not based on five-year historical data. Mr. Joyce testified his methodology is consistent with Commission precedent, which has consistently affirmed the use of a five-year average in determining LAUF gas and GIK.[519]

Based on the record and arguments of the parties, this PFD finds the Company's position more persuasive. While the Attorney General is correct that the large adjustment early in the five-year period resulted in a higher average, she did not provide sufficient justification to depart from the use of a five-year average, which is intended to smooth out significant variations like the storage loss adjustment in 2013-2014. And, because the

[516] 5 Tr 881.
[517] Exhibit A-78. Attorney General Initial Brief, p. 91.
[518] 7 Tr 1710; Exhibit AG-39.
[519] 5 Tr 882.

Attorney General's adjustment to GIK also relied on a three-year average, this disallowance should also be rejected. Accordingly, this PFD recommends the Commission adopt the Company's expense amount of $8,317,000 for LAUF gas and an amount of $5,101,000 for company use gas.

Staff also proposed that gas vented through relief valves be accounted for as company use gas.[520] Staff asserts that releases from relief valves are very similar to releases which occur during an emergency shutdown.[521] In rebuttal, Mr. Joyce testified that the Company agreed with Staff and stated, "the Company will commit to investigating the feasibility of setting up a process which will allow the classification of gas lost through . . . relief valves . . . as Company Use Gas."[522]

This PFD agrees with Staff's proposal and recommends that the Commission direct the Company to set up the required process for including gas vented through relief valves as a component of company use gas.

D. <u>Other Operations and Maintenance Expense</u>

The Company projected other operations and maintenance (O&M) expense for the test year of $391,548,000.[523]

Staff and the Attorney General recommended numerous adjustments to the Company's projection. Overall, Staff proposed to reduce the Company's projected other O&M expense by $9,570,000, supporting a total expense in the amount of

[520] Staff Brief, p. 69.
[521] 7 Tr 2193.
[522] 5 Tr 880.
[523] Staff Brief, Appendix C.

$379,463,000.[524] The Attorney General recommends decreasing the Company's projection by $25,600,000.[525]

The parties either did not contest, or they ultimately agreed upon, test year O&M expenses for: (1) Gas Engineering and Financial Management ($7,102,000); (2) Gas Operations ($93,938,000); (3) Gas Compression and Gas Management Services ($23,097,000); (4) Cathodic Protection/Corrosion Control ($4,291,000 total); (5) Facilities Expense ($14,697,000); (6) Fleet Services Expense ($66,000);[526] (7) Right of Way (ROW) Clearing ($1,814,000); (8) pipeline integrity;[527] (9) inflation[528] and (10) Manufactured Gas Plant Direct Management Expense ($756,000). The adjustments that remain in dispute are discussed below.

1. <u>Right-of-Way Clearing</u>

As noted above, there was no objection to the Company's proposed expense amount for ROW clearing, which includes funds for a shortened clearing cycle. Staff, however, expressed concern with the Company's commitment to maintain the clearing cycle. Ms. Creisher reintroduced a recommendation first presented in Case No U-17882:

> Staff recommends that the Company provide Staff with an annual performance report related to the work completed for each calendar year of the program. At a minimum, the report should include the total O&M expenses for right-of-way clearing completed and total miles cleared, including delineation of expenses and miles for scheduled clearing per the

[524] Id.
[525] Attorney General Brief, p. 103.
[526] The Attorney General's proposed disallowance for Fleet Services capital expense is discussed above.
[527] As discussed above, the Attorney General's recommended disallowance for pipeline integrity carryover costs is adopted.
[528] Staff made several adjustments for inflation, that were disputed by the Company. In its brief, Staff states that it adopts the Company's initially-filed amounts for inflation for gas transmission and distribution. Staff Brief, p. 86. It also appears that Staff's position on an inflation adjustment of $1,388,000 to Gas Operations Expense has been abandoned.

> 10-year cycle and clearing for emergent work. The report should specifically include a list of right-of-way cleared per 10-year cycle that details the pipeline system; length of segment cleared; approximate segment location or segment identifying information; O&M expense; the type of clearing work required such as clearing of woody vegetation or mowing; work completed by Company or contractor crews; and the type of pipeline system such as transmission, distribution, or transmission pipeline operated within the distribution system.[529]

While the Company did not oppose Staff's proposal, Mr. Crews testified that the Company recommended changes to the proposed reporting requirement, if approved. First, Mr. Crews recommended removing the "type of clearing work" category from the report. The Company asserted that it would be difficult to track the type of work performed because ROW clearing often involves both clearing woody vegetation and mowing of the same parcel. And, the Company proposes to file the report "no later than April 30 for the preceding year, following the first full year" to allow time to develop the reporting structure.[530] Staff did not take issue with the Company's modifications. This PFD therefore recommends that the Commission adopt Staff's ROW reporting requirement with adjustments recommended by the Company.

2. <u>Information Technology O&M Expense</u>

Mr. Varvatos testified regarding the utility's projected information technology (IT) O&M expenses, and he provided Exhibit A-116, which is an overview of IT expense categories and actual and projected expenses for 2017 through the test year. Mr. Varvatos testified that IT O&M expense was $30,960,000 in the 2017 historical year, $41,262,000 projected for 2018, $34,822,000 projected for 2019, and $35,145,000 for the

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[529] 7 Tr 1980.
[530] 6 Tr 1155.

projected test year.[531] Mr. Varvatos described IT O&M expense as predictable, stable, and tied to previous IT capital expenditures.[532] Mr. Varvatos added that:

> The IT Department benchmarks costs, workload, staffing, and performance metrics against a consortium of utilities as part of the Utility Information Technology Benchmark ("UNITE"). This exercise allows the Company to understand how it compares with other utilities in specific IT service areas, identify areas for improvement, and develop action plans to improve in those areas where practical, taking into account the balance between cost, performance, and functionality expected by its customers.[533]

According to Mr. Varvatos, in a UNITE evaluation for 2017, the Company was near the median in total spending measured as both a percentage of revenue and on a per-customer basis.[534] He also testified that in addition to benchmarking, the Company utilizes competitive bidding and cost control measures, such as consultation with third parties, to evaluate projects to insure competitive market rate pricing.

Ms. McMillan-Sepkoski testified in support of reducing the test year IT O&M expense by $3,585,000, proposing an IT O&M expense of $31,560,000.[535] She testified that Staff based its IT expense projection in part on a five-year historical average of IT O&M expense from 2014 to 2018. Ms. McMillan-Sepkoski explained:

> The Company's Exhibit A-116 (CJV-1) projected IT O&M expense amounts for 2018, 2019, and 2020 are $41.3 million, $34.8 million, and $35.1 million, respectively. Staff requested the Company supply actual amounts for the years 2014 through 2018. The Company's response is seen on Staff Exhibit S-13.1. As can be seen on Exhibit S-13.1, the amount projected by the Company changed for year ended December 31, 2018 with a preliminary decrease of $3.1 million. The actual amounts expensed/projected from 2014-2020 have been sporadic and/or volatile. The yearly amounts for IT

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[531] Id. at 1466-1467.
[532] Id. at 1471-1472.
[533] 6 Tr 1475.
[534] Id.
[535] 7 Tr 2115; Exhibit S-10.

> expense from 2014 through 2018, in millions are $33.7, $29.2, $29.5, $31, and $38.1 respectively, as shown on Exhibit S-13, line 4. Using a historic average for expense items that have historically been sporadic and/or volatile is an appropriate method to forecast projected test year expense.[536]

Ms. McMillan-Sepkowski further testified that Staff also removed $594,000 for origination costs/expenses[537] because these expenses "are highly speculative and contingent upon progressing forward as an actual project." Ms. McMillan-Sepkowski opined that ratepayers should not bear the risk of such unpredictable costs for projects that may not materialize. Finally, Ms. McMillan-Sepkowski testified that Staff's proposed adjustments should be adopted because the Commission has adopted a five-year average for expenses that are similarly volatile, and because the origination expense projection is too speculative, noting that the Commission used a five-year average for IT expense, and it disallowed origination expense in Case No. U-18124.

In rebuttal, Mr. Varvatos points out that in the Company's most recent gas rate case, Staff did not recommend the use of a five-year average for IT expense, nor did it recommend disallowance of origination expense.[538] Mr. Varvatos testified that IT expense is predictable, stable, and undergoing growth. Mr. Varvatos explained that if the Commission fails to provide sufficient O&M funds for IT:

> [T]he Company would be unable to provide the required level of operational support for current and planned technology investments deemed prudent in prior rate cases, putting system operations at risk. The Company's customers have benefitted from the system stability and reliability that has

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[536] 7 Tr 2116.
[537] Mr. Varvatos described origination expense as costs associated with "identifying high-level business requirements, determining whether the technology needed actually exists, exploring alternatives, identifying performance requirements, working with vendors to demonstrate the effectiveness of their products, including cloud solutions, and developing the business case." 6 Tr 1473.
[538] See PFD Case No. U- 18242, July 2, 2018, p. 232.

> resulted from system monitoring, break/fix activity, maintenance activity, vendor support, technology and application upgrades, security patching and other IT operations activities covered by IT O&M expense. As the Company invests the approved IT capital as authorized in prior rate cases, those assets require maintenance to continue to perform at optimal levels and obtain the committed value for the Company and its customers.[539]

With respect to Staff's disallowance of origination costs, Mr. Varvatos disagreed that these expenses are speculative, stating that origination is a part of due diligence and that customers benefit from origination spending because the Company invests small amounts to avoid wasting ratepayer funds later.[540] Mr. Varvatos added that "the Company completes many of the due-diligence activities specified in the [Financial Accounting Standards Board] FASB guideline ASC 350-40 for Internal Use Software as activities to be expensed in the Preliminary Project Stage."[541]

In its brief, Staff reiterates that a five-year average of actual expenses is a reasonable and prudent method to project IT O&M expenses. "This is because a[n] historical average anchors IT O&M expense projections in audited and verified actual expense experience[.]"[542] Staff contends that while the FASB requires origination expense to be booked, FASB guidelines do not require unknown and unmeasurable expenses to be recovered in rates. Finally, Staff points to Case No. U-18124 where the Commission found that the five-year average approach to projecting IT expense and the disallowance of origination expense were reasonable.

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[539] 6 Tr 1518.
[540] Id. at 1519.
[541] Id.
[542] Staff Brief, p. 77.

The Company argues that based on the benchmarking and cost control measures it provided in Mr. Varvatos' testimony, the Commission should approve the proposed IT O&M expense. The Company further argues that in the Company's most recent rate case, Case No. U-18424, Staff did not recommend the use of a five-year average for IT expense, nor did it recommend disallowance of origination costs. The Company also maintains that Staff's position here is contrary to its position in Case No. U-20162, a recent electric case, where Staff opposed that utility's use of historical spending to project IT expense. In that case, the Administrative Law Judge and the Commission agreed with Staff's position.[543] The Company further contends that it provided significant detail about cost projections for its IT programs, a far more accurate way to determine spending than "a backward-looking 5-year average[.]"[544] The Company reiterated that reducing IT O&M expense amounts could adversely affect its ability to provide support for its existing IT operations and could put these systems at risk.

In its reply brief, Staff points out that the Company's comparison of Staff's position here to its position in Case No. U-20162 is inapposite. According to Staff, Case No. U-20162 involved capital spending on a new IT project, whereas the dispute in Case No. U-18124 involved projected spending on IT O&M. While there was no historical data for spending on the new IT project in Case No. U-20162, there is significant historical spending data for the IT O&M expense at issue in this case.

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[543] Company Brief, p. 156-157, quoting May 2, 2019 order in Case No. U-20162, p. 40.
[544] Company Brief, p. 157, quoting 6 Tr 1518.

In the July 31, 2017 order in Case No. U-18124, the Commission found that using a five-year average for determining the projection for IT O&M expense is reasonable and prudent. The Commission examined the record and found that the five-year average spending was considerably less than the Company's projection and further observed that the Company had significantly over-projected IT spending in a previous rate case. In addition, the Commission disallowed origination costs, finding that those costs were not well-supported.

This PFD finds that the Staff's total adjustment for IT O&M expense should be adopted. A review of Staff Exhibit S-13 demonstrates that overall spending on IT programs has varied considerably, dropping from $33.7 million in 2014 to $30.9 million in 2017. In addition, although the Company originally projected actual spending of $38.1 million in 2018, this projection was revised downward over the course of the proceeding. And, although the Company provided some details on origination costs, this PFD agrees that the origination costs are speculative and may not lead to projects that are used and usefulin the provision of utility service. Accordingly, this PFD recommends the Commission adopt the Staff's recommended $31,560,000 for IT O&M expense.

3. Corporate Services Expense

The Company projects its corporate services O&M expense for thetest year for the gas utility portion of the Company to be $30,297,000.[545] Mr. Rueckert proposed a $50,000 reduction to this projected expense based on inflation.[546] However, beyond including this

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[545] Company Brief, p. 160.
[546] Staff Brief, p. 79-80.

amount in Exhibit S-3, Schedule C-5, and its initial brief (page 79), Staff did not provide any reason for this disallowance. It also appears that the $50,000 adjustment may have been part of Staff's overall inflation adjustment that Staff withdrew in its initial brief.[547] Therefore, this PFD finds Staff did not adequately support this proposed disallowance and that the Company's projected corporate services expense amount of $30,297,000 be adopted by the Commission.

4. <u>Pension and Benefits Expense</u>

The Company initially projected the employee benefits O&M expense for the test year to be $1,752,000.[548] The Company asserted this amount is comprised of: (i) a pension plan expense of $11,472,000; (ii) a defined company contribution expense (DCCP) of $5,806,000; (iii) a 401k employees savings plan (ESP) expense of $4,941,000; (iv) an active employee health care, life insurance, and long-term disability (LTD) insurance expense of $16,405,000; (v) a retiree health benefit expense of negative $37,840,000; and (vi) absence management and education assistance expense of $968,000.[549]

Staff originally proposed a total reduction to employee benefits expense based on its assertion that the Company's growth rate assumptions in the categories of defined company contribution expense, 401k employees savings plan expense, and the active employee health care, life insurance, and long-term disability insurance expense do not

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[547] Id. at 86.
[548] See Exhibit A-42.
[549] Company Brief, p. 161.

consider actual, historical expense experience. However, in its initial brief Staff withdrew this disallowance.[550]

Staff also proposed to reduce the Company's absence management and educational assistance expense by $389,000.[551] Mr. Rueckert testified that, consistent with the Company's methodology, Staff updated the expense for 2018 actuals resulting in a projection of $579,000 for the test year.[552]

The Company disagreed with Staff's recommendation, stating that reduced absenteeism results in reduced labor costs, and the educational assistance program is important to attract and retain qualified employees.[553] The Company confirmed Staff's assertion that it projected an increase in this expense from 2017 to 2018, which did not materialize.[554] Ms. Christopher testified this expense was historically low in 2018 and indicated the expense is generally larger.[555] The Company also asserted it expects to increase its educational assistance in the future.[556]

In response, Staff pointed out that the details for specific program enhancements that the Company claims will be made in the test period were not provided, and it argues that the Company should have quantified the amounts it intends to expend for this program.[557]

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[550] Staff Brief, p. 78-79.
[551] Id. at p 78; Exhibit S-3, Schedule C5.1.
[552] 7 Tr 2211.
[553] 5 Tr 752.
[554] Company Brief, p. 112.
[555] 5 Tr 753.
[556] 5 Tr 752
[557] Staff Brief, p 79.

This PFD finds Staff's position persuasive. While the Company confirmed the projected spending increase for 2018 did not materialize, its assertions that the expense in 2018 was historically low is not supported. Moreover, as Staff points out, if the Company is planning enhancements to programs and increased spending in this O&M category, those program enhancements and additional spending amounts should be quantified and presented. Indeed, the low level of past spending could be repeated if it reflects a lack of Company commitment to the program. Therefore, this PFD recommends that Staff's proposed reduction of $389,000 to absence management and education assistance expense be adopted by the Commission.

The Attorney General recommends a reduction of $1,600,000 to pension expense and a reduction of $1,000,000 to OPEB expense to reflect a projected rate of return on plan assets of 7.00% instead of the Company's projected rate of return of 6.75%.[558] Referencing Ms. Christopher's Exhibit A-44, Mr. Coppola testified that the Company projects a decrease in the return rate from 7.00% in 2019 to 6.75% in 2020 and from 6.75% in 2020 to 6.50% in 2022. According to Mr. Coppola, the Company provided no support for its forecasted reductions in return rate.[559] Mr. Coppola further explained:

> A decrease in the Expected Return on the invested fund assets increases pension and OPEB expense for the projected test year. The lower return on the invested assets results in lower income offsetting the same amount of future pension costs. Therefore, any assumed changes in the Expected Return rate must be carefully evaluated and supported to ensure they are based on valid data and reasonable future expected performance of the invested assets in the financial markets.[560]

[558] Exhibits AG-41 and AG-42.
[559] 7 Tr 1706.
[560] Id. at 1707.

Mr. Coppola added that financial markets have been performing well in recent years, "[t]hus, it is befuddling why the Company is lowering the Expected Return rate for 2020 and future years at this time."[561] The investment results would justify at worst a continuation of the same Expected Return rate in 2020 as set for 2018 and 2019, and perhaps even an increase in the Expected Return rate."[562] In its brief, Staff agreed with the Attorney General's proposed reduction.[563]

In rebuttal testimony, Ms. Christopher explained that the Company uses an outside investment consultant to develop assumptions about return rates for pension and OPEB assets. In addition, Ms. Christopher testified that the Company's return on 2018 pension plans was -6.7% and the 2018 health care accounts return was -6.4% and -6.7%, adding:

> The 2-year annual return is between 4.2% and 4.7% for the Pension and health care plans, and the 3-year annual return is between 5.7% and 6.1%. The 5-year annual return is between 4.2% and 4.5%. These amounts are shown in Confidential Exhibit A-132 (LBC-8). Thus, looking at only recent performance, the expected return of 7% in 2019 and 6.75% in 2020 would seem too high.[564]

In her brief, the Attorney General points to cross-examination of Ms. Christopher, where she admitted that the Company relies on NEPC, LLC to provide expected return rates, which the Company then reviews. Ms. Christopher further testified that unless NEPC recommends something unethical or if NEPC's strategy deviates from the Company's strategy, NEPC's recommendation is generally relied upon.[565] The Attorney General

561 7 Tr 1707.
562 Id.
563 Staff Brief, p. 83.
564 5 Tr 754-755.
565 5 Tr 762; Exhibit AG-54.

contends that Ms. Christopher did not identify any ethical or strategy concerns on the part of NEPC, therefore the Company's reduction in its rate of return for pension and OPEB assets is unsupported.

The Company disagrees with the Attorney General's proposed disallowances, asserting that it confers with investment consultants, actuaries and auditors to make long-term assumptions, and does not develop the expected return based solely on market performance.[566] Ms. Christopher testified:

> The Company uses future expected capital market assumptions, asset allocation information, and other resources provided by its consultants, which may include survey data and analysis of the Pension Plan's asset allocation. The expected return assumption is based on long-term expectations and not short-term returns. The Company uses all of this information to establish an expected return on plan assets assumption that best estimates its expectation. While this assumption is reviewed for each plan measurement, it may or may not be updated annually depending on the information that is presented.[567]

The Company also points out that it is not required to base its projections on NEPC data.[568] And, as quoted above, the Company does not rely solely on third parties to develop its pension and OPEB return rates. Finally, the Company maintains that the Attorney General and Staff rely on information on projected return rates for 2019 that was not available at the time the case was filed. The Company argues that if the Commission relies on this more recent information, it must also accept the 2018 year-end actuarial remeasurement of the Company's pension and OPEB plans. The Company explains:

> As the Company indicated to Staff in response to audit in this proceeding, the 2018 year-end actuarial measurement used to forecast pension and OPEB costs in the Company's 2018 10k filing results in an increase in the projected

[566] 5 Tr 755, 760.
[567] 5 Tr 719
[568] Company Brief, 116.

