Founded in 1852
by Sidney Davy Miller

SHERRI A. WELLMAN
TEL (517) 483-4954
FAX (517) 374-6304
E-MAIL wellmans@millercanfield.com

MILLER CANFIELD

Miller, Canfield, Paddock and Stone, P.L.C.
One Michigan Avenue, Suite 900
Lansing, Michigan 48933
TEL (517) 487-2070
FAX (517) 374-6304
www.millercanfield.com

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March 1, 2024

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing MI 48917

Re: Michigan Gas Utilities Corporation
Case No. U-21540

Dear Ms. Felice:

Enclosed for electronic filing in the above matter are:

(1) Application;
(2) Proposed Notice of Hearing;
(3) Certification of Richard F. Stasik;
(4) Index of Exhibits;
(5) Non-confidential Direct Testimony and Exhibits of Richard F. Stasik, Anthony Reese, Jared J. Peccarelli, Ann E. Bulkley, Riley O’Brien, Shannon L. Burzycki, and Nathan W. Lee.
(6) Non-confidential documentation which complies with Part II of the Rate Case Filing Requirements established by the Commission’s Order dated May 18, 2023, issued in Case No. U-18238;
(7) Proposed Protective Order;
(8) Appearances of Sherri A. Wellman, Paul M. Collins, and Benjamin J. Holwerda; and
(9) Proof of Service reflecting electronic service on the Staff case coordinator and intervenors in Case Nos. U-20718 and U-21366.

Concurrently with this filing, the Staff case coordinator and the parties to Case Nos. U-20718 and U-21366 are being provided all exhibits and workpapers in native format with all formulae intact, as well as documentation addressing Part III of the Rate Case Filing Requirements approved in Case No. U-18238, via the following secure portal link:

https://filelocker.mcps.com/pickup?claimID=EMXzMmpWdXyv3vJg&claimPasscode=xvKGw2GDQFc6TRzc&emailAddr=35629

You have 7 days to retrieve the drop-off; after that the link above will expire.

Claim ID: EMXzMmpWdXyv3vJg
Claim Passcode: xvKGw2GDQFc6TRzc

Finally, as requested by the Staff case coordinator, hard copies of this filing and the workpapers will be directly served on the case coordinator.

Should you have any questions, please kindly advise.

Very truly yours,

Miller, Canfield, Paddock and Stone, P.L.C.

By: ___________________________________
Sherri A. Wellman

SAW/ko
Enclosures
cc w/enc: Richard Stasik (Richard.Stasik@wecenergygroup.com)
Koby Bailey (Koby.Bailey@wecenergygroup.com)
Theodore Eidukas (Theodore.Eidukas@wecenergygroup.com)

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
MICHIGAN GAS UTILITIES CORPORATION	)	Case No. U-21540
for authority to increase retail natural gas rates	)	
and for other relief.	)	

APPLICATION

Michigan Gas Utilities Corporation ("MGUC" or the "Company") hereby requests authority from the Michigan Public Service Commission ("MPSC" or the "Commission") to, among other things, (i) increase rates for the sale, distribution, and transportation of retail natural gas, (ii) continue its Demand Response Pilot Program, (iii) continue its Main Replacement Program ("MRP") rider as approved in Case No. U-21366 and implement MRP surcharges in 2026 and 2027, (iv) continue the relief granted in Case No. U-21114 and extended in Case No. U-21366 by waiving the meter testing requirements of R 460.2351 and authorizing the use of R 460.2351a(3) for sampling and testing, (v) implement a regulatory deferral mechanism for costs incurred to comply with future Leak Detection and Repair ("LDAR") rules as an alternative to rate recovery in this case, and (vi) approve miscellaneous tariff revisions. In support of these requests, MGUC respectfully represents as follows:

I. INTRODUCTION

1. MGUC is a public utility engaged in the purchase, storage, transportation, distribution, and sale of natural gas to approximately 185,000 customers in the Southern and Western portions of Michigan's Lower Peninsula.

2. MGUC is a corporation organized under the laws of the state of Delaware, with its principal office located at 899 South Telegraph Road, Monroe, Michigan 48161, and is authorized to transact business in the state of Michigan. MGUC is a subsidiary of WEC Energy Group, Inc.

3. MGUC's retail natural gas business is subject to the jurisdiction of the Commission pursuant to 1909 PA 300, as amended, MCL 462.2 et seq.; 1919 PA 419, as amended, MCL 460.51 et seq.; 1939 PA 3, as amended, MCL 460.4 et seq and the Michigan Administrative Hearing System's Administrative Hearing Rules, R 792.10401 et seq. Pursuant to these statutory and regulatory provisions, the Commission has jurisdiction to regulate the Company's retail natural gas sales, distribution, and transportation rates to provide the Company with a fair opportunity to recover the costs of providing service to its customers.

4. MGUC's last general base rate proceeding was Case No. U-21366 and concluded by Commission Order Approving Settlement Agreement dated August 30, 2023. The revised rates approved in Case No. U-21366 were based on a 2024 projected test year and an authorized rate of return on common equity of 9.80%.

5. On December 28, 2023, MGUC filed its rate Filing Announcement in Case No. U-21540 pursuant to the Rate Case Filing Requirements established by the Commission's May 18, 2023 Order in Case No. U-18238.

6. This Application is accompanied and supported by the written testimony, exhibits and workpapers of seven Company witnesses. The Company's presentation in this case was prepared in accordance with the Rate Case Filing Requirements of Case No. U-18238 as approved

in the Commission's May 18, 2023 Order and consistent with the temporary waiver relating to Part III.[1]

II. REQUESTED BASE RATE INCREASE

7. Based on 2025 projected costs of providing service to the Company's customers, and due, in large part, to inflation and increased debt costs the Company's retail base rates for natural gas services will be unreasonably low and inadequate.

8. Additionally, this rate filing presents data for a historical year ended December 31, 2022, as required by the Rate Case Filing Requirements. MGUC proposes that rates be established based upon a projected 12-month test year ending December 31, 2025. The use of this projected test year data allows the revised base rates established in this case to more closely reflect the conditions that will likely exist at and after the time the revised base rates set by the final order in this case are placed in effect.

9. Several factors have, and are expected to continue to have, a significant impact on the Company's costs of providing service to its customers, rendering existing base rates unreasonably low, inadequate, and precluding the Company from earning a reasonable return on its investments to provide service to customers. The key drivers for this request include, among other things, historic levels of inflation for materials and labor and increases in interest rates. These inflationary pressures are expected to increase capital projects, operating and maintenance expenses into the 2025 test year, property taxes, the cost of equity, and the cost of debt. Additionally, the Company expects to make infrastructure investments to maintain reliability and safety, and to address new LDAR rules.

[1] MGUC represents that pursuant to the waiver, Attachments 14 and 15 are not part of the Company's Part III filing.

10. The Company will experience a revenue deficiency of $17,575,013 in 2025. The 2025 test year revenue deficiency represents the results of a complete examination of the relevant items of investment, expenses, and revenues for the determination of just and reasonable retail natural gas rates for MGUC's customers.

11. MGUC proposes that retail natural gas rates be established with a rate of return on common equity of 10.25%.

12. MGUC represents that the proposed revenue increase of not less than $17,575,013 annually is required in order for the Company to maintain an adequate, reliable, and safe natural gas transportation and distribution system and to allow MGUC a reasonable opportunity to earn the return to which the Company is entitled by law.

III. RATE DESIGN, TARIFF AND OTHER RATE-RELATED PROPOSALS

13. Effective January 1, 2025, MGUC's proposed rates for each customer class rate schedule reflected in Exhibit A-16, Schedule F5. These rates are designed to recover the projected revenue deficiency of not less than $17,575,013.

14. The Company is proposing to continue its Demand Response Pilot program approved in Case No. U-21366. The Company is also proposing to continue its MRP rider as approved in Case No. U-21366 except because 2025 MRP costs will be rolled into base rates, the Company is requesting to restart its MRP surcharges January 1, 2026 and continue to implement surcharges through 2027 to recover costs incurred after the test year associated with capital investments in the MRP.

15. The Company is also seeking a continuation of the relief granted in Case No. U-21114 and continued in Case No. U-21366, whereby MGUC was authorized to (i) waive the meter testing requirements in Rule 51 of the Technical Standards for Gas Service, Mich Admin Code, R 460.2351 and (ii) use Mich Admin Code, R 460.2351a(3) for statistical sampling and apply the

Natural Gas Diaphragm Meter Testing Procedures used by the American National Standards Institute/American Society for Quality Control ANSI/ASQC Z1.4. Consistent with the Settlement Agreement in Case No. U-21366, as part of this filing, MGUC is providing an evaluation and supporting information addressing why termination cannot occur any sooner than December 31, 2028.