> benefits expense of $5.431 million in the test year. 5 TR 743. Specifically, applying the 2018 year-end actuarial measurement would update the test year Pension Plan expense to $7.640 million and the OPEB expense to negative $28.577 million. 5 TR 743. See Exhibit A-131 (LBC-7) for the 2018 year-end actuarial measurement pension and OPEB expense projections.[569]

Finally, the Company states the Commission has required updated projections for pension and OPEB be based on actuarial information, whereas the Attorney General's projections are not based on any actuarial analysis.[570] The Company concludes:

> The pension and OPEB expenses were determined using actuarial analysis performed annually by the Company's actuary in accordance with ASC 715. 5 TR 716-717, 744. The Pension and OPEB Plans were measured on December 31, 2017 for year-end purposes and updated as of June 30, 2018 by the Company's actuary. 5 TR 717, 744. The expected return for 2020 was reasonably established considering the NEPC projections available at the time, as well as other relevant factors, such as the lower return expected as a result of the Company's ability to maintain its funded position with less risk as the plans become increasingly funded. 5 TR 755. If the Commission updates the Company's projected pension and OPEB expenses based on the record in this case, then the update must include a $5.431 million increase in the benefits expense as a result of the 2018 year-end actuarial measurement.[571]

This PFD finds the Company's arguments persuasive. The Company provided a detailed explanation and supporting exhibits to show the method used to calculate the projected return on assets assumption rates. The Company used actuarial data and based its projections on long-term expectations. The Attorney General did not use actuarial projections and based his disallowance on rate of return information made available after the Company developed its projected test year expenses for pension and OPEB. As the Company argues, if the Commission does rely on this information, it must

[569] Company Reply Brief, p. 116.
[570] February 28, 2017 order in Case No. U-17990, p. 97.
[571] Company Reply Brief, p. 118-119.

also consider updated information concerning the 2018 actuarial remeasurement, resulting in an increase in pension and OPEB expense of $5.4 million. Accordingly, this PFD rejects the Attorney General's proposed disallowance of $2,600,000 to pension and benefit expense.

5. Incentive Compensation Expense

The Company seeks to recover the projected test year costs for its employee incentive compensation plan (EICP) in the amount of $2,961,975, which includes $988,000 linked to operating performance metrics and $1,973,975 linked to financial performance metrics.[572] The Company relies on the testimony of Ms. Conrad, Mr. Shirkey, and Mr. Maddipati. Ms. Conrad provided a general overview of the Company's compensation philosophy and structure, as well as the components of the overall compensation for non-officer employees and officers of the Company and testified that the projected costs are reasonable. She testified: "The incentive compensation is part of the overall market-based competitive level. It is not in addition to it. Total compensation is targeted at approximately the market median (50th percentile)."[573]

Ms. Conrad described the goals in place for 2018, presenting Exhibit A-50. She testified that the specific performance measures and targets for 2019 have not been finalized yet, but she anticipated that the goals for the non-officer plan will be equally weighted between operational measures and financial measures.[574] For the officer plan, she testified that the goals are the same, but the weightings are different, characterizing the

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[572] Company Brief, p. 167 and Exhibit A-52.
[573] 6 Tr 1085.
[574] 6 Tr 1101.

operational goals as a “plus or minus modified to the financial goals.”[575] She also anticipated that in 2019, attainment of the financial goals would continue to be a threshold for incentive compensation under the officer plan.[576]

She asserted removal of the incentive compensation would result in uncompetitive pay levels for employees, which would result in a less qualified workforce:

> The Company is able to attract, retain, and motivate talented employees when its overall compensation is competitive with market levels. A decision to compensate employees below market levels would detract from the Company’s ability to assemble the committed workforce our customers deserve. Over time, this would be detrimental to customers, as well as being unfair to our diligent, hardworking employees. Compensating employees below market levels will eventually result in them leaving for jobs that are paying at market levels. Over time, the workforce would tend to be less qualified, less experienced, or less capable (as the most capable would, in general, tend to go to employers paying at competitive levels). This, in turn, could lead to less efficiency and could result in a need to hire more employees to produce the same service to customers, thus increasing costs to our customers.[577]

Ms. Conrad also discussed a 2011 order issued by the Indiana Regulatory Commission for Southern Indiana Gas and Electric Company and recommended that the Commission adopt the approach to incentive compensation used by the Indiana commission as reflected in that order.[578]

Mr. Shirkey presented the company’s quantitative analysis of the benefits associated with two of the operational metrics included in the 2018 plan, employee safety and distribution reliability. He testified:

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[575] 6 Tr 1087.
[576] 6 Tr 1101.
[577] 6 Tr 1091.
[578] 6 Tr 1110-1113.

> Employee safety incidents decreased by 87% from 2006 through 2017. The resulting reduction in lost work days and medical expenses approximates $4.2 million of annual direct savings, and $7.2 million of annual total savings that accrue to the benefit of the customer. The second metric that can be translated to cost avoidance for our customers is in the area of distribution reliability. Using cost per outage minute estimates from Berkeley Labs, the 10 minute annual average reduction in outage minutes from 2006 to 2017 results in annual economic benefits to our customers in excess of $28.3 million.[579]

He also identified indirect or qualitative benefits associated with other operational metrics.[580] He testified that because the metrics benefit customers through increased productivity and customer value, a quantitative measure of the benefits of the program is shown by the extent to which the company's O&M costs have not increased at the rate of inflation as measured by the Consumer Price Index.[581] He thus testified:

> Since the deliberate focus on productivity and customer value EICP metrics against the 2006 performance baseline, the Company's O&M costs decreased by 1.0% on average, while the United States CPI inflation rate grew by an average of 1.8% per year. The average annual savings during this time period is $238.2 million, which benefits customers.[582]

Recognizing that his calculation included both gas and electric operations, he testified that approximately 37% of the benefits go to gas customers, since gas employees are 37% of the company's total workforce.[583]

Mr. Maddipati testified in support of the financial measures:

> Including financial measures as part of the performance measures in the Company's EICP provides customers with both qualitative and quantitative benefits. A financially healthy utility benefits customers in part through lower funding costs which reduce gas bills as highlighted above and helps to

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[579] 6 Tr 1434-1435.
[580] 6 Tr 1435-1437.
[581] 6 Tr 1437.
[582] 6 Tr 1437.
[583] 6 Tr 1438.

> provide customers with better service. As I stated earlier, a virtuous cycle is created by constructive regulation, which creates a financially healthy utility capable of attracting capital, which it then invests in order to improve customer experience/service. It is not simply enough for a utility to have the opportunity to earn a fair return – in order to attract capital, the management and employees must actually achieve results. The inclusion of financial measures in the Company's incentive compensation plans ensures that employees are incented to achieve results which benefit customers as well as attract capital. Additionally, financial performance is required to maintain healthy credit ratings – if the Company were to not meet certain financial measures, it would potentially result in a downgrade of the Company which would in turn result in higher interest costs being borne by the Company. Because of these dynamics, including financial incentive measures in the EICP provide appreciable benefits to Consumers Energy's customers.[584]

He explained the role of the two financial metrics in the company's plan, earnings per share and operating cash flow, in maintaining the Company's credit. He presented page 7 of Schedule D5 in Exhibit A-14 to show that increased credit ratings save customers $51 million annually in interest.[585] This page presents a calculation of the total interest cost savings attributable to the increase in the Company's credit rating over the years 2006 through 2018, moving from an S&P Senior Secured Debt Credit Rating of BBB- to A over that period.[586]

Witnesses for Staff and the Attorney General took issue with the Company's proposal. Consistent with prior Commission orders on incentive compensation, Ms. McMillan-Sepkoski presented Staff's recommendation that the Commission allow rate recovery only for the $988,000 projected cost associated with the operational measures of

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[584] 4 Tr 174.
[585] 4 Tr 132, 175, 253.
[586] See, e.g., 4 Tr 296-297.

the EICP.[587] Mr. Coppola recommended against rate recovery for all costs of the program, including the operational and financial measures.[588]

Specifically addressing the operational measures, Mr. Coppola objected to what he perceived as significant duplication in the measures, citing three measures in the customer service area.[589] He also objected to what he characterized as a low threshold for payout, noting that performance must be satisfactory on only four of the nine measures for employees to receive at least a 50% payout.[590] Mr. Coppola also presented data showing salary increases over the period 2009 to 2016 for officers, non-officer management, and other non-union employees.[591]

Taking issue with Mr. Shirkey's quantification of benefits related to employee safety, Mr. Coppola testified that performance trends have recently reversed and safety incidents increased 32% in the gas business and 87% in the electric business in 2018 compared to 2017.[592] Regarding distribution reliability, he cited SAIDI statistics showing an increase in SAIDI from 168 minutes in 2014 to 201 minutes in 2018. To Mr. Coppola, the recent data show "despite the incentives of the EICP, certain key measures are moving in the wrong direction."[593] Regarding the $238.2 million in annual savings Mr. Shirkey attributed to the Company's efforts to keep O&M expenses below the rate of inflation, Mr. Coppola characterized these as "not real savings but simply a 'what-if' exercise," and testified that

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[587] 7 Tr 2112-2114
[588] 7 Tr 1711-1721.
[589] 7 Tr 1714-1715.
[590] 7 Tr 1715.
[591] 7 Tr 1716.
[592] 7 Tr 1717.
[593] 7 Tr 1717.

the company is projecting O&M expenses to increase by 12% from 2017 to the end of the September 2020 projected test year.

Addressing the financial measures, Mr. Coppola objected that the plan is "too heavily weighted toward financial measures that mostly benefit shareholders and not customers."[594] Responding to Ms. Conrad's testimony that the officer plan uses the financial performance measures as a threshold, Mr. Coppola testified:

> As such, the officer group that sets the direction of the Company is far too focused on financial results. Customers do not directly benefit from shareholders achieving a higher return on their investment. Although the Company argues that happy investors will be more attracted to the Company debt and common stock issues and therefore provide a lower cost of capital, it has not offered direct proof to support this argument. The argument is particularly hollow since the Company has not issued any significant common stock in more than five years.[595]

In their rebuttal testimony, Company witnesses Conrad, Shirkey, and Maddipati largely repeated their direct testimony.[596] Ms. Conrad, responding to Mr. Coppola's discussion of salary increases, testified that the Company has "no set annual increase for employees," but reviews salary structures and trends annually.[597] Mr. Shirkey acknowledged that partial payout only requires 4 of the 9 operating measures to be met, but testified that the Company has increased the goals that must be met for full payout to 6 out of 9.[598] He also characterized the goals as aggressive.[599] Regarding the Company's SAIDI statistics, Mr. Shirkey also acknowledged "ebbs and flows in

[594] 7 Tr 1714.
[595] 7 Tr 1714.
[596] See Conrad, 7 Tr 1123-1131; Shirkey, 7 Tr 1442-1446; Maddipati; 4 Tr 252-255.
[597] 7 Tr 1130.
[598] 7 Tr 1443, 1444.
[599] 7 Tr 1444.

performance," but testified that the overall improvement trends are clear.[600] And he defended his comparison of the Company's actual O&M expenses to Consumers Price Index increases.[601] In his rebuttal, Mr. Maddipati disputed Mr. Coppola's testimony that earnings per share and operating cash flow are duplicative.[602]

In its briefs, the Company relies heavily on the testimony of these three witnesses.[603] It argues that its overall compensation philosophy and structure is reasonable, and argues that it has quantified benefits to customers from the EICP that far outweigh the proposed cost. It notes that it is only seeking cost recovery associated with a 100% payout level, although actual payouts may be higher, and that shareholders would absorb the additional costs. And it defends its request to recover the costs of the financial measures based primarily on Mr. Maddipati's testimony.

Citing Mr. Coppola's testimony, the Attorney General argues that the projected EICP expense should be rejected in its entirety.[604] To the Attorney General, the Company has not met its burden to show the plan benefits ratepayers. Citing the Commission's December 22, 2005 order in Case No. U-14347, the Attorney General argues: "To recover incentive pay, Consumers has a three-part burden of showing (1) that benefits accrue to ratepayers as a result of the bonus and incentive plans; (2) that those benefits are at least equal to the cost; and (3) exactly how ratepayers are benefited by the incentive pay

[600] 7 Tr 1445.
[601] 7 Tr 1445.
[602] 4 Tr 253.
[603] See Company Brief, p. 166-176
[604] See Attorney General Brief, p. 94-103.

plan."[605] The Attorney General argues that the Company's analysis of the benefits it attributes to the EICP does not account for other factors that influence employee performance, also objecting that some of the measures do not relate to the Company's gas operations. The Attorney General opposes the Company's request that the Commission adopt new standards based on the Indiana regulatory commission order cited by Ms. Conrad, but argues that even under that test, the Company should not be able to recover the EICP costs from ratepayers.[606]

Consistent with Ms. McMillan-Sepkoski's testimony, Staff recommends inclusion of only that portion of the Company's incentive plan costs related to the achievement of non-financial goals. Staff maintains the Commission has repeatedly held that incentives tied to financial metrics are not an allowable expense.[607]

This PFD finds that Staff has correctly presented Commission precedent on this issue.

This PFD is not persuaded any party has presented any new analysis sufficient to alter the Commission's prior findings regarding the Company's EICP. A list of these decisions is contained in Ms. McMillan-Sepkoski's testimony at 7 Tr 2113-2114 and a helpful chart is contained in Staff's brief at page 82.

While the Attorney General has raised some legitimate concerns with the Company's analysis of the benefits of the non-financial measures, the $988,000 proposed expense is small relative to the qualitative as well as quantitative benefits of the

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[605] See Attorney General Brief, p. 95.
[606] See Attorney General Brief, p. 101-103.
[607] Staff Brief, p. 82.

operational goals. And while the Company purports to identify benefits from the financial measures, Mr. Maddipati's willingness to ascribe to these financial measures, the difference in interest costs between a company with a BBB- debt rating and a company with an A rating is unsupported and unconvincing. Myriad factors contribute to the Company's current credit rating, including a series of orders from this Commission approving rate increases for the Company, as shown in Staff's chart, and its consideration in this case of approximately $370 million to $405 million in income[608] to cover the cost of the Company's debt and a return to shareholders.[609] The Company has not provided a basis to overturn the Commission's recent findings in Case Nos. U-18322 and U-18124 that financial measures primarily benefit shareholders.

Therefore, this PFD finds that Staff's proposed reduction of $2 million to the Company's $3 million request is appropriate and consistent with prior Commission decisions.

6. <u>Customer Experience and Operations Expense</u>

Company witness Miller explained that the Company has recently combined its "Customer Experience" and "Customer Operations" organizations into a single department. In describing the work performed within the department, Mr. Miller identified four key efforts: (i) Analytics and Outreach, which involves using data analysis techniques

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[608] These figures are the "income required" under Staff's filed position and the Company's position as set forth in its initial brief, as shown in the Appendix A to the Company's brief.

[609] Note that the Company's testimony regarding the appropriate capital structure to use in this case and the appropriate return on equity to set focused in part on the need to maintain the Company's credit rating. See, e.g. 4 Tr 115-116, 124-125. As Mr. Maddipati testified: "[T]he Company's improved credit ratings over the past several years, resulting in lower long-term debt rates, are due at least in part to the continued supportive regulatory environment and a reasonable authorized ROE." 4 Tr 131.

to understand and communicate with customers; (ii) Customer Interactions, which involves connecting with customers in their preferred channel (phone, text, and email) and enhancing the Company's digital offerings; (iii) Billing and Payment, which involves providing customers timely and accurate bills and consistent payment options; and (iv) Customer Programs, which involves the offering of energy products and services beyond those provided by the regulated utility.[610] A chart in his testimony at 6 Tr 1319 and in Exhibit A-97 shows the components of each area, and how each component tracks back to the prior organizational structure.

The Company's filing projected a test year expense for the new Customer Experience and Operations department of $116.3 million. This amount included $7,186,000 for Analytics and Outreach, $29,457,000 for Customer Interactions, $18,376,000 for Billing and Payments, and $61,244,000 for Customer programs.[611] The Attorney General recommended reductions to the first three expense categories totaling $6.8 million, while Staff recommended reductions to the Customer Interactions and Billing and Payments categories totaling $3.9 million. In the discussion that follows, these recommendations are addressed by expense category.

a. Analytics and Outreach

The Analytics and Outreach category involves research, advertising and other customer communications. Mr. Miller testified that this area "is responsible for understanding who the Company's customers are, how they would like to interact with

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[610] 6 Tr 1314.
[611] Company Brief, p. 177, see also 6 Tr 1319-1320.

the Company, which services they like or dislike, and the effectiveness of Company messaging around safety and reliability, billing and payment, and system improvements."[612] He further subdivided the work of this group into "customer research," "customer data and analytics," and "customer communication and outreach." He testified that the Company is requesting to double the expenses for this work from $3.6 million in 2017 to $7.2 million in the test year.

Mr. Miller testified that the $1 million of the increase would be spent on Customer Research, with four components including "customer segmentation studies," "ethnographic research," "campaign assessment," and "benchmark research." He provided the following explanation of customer segmentation studies:

> The purpose of this study is to divide the customer population into subsets that have, or are perceived to have, common needs, interests, and priorities, and then design and implement strategies to target communications to them on topics that they have indicated are important to them and their communities around safety, reliability, and affordability. These subsets can include demographics (age, gender, ethnicity, education, occupation, etc.), firmographics (industry, geography, revenue, company size, etc.), behaviors, attitudes, etc.[613]

He explained the ethnographic research to be funded:

> This is a research methodology that provides access to a deeper understanding of customer needs by studying customer behaviors in their natural environment with their customers, within their facility, etc. Through a variety of techniques, from traditional in-person observation to online and mobile-facilitated methods, the Company will use ethnography to gather more accurate insights to inform future actions.[614]

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[612] 6 Tr 1321.
[613] 6 Tr 1321.
[614] 6 Tr 1322.

“Campaign assessment” is research to “assess communications effectiveness,” while “benchmark research” covers the cost of access to third-party research, including “best practice support for capturing customer data, managing it across touchpoints, analyzing it . . . and applying those insights to business actions.”[615] No party objected to this proposed research expenditure.

Mr. Miller testified that $2.4 million of the increase would be spent on Customer Communication and Outreach, providing the following description that relates to the Company’s research on “customer segmentation” and “ethnography” described above:

> Real and near real-time communications that adapt to key moments in customer engagement. These communications are highly personalized and informed by an array of data sources, customer segmentation, ethnography, campaign effectiveness, customer engagement modeling and messaging effectiveness. These communications will be tailored to the channels that targeted customer segments prefer about topics important to them that include safety, improvements to the natural gas system occurring in their communities, and assistance programs to help them manage their energy bills. This requires broader media buys across an array of channels (tv, radio, online, social, billboard, email, print, etc.) and incremental creative to support the broader media buys, and more frequent communication touchpoints.[616]

He further testified:

> Customers are interested in a continuous, real-time dialog with their service providers as part of staying informed and understanding the storyline. One way to achieve this is through a “two-speed outreach” process in which messages dynamically evolve based on how each customer engages with the content. This process syncs campaign management with continuous storytelling. In this proceeding the Company is requesting increased funding to develop and implement a two-speed outreach process to provide customers with adaptive messages that better resonate with them and that are determined through customer research and analytics. These messages will be highly personalized and center around campaigns focused on safety

[615] 6 Tr 1322.
[616] 6 Tr 1323.

> and reliability, billing and payment, and infrastructure improvements. In order to be effective, these messages will need to be deployed through communication channels that individual customer segments prefer. The requested funding will also enable the Company to have an ongoing, dynamic conversation with all customers, which is essential to customer satisfaction as customers are demanding this type of interaction.[617]

Mr. Miller also referenced a J.D. Power survey result to show that "communication is roughly 37% of customer satisfaction."[618]

Mr. Coppola recommended that this proposed increase in funding be rejected. He explained:

> Mr. Miller presents no evidence that customers are seeking more information about how to use gas or pay their bill, or need to be informed about other items, in addition to the communication programs the Company has already in place. His testimony on page 19 regarding communication being 37% of customer satisfaction is simply a broad observation by J.D. Power, and does not justify the need for more communication. There is also no basis to conclude that the increased spending on advertising would lead to higher customers are seeking more information and communication methods than the existing methods.[619]

In his rebuttal testimony, Mr. Miller again cited the J.D. Powers study, and additionally testified:

> While good customer research and sound analytics are important parts of communicating with customers, it is equally important to have engaging information delivered in their preferred channel. For example, Deloitte found as part of a 2017 independent survey that customers want their energy provider to: be informative, offer various ways to communicate with them when they so desire, and engage with them through dynamic two-way communications.[620]

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[617] 6 Tr 1328-1329. Several of Mr. Miller's footnotes including a footnote omitted from this quotation include a reference to a third-party website with the statement "available by subscription" at that webpage. See 6 Tr 1329 at n9.
[618] 6 Tr 1329.
[619] 7 Tr 1704
[620] 6 Tr 1371.

In its brief, the Company relies on Mr. Miller's direct and rebuttal testimony, citing additional survey results he offered in his direct testimony:

> Company witness Miller identified several research results that support the Company's customer communication and outreach efforts, including the following: (i) 84% of customers say being treated like a person, not a number, is very important; (ii) 59% of customers say tailored engagement based on past interactions is very important; (iii) customers are twice as likely to view personalized offers as important versus unimportant; and (iv) 64% of consumers and 80% of businesses expect companies to interact with them in real time. 6 TR 1323-1324, 1328.[621]

The Attorney General relies on Mr. Coppola's testimony in arguing there is no basis to conclude the increased spending on advertising in this category will lead to higher customer satisfaction.[622]

This PFD finds that the Company has not justified its proposed increase in spending in this category. The Company's evidentiary presentation is highly generalized and provides no real analysis of what the additional funds will be spent on, relative to the historical test year. Accordingly, this PFD recommends the Commission accept the disallowance of $2,400,000 proposed by the Attorney General. Additionally, while no party objected to the projected research expenditures as noted above, the Commission may want to monitor the data collection and use to ensure adequate privacy protections and protections against discriminatory treatment are in place.

b. Customer Interactions

Mr. Miller explained that this expense incorporates five main areas: Digital Customer Experience, Customer Contact Center, Business Customer Care, Field

[621] See Company Brief, p. 178
[622] See Attorney General Brief, p. 85-86.

Payment Channels and Claims, and Credit and Assistance.[623] He testified that the Company's test year expense projection reflects a $6.6 million increase over 2017 levels in these areas.

i. <u>Digital Customer Experience</u>

The biggest increase is in the "Digital Customer Experience" category, for which the Company projects a $3.6 million increase above the $2.1 million expended in 2017. Mr. Miller presented a breakdown of the $3.6 million increase in a chart at 6 Tr 1332-1333.

Line item E in this chart reflects a proposed expenditure of $1 million for "[a] campaign to increase customer enrollment in electronic billing from 25% to 30% in 2020, an annual postage savings of $6.00 per customer."[624] Mr. Miller testified that currently only 25% of customers receive their bills electronically:

> The industry benchmark has been identified as 50% eBill participation, a gap that is expected to take 12 years to close by maintaining the status quo. One reason for customer reluctance to abandon paper bills is that customers are accustomed to using the paper bill as a visual reminder to make a payment. To address this issue, the Company is proposing an eBill campaign in 2019 and 2020 to encourage customers to use eBill and take advantage of available payment reminders and online features that can alleviate the reliance on a paper bill. The Company understands, however, that each customer is unique and will be reluctant to change in the absence of a compelling reason. To address this, the Company will also leverage the customer data and analytics, described in the Analytics & Outreach section of my direct testimony, to design messages that speak to the benefits most relevant to each customer – such as being environmentally friendly, enhanced security, or overall convenience.[625]

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[623] 6 Tr 1330.
[624] 6 Tr 1333.
[625] 6 Tr 1338.

Mr. Coppola and Ms. Fromm both recommend rejecting the proposed $1 million additional expense for this promotional campaign, on the basis that the Company had already achieved its 30% goal for the test year. In its initial brief, the Company agreed with the $1,000,000 reduction proposed by the Attorney General and Staff, resolving this issue.[626]

ii. <u>Customer Contract Center</u>

In the "Customer Contact Center" category, the Company's expense projection includes a $2.1 million increase over the 2017 level of $14.6 million. Mr. Miller testified that the increase in this expense involves an effort to reduce the Average Speed of Answer (ASA) for customer calls from 152 seconds to 66 seconds in the projected test year.[627] Mr. Miller testified that "customers would prefer spending their time doing something other than waiting for a call center representative."[628]

Ms. Fromm recommended reducing the projected Customer Contact Center expense by $2,077,000.[629] She testified the Company reported an ASA of 37 seconds in its Electric Distribution System Performance Standards report, which was filed on March 14, 2019, after the initial filing in this case.[630] Thus, she reasoned, the Company did not need the additional funds to achieve a goal it reportedly already met.

In his rebuttal testimony, Mr. Miller testified that the Company's requested $2 million increase in funding had two components. He testified that the first component of $1.3 million relates to a contract with a new call center vendor:

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[626] *Id.*
[627] 6 Tr 1361.
[628] 6 Tr 1344.
[629] 7 Tr 2054.
[630] 7 Tr 2054-2055

> The first component concerns a long-term call center service contract that expired in February 2019. Under the service contract, the vendor supported approximately 40% of the call center volume and the Company received a price of $3.19 per call. The $3.19 per call is approximately 50% below the current national market price of $6.39 per call. As the end date of the contract neared, however, the vendor indicated the cost per call would increase to something closer to the market price under a renewed contract. As a result, the Company issued a Request For Proposal in 2018 and selected a new vendor beginning in 2019. Although the Company negotiated a competitive price of $4.81 per call that was below the current national market price, the cost was closer to the current market price and increased the Company's call center operating costs by approximately $1.3 million annually.[631]

He testified that the smaller component concerns the ASA reduction, drawing a distinction between the live-agent answer time and the automated system answer time:

> The 37 seconds speed of answer reported by the Company in its Electric Distribution System Performance Standards represents an aggregated average speed of both live agents and the Interactive Voice Response ("IVR") system. As such, the 37 seconds cited by Ms. Fromm is not the appropriate figure when evaluating the live agent performance and requested increase in funding proposed by the Company in this case. The 152 seconds and 66 seconds referenced on page 34 of my direct testimony referred specifically to the ASA associated with live agent response times. I do not dispute that the Company improved its aggregate ASA from 78 seconds in 2016 to 37 seconds in 2018. Excluding the IVR system, however, the Company improved its live agent ASA from 152 seconds in 2016 to 77 seconds in 2018. To calculate the incremental funding required to reduce the live agent ASA by another 11 seconds, from 77 seconds to 66 seconds, the Company looked at its 2018 live agent staffing levels, its average agent costs, and the additional customer satisfaction and quality metrics the Company planned to implement in 2019.[632]

He then explained:

> As indicated on page 34 of my direct testimony, the Company is in the process of increasing the number of internal call center representatives it has to address customer questions and concerns from 222 to 280 by the end of 2019. The increased cost associated with increasing the number of

[631] 6 Tr 1362.
[632] 6 Tr 1362-1363.

live agents to achieve the ASA of 66 seconds and also improving the overall customer experience is approximately $0.8 million.[633]

Mr. Miller also offered a justification for the 66 second answer goal in his rebuttal testimony, citing "customer feedback collected through the Forrester Customer Experience Index . . . and benchmarking to other utilities." He subsequently acknowledged that the Company had reduced its live answer time to 44 seconds in 2017, but contended this was not ideal because "employees began to feel pressure to provide quick responses to customers without taking the time to completely understand and resolve their issues."[634]

Based on the Company's rebuttal testimony, Staff has withdrawn its opposition to the additional $2.1 million expenditure, and as Staff explained in its brief, now supports the increase, finding that the proposed amount of $2,077,000 is reasonable and prudent.[635]

iii. <u>Field Payment Channels and Claims</u>

Mr. Miller testified that this expense category covers the Company's payment offices, theft investigation, and claims of damage to Company and customer property.[636] He identified a proposed increase in $400,000 for the projected test year for this expense, which he attributed to the hiring of long-term contractors as Company employees beginning in 2018.

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[633] 6 Tr 1363.
[634] 6 Tr 1364-1365.
[635] Staff Brief, p. 71-7272.
[636] 6 Tr 1346.

Ms. Fromm recommended that the Commission reject the proposed $400,000 additional expenditure.[637] She cited an audit response from the Company stating that it was hiring seven full-time and three part-time employees to provide payment processing and customer service support, and attributed the need for the additional employees to increased volume of customers using the payment offices.[638] She testified that another audit response showed that the number of payments and the number of staff have been declining in recent years, which Staff correlates with an increased reliance on electronic billing as discussed above. She explained:

> Since the staffing and number of customers making payments at direct 6 payment offices is on trend with the Company's increase in e-bill enrollment and contradicts the Company's assertion that additional full-time employees are needed at these offices due to the volume of customers using them, Staff recommends the Commission reject the $400,000 O&M increase the Company has attributed to this issue.[639]

In his rebuttal testimony, Mr. Miller testified that the Company decided to convert six long-term contractors to Company employees "in an effort to retain these experienced agents," and "reduce the likelihood of turnover."[640] Mr. Miller provided a chart showing the number of Company employees and contractors in the direct payment offices over the last five years.[641] He further testified:

> DPO employees provide valuable services – such as payment processing and service support – to customers in some of the lowest-income Michigan neighborhoods. While the majority of the Company's customers are switching to alternative payment channels, the DPOs remain a primary payment channel for many of the Company's most vulnerable customers.

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[637] 7 Tr 2055.
[638] 7 Tr 2055, Exhibit S-14.3, p. 9.
[639] 7 Tr 2056.
[640] 7 Tr 1367.
[641] 6 Tr 1368, see Figure 2.

> The Company is committed to providing these customers with experienced, qualified agents focused on assisting them with their energy needs, such as finding assistance to help them reduce their energy bills. Disallowing recovery of these funds would impact not only these employees but also the level of service the Company could provide customers at the DPOs in these neighborhoods. The Company will continue to monitor and balance staffing levels in the DPOs as more customers adopt digital self-service.[642]

The Company's brief relies on Mr. Miller's testimony to support its expense projection. In its brief, Staff accepts Mr. Miller's testimony that the Company is conscious of a downward trend in customer use of the direct payment offices, but remains concerned with the projected expense increase.[643] Staff argues that Mr. Miller's rebuttal testimony identifies six full-time and no part-time contractors hired in 2018, while the audit response in Exhibit S-14.3, page 9, stated that the Company hired seven full-time and three part-time contractors. In addition, Staff argues:

> [W]hile the data in Figure 2 [of Mr. Miller's rebuttal testimony] supports an overall decrease in staffing levels between 2017 and 2018, this conflicts with the Company's request for an increase in expense. Staff understands that the cost to the Company is greater for an internal company employee as opposed to a contractor due to the loadings applied to the Company employee's salary. However, the Company does not provide any evidence to support the incremental increase of six full-time contractors becoming internal employees exceeding the decrease in cost of four fulltime contractors by a margin of $400,000.[644]

This PFD finds Staff's analysis persuasive. While Mr. Miller's chart shows staffing levels for 2014 through 2018, he did not present any information regarding projected staffing levels for the projected test year. As Staff points out, the total staffing levels shown for 2018 are below the 2017 historical test year levels, and the Company has not made any

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642 7 Tr 1367-1368.
643 Staff Brief, p. 74.
644 Staff Brief, p. 74.

showing that the overall cost associated with the 2018 staffing levels, given its composition of Company employees and contractors, is greater than the historic levels. The change in the Company's plans, from the seven full-time and three part-time contractors to be hired as Company employees as presented in the audit request, to six full-time contractors to be hired as Company employees in Mr. Miller's rebuttal testimony, is consistent with the trend of reduced staffing levels. In the absence of more specific information regarding staffing levels for the projected test year, Mr. Miller's testimony is unpersuasive that the Company's projected test year costs for payment office staffing will be greater than 2017 historical levels. Accordingly, this PFD recommends the Commission adopt Staff's proposed reduction of $400,000 to the Company's projected test year expense for this line item.

c. <u>Billing and Payment</u>

This category primarily supports Customer Payment Programs, Customer Billing, and Business Support.[645] The Company is requesting a $4 million increase over 2017 expense levels of $14.4 million for this category. Only the Customer Payment Programs and Business Support line item expense projections are in dispute.[646]

i. <u>Business Support</u>

As Mr. Miller explained, this line item covers stationery, forms, and bill postage.[647] He testified that the Company's projected test year expense of $6.8 million reflects "a modest inflation increase in O&M expenses of $0.3 million" over 2017 expense levels.[648]

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[645] 6 Tr 1349-1350.
[646] *Id.*
[647] 6 Tr 1352.
[648] *Id.*

Ms. Fromm presented Staff's recommendation that the expense allowance for this category be reduced by $422,404 to reflect reduced mailing costs due to the increase in customer participation in electronic billing.[649] She testified that while postage rates will increase in 2019 over 2017 levels, the increased participation in electronic billing should reduce the postage costs:

> To analyze the impact that both e-billing and the postage change would have on postage costs, Staff took the increase in postage of 12% ($0.55 ⁄ $0.49 × 100%) and applied that to the 2017 cost to obtain a baseline of $12,538,770. Staff then took this figure and applied the incremental percentage of customers enrolled in e-billing as a result of the Company's campaign of 9% (34% − 25%). The increase to postage and an additional 9% of customers receiving electronic bills would result in a total cost of $11,410,280 as compared to the 2017 historical actual cost ($12,538,770 ∗ 0.91). Staff is recommending the Commission disallow the difference between the Company's projected postage spend of $11,832,684 and the number generated in Staff's analysis of $11,410,280 to account for the additional success of the Company's e-bill campaign, above what was projected. This results in a downward adjustment of $422,404.[650]

In his rebuttal testimony, Mr. Miller objected to this adjustment on the ground that it was calculated based on the Company's total electric and gas postage expense, proposing a revised calculation of $206,978.[651] He also testified that postage was not the only cost increase reflected in the company's projection, asserting that collection costs for natural gas customers are also expected to increase to reflect "the frequency and number of updates provided to customers having difficulty paying their energy bills."[652] Additionally, he testified that the Company "intends" to use any cost savings Staff

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[649] 7 Tr 2056-2057.
[650] 7 Tr 2057.
[651] 6 Tr 1368-1369.
[652] 6 Tr 1369.

identified "to explore additional opportunities to increase future participation in electronic to 50 percent in the next five years.[653]

The Company's brief relies heavily on Mr. Miller's testimony as discussed above.[654] In its brief, Staff accepted Mr. Miller's revision to its proposed adjustment and recommended an adjustment to the Company's projection of $206,978 rather than $422,000. Staff argues that while it supports future efforts to increase customer participation in electronic billing, if the Commission approves the Company's request to include such costs in this line item, the Company should be required to provide a breakdown of the expenses by postage and e-bill promotion strategies in its next case.[655]

This PFD finds that Staff's comments are well taken, and that it is inappropriate for the Company to claim in rebuttal that it will use excess funds for another category of expense. As discussed above, the Company proposed and then withdrew a requested increase in funding for in e-bill promotional activities, after Staff and the Attorney General provided testimony that increased e-bill participation would lead to offsetting cost reductions. The Company also failed to present a meaningful analysis to show an increase in postage and stationery costs driven by collection activities. Thus, this PFD recommends that the Commission adopt Staff's revised adjustment of $206,978 for this

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[653] *Id.*
[654] See Company Brief, p. 182.
[655] In its reply brief, the Company asserted this reporting requirement is unnecessary because Staff will have the ability to seek the information through the audit and discovery process in the next rate case. Company Reply Brief, p. 131. This response misinterprets Staff's legitimate concern with the need to have expenses properly characterized prior to audit.

category. Additionally, the Commission should direct the Company to continue to report e-bill promotional activities in its “digital customer experience” category.

ii. <u>Customer Payment Programs</u>

The Company projected $8,300,000 in the test year for customer payment programs, reflecting a $3.4 million increase over 2017 levels. Mr. Miller testified that this increase is primarily attributable to the increase in customer use of credit cards to make a payment.[656] He testified that the percentage of customers using credit cards to pay their energy bills has increased from approximately 15% in 2017 to 20% in 2018, and is projected to increase to 25% “over the next two years.”[657]

The Attorney General opposes the $3.4 million increase in this expense category.[658] Mr. Coppola testified that this 70% increase in this expense category over the historical test year was unjustified. First, he objected that the Company had not explained how a 5% increase in customer credit card use resulted in a 70% cost increase. Second, he objected in principle to the absence of a user fee, questioning why 75% of customers should subsidize the 25% of customers using a credit card.[659]

In his rebuttal testimony, Mr. Miller asserted that the Company’s request in this case “is consistent with the level of expenses approved by the Commission in the Company’s previous gas rate case (Case No. U-18424) and in line with the projected increase in the percentage of customers using credit cards.”[660] He testified that the

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[656] 6 Tr 1349-1350.
[657] 6 Tr 1349-1350.
[658] Attorney General Brief, p. 183; see also 7 Tr 1706.
[659] 7 Tr 1705-1706.
[660] 6 Tr 1372. Note that in Case No. U-18424 the Commission approved a settlement agreement.

Company eliminated credit card processing fees to ensure a simple and consistent payment experience, and does not charge other customers a user fee for other payment methods. [661]

In her brief, the Attorney General relies on Mr. Coppola's testimony, and recommends in addition to the cost disallowance that user fees be established for credit card transactions. In its brief, Consumers Energy relies on Mr. Miller's direct and rebuttal testimony. The Company argues that its projected cost increase reflects the increase in customers using credit cards from approximately 15% in 2017 to an expected more than 25% by the end of the test year.

While the Company cites only Case No. U-18424 in support of its request, which was a settled case, in its March 29, 2018 order in Case No. U-18322, the Commission found it reasonable for the Company to waive all credit card fees for customers:

> The Commission finds that because the expense amount was not disputed; all customers benefit from the additional payment channels that Consumers now provides, including the elimination of the $6.25 transaction fee; and the Attorney General did not provide compelling evidence to support his contention that recovery of credit card transaction fees should result in an adjustment to Consumers' uncollectible expense.[662]

Nonetheless, this PFD finds that the Company did not adequately support its proposed expense increase. While it compares the projected credit card use levels at the beginning of 2017 (15%) to the projected levels at the end of the test year (25%), an approximately 66% increase, it has not established that the number of credit card transactions processed in the projected test year will be 70% greater than the number processed in

[661] Company Brief, p. 183.
[662] March 29, 2018 order, Case No. U-18322, p. 70-71.

2017. The chart in Mr. Miller's testimony shows a steep increase in the number of credit card transactions in the 2017 historical test year. Moreover, the Company did not provide a reconciliation of the projected test year credit card costs to the comparable costs in the historical test year; only if the entire amount of the historical expense had been devoted to credit card fees would the projected expense increase reflect only a 70% increase in credit card payment costs. Yet, Mr. Miller testified that this category "provides customers with a consistent payment experience across the different payment channels (mail, online, over the phone, Company payment offices, and authorized third-party retail locations) and options (checking, electronic banking, credit or debit cards, and cash)."[663]

Accordingly, this PFD recommends that the Commission adopt the Attorney General's proposed disallowance of $3,400,000 for this expense.

d. Customer Programs

This expense includes funding for non-regulated customer programs such as Home Energy Products, Industrial Products, and Compressed Natural Gas Stations.[664] The Company's customer programs provide $87,800,000 in revenue with an expense of $61,200,000. This results in a net benefit of $26,600,000 in reduced revenue requirements recognized in this proceeding.[665]

There was no objection to the Company's proposed amount. Therefore, this PFD recommends the Commission adopt the Company's projected net benefit of $26,600,000 for customer programs expense.

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[663] 6 Tr 1349.
[664] 6 Tr 1353-1357.
[665] 6 Tr 1352-1353.

7. Gas Uncollectible Expense

The Company originally projected a test year expense for uncollectable accounts of $15,423,000 based on the three-year average over the years 2015-2017.[666] Mr. Coppola and Mr. Rueckert both proposed a reduction of $4,025,000 to reflect the availability of 2018 data, which reduced the three-year average to $11.4 million for the years 2016-2018.[667] The Company does not oppose the reduction proposed by the Attorney General and Staff.[668] Therefore, this PFD recommends that the Commission adopt the Company's revised uncollectable expense of $11,398,000.

8. Injuries and Damages Expense

The Company has projected a test year gas injuries and damages expense of $1,664,000.[669] Mr. Harry testified that this category includes gas injuries and damages, internal legal costs, and workers' compensation costs.[670] He explained that the Company's projection is based on a five-year average of these expenses, using the years 2013-2017.