16. In addition, MGUC is seeking miscellaneous revisions to the terms and conditions of its tariffs.

17. MGUC proposes to implement its revised rates no earlier than January 1, 2025, and no later than the day after the Commission issues an order approving MGUC's request, if an order is issued after January 1, 2025.

18. MGUC is also seeking to recover in base rates costs related to compliance with new LDAR rules expected to go into effect in 2025. Alternatively, MGUC is requesting the Commission to approve a regulatory deferral mechanism.

IV. TESTIMONY AND EXHIBITS

19. MGUC is filing herewith written testimony, exhibits and workpapers in support of the requested rate increase and related approvals requested herein. The positions and relief described in the direct testimony and exhibits should be considered as if specifically requested in this Application. MGUC is also filing a proposed Protective Order to govern the release, use and disclosure of certain testimony, exhibits, workpapers, and responses in Part III of the rate case filing requirements that contain confidential information, or in future responses to audit inquiries and discovery.

V. REQUEST OF RELIEF

20. MGUC's current natural gas rates, based on the projected 2025 test year, will be unjust and unreasonable. Such rates are insufficient to permit the Company to recover the costs

of providing service to its customers, including a reasonable return on investments to provide such service, to which MGUC is entitled by law. MGUC's retail natural gas rates are expected to be so low as to deprive it of a reasonable return on its property and investments and will amount to confiscation of the Company's property contrary to MGUC's rights under the Constitution of the United States and the Constitution and laws of the State of Michigan. The inadequacy of these rates reduces the Company's revenues and overall rate of return below a proper and reasonable level, and it is unjust and unreasonable to require MGUC to render natural gas service to its customers at such rates.

WHEREFORE, Michigan Gas Utilities Corporation requests the Commission to:

A. Issue and publish its notice of hearing setting an early hearing date;

B. Find and determine, as based on the Company's direct case, that for service rendered beginning January 1, 2025, existing rates and charges are unreasonably low and inadequate and should be increased to protect the constitutional rights of the Company to earn a reasonable and non-confiscatory return;

C. Authorize the Company to adjust its existing rates and charges so as to produce additional revenue of not less than $17,575,103 annually;

D. Approve changes in charges and terms and conditions of service as addressed in the supporting testimony and exhibits;

E. Authorize all other changes and suggestions made and supported in the Company's testimony and exhibits, including but not limited to (i) the continuation of its Demand Response Pilot Program and MRP rider and surcharges as set forth in the testimony, (ii) continuation of the relief granted in Case No. U-21114 and extended in Case No. U-21366 by waiving the meter testing requirements of R 460.2351 and authorizing the use of R 460.2351a(3) for sampling and testing; (iii) alternatively approve a regulatory deferral mechanism, and (iv) approve miscellaneous tariff revisions; and

F. Grant such other and further relief as may be lawful and proper.

Respectfully submitted,

MICHIGAN GAS UTILITIES CORPORATION

Dated: March 1, 2024 By: ____________________________________

One of its Attorneys
Sherri A. Wellman (P38989)
Paul M. Collins (P69719)
Benjamin J. Holwerda (P82110)
Attorneys for Michigan Gas Utilities Corporation
Miller, Canfield, Paddock and Stone, P.L.C.
One Michigan Avenue, Suite 900
Lansing, MI 48933
(517) 487-2070

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

NOTICE OF HEARING
FOR THE NATURAL GAS
CUSTOMERS OF
MICHIGAN GAS UTILTIES CORPORATION
CASE NO. U-21540

- Michigan Gas Utilities Corporation requests Michigan Public Service Commission approval to increase its retail rates for the sale, distribution, and transportation of natural gas and for other relief.

- The information below describes how a person may participate in this case.

- You may call or write, Michigan Gas Utilities Corporation, 899 S. Telegraph Rd, Monroe, MI 48161, (734) 457-6120 for a free copy of its application. Any person may review the application at the offices of Michigan Gas Utilities Corporation.

- The prehearing conference in this matter will be held:

DATE/TIME:	**___________, _________, 2024, at _____ a.m.**
BEFORE:	Administrative Law Judge _____________
LOCATION:	**Video/Teleconferencing**
PARTICIPATION:	Any interested person may participate. Persons needing any assistance to participate should contact the Commission's Executive Secretary at (517) 284-8090, or by email at mpscdockets@michigan.gov in advance of the hearing.

The Michigan Public Service Commission (Commission) will hold a hearing to consider Michigan Gas Utilities Corporation's (MGUC) March 1, 2024 application for approval to increase its rates for the sale, distribution, and transportation of natural gas, and for other related relief. MGUC seeks Commission approval: (1) to increase beginning January 1, 2025 its natural gas base rates so as to produce an annual revenue increase of $17,575,013; (2) of a Rate of Return of 10.25%; (3) to continue its Demand Response Pilot Program; (4) to continue its Main Replacement Program rider and surcharges; (4) to continue the relief granted in Case Nos. U-21114 and U-21366 by waiving the meter testing requirements of R 460.3251 and authorizing the use of R 460.2351a(3) for sampling and testing; and (5) of all other changes and suggestions made and supported in MGUC's testimony and exhibits.

All documents filed in this case shall be submitted electronically through the Commission's E-Dockets website at: michigan.gov/mpscedockets. Requirements and instructions for filing can be found in the User Manual on the E-Dockets help page. Documents may also be submitted, in Word or PDF format, as an attachment to an email sent to: mpscedockets@michigan.gov. If you require assistance prior to e-filing, contact Commission staff at (517) 284-8090 or by email at: mpscedockets@michigan.gov.

Any person wishing to intervene and become a party to the case shall electronically file a petition to intervene with this Commission by **____________, 2024**. (Interested persons may elect to file using the traditional paper format.) The proof of service shall indicate service upon MGUC's attorney, Sherri A. Wellman, Miller, Canfield, Paddock & Stone, P.L.C., One Michigan Avenue, Suite 900, Lansing, MI 48933.

Any person wishing to participate without intervention under Mich Admin Code, R 792.10413 (Rule 413), or file a public comment, may do so by filing a written statement in this docket. The written statement may be mailed or emailed and should reference Case No. **U-21540**. Statements may be emailed to: mpscedockets@michigan.gov. Statements may be mailed to: Executive Secretary, Michigan Public Service Commission, 7109 West Saginaw Hwy., Lansing, MI 48917. All information submitted to the Commission in this matter becomes public information, thus available on the Michigan Public Service Commission's website, and subject to disclosure. Please do not include information you wish to remain private. For more information on how to participate in a case, you may contact the Commission at the above address or by telephone at (517) 284-8090.

Requests for adjournment must be made pursuant to Michigan Office of Administrative Hearings and Rules R 792.10422 and R 792.10432. Requests for further information on adjournment should be directed to (517) 284-8130.

A copy of MGUC's request may be reviewed on the Commission's website at: michigan.gov/mpscedockets and at the office of Michigan Gas Utilities Corporation. For more information on how to participate in a case, you may contact the Commission at the above address or by telephone at (517) 284-8090.

The Utility Consumer Representation Fund has been created for the purpose of aiding in the representation of residential utility customers in various Commission proceedings. Contact the Chairperson, Utility Consumer Participation Board, Department of Licensing and Regulatory Affairs, P.O. Box 30004, Lansing, Michigan 48909, for more information.

Jurisdiction is pursuant to 1909 PA 106, as amended, MCL 460.551 et seq.; 1919 PA 419, as amended, MCL 460.54 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq.; 1969 PA 306, as amended, MCL 24.201 et seq.; 1982 PA 304, as amended, MCL 460.6j et seq.; and the Michigan Administrative Hearing System's Administrative Hearing Rules, 2015 AC, R 792.10401 et seq.

__________, 2024

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the application of	)	
MICHIGAN GAS UTILITIES CORPORATION	)	Case No. U-21540
for authority to increase retail natural gas rates	)	
and for other relief.	)	

CERTIFICATION OF RICHARD F. STASIK

Richard F. Stasik, Director-State Regulatory Affairs WEC Energy Group ("WEC"), states that, other than the new Part III requirements that are subject to the temporary waiver and specifically identified in the Application, he has provided the data required pursuant to the Rate Case Filing Requirements established by the Michigan Public Service Commission's Order dated May 18, 2023 in Case No. U-18238, and pursuant to these requirements, certifies the data so provided on behalf of Michigan Gas Utilities Corporation, a subsidiary of WEC.