Mr. Rueckert testified to Staff's recommended a $365,000 reduction to this expense projection.[671] He testified that he reviewed the amounts the Company recorded in Federal Energy Regulatory Commission (FERC) Account 925, entitled "Injuries and Damages Expense." Explaining that this account is more comprehensive, he testified that

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[666] Company Brief, p. 184, see also Exhibit A-66.
[667] Company Brief, p. 185; see also Exhibit S-3, Schedule C-5.1.
[668] Coppola, 7 Tr 1708; Rueckert, 7 Tr 2209-2210.
[669] Company Brief, p. 186.
[670] 6 Tr 1269.
[671] Staff Brief, p. 80.

Staff recommends using this account to project the test year expense, resulting in Staff's proposed reduction.

In his rebuttal testimony, Mr. Harry acknowledged that the Company's injuries and damages calculation reflects only a subset of the total found in FERC Account 925.[672] He disputed that it is appropriate to use the entire account balance, explaining that one of the included items is Manufactured Gas Plant amortization expense, for which the Commission has established a detailed ratemaking treatment. He also testified that the Company has consistently used the five-year average method reflected in its filing in prior rate cases.[673]

The Company relies on Mr. Harry's testimony in its brief.[674] The Company also argues that Staff did not provide supporting calculations to show how he derived the disallowance in Schedule C5.1 of Exhibit S-3. In arguing in support of its proposed adjustment, Staff brief, Staff addressed Mr. Harry's rebuttal testimony:

> The Company's rebuttal testimony suggests that the use of account 925, which is titled "Injuries and Damages Expense," is an incorrect representation of injuries and damages expense because it includes expenses "covered in other areas of the case." … However, Mr. Harry only provided quantitative support for one. Staff submits that it would be inconsistent to rely on this account for reporting purposes and then claim it to be incorrect for rate case purposes.[675]

In its reply brief, Staff disputes that the calculation of its adjustment was not presented in its Exhibit S-3, Schedule C5.1 and in Mr. Rueckert's testimony.[676]

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[672] 6 Tr 1283.
[673] 6 Tr 1284.
[674] See Company Brief, p. 186-188.
[675] Staff Brief, p. 80.
[676] Staff Reply Brief, p. 12-13.

This PFD finds that Staff has not established that a projection based on FERC Account 925 is more appropriate than the traditional method employed by the Company, given that Account 925 includes MGP expenses, which are separately provided for in rates. For these reasons, this PFD recommends that the Commission reject Staff's proposed adjustment and adopt the Company's projected test year gas injuries and damages expense of $1,664,000.

E. Depreciation and Amortization

There were no methodological disputes regarding the depreciation and amortization expense. Instead, the principal differences between the Company and Staff result from differences in projected test year plant balances.

One issue arose regarding the MGP expense amortization. The Company originally proposed an MGP Amortization Expense of $8,858,000.[677] Staff proposed a $178,000 decrease in test year amortization expenses based on updating the 2018 actual deferred expenditures, as Ms. Edelyn explained in her testimony.[678] The Company agreed to Staff's proposed reduction in rebuttal.[679]

Since there are no methodological disputes, the final depreciation and amortization expense should be determined based on the projected capital additions through the projected test year.

[677] Company Brief, p. 188; see also A-13, Schedule C-6.
[678] 7 Tr 2040.
[679] Coker, 5 Tr 808

F. Taxes

There are no methodological disputes among the parties regarding the calculation of taxes. Mr. VanBlarcum presented the Company's calculations, including a calculation of Federal Income Tax (FIT) expense. In his testimony for Staff, Mr. Nichols recommended a reduction to FIT reflect the Company's position in Case No. U-20309 regarding the treatment of deferred tax balances in light of the TCJA.[680] In his rebuttal testimony, Mr. VanBlarcum explained that the Company had modified its position on rebuttal in Case No. U-20309, and presented the resulting adjustments to the deferred income tax balance and FIT.

The parties are in agreement that the rates set in this case should be consistent with any determinations made in Case No. U-20309.

G. Allowance for Funds Used During Construction

The Company has projected for the test year an allowance for funds used during construction (AFUDC) amount of $2,451,000.[681] No party has recommended an adjustment, and Staff has adopted the Company's figure. Therefore, this PFD recommends the Commission adopt the Company's projected allowance for funds used during construction of $2,451,000.

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[680] 7 Tr 2203-2204.
[681] Company Brief, p. 191.

H. Calculation of Adjusted Net Operation Income

Based on the foregoing discussion regarding test year operating revenue and expenses, this PFD finds that the Company's total projected net operating income for the test year should be set at $277,645,000 as shown in Appendix C to this PFD.

VIII.

OTHER REVENUE RELATED ISSUES

A. Revenue Decoupling Mechanism

The Company is proposing a Revenue Decoupling Mechanism (RDM) using the same methodology that was included in the Settlement Agreement approved by the Commission on August 28, 2018 in Case No. U-18424, with a slight adjustment to the revenues capped under the RDM.[682] Ms. Collins explains that the calculation of the RDM approved by the Commission compares the weather-normalized actual revenue realized by the Company to the approved qualifying rate case revenue by rate schedule.[683] She adds that the Company is not proposing any changes to the RDM methodology in this case.[684]

No party has raised any objection to the Company's proposed RDM. Therefore, this PFD recommends the Commission adopt the Company's proposed RDM.

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[682] 6 Tr 1065.
[683] *Id*.
[684] *Id*.

B. Investment Recovery Mechanism

In Case No. U-18124, the Commission approved an Investment Recovery Mechanism (IRM) for Consumers Energy.[685] The approved IRM allowed for the recovery of incremental 2018 and 2019 capital investment of five transmission and distribution programs. In Case No. U-18424, a similar IRM was approved as part of the Settlement Agreement agreed to by the parties.

In its direct case, the Company proposed a revised IRM with identical mechanics to the IRM approved by the Commission in Case Nos. U-18124 and U-18424.[686] However, concerns were raised by Staff and the Attorney General regarding the continuation of this mechanism. In reviewing the IRM originally requested in this proceeding, the Company determined that the requested IRM was not adequate to extend the period between rate cases.[687] As such, the Company withdrew its request for an IRM in its rebuttal testimony.

Accordingly, this PDF recommends that the Commission accept the Company's withdrawal of its IRM.

C. Excess Revenue Sharing Mechanism

ABATE requests that, if the Company uses a projected test year, the Commission implement an "earnings sharing mechanism" whereby the ratepayers would share in any "over-earnings" by the Company and thereby avoid paying excessive rates for utility services.[688] Ms. LaConte asserts that an earnings sharing mechanism is needed

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[685] MPSC Case No. U-18124, July 31, 2017 Order, pages 102-104.
[686] 6 Tr 1568.
[687] 6 Tr 1576.
[688] 7 Tr 1819.

because the Company has consistently utilized inaccurate cost projections in their projected test year, whereby the Company has consistently earned more than its authorized ROE, which in turn has resulted in higher than necessary rates for customers.[689] Ms. LaConte argues that such a mechanism would allow the Company's customers to benefit if the Company's actual costs are lower than what it projected while still providing the Company with an incentive to reduce costs.[690] Ms. LaConte offered the following example of how an earnings sharing mechanism might work: if the Company's earnings are 50 basis points above its authorized ROE, then 50% of the over-earnings would go to ratepayers and 50% to the Company, with the Company retaining 100% of any earnings that are above 50 basis, and no earnings being shared if the Company earns below its authorized ROE.[691]

Mr. Coppola asserts that if the Investment Recovery Mechanism (IRM) is continued as proposed by the Company, the Commission should implement a "simple earnings sharing mechanism" which would refund to customers 50% of the excess earnings over a weather-normalized ROE threshold, with the threshold set at 25 basis points above the Company's authorized ROE.[692] Such a mechanism would give sufficient incentive to the Company to earn its authorized ROE and retain a significant portion of any excess earnings resulting from realized cost savings, while also benefitting customers

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[689] *Id*.
[690] 7 Tr 1819, 1820.
[691] 7 Tr 1819. The entirety of Ms. LaConte's testimony regarding an excess revenue sharing mechanism is found at 7 Tr 1819-1820.
[692] 7 Tr 1725.

from any excess earnings resulting from the implementation of IRM and other excess cost recovery resulting from any inflated cost forecasts in the normal ratemaking process.[693] Presumably because the Company in its rebuttal abandoned its request for continuation of the IRM, the Attorney General does not address its proposed earnings sharing mechanism in its briefs.

The Company opposes ABATE's proposed excess revenue sharing mechanism, asserting that it is both unlawful and unreasonable. Specifically, the Company argues that the proposed excess revenue sharing mechanism constitutes "unlawful retroactive ratemaking" contrary to the decision in *Michigan Bell Telephone v. MPSC*, 315 Mich 533, 24 NW2d 200 (1946).[694] The Company also quotes from a court decision from another state which suggests such a mechanism might violate due process provisions of state and federal constitutions.[695]

The Company also asserts that ABATE's proposed excess revenue sharing mechanism is unreasonable. Mr. Maddipati asserts that Ms. LaConte's proposal constitutes a recommendation for "a solution to a problem that doesn't exist", as her claim that the Company is consistently over-earning is "misleading, false, and reflects a lack of understanding by Ms. LaConte regarding the relationship between earned and authorized ROE's."[696] Mr. Maddipati acknowledges that the Company's earned ROE has varied, but

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[693] 7 Tr 1726.
[694] Company brief, p. 194-198.
[695] Company brief, p. 198-199.
[696] 4 Tr 245.

points to Staff's Exhibit S-4 which "demonstrates that the Company's earned ROE for its gas business in each of the last three years was less than the authorized amount".[697] Mr. Maddipati asserts that the excess revenue sharing mechanism is unfair as the Company's investors "bear all the risk of under-earning with limited upside", and it discourages the Company from seeking cost savings initiatives "since any potential earnings that would be achieved would immediately be returned to customers".[698] Finally, Mr. Maddipati asserts that Ms. LaConte does not perform an analysis on the impacts of her proposed mechanism on the Company's credit or its ability to attract capital, and argues that her proposal would allow all returns above the authorized ROE to be shared, yet it provides no mechanism to share downside risk in the event the earned ROE were lower than authorized, which is inconsistent with the assumptions of the CAPM and DCF model. [699]

This PFD finds that ABATE's proposed excess revenue sharing mechanism should not be adopted as the record in this case is insufficient to allow the Commission to properly assess whether an excess revenue sharing mechanism is reasonable, prudent, and otherwise allowed in this case. As noted, Ms. LaConte's testimony regarding the implementation of an excess revenue sharing mechanism is cursory at best, with no analysis of how such a mechanism might impact the Company's credit rating and no discussion of how such a mechanism might relate to the ROE projection models

[697] 4 Tr 247.
[698] *Id.*
[699] 4 Tr 249-250.

employed by the parties in this case. Mr. Coppola's testimony regarding such a mechanism is similarly limited and now apparently abandoned with the Company's withdrawal of its request to continue the IRM. The Staff does not offer any testimony or argument in this case regarding implementation of this mechanism. Finally, while Mr. Maddipati offers a more comprehensive explanation of his reasons in opposition to Ms. LaConte's proposal than she offers in favor of it, his testimony similarly is somewhat limited and does not include much independent support for his position. For example, while he points out that Ms. LaConte does not offer any assessment of how this mechanism might impact the Company's credit rating, Mr. Maddipati does not offer any independent support for his implication that such a mechanism would in fact adversely impact the Company's credit rating or the Company's ability to attract capital.

Similarly, the argument and authorities offered by the Company and ABATE on the question of whether an excess revenue sharing mechanism would be illegal in this case are cursory at best. While the Company does cite and quote from the *Michigan Bell* decision and another case which follows *Michigan Bell*, it does not mention let alone discuss the possible application of other, later Michigan Supreme Court, Court of Appeals and Commission decisions which allow refunds to customers of collected revenues contrary to *Michigan Bell*.[700] In addition, the Company's due process argument does not

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[700] *See, e.g., Northern Michigan Water v. MPSC*, 381 Mich 340, 161 NW2d 584 (1968); *Building Owners and Managers Association v. PSC*., 424 Mich 494, 383 NW2d 72 (1986); *Great Wolf Lodge of Traverse City v. PSC*, 489 Mich 27, 799 NW2d 155 (2011); *Michigan Bell Telephone v. Public Service Commission*, 85 Mich App 163, 172, 270 NW2d 546 (1978), *lv. denied*, 405 Mich 822 (1979); MPSC Case No. U-20316, Order, January 18, 2019.

even cite any Michigan court or Commission decisions which apply a due process analysis.[701] Finally, ABATE's legal argument makes no reference to any legal authority at all; rather, ABATE merely questions how the Company can argue that this mechanism would be illegal in this case given that the Company advocated for a similar mechanism in another recent rate case (U-20134).[702] As the parties have not offered any comprehensive legal argument, this PFD and the Commission cannot fairly address the issue.[703]

Accordingly, this PFD recommends that ABATE's request be denied.

D. Request To End O&M Expenses Adjustment

The Company requests that the Commission end the requirement set forth in its June 9, 2016 Order in Case No. U-18002 to report and adjust its O&M expenses for the estimated billing adjustment in future rate cases. As Mr. Crews explains, with the Company's actions to read more meters, reduce estimated reads, and with the full deployment of AMI/Smart Meters and AMR, "these issues and the expenses are de minimus and should not be a requirement to report in future general rate cases."[704] He

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[701] Company brief, p. 198-199.
[702] ABATE Reply Brief, p. 12-14.
[703] *In re Application of Indiana Michigan Power Company*, 275 Mich App 369, 376, 738 NW2d 289 (2007)("A party may not simply announce its position and then leave it to this Court to discover and rationalize the basis for its claims. Furthermore, a party may not give an issue cursory treatment with little or no citation of supporting authority.").

[704] 6 Tr 1151.

adds that the Company has continued to report annually on its estimated billing practices and the improvements made in these practices in Case No. U-18002.[705]

No party has raised any objection to the Company's proposed discontinuance. Therefore, this PFD recommends the Commission accept the Company's proposal to discontinue its reporting and adjusting its O&M expenses for the estimated billing adjustment.

IX.

REVENUE DEFICIENCY SUMMARY

Based on the rate base, cost of capital, and adjusted net operating income as presented above, the Company's revenue deficiency for the projected test year is estimated to be $127,483,000 as shown in Appendix A to this PFD.

X.

COST OF SERVICE, RATE DESIGN, AND TARIFF ISSUES

A. Cost of Service

Ms. Davis testified that a cost of service study (COSS) "quantifies the utility's cost to serve each rate class" based on cost causation.[706] Ms. Davis explained the three steps in the development of a COSS as follows:

> The first step is functionalization, followed by classification, and finally allocation. Cost functionalization involves the identification and separation of plant and expenses into specific categories based on the activity or "function" that each cost is incurred to provide/support. Consumers Energy's functional cost categories are Transmission, Distribution, and Storage. Cost classification, the second step, involves the categorization of functionalized costs into demand, customer, and energy components

[705] *Id.*
[706] 6 Tr 1161.

> according to the primary cost driver(s). The final step is cost allocation. Allocation assigns costs to each customer class using a variety of factors that correlate to the identified cost drivers. Common allocation factors include the number of customers, throughput/usage, and peak consumption among others. This process is relatively standard across the utility industry and supported by the National Association of Regulatory Utility Commissioners ("NARUC") Gas Distribution Rate Design Manual [NARUC Manual].[707]

The Company presented two COSSs. According to Ms. Davis, COSS-Version 1[708] uses the methods previously approved by the Commission, including updates consistent with the rate case filing requirements and changes that were prescribed in the settlement agreement in Case No. U-18424. She testified that COSS Version 2[709] includes the same financial information and data contained in Version 1, along with proposed updates and refinements to the COSS method to better reflect cost-causation.

Ms. Davis testified that there were only minor changes to cost functionalization in COSS-Version 2, specifically noting changes to the functionalization factors applied to the MGP amortization expense and the cash component of working capital. With respect to classification and allocation, Ms. Davis testified that the Company performed a minimum size study[710] to classify and allocate a portion of distribution main costs as customer related.[711] In addition, the Company proposed to allocate working gas on the basis of throughput sales.

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[707] 6 Tr 1162.
[708] Exhibit A-16 (EAD-1) Schedule F-1.
[709] Exhibit A-16 (EAD-2) Schedule F-1a.
[710] "A minimum size study compares the cost to build the utility's distribution system using the smallest, least-expensive pipe presently being installed (i.e., 2 inch plastic main) to the actual system parameters and cost. The minimum size system represents the portion of the system installed to provide customers with system access without any consideration of peak demand (i.e., customer-related)." 6 Tr 1172-1173.
[711] 6 Tr 1169-1171.

Mr. Isakson presented Staff's COSS, which incorporates the Company's use of peak design day for average and peak (A&P) storage allocators, allocation of uncollectibles based on net write-offs, allocation of MGP expense on total plant-in-service, and allocation of customer deposits on revenue including cost of gas.[712] Mr. Isakson testified that Staff's COSS "does *not* incorporate the following Company-proposed changes from its COSS Version 2: allocation of the cash component of working capital on service revenue, allocation of working gas on sales throughput, and classification or allocation of any distribution main costs as customer-related."[713] Mr. Isakson also testified that Staff's COSS allocates credits related to the TCJA Credit C calculation and applied specific IT adjustments to the COSS.[714] Consistent with the latter adjustment, Mr. Isakson recommended that:

> In the future, when the Company submits its COSS in a rate case, projected test year spending should be reflected in the exact, or exact as possible, accounts or COSS categories to which it will be recorded, rather than on how spending occurred in the past. When historic composition is used for test year spending and adjustments, then any change in one account necessarily affects all others. If spending in transmission, storage, distribution, etc. changed by the same proportion to the whole every year, then the COSS could appropriately be simplified as it is presently. In reality that is likely not the case, and relying on historic composition for test year spending creates a disconnect between cost recovery and cost causation. The Commission should require the Company to file a more comprehensive COSS in its next case that includes the direct impact of proposed spending in the appropriate COSS accounts or categories, rather than on historic spending composition.[715]

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[712] 7 Tr 2064-2065.
[713] 7 Tr 2065. Emphasis in original.
[714] In rebuttal, Ms. Davis adopted several Staff adjustments to the COSS, including Staff's proposed treatment of the Calculation C amortization credit and its recommendation to continue using O&M to allocate the cash component of working capital. 6 Tr 1186. COSS Version 2, with these changes, is set forth in Exhibit A-148. In light of the parties' agreement or acquiescence on these specific issues, these adjustments are adopted and are not addressed further in this PFD.
[715] 7 Tr 2069-2070

As the Company and Staff relate in their respective briefs, the only remaining areas of dispute related to the COSS are: (1) the Company's proposal to use a minimum size study to allocate part of distribution main costs using a customer allocator; (2) the allocation of working gas based on throughput; and (3) Staff's proposal to require a more detailed COSS in the company's next rate case filing. These issues are addressed *ad seriatim*.

1. <u>Minimum Size Study and Allocation of Distribution Main Costs</u>

Ms. Davis explained that the Company classifies individual costs as customer, demand, or energy related,[716] or it uses some composite of these costs.[717] Ms. Davis added that in classifying each cost, she considers the nature of the cost, cost drivers, industry best practice, and the NARUC Manual. Ms. Davis pointed to gas distribution main as a cost item where there is more than one driver. To arrive at the correct classification factor, the Company performed a minimum size study which, according to Ms. Davis, demonstrates that 44.23% of distribution main costs are customer-driven, while the remaining 55.77% of costs are demand related.[718]

Ms. Davis testified that the investment in distribution main is a function of both the diameter of the main and its length. "On the first item, the . . . diameter of the main is

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[716] Customer-related costs are those costs "that are incurred to provide system access to a customer regardless of the customer's consumption level[,]" whereas a demand factor "is used to classify costs that are driven by, or related to, peak demand." 6 Tr 1167.
[717] 6 Tr 1165-1166.
[718] Exhibit A-57.

influenced by customer peak demand; a larger peak demand requires larger diameter main to ensure the Company can meet its peak load. The second item, the length or quantity of the main installed, is driven by the need to connect customers to the system."[719]

To support her contention that the cost of distribution main is, in part, customer-related, Ms. Davis analyzed customer and distribution main data from 1984-2017, performing a regression analysis that she asserted demonstrated a statistically significant relationship between the number of customers and the feet of main required. According to Ms. Davis, each customer added to the system requires an additional 93 feet of main.[720] Ms. Davis then described the steps involved in the minimum size study used to determine the ratio of customer- to demand-related costs, and she presented the results in Exhibit A-57.

Ms. Davis further testified that a number of utility commissions across the country have found that gas utility main is both customer- and demand-related, highlighting the fact that in recent contested gas cases from the Midwest, 11 out of 12 decisions relied in part on studies that classify a portion of distribution main as customer-related.[721]

Mr. Pollock supported the Company's proposal, citing language from the NARUC Manual as well as Act 725, an Arkansas statute that requires the allocation of a portion of distribution main costs based on the number of customers, and decisions from the Connecticut Public Utilities Regulatory Authority, and the New York State Public Service

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[719] 6 Tr 1170.
[720] Id. at 1171, Figure 1.
[721] 6 Tr 1172

Commission.[722] Mr. Lyons also supported the Company's proposal to classify distribution mains as customer- and demand-related, quoting a portion of the NARUC Manual and Ms. Davis' testimony.[723] Mr. Lyons testified that, in general, distribution mains provide customers with access to the gas system, and therefore customers are a driver of main cost.

Mr. Isakson testified that while Staff agrees with the Company's claim that the diameter of distribution main is demand-related, it disagrees that the driver of the length of main is customer-related. According to Mr. Isakson:

> Investment in distribution mains do not vary directly with customer count. That is, the marginal customer (i.e. each additional customer beyond the first) does not cause the company to build more distribution main line, only the first customer does. The marginal customer would, however, require a new service lateral, which is customer-related and recovered through the customer charge per my later discussion on the subject. For example, if a distribution main is built to serve one customer but no further main is built, then the main could be considered customer-related. In this example the existence or non-existence of the main is directly incumbent on the existence or non-existence of the single customer. If, again for example, a new distribution main is not required until customers attached to that main reaches one thousand, then the distribution main could be classified as thousand-and-first-customer-related. Further, if customers decide to leave the system, then the Company will still have invested in distribution main for those customers. If the demand of the remaining customers increases such that total demand returns to the previous level, but with fewer customers, the investment in distribution main change does not change, because distribution mains are built and maintained to serve the natural gas demand of customers, and not to serve a specific number of customers.[724]

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[722] 7 Tr 1848-1850, quoting NARUC Manual p. 28; *DPUC Review of Natural Gas Companies Cost of Service Study Methodologies*, Docket No. 99-03-28, Decision at 9-10. (Aug. 2000); and *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric and Gas Service, et al*, Case Nos. 08-E-0887, 08-G0888, 09-M-0004, Order Adopting Recommended Decision with Modifications at 46-48 (June 2009).
[723] 7 Tr 1918, quoting NARUC Manual p. 22.
[724] 7 Tr 2073-2074.

Mr. Isakson quoted the NARUC Manual, highlighting language that states that, with respect to distribution main, “the inclusion of such costs [as customer-related] can be controversial[,]”along with the statement that “mains and service are installed to serve demands of the consumers and should be allocated to that function.”[725] Mr. Isakson testified that the NARUC Manual does not recommend one method over the other.

Mr. Isakson took issue with the Company’s regression analysis, noting that although there does appear to be a correlation between the number of customers and length of main, “[t]he Company’s use of ordinary least squares regression on time series data (in this case annual data) can run into problems with autocorrelation and thus produce spurious results when observing for either correlation or causation.” Mr. Isakson explained:

> Autocorrelation occurs when data is correlated to itself in previous periods, which are called lag periods in econometrics. Autocorrelation violates one of the assumptions of ordinary least squares regression because, “Put simply, the classical model assumes that the disturbance term relating to any observation is not influenced by the disturbance term relating to any other observation.” If the basic assumptions of the technique used for analysis are violated, then the results of that analysis are biased and unfit as evidence.[726]

Mr. Isakson testified that Staff calculated the Durbin-Watson statistic for the Company’s regression analysis, and he presented results indicating autocorrelation in the Company’s analysis. In addition, Mr. Isakson offered a residual plot of the company’s regression, which provided “[m]ore evidence of autocorrelation.”[727] Mr. Isakson

[725] 7 Tr 2075, quoting the NARUC Manual, p. 22-23.
[726] 7 Tr 2076 quoting, Damordar N. Gujarati, *Basic Econometrics*, second edition, p 354.
[727] 7 Tr 2076-2077.

concluded that "[t]he Company's statistical regression analysis does not support the argument that distribution mains should be classified as customer related, because the Company's analysis contains statistical flaws that render it invalid."[728]

Mr. Isakson testified that isolated decisions from other jurisdictions provide limited information, and that if the Commission were to consider decisions from other utility commissions, it would be necessary to examine the reasoning behind those decisions. Quoting orders from the Minnesota Public Utilities Commission and the Illinois Commerce Commission, he opined that these orders demonstrate that there is "still active debate, and even potential changes of course, on the issue."[729]

Mr. Coppola testified that the Company's proposal would result in a $40 million shift in costs to residential customers, an increase of 4.7%.[730] According to Mr. Coppola:

> Currently, the cost of distribution mains is allocated using an Average and Peak ("A&P") usage allocator by customer class. The A&P allocator considers both the average gas usage of the mains during the year and also the peak demand from the utilization of the mains during the highest demand periods of the year. Given that residential customers as a group have higher peak demand than other customer classes, and large commercial and industrial customers have a more leveled flow of gas throughout the year, which is captured in the average usage, the use of the A&P allocation factor has been deemed reasonable and has been generally accepted by regulatory commissions.[731]

Mr. Coppola testified that in this case, the Company proposes to replace the A&P usage allocator with a customer allocator, under the premise that distribution main is significantly built to serve residential customers. He opined that the Company's evidence

[728] Id. at 2078.
[729] 7 Tr 2079.
[730] 7 Tr 1726-1727.
[731] Id. at 1727.

was subjective and not sufficiently compelling to make the change the company proposes. Mr. Coppola pointed out that, "[t]he distribution system is not specifically segregated between residential, commercial and industrial customers. Residential and small commercial customers often are located in close proximity to each other and share the same gas mains."[732]

Mr. Coppola also disputed the weight of Ms. Davis' evidence concerning Midwestern jurisdictions that have moved toward a customer-based allocation of distribution main costs. He testified that there are hundreds of gas utilities in the United States, and the small number cited by Ms. Davis is not significant. Consistent with his testimony, Mr. Coppola recommended that the Commission retain the current A&P allocation method for distribution mains.[733]

In rebuttal testimony, Ms. Davis disagreed with Mr. Isakson and Mr. Coppola, noting that the Company was not proposing to allocate all distribution main costs based on customer count, but rather seeks to "take a balanced approach and consider both customer and demand as contributing factors."[734] Ms. Davis added:

> I disagree with Staff that the entire network of distribution main—roughly 28,000 miles—can be attributed exclusively to the first, last or any one customer added to the system. The Company's distribution system is an extensive network of main, built out over the last century to connect 1.8 million customers all across Michigan. That network has grown (and continues to grow) over time to reach and attach new customers to the system. Basing the cost assignment for all 28,000 miles of pipe on the needs of a hypothetical marginal customer is not appropriate. . . . The COSS is tasked with assigning costs to all 1.8 million customers, not just the customer on the margin. Therefore, the relevant question for cost of

[732] Id. at 1728.
[733] 7 Tr 1728-1729.
[734] 6 Tr 1191.

> service is how the Company's 1.8 million customers contributed to and are responsible for the cost of the system that was built to serve them.[735]

Ms. Davis reiterated that peak demand is not the only factor that directly affects gas main investment, noting that the size of a customer's demand does not affect the number of feet of main required to attach a customer. Ms. Davis also characterized Staff's hypothetical, regarding the relationship between the investment in main and customer gains or losses, as unpersuasive.[736]

In response to Staff's criticism of the Company's regression analysis, Ms. Davis testified that, "[a] finding of correlation can be made without regression analysis by simply calculating the correlation coefficient between the number of customers and footage of main, which is .9909. Perfect positive correlation is 1."[737] Ms. Davis pointed to a graph that showed that, in 2017, the company added 9,700 customers "which required the installation of 1.3 million feet of service line and 1.2 million feet of main. That works out to 134 feet of service and 124 feet of main per customer."[738]

In rebuttal to Staff, Mr. Lyons reiterated his support for the Company's proposal for three reasons: (1) classification of distribution main is consistent with how the system is designed; (2) Staff's position that density influences main footage is not inconsistent with the Company's claim that the length of main installed is driven by the need to connect customers to the system; and (3) although the Company's analysis demonstrates autocorrelation, this problem can be addressed through other statistical methods that

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[735] Id. at 1192.
[736] Id at 1193.
[737] Id at 1194.
[738] Id. at 1195.

would correct for the autocorrelation error.[739] In his rebuttal testimony, Mr. Pollock testified that simply because the addition of one customer to the system does not cause the Company to increase distribution main length, this does not mean that the number of customers and length of main are not related. “Because distribution mains investment is long term in nature, it follows that the application of cost-causation principles should similarly be based on long-term and not short-term relationships.”[740] Mr. Pollock added that the presence of autocorrelation in the data may mean that there are other factors that drive the addition of distribution main construction.[741] Finally, Mr. Pollock pointed out that although the A&P allocation factor is a long-standing method used in the COSS for gas mains, the use of this method substantially under-allocates costs to residential customers and over-allocates costs to large transportation customers.

The parties’ briefs generally tracked the testimony of their respective witnesses. The Company, ABATE, and LBWL-MSU urge the Commission to reject Staff’s and the Attorney General’s criticisms of the Company’s regression analysis and minimum size study, as well as their recommendation to continue to use the A&P allocation factor for distribution mains. The Company provides additional hypotheticals that, it claims, demonstrate that main is in part customer-related. With respect to purported flaws in its regression analysis, the Company continues to maintain that correlation can be

[739] 7 Tr 1929-1930.
[740] 7 Tr 1884.
[741] Id.

demonstrated by means other than regression analysis through calculating the correlation coefficient between the number of customers and footage of main.[742]

In response, Staff points out that because distribution mains are not reduced in size or removed when customer leaves the system, as the Company admits, it is an additional reason not to classify mains as customer-related. Staff asserts: "if those costs only vary with increases and not decreases in customer count in the short- and/or long-term, then they are not customer-related[,]" adding, "[u]ltimately, the Company invests in distribution main only to serve the demand of and use of the system by customers, and not to simply connect the customer to the system."[743]

Staff contends that the Company did not rebut the concerns about autocorrelation in its regression analysis, and instead it pointed to an alternative test of correlation. However, the alternative suffered from the same flaws that the regression model did and was therefore also invalid. Staff notes that LBWL-MSU agreed that autocorrelation was present in the Company's regression analysis; it suggested a solution, but it failed to apply that solution.[744]

This PFD finds that, because the Company's statistical analyses were seriously flawed, and thus did not demonstrate a correlation between customer number and feet of main, the use of a minimum size study to allocate the cost of distribution main is unsupported and should not be approved. Consistent with this dispositive finding,

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[742] Consumers initial brief, p. 210, citing 6 Tr 1194.
[743] Staff Reply Brief, p. 18-19.
[744] Staff Brief, p. 94.

additional arguments concerning the NARUC Manual, the purported "purpose" of the distribution system, and decisions in other jurisdictions are moot.

2. Allocation of Working Gas

The Company proposes to allocate the working gas portion of gas in storage on the basis of sales throughput, reasoning that, because the Company purchases working gas for its full-service customers, these costs should not be allocated to transportation customers who do not use or benefit from that gas.[745] Ms. Davis pointed out that working gas is currently allocated on the basis of the storage allocator, which is offset by an End User Storage Credit.[746] Ms. Davis testified that the Company's proposed method is more accurate and transparent than the storage allocation/offset method.[747]

Mr. Isakson objected to the company's proposal, contending that transportation customers do, in fact, use working gas because, "gas cares not where it goes, nor does it follow the Company's strict instructions to only be delivered to or used to the benefit of sales customers."[748] Consistent with his testimony, Mr. Isakson stated that Staff supports the current allocation method for working gas.

In rebuttal, Ms. Davis agreed that the physical gas in the company's system contains a mix of sales gas and stored transportation gas; however, the apportionment of the physical gas is not at issue here. According to Ms. Davis, "the working gas that is at issue in this case is what is included in the Company's revenue requirement (i.e. what is

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[745] 6 Tr 1178.
[746] Id.
[747] Id.
[748] 7 Tr 2071.

recorded on the Company's balance sheet and included in working capital)."[749] Ms. Davis further clarified:

> The Company does not own or finance the gas injected into storage by transportation customers - it is solely their responsibility. Accordingly, the gas purchased by transportation customers does not appear on the Company's balance sheet or in the revenue requirement being allocated in the COSS. Mr. Isakson's point that transportation customers can get credits for decreased storage utilization via the [authorized tolerance level] ATL credit is not relevant because it fails to recognize the distinction between the costs associated with providing storage s*ervice* (which transportation customers use) and the costs for acquiring Gas Cost Recovery gas *commodity* (which transportation customers do not use). The discounts associated with decreased storage utilization via the ATL credit are meant to address the fact that, at lower storage utilization levels, transportation customers are using less of the service and should pay for less of the service. However, at any ATL subscription level, the cost of working gas purchased for sales customers is currently embedded in the rates everyone pays, including transportation customers who do not use it. If the Commission adopts the Company's proposal to allocate working gas on sales throughput, only sales customers would be responsible for these costs.[750]

Mr. Pollock also took issue with Staff's proposal, noting that under Mr. Isakson's "fungibility theory," bundled customers could also be using gas that was bought and stored for transportation customers, without any mechanism for compensating transportation customers for the use of their gas.[751]

The parties' briefs rely on the testimony of their respective witnesses. The Company emphasizes that its method is more transparent and more accurate with respect to cost assignment. Staff maintains that the cost of working gas should be

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[749] 6 Tr 1188.
[750] 6 Tr 1188-1189.
[751] 7 Tr 1891-1892.

allocated based on the "*use* of the asset, rather than its origin."[752] And because all stored gas can be used by all customers, then the storage allocator is appropriate.

This PFD agrees with the Company and ABATE that the issue here does not involve the behavior of the gas commodity.[753] As the Company explains:

> While it may be true that the physical gas supplied to the system on behalf of transportation customers might ultimately be exchanged on a like-kind, one-for-one basis with other gas on the Company's system before delivery to the customer, neither the transportation customers' gas nor such a conceptual transaction are ever recorded on the Company's books and are not a part of the working capital dollars that are being allocated.[754]

Accordingly, the Company's proposal, which this PFD finds to be a more transparent and accurate method to allocate the cost of gas in storage, should be approved.

3. <u>Cost of Service Study Cost Allocation Detail</u>

As noted above, Staff recommends that, in future rate cases, the Company provide a more detailed COSS that assigns costs to the most specific accounts of COSS categories possible. Staff explains:

> Currently, test-year costs are allocated based on the historic compositions of broad cost categories. For example, the Company's most recent annual report reports total O&M expenses are 53% distribution-related, 12% storage related, and so on. Next, in a typical Company test-year COSS, 53% of the total adjustments to O&M are then recorded as distribution related, and likewise those total adjustments are recorded as 12% storage-related. Essentially, the historic composition of O&M expense is used as a functional allocator for the total test-year O&M expense. (7 TR 2067.) When Staff makes adjustments to the Company's test-year capital and O&M, some of those adjustments are specific to certain accounts. (7 TR 2068.)

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[752] Staff Brief, p. 103.
[753] *See,* September 8, 2016 order in Case No. U-17929, p. 40-42, for a discussion of the diffusive property of gas.
[754] Company Brief, p. 207.

> For example, adjustments to capital costs of meters can be directly linked to the "services and meters" account. However, under the Company's COSS paradigm that adjustment would be made to total distribution plant, then allocated to the services and meters account based on its proportion to all other distribution plant. In order to most accurately allocate costs, Staff recommends the Company do away with its reliance on historic composition of costs in the COSS where actual spending can be tied directly to COSS accounts. (7 TR 2070.) In the interim, Staff proposes to make direct adjustments to the COSS where feasible. (7 TR 2069.)[755]

In response, the Company avers that Staff's proposal is not practicable at this time. The Company contends that it would have to replace its current system for operational planning, which is based on projects or program areas, to one based on FERC accounts. The Company added that although Staff's recommendation might improve the precision of certain cost allocations, this improvement may not be justified by the cost to replace the company's current planning system. The Company therefore recommends that the current method for allocating costs be retained until the feasibility, timing, costs, and benefits of Staff's proposal can be determined.[756]

Staff provides an alternative proposal, recommending that the Commission "direct the Company to explore alternative methods of performing its revenue requirement calculation and COSS to reduce reliance on historic composition of costs. If that happens, the Company should consult with Staff to examine these alternatives to ensure appropriate test-year cost allocation."[757]

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[755] Staff Brief, p. 104-105.
[756] Company Brief, p. 210-211.
[757] Staff Brief, p. 105. Staff also points out that the use of an historical test year would greatly improve the accuracy of the COSS. Issues concerning historical versus projected test years are discussed in detail *supra*.

This PFD finds that, although Staff's primary proposal has merit, absent additional information concerning the benefits to be obtained from greater precision in the COSS, as well as the implementation cost, the proposal should not be approved at this time. However, Staff's alternative recommendation, namely that the Company should evaluate opportunities to reduce reliance on historical costs in its COSS, is reasonable. This PFD therefore recommends that the Commission direct the Company to consult with Staff and provide a report in its next rate case on options for better matching the COSS with test year spending. The report should include costs and benefits associated with alternative courses of action and implementation timelines.

4. Summary

This PFD recommends that the Commission adopt Staff's COSS, set forth in Exhibit S-6, F-1, modified with the Company's change to the allocation to working gas based on throughput sales discussed above.

B. Rate Design

The Company and Staff provided rate design proposals that were generally consistent in approach, with the parties proposing to collect class revenue requirements in accordance with their respective COSSs. Mr. Revere testified that as a result of past rate case settlements that did not reflect cost-of-service increases, Staff recommends limiting the increase for Rate GS-3 and Rate XLT to 30% or less "as such an increase reasonably balances the need to limit the impact of rate increases to prevent rate shock with the need to limit the impact on other customers of settlements not reflecting the cost to serve."[758]

ABATE recommended that any increase for Rate XLT should not exceed the system-average increase. According to Mr. Pollock, "the Rate XLT class is providing an above-average rate of return at present rates."[759] In response, Staff maintains that its COSS does not result in an above average rate of return for Rate XLT, "and . . . the realities of a breakeven-based rate design make such a position untenable."[760] The Company agreed with Staff's position.

This PFD finds that ABATE did not provide any support for its position whereas Staff's COSS demonstrates that its rate design targets are reasonable. That said, as the Company indicates, "rates approved by the Commission should be designed so that the revenue recovered from each customer class reflects the final Commission-approved revenue requirements allocated to each rate class based on the test year COSS authorized by the Commission."[761] The disputes related to rate design are addressed below.[762]

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[758] 7 Tr 1958. Mr. Revere's specific recommendations for each class are listed at 7 Tr 1957.
[759] 7 Tr 1858.
[760] Staff Brief, p. 113, citing 7 Tr 1961.
[761] Company Brief, p. 215.
[762] The Company agreed to Staff's recommendation regarding an annual report detailing waivers for unauthorized gas usage charges. This issue is considered settled and will not be addressed further in this PFD.

1. Customer Charges

a. Residential Customers

Through the testimony and exhibits of Ms. Collins, the Company initially proposed to increase the monthly customer charge for the residential class from $11.75 to $26.34, with the remainder of the costs collected through a volumetric charge.[763] The Company also proposed an increase to the Excess Peak Demand Charge for Rate A and A-1 customers by a percentage equal to the increase in the customer charge.