Dated: March 1, 2024

Richard F. Stasik

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **MICHIGAN GAS UTILITIES CORPORATION** for authority to increase retail natural gas rates and for other relief.	)))))	Case No. U-21540

DIRECT TESTIMONY OF
RICHARD F. STASIK

FOR

MICHIGAN GAS UTILITIES CORPORATION

March 1, 2024

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **MICHIGAN GAS UTILITIES CORPORATION** for authority to increase retail natural gas rates and for other relief.	)))))	Case No. U-21540

QUALIFICATIONS
OF
RICHARD F. STASIK
PART I

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Richard F. Stasik. My business address is WEC Energy Group, 231 West Michigan Street, Milwaukee, Wisconsin 53203.

Q. IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am Director – State Regulatory Affairs at WEC Energy Group ("WEC"). WEC is the parent company of Michigan Gas Utilities Corporation ("MGUC" or the "Company").

Q. PLEASE ADDRESS YOUR RESPONSIBILITIES AS DIRECTOR – STATE REGULATORY AFFAIRS AT WEC.

A. I oversee regulatory rate reviews, policy, and advocacy efforts across the holding company, including proceedings before Michigan Public Service Commission ("MPSC" or the "Commission") and regulatory bodies in other states, including Wisconsin and Minnesota. I also act as one of the lead witnesses for WEC's operating utility subsidiaries in those proceedings.

Q. WHAT IS YOUR EDUCATIONAL AND BUSINESS EXPERIENCE?

A. I hold a bachelor's degree, summa cum laude, in accounting and management information systems from the University of Wisconsin – Milwaukee and am a licensed Certified Public Accountant in the State of Wisconsin. Before joining WEC's regulatory team, my current role, in 2016 I was the IT Audit Manager at the Company starting in 2013. Prior to that I held internal and external audit positions in public accounting and companies in the financial services, manufacturing and health care industries for more than ten years.

Q. ON WHOSE BEHALF ARE YOU OFFERING THIS DIRECT TESTIMONY?

A. I am offering this direct testimony on behalf of MGUC.

Q. HAVE YOU EVER TESTIFIED BEFORE A REGULATORY AGENCY?

A. Yes. I have provided direct testimony to the MPSC in the annual reviews of the State Reliability Mechanism charge for UMERC in Case Nos. U-20751, U-21103, and U-21222. I have also provided direct and rebuttal testimony on behalf of UMERC in its Integrated Resource Plan filing in Case No. U-21081, and I have provided direct testimony on behalf of UMERC and its preferred criteria for Legally Enforceable Obligations in Case No. U-21130. I have also provided direct testimony in Michigan Gas Utitlies Company's ("MGUC's") Test Year 2024 rate case in Case No. U-21366.

Outside of Michigan, I have provided testimony to the Federal Energy Regulatory Commission on rate and accounting issues associated with WEC's retired power plant cases (Docket Nos. ER19-226-000, AC19-49-000, AC18-231-000, and ER19-103-000) and to the Public Service Commission of Wisconsin on rate-making issues in rate case cases (Docket Nos. 5-UR-109, 5-UR-110, 6690-UR-126, and 6690-UR-127).

RICHARD F. STASIK
DIRECT TESTIMONY
PART II

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide (1) an overview of MGUC, (2) background on WEC and WEC Business Services ("WBS") and how each of these entities support MGUC's operations, (3) key corporate initiatives for 2025, and (4) MGUC's 2025 projected test year, including a summary of new matters that are starting with the test year and impact MGUC's test year forecast.

Lastly, I will introduce the witnesses that will file direct testimony in support of MGUC's rate application.

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

A. No.

<u>MGUC Overview</u>

Q. Please describe MGUC.

A. MGUC was originally incorporated as the Monroe Gas Light Company in 1859, becoming MGUC in 1951 after almost 100 years of subsequent acquisitions and mergers. While initially in the business of manufacturing gas for its customers, MGUC converted its system to the delivery of natural gas in the early 1950s and expanded dramatically throughout southern Michigan over the next 20 years. MGUC was acquired in 1989 by what is now known as Aquila, and for a brief period was renamed Aquila-Michigan. In 2006, Integrys Energy Group ("Integrys") acquired the utility and restored the name of MGUC. Integrys was acquired and became part of the newly-formed corporate parent, WEC, on June 29, 2015. MGUC continues to operate as a separate utility under its new parent, serving approximately 183,400 natural gas customers in and around Grand Haven, Otsego, Benton Harbor, Coldwater and Monroe.

<u>WEC and WBS Background</u>

Q. Please describe WEC.

A. WEC is a diversified energy production and delivery company with $26.6 billion in market cap as of year-end 2023, serving approximately 1.6 million electric and 3.0 million natural gas customers in Wisconsin, Michigan, Minnesota and Illinois. WEC owns 52,000 miles of gas distribution in addition to 71,700 miles of electric distribution and holds a 60% ownership of American Transmission Company. Other energy infrastructure investments include 100% ownership of Bluewater Gas Storage LLC and ownership interests in several wind energy farms in the Midwest.

Q. Please describe WBS and describe its relationship to MGUC?

A. WBS is a non-regulated subsidiary of WEC. WBS provides a number of shared services to WEC and its operating subsidiary companies, including MGUC, under an affiliated interest agreement ("Agreement") that applies to regulated and non-regulated companies. The Agreement identifies the types of services that the affiliates may provide and receive, as well as certain requirements that are unique to WBS as a centralized service company. The Agreement regarding the specific arrangements between WEC and MGUC was reviewed by the Commission in Case No. U-17682.

Q. What services are provided to MGUC by WBS?

A. WBS provides the following services to MGUC and its other affiliates:

- Administrative (e.g., facility management, printing services);
- Communications (e.g., preparation and dissemination of information to employees, customers, governmental officials, the public and the media);
- Customer (e.g., meter reading and billing, credit, collections, call center operations, market research);
- Environmental (e.g., assessments, investigations, remediation);
- Executive Management (e.g., general business planning, allocation of financial resources);
- External Affairs (e.g., governmental relations, community support, regulatory policy, rate administration);
- Finance (e.g., accounting, finance, treasury, tax, internal audit, risk management, insurance and related financial services);
- Human Resources (e.g. employment, compensation, benefits, wellness);
- Information Technology (e.g., computing hardware, telecommunications, electronic data processing services, infrastructure and application architecture);
- Legal and Governance (e.g., legal advice, regulatory matter administration, real estate, shareholder services); and,
- Supply Chain (e.g., acquisition and provision of goods and services other than fuel, energy commodities or energy transmission).

WBS also provides the following specific services only to its regulated utility affiliates such as MGUC:

- Operational Support and Development (e.g., design, construction and maintenance of distribution lines, technical training, project management, geospatial services, contract administration) and,
- Wholesale Energy and Fuels (e.g., purchasing, marketing and selling natural gas, scheduling and dispatching deliveries, operating natural gas storage facilities).

Q. How are costs allocated between the affiliated companies?

A. The basic pricing principles included in the Agreement are unchanged from the arrangement that MGUC had with WEC and its non-regulated service company, WBS, that was in effect at the time of the filing of MGUC's last rate case, U-21366.

Services that WBS provides to a regulated utility affiliate are priced at cost. Services that a regulated party like MGUC receives from a non-regulated party (except WBS) are priced at the lower of market price or 10% over fully allocated embedded cost. Services that MGUC provides to another affiliated (regulated or non-regulated) party are priced at the higher of market price or fully allocated embedded cost.

Q. Is the arrangement between WBS and MGUC a benefit to MGUC and its customers?

A. Yes, it is. The services provided by WBS represent activities that any utility would need to perform to effectively function as a separate company. WBS generates savings for MGUC and its customers because of the efficiencies and synergies it brings in providing these necessary services. Because WBS provides the same services to all operating utilities within WEC, the costs of these activities can be shared among all of operating utility companies. Although some costs are variable to the size of the company, many of these costs are fixed; therefore, a smaller company would pay a higher amount in proportion to its relative size if the service was provided by an outside party exclusively to MGUC or fully staffed at the local level to perform the functions. MGUC could not self-provide the same overall services provided by WBS at a lower – or even the same – cost.

In addition to economies of scale, MGUC receives the benefit of access to in-house experts who can be retained only by larger companies. For example, many of the same requirements that one utility may face from an environmental or safety compliance perspective will impact other companies within WEC. Having one combined group providing support and research not only lowers the costs but helps to ensure strong compliance programs with broad internal institutional knowledge.

Key Corporate Initiatives

Q. What are MGUC's overall business objectives?

A. MGUC and its sister companies at WEC are focused on fundamentals such as safety, world-class reliability, customer care, financial discipline and operating efficiency. By focusing on these fundamental objectives every day, WEC, and of course MGUC, provide safe, reliable energy to customers at a reasonable cost.