Mr. Isakson testified that Staff was recommending no increase to the residential customer charge. Mr. Isakson explained that, consistent with Commission guidance, Staff only includes costs directly associated with supplying service to the customer (i.e., meters, service laterals, customer billing), were included in the Staff's calculation.[764] Mr. Coppola also disagreed with the Company's proposal, observing that "[t]he proposed change from $11.75 to $26.34 per month represents an increase of 125%. Such a large increase could cause rate shock to customers in smaller households who use less gas than the average customer[,]" adding that higher fixed monthly charges tend to discourage energy efficiency.[765] Mr. Coppola recommended that monthly residential customer charges remain at $11.75, or, if the Commission decides an increase is warranted, that the increase be no more than $1.00.[766]

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[763] 6 Tr 1060, Exhibit A-16.
[764] 7 Tr 2081; Exhibit S-6, Schedule F-1.1.
[765] 7 Tr 1729.
[766] Id. at 1730.

In rebuttal, Ms. Collins explained that the COSS updated in rebuttal supports a residential customer charge of $21.66 per month. Ms. Collins testified that although this is a significant increase, there are benefits to collecting costs through higher fixed charges. According to Ms. Collins, higher fixed charges mean lower volumetric charges, which is particularly advantageous for more vulnerable customers during winter when gas bills are highest. Nevertheless, in light of concerns about rate shock, Ms. Collins recommended a more gradual increase in the customer charge, from $11.75 to $15.00 per month.[767]

This PDF agrees with Staff and the Attorney General that an increase in the residential customer charge is not supported by the record. Moreover, as Mr. Isakson testified, the Commission has consistently recognized that the costs to be included in the monthly service charge are only those items that are required to connect the customer to the system – namely, meters, meter reading, customer account services, and service lines. And, while it is true that higher fixed charges equate to lower volumetric distribution charges, the Company's proposal does not affect the cost of the commodity, which is a substantial portion of a customer's monthly bill during the winter months. Thus, shifting distribution charges from volumetric to fixed would not have as significant an effect on winter gas bills as the Company claims, and such a change could impede the Company's energy conservation efforts.

[767] 6 Tr 1074.

b. General Service Rates

As adjusted in rebuttal testimony, Ms. Collins recommended increasing the Rate GS-1 customer charge from $14.00 to $18.00 per month, rather than the Company's calculated COS-based charge of $28.02 per month. The Attorney General asserts that any increase in Rate GS-1 should be limited to $1.00. In its brief, Staff maintains that Rate GS-1 charges should remain at $14.00 per month under the same rationale it provided for maintaining residential customer charges.

In light of the determination above, that residential customer charges should be maintained at current levels, this PFD agrees that charges for Rate GS-1 should likewise remain at $14.00. In addition, consistent with the general conclusion that Staff's COSS and rate design methods are just and reasonable, this PFD finds that, as recommended by Mr. Ruggles, Rate GS-2 and Rate GS-3 customer charges should be reduced to $80.73 and $436.56 respectively with the remainder of costs collected through volumetric distribution charges.[768]

c. Transportation Rates

In direct testimony, Ms. Collins proposed changes to master customer charges for Rates ST, LT, and XLT, along with "a contiguous customer charge of $60.00 for all ST, LT, and XLT contiguous accounts[,]" based on the Company's COSS.[769] Mr. Ruggles recommended that the Rate ST customer charge be increased to $550.00, the Rate LT customer charge should be increased to $2,776.21, and that Rate XLT and Rate XXLT

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[768] 7 Tr 2220.
[769] 6 Tr 1061.

customer charges should be reduced to $5,743.51 and $40,096.32 respectively, with the remainder of the revenue requirement collected through distribution charges, contiguous meter charges, or the ATL adjustments.[770]

In rebuttal, Ms. Collins proposed to increase the Rate ST customer charge to $570.30, decrease the Rate LT customer charge to $2,458.09, increase the Rate XLT customer charge to $7,685.85, and decrease the Rate XXLT customer charge to $32,193.94, with no change to the contiguous customer charge.[771]

In light of the forgoing determination that Staff's COSS should be adopted (except for the adjustment for the cost of working gas discussed above) this PFD finds that the Staff's proposed fixed charges for Rates ST, LT, XLT, and XXLT should be approved.

2. Economic Breakeven Points

The Company proposed to maintain the economic breakeven points set in Case No. U-18124. Specifically, "the Company proposed to maintain the economic breakeven points between Rate Schedules GS-1 and GS-2 at 1,000 Mcf annually, and between Rate GS-2 and Rate GS-3 at 10,000 Mcf annually. . . . Furthermore, the Company proposed to maintain the economic breakeven points between Rate ST and Rate LT at 100,000 Mcf annually, and between Rate LT and XLT at 500,000 Mcf annually."[772] The Company also proposed to maintain Rate XXLT as a cost-based rate with a minimum eligibility requirement of 4.0 Bcf annual usage. Staff agreed with the company's proposals.

[770] 7 Tr 2220-2221; Exhibit S-6, Schedule F-2.2.
[771] Exhibit A-142.
[772] Company Brief, p. 219, citing 6 Tr 1061-1062.

Energy Michigan contends that the minimum eligibility for customers under Rate XXLT should be reduced to reflect the economic breakeven point between Rate XLT and Rate XXLT. Mr. Wilken testified that he calculated the mathematical breakeven point for Rate XXLT and determined that customers using 1.05 Bcf per year should be eligible for Rate XXLT.[773] Mr. Wilken explained that eligibility for different rates should reflect economic breakeven points, opining that:

> To do otherwise simply forces a customer to pay the utility more for its service than it would otherwise need to. This needlessly raises costs for customers. If the utility has a rate structure in place under which it could serve the customer, and do so more inexpensively, but sets barriers in place in the way of arbitrary eligibility requirements, then it raises concerns that the rate is not designed to reflect the utility's cost of service, but rather to simply recover greater revenue for the utility.[774]

In rebuttal, Mr. Lyons testified that Rate XXLT is a cost-based rate, meaning that customers using less than 4.00 Bcf would not be paying COS rates: "[I]f Rate XXLT cost of service and Rate XLT cost of service were blended, then Rate XXLT customers would pay a rate higher than their cost of service while Rate XLT customers would pay a rate lower than their cost of service."[775] Mr. Lyons explained that the unit COS for rate XXLT is significantly lower than the unit COS for Rate XLT, primarily because Rate XXLT has an annual demand that 26 times greater than Rate XLT, Rate XXLT has a load factor that is 40% higher than Rate XLT, and Rate XXLT uses only the Company's high pressure distribution system.[776]

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[773] 4 Tr 93-94. The 1.05 Bcf annual demand assumes a 4% ATL and no IRM surcharge. If there is an IRM surcharge, the breakeven point is 1.09 Bcf.
[774] 4 Tr 94.
[775] 7 Tr 1935.
[776] Id. at 1935-1936.

Staff also opposes Energy Michigan's proposal. Mr. Ruggles testified that when Rate XXLT was first proposed as a pilot rate in Case No. U-18242, it was intended for two gas-fired generation facilities whose usage characteristics differed significantly from the typical industrial load. Mr. Ruggles explained that the two facilities on the XXLT rate only take service from the Company's transmission and high-pressure distribution systems, while Rate XLT customers may be taking service from the Company's low-pressure distribution system. "Therefore, to ensure that customers on the low-pressure distribution system do not take service on Rate XXLT, which does not and is not intended to include costs for the low-pressure distribution system, Staff opposes Energy Michigan's proposal to lower the eligibility requirement to mirror the calculated economic breakeven point."[777]

Ms. Collins testified that because Rate XXLT is cost-based, meaning that the rate is designed to collect all costs from the two customer served by that rate, if the eligibility requirement is changed, an new COSS would need to be performed, and a new rate design would need to be developed. Like Mr. Lyons and Mr. Ruggles, Ms. Collins highlighted the fact that the facilities eligible for Rate XXLT have significantly different operating characteristics than the typical industrial load.

The Company's, Staff's, and LBWL-MSU's initial briefs summarize the testimony of their respective witnesses. In its reply brief, Energy Michigan states that it accepts the explanation for the purpose and function of Rate XXLT. Nevertheless, Energy Michigan requests that "the current eligibility requirement based on customer usage be stricken

[777] 7 Tr 2226-2227.

and replaced with language indicating that the rate is available to customers who are making use only of Consumers Energy's high-pressure distribution system. In this way, the eligibility requirement will properly reflect the actual purpose of and basis for the rate, and will be properly set to capture the correct customer group."[778]

The ALJ finds that the parties weighing in on this issue, including Energy Michigan, agree that the 4.00 Bcf eligibility requirement for Rate XXLT is reasonable and appropriate given the unique characteristics of the two gas-fired generation facilities taking service under that rate. The PFD also finds reasonable Energy Michigan's proposed change to the Rate XXLT tariff language. However, because this recommendation came so late in the proceeding, any discussion of changes to the Rate XXLT tariff language should be addressed in the Company's next general rate case.

3. XXLT Storage Adjustment

Ms. Collins explained that "[a]n ATL is a percentage of a transportation customer's annual contract quantity. A transportation customer's annual contract quantity [ACQ] is the greatest contracted quantity of gas that can be delivered for transportation on the customer's behalf for any given year as specified in the customer's transportation contract with the Company."[779] Ms. Collins testified that, for the sake of consistency, the Company is proposing to address all ATL adjustments in rate design using the methodology approved in Case No. U-14547, including for Rate XXLT, for which the ATL adjustment has been addressed in the COSS.[780] Ms. Collins further explained, with respect to

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[778] Energy Michigan Reply Brief, p. 2.
[779] 6 Tr 1063.
[780] Id., Exhibit A-47 shows proposed ATL adjustment increases and decreases.

adjustment for Rate XXLT, that the Company is proposing to spread the 4% ATL adjustment back to other transportation rate schedules based on storage allocation percentages from the COSS. Ms. Collins clarified that Rate XXLT is only allowed a 4% ATL, however the transportation class overall uses storage at a weighted average ATL of 7.2%. "Without this adjustment the XXLT rate class would be assigned a higher cost for storage than what they are allowed to use."[781]

Mr. Revere testified that the Company's ATL adjustment calculation was flawed, and he recommended two changes. First, he explained that storage cost per Mcf should be divided by 7.2%, rather than 8.5%, to reflect the average ATL for the transportation class. Second, Mr. Revere explained:

> As the ATL adjustment is charged on the basis of throughput, not ACQ, the application of the ratio between throughput and ACQ inappropriately inflates the adjustment. . . . Staff determined that the appropriate way to determine the adjustments was to directly adjust the per Mcf storage cost based on the ratio of the ATL tiers and the average ATL of 7.2%. This results in a cost per Mcf for each tier of ATL. As this results in a charge for the 8.5% tier, it is then necessary to adjust each of the tiers by the 8.5% tier to reach the appropriate adjustments.[782]

Mr. Revere testified that Staff agrees with the Company that a storage adjustment for Rate XXLT is needed, but he recommended a correction to the Company's calculation.[783] Mr. Revere testified that the calculation included an error that resulted in a negative storage cost for Rate XXLT. To correct the error, Staff proposed that Rate XXLT's allocated storage costs from the COSS be multiplied by the ratio of 7.2% to 4%,

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781 6 Tr 1064.
782 7 Tr 1955.
783 7 Tr 1953.

with the result subtracted from the allocated amount.[784] In his direct testimony, Mr. Pollock similarly recommended that the Commission reject the Company's proposed storage adjustment for Rate XXLT due to the negative storage costs.[785]

In rebuttal testimony, Ms. Collins agreed with Staff's approach in correcting the ATL and the storage adjustment calculations for Rate XXLT. She provided a revised calculation in Exhibit A-146.[786]

In his rebuttal, Mr. Pollock testified that while Mr. Revere's adjustment was more reasonable than the Company's, it was nevertheless erroneous because:

> [A]s with Consumers' proposed adjustment, it assumes a linear relationship between the contractual ATL and the amount of storage service actually used. The lower the ATL, the lower the amount of storage service used, and vice versa. Further, as with Consumers, Mr. Revere is proposing to spread this adjustment to Rates ST, LT and XLT based on throughput. This would not provide an accurate allocation of the XXLT storage adjustment.[787]

Mr. Pollock further explained that smaller transportation customers (i.e., Rates ST and LT) have higher ATLs than Rate XLT customers, and therefore Rates ST and LT have higher storage costs than Rate XLT. Mr. Pollock recommended that "the XXLT storage adjustment be allocated on a basis that recognizes the differences in ATLs of the Rate ST, LT and XLT classes."[788] Consistent with his recommendation Mr. Pollock provided weighted allocation factors for Staff's Rate XXLT storage adjustment reflecting the higher amount of storage usage by Rates ST and LT.[789]

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[784] 7 Tr 1954; Exhibit S-6, Schedule F2.2, page 1, line 3, column k.
[785] 7 Tr 1857.
[786] 6 Tr 1072.
[787] 7 Tr 1892-1893.
[788] 7 Tr 1893.
[789] Table R-2, 7 Tr 1894.

Mr. Lyons also disagreed with Staff's recommendation, contending that the negative storage costs for Rate XXLT were due to a discrepancy in ACQ "that when corrected resulted in revised ATL adjustment that were approximately 50.0 percent of the proposed ATL adjustment[,]" noting that the revised ACQ adjustment filed by the Company corrected the error in the original calculation resulting in positive storage costs for Rate XXLT.[790]

In response to Mr. Pollock, Mr. Revere testified:

> ABATE witness Pollock is incorrect that the application of the 4% ATL credit ignores the difference in storage usage between transportation users. It is appropriate to recognize the difference in storage usage customers choose to pay for through the ATL; this represents the cost amount of storage available depending on the ATL chosen. This should not vary between rates. The allocation is done on the basis of storage utilization to the transportation class as a whole. To recognize the differences in storage allocation between rates would reflect not the amount of storage customers are willing to pay to have access to, but the averages of those classes' usage of storage, a good portion of which should be determined by the average chosen ATLs of each rate. Customers may be willing to pay for having access to storage they may choose not to use, however, and it is appropriate to allow them to do so. The pricing should reflect this. Therefore, ATLs as a concept or pricing strategy is not in itself incorrect, though the Company's calculation of ATL pricing and the associated storage adjustment were incorrect.[791]

In response to Mr. Lyons, Mr. Revere testified that if the Commission does not adopt Staff's corrected ATL calculation, then Mr. Lyons' adjustment may be appropriate.

This PFD finds Staff's position most persuasive on the appropriate adjustments to ATL and the storage adjustment for Rate XXLT. The ALJ agrees that ABATE's recommendation is misplaced, as Mr. Revere explained, and that LBWL-MSU's concerns

[790] 7 Tr 1931-1932, Exhibit LBWL/MSU R-1
[791] 7 Tr 1959-1960.

about the appropriate allocation of storage costs are addressed by the Staff's modifications.

4. Other Rate Design Issues and Order Implementation Date

Considering the concerns about proper allocation of storage costs, Mr. Pollock testified that the Company should be directed to conduct a study on the use of storage service by transportation customers. LBWL-MSU supported the recommendation. The Company concurred that such a study would be informative and could be undertaken once the proper metering is in place.

Staff was more cautious about the need for a storage study. Mr. Revere testified:

> Consistent with Staff's past positions, absent a request to change the allocation of storage costs, such a study is unnecessary. However, should the Company propose a storage allocation change, or should the Commission approve ABATE's recommendation, the study should be expanded beyond that proposed by ABATE witness Pollock. To truly understand use of the storage system, the study would have to include all classes. In addition, more valuable information about use of the storage balancing function, a crucial component of storage system use, would be available if the data collected were hourly rather than daily. An examination of daily use only partially illuminates the true use of the storage system.[792]

This PFD agrees with Staff. If the Company proposes a change to the storage allocator, then a comprehensive storage study may be justified. Therefore, the PFD recommends that the Company consult with Staff and ABATE to determine the appropriate scope, timing, and implementation costs of the study should one be required.

Through testimony of Mr. Oliker, RESA recommended that the Company revise its tariffs and billing system to allow Rate GS choice customers to participate in contiguous

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[792] 7 Tr 1960.

facilities aggregation[793] in the same manner as full-service GS customers. RESA contends that the current practice unreasonably discriminates against gas choice customers. The Company agreed and no other party opposed the recommendation. In rebuttal, Ms. Collins testified that the Company requests 90 days from the date of the Commission order to fully implement the change. RESA had no objection to the Company's 90-day implementation timeframe. Given the agreement of the parties, the PFD finds that the change to the Company's tariff and billing system allowing contiguous facilities aggregation for Rate GS choice customers should be approved and changes to the tariff language and billing system should be implemented within 90 days of the Commission order.

Mr. Revere testified that the rates approved by the Commission should be effective seven days after the final order to allow the Company time to update its rates and tariffs.[794] Staff added that under no circumstance should new rates go into effect before the beginning of the test year.[795] In rebuttal, Ms. Collins testified that the Company would be able to implement new rates the day after a Commission order. In light of Ms. Collins' rebuttal, Staff agreed that the Commission should permit the Company to implement rates on and after the date of the Commission order. Consistent with the parties' agreement, the PFD recommends that new rates be effective on and after the date of the Commission

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[793] "Contiguous Facilities Aggregation permits a customer that occupies a group of buildings or parts of buildings which are exclusively used by the customer and served under the same rate schedule to have the quantities of gas delivered to be added for billing purposes under specified circumstances. A key benefit of Contiguous Facilities Aggregation is that the customer pays one distribution charge for the master account and a reduced contiguous customer charge for each aggregated account, rather than Consumers' distribution charge for each account." RESA's Brief, p. 2-3.
[794] Id. at 1957.
[795] Staff Brief, p. 114.

order, provided that the Commission order is issued on or after the beginning of the test year.

C. Tariff Issues

Ms. Miles testified concerning the company's proposed tariff changes, the majority of which were uncontested and should therefore be approved.[796] Mr. Ruggles pointed out in the Company's previous rate case, Staff took the position that the excess peak demand charge is demand-related and should therefore be moved from the "Customer Charge" section of the tariff book to the "Distribution Charge" section. According to Mr. Ruggles, the Company agreed to this change; however, the change was not made to the tariff book after the Commission order approving the settlement agreement in that case. The Company did not contest Mr. Ruggles' recommendation; therefore, Staff's proposed change to the tariff book should be approved (and implemented).

Finally, Staff proposed to establish a new Power Generation (PG) tariff for the MCV, with associated rate treatment of costs and revenues. Staff's proposal was disputed by the Company.

Mr. Revere testified that service to the MCV is currently provided according to the terms and conditions set forth in two Act 9 contracts.[797] Mr. Revere testified that at the time the original Act 9 contracts were entered into, the Company did not have transportation tariffs that were appropriate for the type of service provided to the MCV. In addition, the MCV was served in part by facilities regulated by the federal government.[798]

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[796] 6 Tr 1302-1308; Exhibits A-96 and A-16, Schedule F-5.
[797] 1929 PA 9, MCL 483.1 *et seq.*
[798] 7 Tr 1946-1947.

Now that circumstances have changed, Mr. Revere stated that the MCV should be served under a tariff or a special contract. However:

> If treated as a special contract, rate recovery of any discount from the appropriate tariff rate should be subject to the requirements under MCL 460.6a(7), as clarified by the guidelines recently approved by the Commission in MPSC Case No. U-18999. Even considered as an Act 9 contract, any difference between the contract rates and cost-based rates should be subject to the same rules for the same reasons. Contract discounts should only be recoverable from other customers if those discounts are cheaper than the discounted customer leaving the system (assuming it is viable for them to do so).[799]

Mr. Revere testified that although the Company now has tariffed rates available for large transportation customers, none of the current tariffs, including Rate XXLT, are appropriate because the characteristics of the service provided to the MCV differ significantly from those of Rate XXLT customers. Mr. Revere highlighted the fact that the MCV is "effectively an off-system customer[,]" connected directly to the Company's transmission system, unlike rate XXLT customers who are connected to the high-pressure distribution system and pay the associated costs.[800]

Mr. Revere stated that to determine the appropriate COS-based rate for the MCV, it requested analyses from the Company on the cost to serve the plant. "In response, the Company provided a newly developed Power Generation rate, accompanied by a . . . COSS with MCV as its own class, a modified rate design model incorporating the new rate, and an associated tariff." He testified that the PG rate is appropriate because it identifies only those costs associated with serving the MCV. Thus, according to Mr.

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[799] 7 Tr 1947, citing September 9, 2018 order in Case No. U-18999, p. 103.
[800] 7 Tr 1948.

Revere, “this is the rate which should be used to either apply to MCV or be used to determine the discount provided to MCV.”[801]

Mr. Revere testified that the discount should be calculated as the difference between what the Company collects under the MCV contract and the amount that would be received under the PG tariff. Based on its COSS, Staff calculated the discount amount as approximately $13 million.

Mr. Revere described the structure of the PG tariff and provided Staff’s recommendations for changes to the tariff including: (1) modification of the GIK percentage; (2) removal of references to maximum daily quantity (MDQ), including metering and equipment requirements; and (3) rates that reflect Staff’s proposed rates or rates resulting from the final COSS and rate design in the instant case.

Mr. Revere explained that in determining whether the MCV discount should be paid by other ratepayers, the Commission must consider MCL 460.6a(7) and the guidance the Commission provided in Case No. U-18999. Mr. Revere listed the various criteria contained in the statute and order. According to Mr. Revere, “Staff did attempt . . . to ascertain from the Company the status of these criteria and subfactors regarding MCV through discovery. The Company was unable to show that the discount was justified, or that it should be recovered from other customers per the Commission’s and the legislature’s guidance. Therefore, the discount should not be recovered from other customers.”[802]

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[801] Id.; Exhibits S-20.1 (MCV COSS), S-20.2 (rate design model for MCV), and S-20.3 (PG tariff).
[802] 7 Tr 1953.

Ms. Aponte disagreed that an Act 9 contract is no longer appropriate for the MCV, noting that in Case No. U-8678, the Commission found that Act 9 contracts are reasonable for off-system gas customers. Ms. Aponte added that the Commission has reviewed and approved the MCV contract every time it has been amended "which necessarily indicates that the Commission has already made the determination that the use of an Act 9 contract for service to MCV is appropriate."[803]

Ms. Aponte also disputed Staff's interpretation of MCL 460.6a(7), which states that "The commission shall, **if requested by a gas utility,** establish a load retention transportation rate . . ." Ms. Aponte testified that in Case No. U-18010, the Company is not requesting a load retention transportation rate, and in fact proposes that the MCV pay its full cost to serve. Ms. Aponte added:

> Notably, the agreement at issue was not contemplated to be below cost of service at the time it was executed. Instead, it has become below cost to serve through the passage of time. Therefore, the guidelines recently approved by the Commission in Case No. U-18999 do not apply, and Staff's position should be rejected.[804]

Ms. Aponte agreed with Staff that the MCV should be charged the rates contained in the PG tariff, consistent with the position the Company has taken in Case No. U-18010. Ms. Aponte testified that in that proceeding, the Company has requested that the Commission approve the Rate PG tariff, which would be applied beginning in 2023, after

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[803] 6 Tr 976.
[804] Id. at 977.

the current Act 9 contracts expire. The Company has also requested that the Commission approve new Act 9 contract rates that are the same as those contained in the tariff.[805]

In response to Staff's COSS for the MCV, Ms. Aponte sponsored Exhibit A-120, Schedule F-1, Gas Cost of Service Study Version 2.2, which provides updated revenues from the MCV, based on the proposed PG COSS presented in Case No. U-18010. Ms. Aponte testified that if, before it issues an order in this case, the Commission approves the Company's proposed contract rate in U-18010, the revenue from MCV would be $20.7 million, equal to the amount to be collected by the PG tariff.[806] In that event, the Company's revenue requirement would decrease by $8.8 million. Conversely, if the Commission issues an order changing the MCV contract rate in Case No. U-18010 after the order is issued in this case, then the Company proposes to create a regulatory liability reflecting the amounts to be collected under the new tariff. Ms. Aponte opined that "this is the most appropriate way to address any potential rate change for MCV . . . because it recognizes that MCV's current rates in its existing Act 9 contract are the approved rates unless and until they are reset by the Commission."[807] Ms. Aponte contended that Staff's recommended approach is improper, claiming:

> Mr. Revere repeatedly refers to MCV's rate as being subject to a "discount," but as discussed above, it is not a discounted rate. It is the Commission-approved rate. It would not be appropriate to intentionally allocate costs to MCV in the cost of service model while simultaneously leaving in place a rate that is not designed to recover those costs. If the Commission believes that those costs should be assigned to MCV rather than the Company's other customers immediately as part of this case, then it should

[805] Id. Alternatively, the Company points out that the Commission could abrogate the existing contract and immediately place the MCV plant on the PG tariff.
[806] 6 Tr 979.
[807] 6 Tr 979.

> simultaneously approve a new rate for MCV that is designed to recover those costs.[808]

Mr. Torrey testified that the MCV contracts were originally executed in 1988 and are due to expire in 2023. Mr. Torrey opined that due to the long-term nature of the contracts, the terms and conditions of which were approved by the Commission, it would be unreasonable to apply the new requirements for special contracts to the MCV Act 9 contracts. Mr. Torrey recommended that the issues raised by Mr. Revere be resolved in Case No. U-18010, where the Commission has an opportunity to adjust the Act 9 contract prices, concluding that:

> Staff's proposal to disallow Consumers Energy recovery of any difference between the current MCV Act 9 contract revenues and the costs identified under the Power Generator gas transportation tariff amounts is unreasonable and amounts to a penalty for satisfying a contractual relationship that was approved by the MPSC under circumstances that existed 31 years ago.[809]

In its brief, the Company summarized Staff's position, as set forth in Mr. Revere's testimony, as a request to:

> (i) implement a new Power Generation tariff for gas transportation service provided to natural-gas-fueled electric generating plants, which is based on a tariff developed by the Company but includes certain changes proposed by Mr. Revere; (ii) allocate costs to that new tariff as if MCV were taking service on the new tariff; and (iii) remove the expected revenue under MCV's Act 9 contract from Other Gas Revenue, reflect it in the rate design as current revenue associated with the Power Generation tariff, and design new rates for the Power Generation tariff using MCV's forecasted determinates. After doing all of that, however, Mr. Revere recommends that the Commission not actually require MCV to take service under the new Power Generation tariff.[810]

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[808] 6 Tr 979-980.
[809] 6 Tr 1575-1576.
[810] Company Brief, p. 224-225.

With respect to these proposals, the Company states that it is “indifferent” about the timing of the implementation of the PG rate: whether it occurs in this case or later. If the Commission does decide to implement the PG tariff now, the Commission should adopt the COSS and rate design, and tariff proposed by the Company, pending the resolution of Case No. U-18010.[811]

The Company states that it disagrees that an Act 9 contract is no longer appropriate for service to the MCV, but it does agree that if a tariffed rate is to apply, none of the company’s existing transportation rates are appropriate for service to the MCV. The Company further indicates that whether to assign the MCV to the PG tariff now or wait until 2023 when the current contracts expire is better addressed in Case No. U-18010. After citation to various authorities that support the legitimacy of retaining the MCV as an Act 9 contract customer, the Company admits that under the holding in *Midland Cogeneration Venture Ltd Partnership v Pub Serv Com'n*, 199 Mich App 286, 310; 501 NW2d 573 (1993), the Commission does have discretion to change its policy concerning Act 9 contracts for off-system customers like the MCV. The Company reiterates that although the Commission has the authority to approve a PG tariff in this case, it nevertheless maintains that it would not make sense to do so unless the Commission intends to immediately move the MCV to that tariff.

Next, the Company questions why Staff proposes that a new tariff be approved in this proceeding, while at the same time it recommends that the decision as to whether to move the only eligible customer to that tariff be made in Case No. U-18010. According

[811] Id. at p. 225.

to the Company, Staff's intention is to simply allocate $24.623 million to the Rate PG class. The Company added:

> [S]ince Mr. Revere proposed that the Commission should not require MCV to take service under the Power Generation tariff in this rate, there will not be any customer on the Company's system paying the Power Generation rate; hence, the Company will not collect the $24.623 million of its revenue requirement allocated to that rate. Because MCV will continue to pay its current Act 9 contract rate at least until the Commission's final order in Case No. U-18010 under Mr. Revere's proposal, the Company would continue to collect the $11.864 million of expected revenue during the test year under that contract. . . . But, that means that Consumers Energy would be collecting $12.795 million less than it needs to collect in order to recover all of the costs allocated to the Power Generation tariff. As a result, even if the Commission adopts Staff's proposed $146 million revenue deficiency in this case, the rates designed under Mr. Revere's proposal are intentionally designed to only collect $133 million of incremental revenue, thereby deliberately shorting the Company of approximately $13 million of annual revenue to cover costs that Staff itself has determined to be reasonably and prudently incurred. . . . [I]t may fairly be presumed that Staff does not include costs for recovery in its revenue requirement calculation that Staff deems to be unreasonable or imprudent). Again, Mr. Revere's proposal seems to present a question about why Staff would recommend that the Commission intentionally design rates that would not allow the Company to recover all of its reasonably and prudently incurred costs. [812]

The Company also takes issue with Staff's characterization of the MCV rates as "discounted" rates. The Company argues that the rates at issue are Commission-approved rates that were cost-based at the time the Act 9 contracts were signed. Over time, however, these contract rates have become below the cost of service. Nevertheless, the Company contends, based on a line of cases, that the rates currently charged to the MCV are reasonable as a matter of law. Therefore, Staff's proposal to set

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[812] Company Brief, p. 231-232, citing Exhibit S-6, Schedule F-2.2, page 1, line 7 (column "Power Gen") and Exhibit S-6, Schedule F-2, page 2, line 14, column (d) and Staff's revenue deficiency calculation of approximately $146 million shown in Exhibit S-1, Schedule A-1, line 8, column (e).

up a rate class, assign costs and revenues to that class based on rates that are not currently in effect, is unlawful.[813]

According to the Company, the circumstances here are analogous to those presented in *Consumers Power Co v Michigan Pub Serv Comm'n*, 415 Mich 134; 327 NW2d 875 (1982). The Company explains that in *Consumers Power,* the Commission bifurcated the rate proceedings, finding a revenue deficiency of $16.5 million in the first part, and then deciding to hold a second hearing on cost allocation and rate design, which was completed six months later. The Court upheld a lower court ruling granting the Company injunctive relief, finding that the utility had a substantive right to immediate rate relief. The Company contends that the situation in this case would be the same if Staff's recommendation is approved. According to Consumers, "Staff has proposed a finding that the Company has a revenue deficiency for the test year of $146 million[,] [b]ut . . . is proposing to delay rate recovery of $13 million of that revenue deficiency until a subsequent decision can be made on the rate design for MCV's rates in a subsequent hearing." The Company characterizes this outcome as even more unjust because the U-18010 proceeding is currently delayed pending decisions on procedural motions. Finally, the Company reiterates that:

> [T]he most reasonable approach to the cost of service and rate design in this case, regardless of whether the Commission chooses to adopt a Power Generation tariff now, would be to use the COSS Version 2.1 and the rate design proposed by Company witnesses Davis and

[813] Company Brief, p. 233-235, citing *Michigan Bell Tel Co v Michigan Pub Service Comm'n*, 315 Mich 533, 551; 24 NW2d 200, 207 (1946); *N Michigan Water Co v Michigan Pub Serv Comm'n*, 381 Mich 340, 352; 161 NW2d 584 (1968); and *In re Application of Detroit Edison Co,* 276 Mich App 216, 227; 740 NW2d 685, 694 (2007), aff'd in part, rev'd in part on other grounds 483 Mich 993; 764 NW2d 272 (2009).

> Collins respectively, which are discussed above. The Power Generation rate schedule is not included in their proposed COSS Version 2.1 or rate design, so no costs are allocated to a rate schedule that will be unused during all or some portion of the test year. If the Commission subsequently approves the Company's requested rate increase in Case No. U-18010 (or any rate increase), it would create a revenue surplus, but that could be addressed by the creation of a regulatory liability account to collect those revenues until they can be returned in a subsequent rate case.[814]

Staff responds that the Company is mistaken in its claim that the rates paid by the MCV are not discounted, contending that because the current rates are below the cost of service, these rates meet the dictionary definition of "discounted" rates.[815] Staff further points out that while it is true that Commission-approved rates are presumed reasonable, the Commission nevertheless has the right to address discounted rates through appropriate ratemaking treatment. Staff points out that in its most recent MCV contract amendment, the Company did not request, nor did it receive, any assurances on ratemaking treatment for the MCV contracts. According to Staff:

> The reason for this separation of contract approval and ratemaking treatment thereof is the nature of negotiated rates. As stated by the Commission in U-10646:
>
> > The contract pricing and terms [approved by the Commission in the same order] differ from utility service under tariff because the contracts are the product of Detroit Edison's negotiations. It follows that Detroit Edison should assume full responsibility for negotiating the discounted prices and that its shareholders should expect to absorb much, if not all, of any revenue shortfall caused by the pricing and other contract provisions that the utility negotiates. [MPSC Case No. U-10646, Order dated March 23, 1995, p. 21.][816]

[814] Consumers' initial brief, p. 238. The Company presented an alternative method for treating costs in the event the Commission approves the PG tariff.
[815] Staff's reply brief, p. 25-26.
[816] Staff Reply Brief, p. 27.

Staff points to a recent order in Case No. U-20052, which affirms that contract approval and ratemaking treatment are separate inquiries, and that ratemaking treatment is "based upon the same general principles for special contracts as discussed in the April 11 order and later updated in the September 13, 2018 order in Case No. U-18999, pp. 103-106."[817]

In response to the Company's claim that imputing costs to the Rate PG tariff is equivalent to disallowing reasonable and prudent expenditures, Staff states, "The Company misunderstands the nature of revenue imputation as ratemaking treatment for discounted rates not shown to be a benefit to other customers, as has been applied by the Commission for years with no successful legal challenge."[818] Staff continues:

> In this case, Staff has proposed imputing revenue for MCV based on the cost-based rate. Staff is not recommending that the Company not be allowed to recover its costs. Instead, Staff is recommending the application of the same principles contemplated by the law and numerous other unchallenged Commission decisions; when the Company negotiates contract rates and provisions, it is incumbent upon the utility to ensure that those rates and provisions benefit other customers. If they do not, the utility's shareholders will properly, reasonably, and legally cover the cost of those rates and provisions. Insofar as the contracts result in revenue lower than deemed prudent from those contracts, it is due to the imprudence of the Company's negotiations of the contract. Therefore, the Company should be held responsible for such shortfalls.[819]

As an initial matter, the PFD finds that the Rate PG tariff, as provided by the Company and modified by Staff, should not be approved as part of this proceeding. The ALJ finds that the record is not sufficiently developed to address disputes over several of

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[817] Id., citing October 24, 2018 order in Case No. U-20052, p. 3.
[818] Staff Reply Brief, p. 27-28 (internal citations omitted).
[819] Staff Reply Brief, p. 28.

the terms and conditions of service contained in the Rate PG tariff. And, it is not clear when, if ever, the Rate PG tariff will be implemented, considering the Commission's policy that permits Act 9 contracts for off-system customers and that the current MCV Act 9 contracts do not expire until 2023. Finally, if the MCV Act 9 contracts continue until their expiration, certain conditions of service to the MCV may change in the interim, necessitating additional modifications to the tariff. For these reasons, this PFD recommends that Rate PG tariff issues be addressed either as part of the U-18010 proceedings (if appropriate) or in a future rate case.

Concerning the remaining disputes over the MCV contract discount, Staff correctly points out that contract approval and ratemaking treatment are two distinct processes, as was discussed in detail in the March 23, 1995 order in Case No. U-10646, pp. 18-19.[820] In that order, the Commission approved, with some reservation, special transportation contracts for certain large industrial customers receiving service from The Detroit Edison Company, finding that, "Detroit Edison has presented adequate justification for extending the discounted pricing to its three largest automotive customers as a means of retaining their load."[821] The Commission further determined that although it would not issue a definitive ruling on how contract costs should be addressed for ratemaking purposes, it would provide some guidance for future proceedings. As quoted above, the Commission found that the utility and its shareholders bore full responsibility for any revenue deficiency that might result from the contracts, unless the company fully justified a different

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[820] See also, March 11, 1996 order in Case No. U-10755, p. 36-38; April 28, 2005 order in Case No. U-13898 et al., p. 55-56; June 3, 2010 order in Case No. U-15985, p. 45-46
[821] Order, p. 19.

ratemaking treatment. "This burden would require, at a minimum, a clear, convincing, and unequivocal demonstration either (1) that the contract prices and terms are justified on the basis of the cost of service, or (2) that the benefits for the other (non-participating) ratepayers are substantial and have a value that outweighs the costs that are not recovered from the contract customers." In other words, rates must be cost based or, if discounted, the cost of the discount must be shown to be less than the benefit to other customers of keeping the customer on the system.

The Company complains that MCL 460.6a(7) and the guidelines for ratemaking treatment of special contract discounts, set forth in Case No. U-18999, should not apply here because the MCV Act 9 contracts were executed over 30 years ago and were approved by the Commission. The Company's argument is not well-taken. As quoted above, and discussed extensively in Staff's reply brief, the criteria used to determine whether a particular customer discount is justified, although recently codified in Section 6a(7) and refined in Case No. U-18999, is really nothing new.[822] Moreover, the Company's argument that the Act 9 contracts at issue have been in force for 30 years and the Company should not be penalized for abiding by the terms of those contracts, is unavailing.

Michigan Consolidated Gas Company (Mich Con) made a similar argument concerning customer discounts in Case No. U-13898, asserting that because the Commission had allowed recovery of the discounts in two previous rate cases, the

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[822]*See, e.g.,* March 11, 1996 order in Case No. U-10755, p. 36-38.

Commission's authority to address the discounts in the next case was limited. The Commission disagreed, finding:

> In the decade since that last rate order, the Commission has continually provided additional guidance on the appropriate recovery of discounts. The Commission has consistently stated with regard to transportation customer discounts that should Mich Con seek rate recovery of those discounts—thus shifting to other customers the cost of discounts given to favored customers—the company would bear a substantial evidentiary burden. The Commission has explicitly and repeatedly stated that when rate recovery was sought, at a minimum Mich Con would need to present a clear, convincing, and unequivocal demonstration that either: 1) the rate and service terms provided are justified on the basis of the cost of service, or 2) the benefits to other ratepayers are substantial and have a value that outweighs the costs that are not recovered from the discounted rate customer.[823]

The fact that the contracts at issue are Act 9 contracts, and therefore subject to Commission approval, is also immaterial to the issue of appropriate ratemaking treatment. In an analogous situation, considering Act 9 contract costs in a gas cost recovery (GCR) proceeding, the Commission stated:

> Given the different purposes of Acts 9 and 304, the Commission finds that the Legislature did not intend that cases arising pursuant to Act 9 should control decisions made pursuant to Act 304. Specifically, Act 9 does not contemplate a process to review the reasonableness and prudence of a utility's gas acquisitions. Rather, Act 9 reviews a change in the contractual relationship between a producer and a common purchaser in light of their initial contract relationship. The Commission simply approves or rejects any contract revisions proposed by the parties. This is an important and distinguishing fact because, under Act 304, the Commission is not bound to merely accept or reject the GCR factor proposed by the utility. Rather, the Commission independently determines reasonable and prudent cost levels. Therefore, Act 304 gives the Commission much more latitude in reviewing costs for their reasonableness and prudence than does Act 9. Under Act 9, the Commission examines the proposed pricing provision in light of the current market and determines whether the proposed price is fairer than the existing price. In contrast, under Act 304, even if a price is fair, the

[823] Order, p. 55-56.

> Commission may nevertheless determine that alternative supplies are cheaper.
>
> For these reasons, price approvals previously granted by the Commission pursuant to Act 9 fall far short of the comprehensive cost analysis required by Act 304 and should not be used as a substitute in an Act 304 proceeding. As a result, the Commission agrees with the RRC that the ALJ's recommendation that any price revision approved in a subsequent Act 9 case should be adopted for use in Mich Con's 1991 GCR reconciliation is premature and beyond the scope of this plan case.[824]

Like an Act 304 case, the inquiry in a utility rate case is a detailed and comprehensive assessment of the reasonableness and prudence of various utility costs and revenues, whereas, "[u]nder Act 9, the Commission examines the proposed pricing provision in light of the current market and determines whether the proposed price is fairer than the existing price." Thus, in both a GCR case and a base rate case, the Commission-approved price paid pursuant to an Act 9 contract is not dispositive of the reasonableness and prudence of that cost, or, as is at issue in the instant case, the reasonableness of any discount.