Q. What are some WEC corporate initiatives that impact MGUC and its customers?

A. Between 2025 and 2028, WEC expects to invest more than $20 billion across the company with a focus on modernizing infrastructure, reshaping its generation fleet for a clean, reliable future, continuing its rollout of advanced metering functionality, and upgrading systems and equipment. Included in these initiatives are programs that will benefit MGUC and its customers:

- Enhancing reliability: continued pipeline replacement and system modernization projects, which include the projects that are currently recovered in the Main Replacement Program ("MRP") rider which was approved in Case No. U-20718 and extended/amended in Case No. U-21366. MGUC will also replace the compressor station at Unit 5 at the Partello storage facility to maintain reliability.
- Enhancing field operations to maintain and improve customer care: replacing and standardizing the Work Management system, to Maximo, and upgrading the PCAD system. These projects will reduce system maintenance and operating costs and streamline dispatch and work order management processes.
- Methane reduction goal: a net zero rate of methane emissions from the natural gas distribution lines in our network, represents a decrease of 100% in the rate of methane emissions, per mile, by the end of 2030 from a 2011 baseline.

WEC's long-running focus on customer satisfaction has directly benefitted MGUC customers since WEC's acquisition of Integrys Energy, including MGUC, in 2015. In fact, over the past several years, MGUC was ranked one of the top five midsize natural gas utilities operating in the Midwest in the annual J.D. Power Gas Utility Residential Customer Satisfaction Study. This recognition of MGUC's commitment to customer satisfaction is highlighted by J.D. Power ranking MGUC first in the Midwest in 2018, as well as second in both 2020 and 2021.

Furthermore, the WEC companies, including MGUC, are able to leverage their expertise across the four state jurisdictions, by bringing to bear best practices in operations, customer service, and other areas that directly impact the service provided to customers as well as a superior ability to deliver that service safely and reliably. In its procurement practices, WEC is committed to developing a high-quality supply base to meet its current and future business requirements across the Midwest with particular emphasis on safety, supplier diversity, innovation, and cost reduction.

Q. How do MGUC and WEC together serve local communities in Michigan?

A. Local communities are served by MGUC and WEC in several ways. The Company provides a positive economic impact by hiring employees in the communities it serves and by obtaining services in many cases from local vendors and contractors. MGUC provided $50,000 of support to community-based organizations in 2023 and sponsors community events such as Stockings 4 Soldiers, Ida Festival of Lights, Power of the Purse and local Red Kettle campaigns throughout the service territory.

One of WEC's foundations, the WPS Foundation, supports MGUC directly, reviewing grant proposals and directing donations to nonprofit organizations in MGUC's service territories. For example, over $75,000 in funding was provided in 2023 to community-based organizations like Big Brothers Big Sisters, United Way and Girls on the Run. Funding was also provided to first responders for safety grants to purchase equipment and safety gear. WEC also provides matching gift programs for contributions made by its employees, both active and retired, that support local nonprofit organizations.

<u>MGUC's 2025 projected test year rate case</u>

Q. When were MGUC's base rates last approved?

A. MGUC's base rates were last approved in Case No. U-21366 pursuant to the Commission's August 30, 2023 Order Approving Settlement Agreement.

Q. Is MGUC seeking any changes in its authorized return or capital structure?

A. Yes. As covered in greater detail in the direct testimony of MGUC Company Witnesses Ann Bulkley and Anthony Reese, the Company is seeking a Return on Common Equity of 10.25%, compared to its currently authorized 9.80%.

Q. Is there anything you would like to highlight related to MGUC's proposed capital structure?

A. Yes. While MGUC's analysis actually supports an increase in its authorized permanent equity portion of its capital structure, MGUC is proposing a reduction in its currently authorized permanent equity of 51.0% to 50.9%. This proposed permanenet equity is consistent with the Commission's stated policy objective of utilities to move towards a balanced capital structure of 50% equity and 50% debt.

Q. What is the level of annual increase in base rates that MGUC is seeking in this case?

A. Based on a 2025 projected test year, MGUC's direct case supports a total revenue increase of $17.6 million in its base rates, which represents an increase of approximately 9.74% when compared to the Company's current base rates.

Q. What are the key drivers of this rate case?

A. The underlying conditions giving rise to the key drivers for this rate increase request are simply, (i) the historically high levels of inflation for materials and labor that MGUC has experienced and expects to persist through the test year (summarized in Table 1 below), and (ii) the significant increases in interest rates that have taken place since early 2022, (shown in Table 2 below).

Table 1: Annual Inflation for 2021, 2022 and 2023[1]

Month	2021 Annual Inflation Rate	2022 Annual Inflation Rate	2023 Annual Inflation Rate
January	1.4%	7.5%	6.4%
February	1.7%	7.9%	6.0%
March	2.6%	8.5%	5.0%
April	4.2%	8.3%	4.9%
May	5.0%	8.6%	4.0%
June	5.4%	9.1%	3.0%
July	5.4%	8.5%	3.2%
August	5.3%	8.3%	3.7%
September	5.4%	8.2%	3.7%
October	6.2%	7.7%	3.2%
November	6.8%	7.1%	3.1%
December	7.0%	6.5%	3.4%

Table 2: Federal Reserve Interest Rate Decisions since January 2022[2]

FOMC Meeting Date	Rate Change (bps)	Federal Funds Rate
July 26, 2023	+25	5.25% - 5.50%
May 3, 2023	+25	5.00% - 5.25%
March 22, 2023	+25	4.75% - 5.00%
February 1, 2023	+ 25	4.50% - 4.75%
December 14, 2022	+ 50	4.25% - 4.50%
November 2, 2022	+ 75	3.75% - 4.00%

[1] https://www.bls.gov/charts/consumer-price-index/consumer-price-index-by-category-line-chart.htm
[2] https://www.forbes.com/adivosor/investing/fed-funds-rate-history/

FOMC Meeting Date	Rate Change (bps)	Federal Funds Rate
September 21, 2022	+ 75	3.00% - 3.25%
July 27, 2022	+ 75	2.25% - 2.50%
June 16, 2022	+ 75	1.50% - 1.75%
May 5, 2022	+ 50	0.75% - 1.00%
March 17, 2022	+ 25	0.25% – 0.50%

The inflationary pressures have increased not only Operations and Maintenance ("O&M") expenses over the past three years and continuing into the 2025 test year, but also the costs to complete capital projects, including those placed in-service during 2023 and forecasted to be placed in service during the bridge year (2024) and the 2025 test year.

The most significant upward driver for the total revenue requirement are the costs associated with capital investments made by MGUC since it filed its last rate case. This driver is responsible for $4.2 million of the total revenue requirement increase. This includes $3.3 million of revenue requirement associated with capital projects that will be placed in service through 2025 that are currently included in the MRP rider to be rolled into the Company's base rates.

Non-rate base drivers include day-to-day O&M expenses, bad debt expense, property taxes, along with the cost of equity and the cost of debt. Day-to-day operations and maintenance expenses are forecasted to be $3.1 million higher than they were when MGUC's base rates were last approved in Case No. U-21366. Taxes other than Income Taxes are forecast to increase by $1.2 million, while bad debt expense is forecast to decrease $0.3 million as compared to MGUC's most recent rate case. MGUC's forecasted revenue deficiency includes an increase of $2.9 million resulting in proposed changes to MGUC's capitalization, which is comprised of $1.2 million for the cost of equity and $1.7 million for the cost of debt. MGUC also has a $2.6 million revenue requirement increase related to a forecasted reduction in weather-normalized sales volumes.

Further discussion of these drivers is included in the direct testimony of Company Witness Reese.

Q. Will MGUC be introducing any changes to the MRP approved by the Commission in Case No. U-21366?

A. MGUC is proposing in this case to continue the MRP rider as approved in Case No. U-21366 except because 2025 MRP costs will be rolled into base rates the Company is requesting to further delay implementing MRP surcharges until January 1, 2026 and then will continue to implementing the surcharges through 2027, to recover costs incurred after the test year associated with capital investments included in the MRP rider previously approved by the Commission.

Company Witness Burzycki addresses the updated proposed MRP rider rates for 2026 and 2027 in her direct testimony.

<u>**Leak Detection and Repair**</u>

Q. Does MGUC's revenue requirement for the 2025 test year include the impacts of any regulatory changes?

A. Yes. MGUC's revenue requirement includes the expected impacts of the Pipeline and Hazardous Materials Safety Administration ("PHMSA") Notice of Proposed

Rulemaking ("NPRM") for Leak Detection and Repair ("LDAR") which was released on May 18, 2023 consistent with a the congressional mandate included in the Protecting our Infrastructure of Pipelines and Enhancing Safety ("PIPES") Act of 2020. Company Witness Lee addresses the specific requirements included in PHMSA's proposed NPRM for LDAR.

Q. How has MGUC reflected the impact of PHMSA's proposed NPRM for LDAR in its 2025 test year revenue requirement?

A. As is further explained in Company Witness Lee's direct testimony, PHMSA's proposed NPRM for LDAR increases the amount of MGUC's forecasted Operations and Maintenance costs for the test year by approximately $2 million. Additionally, the proposed PHMSA rules is also expected to increase the amount of MGUC's rate base by approximately $2 million, which increase MGUC's revenue requirement by approximately $0.2 million for the 2025 test year. Witness Reese identifies these costs in his direct testimony and exhibits.

<u>**Introduction of Company Witness**</u>

Q. Please introduce the witnesses that MGUC is providing to support its request for rate relief.

A. MGUC's witnesses include:

1. Financial schedules, capital spending, impacts of the new PHMSA rules on the forecasted capital and O&M forecasts, cost of debt and a summary of the Company's incentive compensation plans – Anthony Reese
2. Return on equity and capital structure – Ann Bulkley of the Brattle Group
3. Rate design & tariff updates – Shannon Burzycki
4. Cost of service – Riley O'Brien

5. Sales forecast – Jared Peccarelli
6. Capital investments made by MGUC since its last rate case and expected cost increases for operations and maintenance and capital projects related to new PHMSA rules – Nathan Lee

Q. Does this conclude your pre-filed direct testimony at this time?

A. Yes it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **MICHIGAN GAS UTILITIES CORPORATION** for authority to increase retail natural gas rates and for other relief.	)))))	Case No. U-21540

DIRECT TESTIMONY AND EXHIBITS OF

Anthony Reese

FOR

MICHIGAN GAS UTILITIES CORPORATION

(PUBLIC REDACTED VERSION)

March 1 2024

Table of Contents

Qualifications of Anthony Reese

Q. Please state your name, business address and position.

A. My name is Anthony Reese. My business address is 231 West Michigan Street, Milwaukee, Wisconsin 53203. I am employed by WEC Business Services, LLC ("WBS"), a subsidiary of WEC Energy Group, Inc. ("WEC"), as Vice President and Treasurer. As part of that role, I am also the Vice President and Treasurer for MGUC.

Q. **For whom are you providing testimony?**

A. I am providing testimony on behalf of Michigan Gas Utilities Corporation ("MGUC" or the "Company"), which is a subsidiary of WEC.

Q. Please describe briefly your educational, professional, and utility background.

A. I have a Bachelors of Arts degree in Accounting from Lakeland College and a Masters of Business Administration from the University of Wisconsin - Milwaukee. I am also a Certified Public Accountant. Prior to joining WEC, I worked for three years in public accounting. Since 2006, I have held a number of positions of increasing responsibility within the finance organization, including Manager of Financial Planning and Analysis from 2011 to 2015, and I was appointed Controller of North Shore Gas Company and The Peoples Gas Light and Coke Company a few months after WEC was formed in 2015. In October 2019, I was named Vice President and Treasurer for WEC. I am responsible for long-range financial planning, forecasting and managing the utilities' revenue requirements, and oversight of WEC's treasury and cash management functions. I have also been involved in all aspects of financial rate case preparation, including evaluation of budgets, sales forecasting, and determination of revenue deficiencies.

Q. Have you previously testified before any regulatory agency?

A. Yes, I have. I have provided direct and rebuttal testimony to the Public Service Commission of Wisconsin associated with rate cases (Docket No. 5-UR-109 & 6690-UR-126), environmental trust financing (Docket No. 6630-ET-101), and renewable asset acquisition (Docket No. 6630-EB-103). I have also provided direct testimony to the Michigan Public Service Commission ("MPSC" or the "Commission") MGUC's 2024 Test Year rate case in Case No. U-21366.

Summary and Purpose of Testimony

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide an explanation of the methodology used to develop MGUC's revenue deficiency for the 2025 projected test year, summarize the drivers of MGUC's 2025 projected revenue deficiency, provide an overview of the required financial filing schedules, and to summarize the Company's incentive compensation plans and how their design provides benefits to MGUC's customers.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-1, Schedules A1 and A2,
Exhibit A-2, Schedules B1 through B4,
Exhibit A-3, Schedules C1 through C11,
Exhibit A-4, Schedules D1 through D5,
Exhibit A-11, Schedules A1 and A2,
Exhibit A-12, Schedules B1 through B5.5,
Exhibit A-13, Schedules C1 through C11,
Exhibit A-14, Schedules D1 through D5,
Exhibit A-17 Known and Measurable ("K&M") O&M,
Exhibit A-18 K&M Inflation,

Exhibit A-19 (confidential and public versions),
Exhibit A-20 (confidential and public versions),
Exhibit A-21 (confidential and public versions),
Exhibit A-22 (confidential and public versions).

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

A. Yes, they were.

Q. Please provide a summary of the subjects you will address in your testimony.

A. I provide testimony and evidence regarding:

1. The revenue deficiency, including:
    a. Capital Structure,
    b. Inflation Rates,
    c. Operations and Maintenance ("O&M") Expenses,
2. Gas Costs and Revenues
3. Incentive Compensation

Q. Please explain, generally, why rate relief is sought at this time.

A. As detailed in my testimony or that of other Company witnesses, MGUC expects a revenue deficiency of approximately $17.6 million or 9.7% in 2025 driven by many reasons including, but not limited to:

- Investing in capital projects that upgrade the gas transmission and distribution systems including investments currently being recovered in the Company's Main Replacement Program ("MRP") rider and moving into base rates;
- Day-to-day operating and maintenance cost increases to ensure safe and reliable gas service; which includes certain Pipeline and Hazardous Materials Safety Administration ("PHMSA") regulatory changes;
- Property tax increases associated with capital investments and tax rate increases; and
- Projecting a higher cost of capital in the 2025 test year.

Witness Lee supports the Company's capital investments and PHMSA regulatory changes and Witness Bulkley supports return on equity and capital structure.

These drivers are being impacted by two Macroeconomic factors (a) historic and projected levels of inflation for materials and labor as well as (b) the significant and swift increases in interest rates that have been taking place since early 2022. Company Witness Stasik provides a table detailing out the Federal Reserve interest rate decisions since January of 2022 and annual inflation rates for 2021, 2022 and 2023 by month.

<u>The Revenue Deficiency</u>

Q. What is the amount of rate relief MGUC is seeking in this proceeding?

A. MGUC's analysis of the test year ending December 31, 2025 indicates a need for an annual rate increase of $17,575,013, approximately $17.6 million or 9.74%, for retail gas operations.

This increase is based off the rates authorized in the Commission's August 30, 2023 Order Approving Settlement Agreement in Case No. U-21366, a proposed return on common equity of 10.25% which is supported by the testimony of Witness Bulkley of the Brattle Group ("Brattle") and total depreciation and amortization expense based on rates and practices from Case No. U-21329. The rates sponsored by Company Witness Burzycki are designed to produce the requested revenue requirement and are based on the cost of service study results sponsored by Company Witness O'Brien.

Q. What test period is MGUC's proposed rate increase based on?

A. MGUC has used a projected test year ending December 31, 2025.

2022 Historic Test Year Exhibits

Q. Please explain Schedule A1 of Exhibit A-1.

A. Schedule A1 of Exhibit A-1 calculates MGUC's 2022 historic test year revenue deficiency based on its rate base, adjusted net operating income, rate of return, and revenue conversion factor. This schedule develops the 2022 Total Company revenue deficiency of $0.8 million, as shown on Line 16, using the 2022 authorized 9.85% return on equity. The component parts of this schedule are taken from the various sources indexed to the left of these amounts.

Q. Please explain Schedule A2 of Exhibit A-1.

A. Schedule A2 of Exhibit A-1 provides 2018 through 2022 historical year financial metrics. The ratios calculated include Return on Common Equity, EBIT Interest Coverage, EBITDA Interest Coverage, FFO Interest Coverage, Overall Fixed Charge Coverage, Cash Flow Coverage of the Dividend, Common Dividend Payout Ratio, and Permanent Capitalization Balances and Percentages.

Q. Please explain Schedule B1 of Exhibit A-2.

A. Schedule B1 of Exhibit A-2 calculates MGUC's 2022 historic test year rate base. The component parts of this schedule are taken from the various sources indexed to the left of these amounts.