Consistent with the decision in Case No. U-13898, and others discussed above, the Commission has the discretion to review contract discounts over time to ensure that the subsidization of these contracts remains economically justified. And, although it disagrees with Staff's amount, the Company does concur that the MCV's rates are now well below COS, as evidenced by its application filed in Case No. U-18010 requesting a significant increase in the rates paid by the MCV pursuant to the Act 9 contracts.[825] The

[824] March 28, 1991 order in Case No. U-9650, p. 26-27.
[825] It should be noted that the Company filed its request to increase the MCV's rates (among other contract amendments) in Case No. U-18010, on December 21, 2015. Since then, the case has proceeded at what could only be described as a desultory pace.

PFD finds that, because the MCV contract rates are below the cost to serve, the rates are in fact discounted.

Nevertheless, as discussed above, discounted rates may still be reasonable if the benefit of retaining the customer is clearly shown to be greater than the cost of the discount. In this case, the Company failed to provide information or analysis that would justify the discount for the MCV, as Mr. Revere testified. Because the Company made no showing of any benefit resulting from the reduced rates to the MCV, the discount should not be recovered from other customers.

Although Staff's approach to imputing discount revenue to the MCV contracts is reasonable, this PFD recommends the more straightforward approach that appears to have been adopted by the Commission in Case Nos. U-10755 and U-13898, where the discount was calculated and in reply imputed to total revenue. The ALJ emphasizes that under either approach, whether imputing the unrecovered costs via Staff's recommended method or directly assigning the discount to miscellaneous revenues, as was done in this PFD, the outcome is the same.

XI.

ACCOUNTING TREATMENT

The Company requests approval of several accounting changes discussed in turn below.

First, the Company seeks accounting approvals related to its proposed gas revenue decoupling mechanism (RDM), which no party opposed as discussed above. Mr. Harry explained the company's request for authority to recognize regulatory assets and liabilities as appropriate to record deferred debits and credits associated with the mechanism pending reconciliation and the necessary refunding or surcharging. He testified that the regulatory asset or liability would accrue interest at the company's short-term borrowing rate.[826] No party opposed the Company's request and consistent with the recommended approval of the Company's proposed RDM, the ALJ recommends that the accounting approval be granted.

Second, the Company seeks approval of deferred regulatory accounting treatment for specific gas compression plant inventory upon retirement, based on its plants to retire the following gas compression plants: Ray Plant 1, St. Clair Plant 2, and Muskegon River Plant 3. Mr. Harry also testified in support of the Company's request, explaining that on plant retirement, the inventory of replacement parts to maintain the plants that cannot be sold or repurposed must be charged as an expense under the Uniform System of Accounts. He testified that Commission approval of the Company's accounting change would allow it to charge the inventory costs to the cost of removal.[827] In support of its request, the Company cites approval the Commission granted in Case No. U-18048 for inventory related to the retirement of the Company's Classic 7 electric generating plants.[828] The Company also requests that the approval be extended to other gas compression plants that are retired in the future.[829]

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[826] 6 Tr 1273.
[827] 6 Tr 1273-1274.
[828] Company Brief, p. 246.
[829] Company Brief, p. 246.

Staff opposes the Company's request. Ms. McMillan-Sepkoski testified that the circumstances presented in Case No. U-18048 were different, and explained Staff's objection to the Company's request as follows:

> Staff does not agree with this accounting treatment for three (3) reasons. First, the case that the Company refers to as receiving approval to use COR (U-18048) was dealing with a special set of circumstances in regard to the inventory to be labeled as obsolete. Second, part of running a business is having some inventory become obsolete over time; it not an unusual circumstance in most cases. Third, the fire at Ray Compressor Plant on Wednesday, January 30, 2019 has left uncertainty as to whether the retirement of the plant will happen per the Company's schedule.[830]

Citing Mr. Harry's rebuttal testimony at 6 Tr 1284-1286, the Company disputes that the circumstances presented in Case No. U-18048 were distinguishable.[831] In his rebuttal testimony, while agreeing that obsolete inventory is a normal part of running a business, he testified that plant retirements are unusual events. He also testified that the three plants at issue have already been retired, and $3 million in inventory has already been expensed.

In its brief, Staff argues that the closing of a gas compression plant is not similar to the closing of the Classic 7 electric generating plants, because the Company's commitments to retire those plants were reflected in a settlement agreement with U.S. EPA.[832] Staff also cites the Company's statement in Case No. U-18048 to the effect that its request would not preclude parties to future cases from challenging rate recovery for amortized or unamortized plant inventory.

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[830] 7 Tr 2118.
[831] Company Brief, p. 247.
[832] See Staff Brief, p. 84-85.

Requests of the nature of the Company's request in this case are generally addressed to the Commission's discretion. While there are similarities between the Company's request in Case No. U-18048 and in the present case, there are also differences. Case No. U-18408 was not a rate case, and the Company's March 4, 2016 filing in that case indicated that the Classic 7 retirements would shortly take place on April 16, 2016. The Commission's order granted *ex parte* approval of this request on May 20, 2016. At that time it filed its application, the Company estimated inventory write-offs of $5.8 million in the future, and also sought the same treatment for a 2015 inventory-related expense of $1.9 million, for a total of $7.7 million estimated expense.

In this rate case, the Company estimated a total write-off of $3 million associated with the identified gas compression plants but did not address the timing of the expense components in its application. In his direct testimony, which was filed with the Company's November 30, 2018 application, Mr. Harry stated that the Company "has retired or is in the process of retiring" the gas compression plants.[833] In his rebuttal testimony, he stated that they had all been retired, and the $3 million of inventory write-off had been expensed, as of September 2018, or two months before the Company filed its application in this case.[834] Thus, at this point, the Commission is faced with the question whether to relieve the company of expenses that by its own testimony it has already incurred, without the detail presented in Case No. U-18048. The magnitude of the estimated expense is less than half of the amount at issue in Case No. U-18048. Additionally, Ms. McMillan-

[833] See 6 Tr 1274.
[834] See 6 Tr 1284-1285.

Sepkoski's testimony is persuasive the circumstances surrounding the Company's decision to simultaneously retire seven of its electric generating plants is not the same as the more usual situation of obsolete inventory. Mr. Harry's rebuttal testimony to the effect that any plant retirement is "an unusual, one-time event" does not substantiate that the circumstances are similar to those presented in Case No. U-18048.[835] The ALJ also notes that given the number of issues presented in rate cases, it adds unnecessarily to the burden of addressing them in the limited time available for the Company to include requests to be relieved of expenses incurred prior to the test year. As it did in Case No. U-18048, Consumers Energy could have filed a standalone application to change the accounting treatment for obsolete inventory at the retiring plants, and could have filed that application before the obsolete inventory was expensed, but instead chose to inject this issue into a general rate case. Because the ALJ finds that the Company has failed to establish that the circumstances surrounding its request are substantially similar to the circumstances in Case No. U-18048, the ALJ recommends that the Company's requested accounting treatment be rejected.

Third, the Company asks the Commission to approve the use of a regulatory liability to record any additional revenues, not reflected in this case, the Company may receive through its contract with MCV as a result of its application in Case No. U-18010.[836] Mr. Harry explained this proposal in his rebuttal testimony, to accompany the recommendations Ms. Aponte made in her rebuttal testimony regarding the treatment of

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[835] See 6 Tr 1285.
[836] See Company Brief, p. 238-240, and 248-249.

the MCV contract. Mr. Harry testified that under this proposed regulatory liability, the Company would refund the recorded amounts as soon as possible but not later than its next rate case.[837]

As an alternative to the use of a regulatory liability as a companion to the Company's preferred approach to the MCV contract revenues, Mr. Harry proposed a regulatory asset that would allow the Company to recover from ratepayers any revenue imputed to the Company that it does not recover through its application in Case No. U-18010, which would correspond to the Company's second approach to the MCV contract explained in Ms. Aponte's rebuttal testimony.[838] He explained that cost recovery for the regulatory asset would be allocated to MCV in a future rate case to the extent of any rate increase ultimately approved in Case No. U-18010, with the balance allocated to other customers.[839]

In its initial brief, Staff explained and advocated for its recommended approach to the MCV contract.[840] In its reply brief, Staff argues specifically that the Company's deferred accounting proposals "fail to accomplish the imputation of revenue necessary to ensure other customers do not bear the cost of the unjustified discount to MCV."[841] This PFD addressed the MCV contract in section X.C. above, and consistent with the findings and conclusions reached in that section, does not recommend that the Commission deny the Company either alternative accounting treatment it requests.

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[837] See 6 Tr 1287.
[838] See 6 Tr 1287-1288.
[839] See 6 Tr 1288.
[840] Staff Brief, p. 114-117.
[841] Staff Reply Brief, p. 29.

XII.

CONCLUSION

Based on the foregoing discussion, this PFD recommends that the Commission adopt the findings, conclusions and recommendations set forth above, including the findings and recommendations on rate base, capital structure, cost of capital, and operating revenues and expenses leading to an estimated revenue deficiency of approximately $127,483,000 with an authorized return on equity of 9.8% and an overall cost of capital of 5.80%, as well as recommendations regarding ratemaking mechanisms, cost of service allocations, rate design, and tariff modifications.

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES
For the Michigan Public Service Commission

Jonathan F. Thoits

Digitally signed by: Jonathan F. Thoits
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Date: 2019.08.01 15:13:11 -04'00'

Jonathan F. Thoits
Administrative Law Judge

August 1, 2019
Lansing, Michigan

MICHIGAN PUBLIC SERVICE COMMISSION Appendix A

Consumers Energy Company PFD

Revenue Deficiency (Sufficiency) Case No.: U-20322

for the Projected 12-Month Period Ending September 30, 2020

($000)

	(a)	(b)	(c)	(d)	(e)
Line No.	Description	Source	Applicant Projection (Initial Brief)	PFD Adjustment	PFD Projection
1	Rate Base	Appendix B	$ 6,501,069	$ (67,566)	$ 6,433,503
2	Adjusted Net Operating Income	Appendix C	252,631	25,014	277,645
3	Overall Rate of Return	Line 2 / Line 1	3.89%	0.43%	4.32%
4	Required Rate of Return	Appendix D	6.23%	-0.43%	5.80%
5	Income Requirements	Line 1 * Line 4	405,026	(32,179)	372,847
6	Income Deficiency / (Sufficiency)	Line 5 - Line 2	152,395	(57,193)	95,202
7	Revenue Conversion Factor	Exhibit: A-13 (JRC-47)	1.3391	0.0000	1.3391
8	Revenue Deficiency / (Sufficiency)	Line 6 * Line 7	$ 204,067	$ (76,584)	$ 127,483

MICHIGAN PUBLIC SERVICE COMMISSION Appendix B

Consumers Energy Company PFD

Projected Rate Base Case No.: U-20322

for the Projected 12-Month Period Ending September 30, 2020

($000)

	(a)	(b)	(c)	(d)	(e)
Line No.	Description	Source	Applicant Projection (Initial Brief)	PFD Adjustment	PFD Projection
1	Plant in Service	Exhibit: A-12 (JRC-42)	8,499,739	(69,493)	8,430,246
2	Plant Held for Future Use	Exhibit: A-12 (JRC-42)	192	-	192
3	Construction Work in Progress	Exhibit: A-12 (JRC-42)	631,603	-	631,603
4	Total Projected Utility Plant	Sum Lines 1 - 3	9,131,534	(69,493)	9,062,041
5	Less: Depreciation Reserve	Exhibit: A-12 (JRC-43)	(3,415,243)	1,927	(3,413,316)
6	Net Utility Plant	Line 4+ Line 5	5,716,291	(67,566)	5,648,725
7	Retainers and Customer Advances	WP-JRC-3	(39,193)	-	(39,193)
8	Adjusted Net Utility Plant	Sum Lines 6 - 7	5,677,098	(67,566)	5,609,532
9	Working Capital	Exhibit: A-12 (JRC-44)	774,316	-	774,316
10	Net Unamortized MGP	Exhibit A-68 (DLH-5)	49,655	-	49,655
11	Total Projected Rate Base	Sum Lines 8 - 10	$ 6,501,069	$ (67,566)	$ 6,433,503

MICHIGAN PUBLIC SERVICE COMMISSION **Appendix C**

Consumers Energy Company PFD

Projected Net Operating Income Case No.: U-20322

for the Projected 12-Month Period Ending September 30, 2020

($000)

Line No.	Description (Witness)	Revenue: Sales Revenue	Revenue: Transport Revenue	Revenue: Other Gas Revenue	Revenue: Total	Expenses: Cost of Gas Sold	Expenses: LAUF	Expenses: Company Use	Expenses: Other O&M	Expenses: Depreciation & Amort.	Expenses: R&PP Tax	Expenses: Other General Taxes	Expenses: Other (or Local) Taxes	Expenses: State Income Tax	Expenses: FIT	Expenses: Total	NOI: NOI	NOI: Other Operating Income Adj.	NOI: AFUDC	NOI: Adjusted NOI
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
	Company Filed																			
	Operating Income (Initial Filing)	1,513,094	70,646	114,426	1,698,166	633,882	8,317	5,101	383,155	276,075	112,600	16,268	402	10,621	16,228	1,462,650	235,517	-	2,451	237,968
	Adjustments																			
	Other Gas Revenue			(283)	(283)								(0)	(15)	(56)	(72)	(211)			(211)
	Interest Income			375	375								1	20	74	95	280			280
	eBill Promotion				-				(1,000)				2	53	199	(747)	747			747
	Uncollectibles Expense				-				(4,025)				6	214	799	(3,006)	3,006			3,006
	Impact of Capital Spend Adj.				-					(952)	(492)		2	77	287	(1,078)	1,078			1,078
	MGP Amortization Expense				-					(178)			0	9	35	(133)	133			133
	TCJA Credit C Amortization				-								-	-	(10,302)	(10,302)	10,302			10,302
	Proforma Interest				-								4	138	518	660	(660)			(660)
	Interest Synchronization	-	-	-	-	-	-	-	-	-	-	-	-	1	4	5	(5)	-	-	(5)
	Operating Income (Rebuttal Filing)	1,513,094	70,646	114,518	1,698,258	633,882	8,317	5,101	378,130	274,945	112,108	16,268	417	11,118	7,785	1,448,072	250,187	-	2,451	252,638
	Proforma Interest/Interest Sync													1	6	7	(7)			
		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1	**Operating Income (Initial Brief)**	1,513,094	70,646	114,518	1,698,258	633,882	8,317	5,101	378,130	274,945	112,108	16,268	417	11,119	7,791	1,448,079	250,180	-	2,451	252,631
	PFD Adjustments																			
2	Other Gas Revenue (Ruggles)			-	-								-	-	-	-	-			-
3	MCV Revenue (Revere)				-								-	-	-	-	-			-
4	MCV Imputed Revenue			12,759	12,759								20	678	2,533	3,231	9,528			9,528
5	Customer Experience & Operations (Fromm)								(607)				1	32	120	(453)	453			453
6	Information Technology (McMillan-Sepkoski)								(3,585)				6	190	712	(2,677)	2,677			2,677
7	Other Benefits (Rueckert)								(389)				1	21	77	(291)	291			291
8	Corporate (Rueckert)								-				-	-	-	-	-			-
9	Injuries & Damages (Rueckert)								-				-	-	-	-	-			-
10	Incentive Compensation (McMillan-Sepkoski)								(1,974)				3	105	392	(1,474)	1,474			1,474
11	Penson Exp								-				-	-	-	-	-			-
12	OPEB Exp								-				-	-	-	-	-			-
13													-	-	-	-	-			-
14	Uncollectibles (AG)								(4,025)				6	214	799	(3,006)	3,006			3,006
15	Customer Exp (AG) Broader Media Buys								(2,400)				4	127	476	(1,792)	1,792			1,792
16	Pipeline Integrity (AG)								(5,000)				8	266	993	(3,734)	3,734			3,734
17													-	-	-	-	-			-
18													-	-	-	-	-			-
19	MGP Amortization (Edelyn)												-	-	-	-	-			-
20	TCJA Credit C Amortization (Nichols)												-	-	-	-	-			-
21	Impact of Cap Ex. Adj. on Deprec. & Prop. Tax (Edelyn)									(1,958)	(901)		5	152	568	(2,135)	2,135			2,135
22	Other Operating Income Adjustments - Interest Income (Edelyn)																			-
23	Proforma Interest (Nichols)				-								0	16	59	76	(76)			(76)
24	Interest Synchronization (Nichols)	-	-	-	-	-	-	-	-	-	-	-	0	0	0	1	(1)	-	-	(1)
25	**Total Adjustments**	-	-	12,759	12,759	-	-	-	(17,980)	(1,958)	(901)	-	54	1,800	6,729	(12,255)	25,014	-	-	25,014
26	**PFD NOI - Test Year**	1,513,094	70,646	127,277	1,711,017	633,882	8,317	5,101	360,150	272,988	111,207	16,268	471	12,919	14,521	1,435,824	275,194	-	2,451	277,645

Consumers Energy Company
Overall Rate of Return Summary
Projected Capital Structure & Cost Rates
for the Projected 12-Month Period Ending September 30, 2020

Appendix D
PFD
Case No.: U-20322

		13-Month	% of	% of		Weighted Cost			
		Average	Permanent	Total	Cost	Permanent	Total	of	Pre-Tax
Line	Description	($000)	Capital	Capital	Rate	Capital	Capital	Debt	Basis
	(a)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Long Term Debt	$ 7,080,064	47.70%	38.30%	4.20%	2.00%	1.61%	1.61%	1.61%
2	Preferred Stock	37,315	0.25%	0.20%	4.50%	0.01%	0.01%		0.01%
3	Common Equity	7,725,058	52.05%	41.78%	9.80%	5.10%	4.09%		5.48%
4	Permanent Capital	$ 14,842,437	100.00%			7.12%			
5	Total Short Term Debt	150,940		0.82%	4.63%		0.04%	0.04%	0.04%
6	Deferred FIT	3,378,368		18.27%	0.00%		0.00%		0.00%
	Deferred JDITC/ITC								
7	Long Term Debt	53,818		0.29%	4.20%		0.01%	0.01%	0.01%
8	Preferred Stock	362		0.00%	4.50%		0.00%		0.00%
9	Common Equity	62,246		0.34%	9.80%		0.03%		0.04%
10	Total Capitalization	$ 18,488,171		100.00%			5.80%	1.66%	7.20%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capital Expenditure and Rate Base Adjustments
for the Projected 12-Month Period Ending September 30, 2020
($000)

Appendix E
PFD
Case No.: U-20322

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Total	Test Year Impacts From Staff Adjustments to Cap Ex Projects				
Line	**Adjustment Description**	**Cap Ex Adj.**	**Plant Adj.**	**Accum Depr.**	**Rate Base**	**Depreciation**	**Property Tax**
1	Contingency 2018	(8,498)	(8,498)	(376)	(8,122)	(215)	(110)
2	IT - Upgrades & Replacements (3 ARP Projects)	(1,628)	(1,342)	(203)	(1,139)	(156)	(17)
3	DISTRIBUTION - Material Condition VSR	(28,555)	(20,135)	(429)	(19,706)	(598)	(261)
4	GAS COMPRESSION & GAS STORAGE - Well Rehab. - ($7m Well & $10.5m Storage)	(17,506)	(12,523)	(233)	(12,290)	(321)	(162)
5	DISTRIBUTION - New Business (3 Other Large Projects)	(10,500)	(9,034)	(218)	(8,815)	(268)	(117)
6	REG COMPLIANCE - Pipeline Integrity - Carryover Costs	(10,481)	(7,469)	(126)	(7,343)	(174)	(97)
7	TED-I - Mid Michigan Pipeline Project	(8,522)	(7,387)	(314)	(7,072)	(172)	(96)
8	OPERATIONS SUPPORT - Asset Preservation	(6,213)	(3,107)	(27)	(3,079)	(54)	(40)
9	**TOTAL**	(91,903)	(69,493)	(1,927)	(67,566)	(1,958)	(901)
11	**TOTAL RATE BASE ADJUSTMENTS**				(67,566)		