Q. Please explain Schedule B2 of Exhibit A-2.

A. Schedule B2 of Exhibit A-2 calculates MGUC's 2022 historic test year utility plant.

Q. Please explain Schedule B3 of Exhibit A-2.

A. Schedule B3 of Exhibit A-2 depicts MGUC's 2022 historic test year accumulated provision for depreciation.

Q. Please explain Schedule B4 of Exhibit A-2.

A. Schedule B4 of Exhibit A-2 calculates MGUC's 2022 historic test year working capital.

Q. Please explain Schedule C1 of Exhibit A-3.

A. Schedule C1 of Exhibit A-3 calculates MGUC's 2022 historic test year adjusted net operating income. Adjusted net operating income includes a $1.25 million adjustment associated with the amortization of a $5.0 million deferral of 2021 interest and depreciation expense associated with capital investments in 2021 and previous years.

Q. Please explain Schedule C2 of Exhibit A-3.

A. Schedule C2 of Exhibit A-3 calculates MGUC's 2022 historic test year gross revenue conversion factor.

Q. Please explain Schedule C3 of Exhibit A-3.

A. Schedule C3 of Exhibit A-3 calculates MGUC's 2022 historic test year total revenue.

Q. Please explain Schedule C4 of Exhibit A-3.

A. Schedule C4 of Exhibit A-3 calculates MGUC's 2022 historic test year cost of gas.

Q. Please explain Schedule C5 of Exhibit A-3.

A. Schedule C5 of Exhibit A-3 calculates MGUC's 2022 historic test year total O&M expense, exclusive of the cost of gas.

Q. Please explain Schedule C6 of Exhibit A-3.

A. Schedule C6 of Exhibit A-3 depicts MGUC's 2022 historic test year total depreciation and amortization expense.

Q. Please explain Schedule C7 of Exhibit A-3.

A. Schedule C7 of Exhibit A-3 calculates MGUC's 2022 historic test year total for taxes other than income taxes.

Q. Please explain Schedule C8 of Exhibit A-3.

A. Schedule C8 of Exhibit A-3 depicts MGUC's 2022 historic test year federal income taxes.

Q. Please explain Schedule C9 of Exhibit A-3.

A. Schedule C9 of Exhibit A-3 depicts MGUC's 2022 historic test year state income taxes.

Q. Please explain Schedule C10 of Exhibit A-3.

A. Schedule C10 of Exhibit A-3 depicts MGUC's 2022 historic test year local taxes.

Q. Please explain Schedule C11 of Exhibit A-3.

A. Schedule C11 of Exhibit A-3 depicts MGUC's 2022 historic test year AFUDC.

Q. Please explain Schedule D1 of Exhibit A-4.

A. Schedule D1 of Exhibit A-4 develops MGUC's 2022 historic test year overall rate of return of 5.30% (shown on Line 20) based on MGUC's 13-month average capital structure, and a 9.85% ROE.

Q. Please explain Schedule D2 of Exhibit A-4.

A. Schedule D2 of Exhibit A-4 develops MGUC's 2022 historic test year embedded cost of long-term debt of 3.29%, based on a 13-month average, as shown on Line 20.

Q. Please explain Schedule D3 of Exhibit A-4.

A. Schedule D3 of Exhibit A-4 develops MGUC's 2022 historic test year cost of short-term debt of 3.17%, based on a 13-month average, as shown on Line 26.

Q. Please explain Schedule D4 of Exhibit A-4.

A. Schedule D4 of Exhibit A-4 indicates that MGUC has no preferred equity outstanding, as shown on Line 2.

Q. Please explain Schedule D5 of Exhibit A-4.

A. Schedule D5 of Exhibit A-4 develops MGUC's 13-month average balance of Adjusted Common Equity of $172.8 million for the 2022 historic test year, as shown on Line 16.

2025 Projected Test Year Exhibits

Q. Please explain Schedule A1 of Exhibit A-11.

A. Schedule A1 of Exhibit A-11 calculates MGUC's 2025 projected test year revenue deficiency based on its rate base, adjusted net operating income, required rate of return (reflective of a return on equity ("ROE") of 10.25%), and revenue conversion factor. This schedule indicates that the 2025 Total Company revenue deficiency is $17.6 million, or 9.74%. The component parts of this schedule are taken from the various sources indexed to the left of each value.

Q. Please explain Schedule A2 of Exhibit A-11.

A. Schedule A2 of Exhibit A-11 provides 2025 projected test year financial metrics with and without rate relief on a ratemaking basis. The ratios calculated include Return on Common Equity, EBIT Interest Coverage, EBITDA Interest Coverage, FFO Interest Coverage, Overall Fixed Charge Coverage, Cash Flow Coverage of the Dividend, Common Dividend Payout Ratio, and Permanent Capitalization Balances and Percentages.

Rate Base

Q. Please explain Schedule B1 of Exhibit A-12.

A. Schedule B1 of Exhibit A-12 calculates MGUC's 2025 projected test year rate base. The component parts of this schedule are taken from the various sources indexed to the left of these amounts.

Q. Please explain Schedule B2 of Exhibit A-12.

A. Schedule B2 of Exhibit A-12 depicts MGUC's 2025 projected test year utility plant. To arrive at the 2025 projected test year utility plant, the September 30, 2023 actual balance of utility plant was projected forward using MGUC's 2023, 2024, and 2025 construction projections.

Q. Please explain Schedule B3 of Exhibit A-12.

A. Schedule B3 of Exhibit A-12 depicts MGUC's 2025 projected test year accumulated provision for depreciation. To arrive at the 2025 projected test year accumulated provision for depreciation, the September 30, 2023 actual balance of accumulated provision for depreciation was projected forward using MGUC's existing plant and 2023, 2024, and 2025 construction projections.

Q. Please explain Schedule B4 of Exhibit A-12.

A. Schedule B4 of Exhibit A-12 calculates MGUC's 2025 projected test year working capital.

Q. Please explain Schedule B5 of Exhibit A-12.

A. Schedule B5 and associated sub schedules 5.1 through 5.5 of Exhibit A-12 depict MGUC's capital expenditures by function and FERC plant account for the 2022 historical year, projected bridge period and 2025 test year.

<u>**Operating Income**</u>

Q. Please explain Schedule C1 of Exhibit A-13.

A. Schedule C1 of Exhibit A-13 calculates MGUC's 2025 projected test year adjusted net operating income.

Q. Please explain Schedule C2 of Exhibit A-13.

A. Schedule C2 of Exhibit A-13 calculates MGUC's 2025 projected test year gross revenue conversion factor.

Q. Please explain Schedule C3 of Exhibit A-13.

A. Schedule C3 of Exhibit A-13 calculates MGUC's 2025 projected test year total revenue.

Q. Please explain Schedule C4 of Exhibit A-13.

A. Schedule C4 of Exhibit A-13 calculates MGUC's 2025 projected test year cost of gas.

Q. Please explain Schedule C5 of Exhibit A-13.

A. Schedule C5 of Exhibit A-13 calculates MGUC's 2025 projected test year total O&M expense, exclusive of the cost of gas by function.

Q. Please explain Schedule C6 of Exhibit A-13.

A. Schedule C6 of Exhibit A-13 depicts MGUC's 2025 projected test year total depreciation and amortization expense based on rates and practices approved in Case No. U-21329.

Q. Please explain Schedule C7 of Exhibit A-13.

A. Schedule C7 of Exhibit A-13 calculates MGUC's 2025 projected test year total for taxes other than income taxes.

Q. Please explain Schedule C8 of Exhibit A-13.

A. Schedule C8 of Exhibit A-13 depicts MGUC's 2025 projected test year federal income taxes.

Q. Please explain Schedule C9 of Exhibit A-13.

A. Schedule C9 of Exhibit A-13 depicts MGUC's 2025 projected test year state income taxes.

Q. Please explain Schedule C10 of Exhibit A-13.

A. Schedule C10 of Exhibit A-13 depicts MGUC's 2025 projected test year local taxes.

Q. Please explain Schedule C11 of Exhibit A-13.

A. Schedule C11 of Exhibit A-13 depicts MGUC's 2025 projected test year AFUDC.

<u>Capital Structure</u>

Q. Please explain Schedules D1 of Exhibit A-14.

A. Schedule D1 of Exhibit A-14 develops MGUC's 2025 projected test year overall rate of return of 6.22%, shown on Line 22, Column G based on MGUC's 13-month average permanent common equity ratio set at 50.9% with a 10.25% ROE, as shown on Line 6.

Q. What adjustments were made to the equity portion of MGUC's capital structure?

A. MGUC has removed certain accounts both from the 2022 historic test year and the 2025 projected test year. For both the 2022 historic test year and the 2025 projected test year Trade Name, Goodwill, and the deferred income taxes associated with Goodwill were removed from MGUC's equity balance. This resulted in a reduction of equity of $29.5 million in 2022, and $29.5 million in 2025, which reduces the revenue requirement.

Q. Please explain Schedules D2 of Exhibit A-14.

A. Schedule D2 of Exhibit A-14 develops MGUC's 2025 projected test year embedded cost of long term debt of 4.91%, based on a 13-month average, as shown on Line 20. There is one new debt issue for the 2024 bridge year, a $40 million 30-year issue in August, with an expected interest rate of 6.65%. There is one new debt issue for the 2025 test year, a $70 million 30-year issue in May, with an expected interest rate of 6.65%.

Q. Please explain Schedules D3 of Exhibit A-14.

A. Schedule D3 of Exhibit A-14 develops MGUC's 2025 projected test year cost of short-term debt of 4.56%, based on a 13-month average, as shown on Line 26. The forecasted borrowing rate includes $157 thousand of fixed fees for credit facility fees and amortization and guarantee fees.

Q. How did you determine the cost rates of long and short term debt reflected in the weighted cost of capital?

A. The cost rate of long term debt reflects the embedded weighted cost of existing long term debt adjusted for two forecasted new issue. The rate for both the August 2024 and May 2025 forecasted issue is 6.65%. It includes the 30 year forecasted benchmark Treasury at 4.60% plus a 205 basis point spread. The 205 basis point spread can be split into multiple components – 120 basis points for the historical credit spread between Treasuries and A rated utilities when the markets are in good order, 15 basis points for private placement, infrequency of issuance and small size and 70 basis point spread risk based on historical market volatility. MGUC estimated a test year incremental short term debt rate of 4.13% using the existing Q3 2023 1 month Commercial Paper rate of 5.50% less projected Federal Reserve Bank Federal Funds rate quarterly decreases of 25 basis points in Q2 2024 through Q4 2025.

Q. Please explain Schedule D4 of Exhibit A-14.

A. Schedule D4 of Exhibit A-14 indicates that MGUC has no preferred equity outstanding, as shown on Line 2.

Q. Please explain Schedule D5 of Exhibit A-14.

A. Schedule D5 of Exhibit A-14 develops MGUC's 13-month average balance of Adjusted Common Equity of $202.1 million for the 2025 projected test year, as shown on Line 16. MGUC requests a 10.25% ROE for the 2025 projected test year in this general rate case proceeding, as supported by Witness Bulkley.

Q. Does MGUC present any other evidence on cost of capital?

A. Yes, it does. Witness Bulkley provides evidence on MGUC's cost of equity by presenting analytical studies employing various utility industry models.

<u>Inflation Rates</u>

Q. Please explain Exhibit A-18.

A. Exhibit A-18 calculates the non-labor inflation rates for 2024 and 2025 using a methodology similar to that used by MGUC in Case No. U-21366. The non-labor inflation rates calculated are 2.5% for 2024 and 2.35% for 2025.

<u>O&M Expenses</u>

Q. Please describe how MGUC developed 2025 O&M expenses.

A. MGUC started with 2023 actual O&M expenses and inflated them to 2025 using the rates developed on Exhibit A-18 for non-labor. The labor inflation factors used were 4.53% for 2024 and 3.99% in 2025, which includes a market adjustment for represented labor in Local 12295 in each year. The labor inflation factors were calculated by using the projected general wage increases by pay group (contract rates for union employees) and weighting them by end of September 2023 MGUC headcount. MGUC then adjusted this 2025 O&M expense value for the K&M items and incremental O&M, as described later in my testimony.

Q. Have any of the MGUC represented contract rates been recently re-negotiated.

A. No, the Local 12295 contract was renewed January 16, 2023 and runs through Janauary 15, 2026 while the Local 417 contract was renewed February 15, 2022 and runs through February 15, 2025. We estimated the Local 417 labor inflation at [redacted] for 2025 based on other WEC represented contracts negotiated during 2023.

Q. Please explain Schedule G1 of Exhibit A-17.

A. Schedule G1 develops the O&M costs for MGUC's 2025 projected test year. This exhibit begins with 2023 actual O&M amounts. The 2023 expenses were first inflated at the estimated inflation factors as calculated on Exhibit A-18. The O&M accounts were further adjusted for known and measureable items.

<u>Known and Measurable Items</u>

Q. Please describe the K&M adjustments included in the 2025 projected test year O&M expenses, as detailed on Schedule G1 of Exhibit A-17 compared to actual O&M expenses from 2023.

A. There are 28 FERC accounts effected by K&M adjustments. MGUC has defined K&M items to be any O&M cost item that was increased (or decreased) at a rate other than the rates of inflation calculated on Exhibit A-18.

Each of these K&M adjustments is discussed in further detail below.

Q. Please explain Schedule G2 of Exhibit A-17.

A. Schedule G2 of Exhibit A-17 calculates the K&M decrease regarding costs to remediate former manufactured gas plant sites in Account 735 Miscellaneous Production Expenses. In its March 30, 1994 order in Case No. U-10503, and its November 10, 2005 order in Case No. U-14657, the Commission authorized MGUC to employ deferred accounting treatment for costs associated with the remediation of former manufactured gas plant ("MGP") sites. Since 2002, MGUC has conducted remediation activities at former manufactured gas plant sites located in:

1. Benton Harbor (Remedial investigations, source removal, groundwater monitoring, and property acquisition),
2. Cadillac (Remedial investigations, groundwater monitoring, source removal, and property acquisition),
3. Coldwater Race Street (Remedial investigations, source removal, groundwater monitoring, and closure documentation),
4. Grand Haven (Remedial investigations, source removal, and groundwater monitoring),
5. Hillsdale (Remedial investigations, source removal, and groundwater monitoring),
6. Otsego (Remedial investigations, source removal, groundwater monitoring, and property acquisition),
7. South Haven (Remedial investigations, source removal, and property acquisition),
8. Sturgis (Groundwater monitoring and closure documentation),
9. Traverse City (Source removal and groundwater monitoring),
10. Coldwater Chicago Street (Remedial investigations and source removal), and
11. Monroe (Remedial investigations).

On page 2 of 2 of Schedule G2 of Exhibit A-17, MGUC calculated the 2025 projected test year amortization expense in accordance with the Commission's current practice of amortizing deferred MGP remediation costs on a vintage basis over ten years. Therefore, for the 2025 projected test year, MGUC has calculated a K&M decrease of $334,944 in Account 735, as shown on Line 8 of page 1 of 2 of Schedule G2 of Exhibit A-17.

Q. Please explain Schedule G3 of Exhibit A-17.

A. Schedule G3 of Exhibit A-17 calculates the K&M increase related to account 832 Maintenance of Reservoirs and Wells. This expense relates to well logging which is the evaluation of well bores and casings for corrosion. It is a PHMSA requirement for each well to be logged every seven years. Two wells are planned to be logged in 2025 while there was only one well in the 2024 test year rate case. The increase of K&M for well logging is estimated to be $60,000 in test year 2025.

Q. Please explain Schedule G4 of Exhibit A-17.

A. As is further explained in Company Witness Lee's direct testimony, PHMSA is proposing new rules for Leak Detection and Repair ("LDAR"), with final rules expected to be published in Fall 2024. Based on analysis of the proposed rules, additional costs at MGUC have been calculated, and include the following work in the specified FERC accounts: 840, 843.7, 856, 863, 865, 870, 874, 875, 878, and 885.

Schedule G4 of Exhibit A-17 calculates the K&M adjustment for account 840 Operation Supervision and Engineering of Storage Facilities. As it relates to the LDAR rules mentioned above, each operator must prepare and follow for each facility one or more manuals of written procedures for conducting operations, maintenance, and emergency preparedness and response activities. Additionally, such manuals must include procedures for eliminating leaks and minimizing releases of gas for storage fields. The Company projects a K&M increase of $25,000 for the 2025 test year.

Q. Please explain Schedule G5 of Exhibit A-17.

A. Schedule G5 of Exhibit A-17 calculates the K&M adjustment for account 843.7 Maintenance of Compressor Equipment. As it relates to the LDAR rules mentioned under the explanation of Schedule G4 of Exhibit A-17, compressors must discharge gas from the blowdown piping at a location where the gas will not create a hazard to public safety. The Company projects a K&M increase of $50,000 for the 2025 test year.

Q. Please explain Schedule G6 of Exhibit A-17.

A. Schedule G6 of Exhibit A-17 calculates the K&M adjustment for account 856 Transmission Mains Expenses. The first associated item is an increase in Casing Vent Replacement expenses. On casings that are not scheduled for replacement, there is a requirement for all casings to have vents installed on an existing casing. This work is completed by contractor crews based on the conditions of the installation and the specialized equipment requirements associated with the installation. These costs represent an estimated four projects at a cost of $25,000 for each of the projects found. The Company projects a K&M increase of $100,000 for the 2025 test year. The second item is the K&M expense regarding the proposed LDAR rules mentioned under the explanation of Schedule G4 of Exhibit A-17. As part of the proposal, MGUC will be required to report any releases greater than 1 MMCF (one million cubic feet) within thirty days of detection, with limited exceptions. Additionally, all transmission lines must be patrolled on a monthly basis, whereas in previous years, transmission lines would be patrolled at a minimum once every three months and up to once every year. The Company projects a K&M increase of $285,000 for the 2025 test year. In total, the Company projects a K&M increase of $385,000 for the 2025 test year for account 856.

Q. Please explain Schedule G7 of Exhibit A-17.

A. Schedule G7 of Exhibit A-17 calculates the K&M adjustment for account 863 Maintenance of Mains. As it relates to the LDAR rules mentioned under the explanation of Schedule G4 of Exhibit A-17, MGUC will be required per the NPRM document 88 FR 31890 §192.770 to take action in order to minimize the release of gas during pipeline blowdowns. Such actions would include minimizing the affected section, flaring, using an in-line or mobile compressor to reduce line pressures, or transferring gas to a segment of lower pressure. The Company projects a K&M increase of $300,000 for the 2025 test year.

Q. Please explain Schedule G8 of Exhibit A-17.

A. Schedule G8 of Exhibit A-17 calculates the K&M adjustment for account 865 Maintenance of Measuring and Regulating Station Equipment. The first associated item is continued station maintenance. MGUC is required to rebuild and maintain regulators, relief valves, control valves, etc. on an annual basis. These parts are also replaced as the result of failures of seats, gaskets, etc. The Company projects a K&M increase of $100,000 for the 2025 test year. The second item is the K&M expense regarding the proposed LDAR rules mentionedunder the explanation of Schedule G4 of Exhibit A-17. As part of the proposal, each section of transmission line between the main line valves must have a blowdown valve. The Company projects a K&M increase of $25,000 for the 2025 test year. In total, the Company projects a K&M increase of $125,000 for the 2025 test year for account 865.

Q. Please explain Schedule G9 of Exhibit A-17.

A. Schedule G9 of Exhibit A-17 calculates the K&M adjustment for account 870 Operation Supervision and Engineering of Distribution Systems. As it relates to the LDAR rules mentioned under the explanation of G4 of Exhibit A-17, MGUC is required to have written procedures to assess and repair any pressure-limiting or relief device that fails to operate or vents gas when it isn't supposed to. This makes leakage survey, investigation, and repair subject to operating qualifications (OQ). The Company projects a K&M increase of $225,000 for the 2025 test year.

Q. Please explain Schedule G10 of Exhibit A-17.

A. Schedule G10 of Exhibit A-17 calculates the K&M adjustment for account 874 Mains and Services Expenses of Distribution Systems. The first item is an increase in overtime labor for Locators. The scope of locates continues to expand each year, putting an upward pressure on O&M expenses. As this trend steadily persists, additional over-time labor is required in order to complete locates within a 72 hour timeframe as mandated by the MISS DIG Underground Facility Damage Prevention and Safety Act. Another significant driver of this increase is the large scale projects for water line replacement as well as additional communication system upgrades. The Company projects a K&M increase of $180,000 for the 2025 test year.

The next associated item is the K&M expense regarding Damage Prevention. MGUC purchases items that contain the MISS DIG logo and the MISS DIG phone number for contractors, public officials, equipment rental businesses, and others that MGUC shares this information with. This also includes funding for onsite meetings with repeat offenders that damage our facilities. We engage MPSC representatives as well during these lunch gatherings. The law along with contractor and company expectations are discussion topics. The Company projects a K&M increase of $125,000 for the 2025 test year.

The third item is the K&M expense regarding the Pipeline Safety Management System (PSMS). PSMS is a recommended practice by The American Petroleum Institute (API) via RP 1173 which has become an industry standard encouraged by

PHMSA. MGUC plans to hire a full time employee to implement and administer this program as well as perform data analysis on integrity management programs. Additionally, current MGUC employees in the Engineering and Compliance departments will be involved in this program. The internal labor for these employees that historically had been charged to capital related work will be decreased, offset by an increase to O&M spend. The Company projects a K&M increase of $150,000 for the 2025 test year.

The fourth item is the K&M expense regarding the proposed LDAR rules mentioned under the explanation of G4 of Exhibit A-17. As part of the proposal, MGUC must implement additional Advanced Leak Detection Program ("ALDP") elements, such as requiring that each operator has possession of and is adherent to a written ALDP. The ALDP will be similar to a DIMP or TIMP program and will require continuous monitoring and updating. Additionally, each operator of a gas distribution pipeline must conduct periodic leakage surveys with approved leak detection equipment. The Company projects a K&M increase of $805,000 for the 2025 test year.

The final item is the K&M expense related the digitization amortization approved in the last rate case. The $1,750,000 is amortized over 15 years starting in January of 2024. The amount of that amortization is $116,700 annually. In total, the Company projects a K&M increase of $1,376,681 for the 2025 test year for account 874.

Q. Please explain Schedule G11 of Exhibit A-17.

A. Schedule G11 of Exhibit A-17 calculates the K&M adjustment for account 875 General Measuring and Regulating Station Expenses. As it relates to the LDAR rules mentioned under the explanation of C4 of Exhibit A-17, MGUC must implement new design standards for any new, replaced, relocated, or otherwise changed relief and limiting devices to minimize unnecessary emissions. The Company projects a K&M increase of $25,000 for the 2025 test year.

Q. Please explain Schedule G12 of Exhibit A-17.

A. Schedule G12 of Exhibit A-17 calculates the K&M adjustment for account 877 Distribution Measuring and Regulating Station Expense. These costs would be associated with maintaining and repairing the grounds of the Benton Harbor, St. Joseph, Coloma, and Wayland gate stations. Such repairs would include—but are not limited to—modification of fencing and gates, increased safety initiatives with lighting upgrades, and repairs associated with grade, drainage, and stone. MGUC would hire contractors to complete the work, and these locations would be based on prioritization rather than district-specific locations. The Company projects a K&M increase of $150,000 for the 2025 test year.

Q. Please explain Schedule G13 of Exhibit A-17.

A. Schedule G13 of Exhibit A-17 calculates the K&M adjustment for account 878 Meter and House Regulator Expenses. As it relates to the LDAR rules mentioned under the explanation of G4 of Exhibit A-17, MGUC must require that each operator or a gas distribution pipeline conducts periodic leakage surveys with approved leak detection equipment. The Company projects a K&M increase of $200,000 for the 2025 test year.

Q. Please explain Schedule G14 of Exhibit A-17.

A. Schedule G14 of Exhibit A-17 calculates the K&M increase for account 880 Other Expenses associated with Maintenance of Facilities. The First item is a K&M associated with moving the dispatch function from an outside contractor to internal personnel. The move is for two primary reasons: first, the vendor contract was up for renewal and proposed pricing was increasing significantly for 2023, and second, MGUC believes through the use of new and existing dispatch employees it can create a larger pool of resources to respond to customer needs along with providing a safer, more reliable and cost-effective service versus the outside vendor. The move results in a K&M decrease of $200,000 in Account 903 and a simultaneous increase for proposed test year 2025 of $647,000 in Account 880. While insourcing the dispatch work has a higher forecasted cost than the current costs, performing these functions with internal resources will be the least costly alternative in 2025. The second item is maintenance work associated with parking lots, building painting (exterior and interior), tuck pointing, upgrades to common areas such as bathrooms and breakrooms, etc. has been identified at certain MGUC facilities. This work will be prioritized based on necessity, with safety being paramount to the decision. The Company projects a K&M increase of $250,000 for the 2025 test year. Further an item associated with gas code compliance leads the Company to project a K&M increase of $100,000 for the 2025 test year.Lastly, a item associated with air quality testing leads the Company to project a K&M increase of $21,000 for the 2025 test year. In total, the Company projects a K&M increase of $1,018,854 for the 2025 test year for account 880.

Q. Please explain Schedule G15 of Exhibit A-17.

A. Schedule G15 of Exhibit A-17 calculates the K&M adjustment for account 885 Maintenance Supervision and Engineering of Facilities. As it relates to the LDAR rules mentioned under the explanation of G4 of Exhibit A-17, MGUC must comply with the PHMSA’s additional notification requirements, which requires references to be more specific. The Company projects a K&M increase of $5,000 for the 2025 test year.

Q. Please explain Schedule G16 of Exhibit A-17.

A. Schedule G16 of Exhibit A-17 calculates the K&M adjustment for account 887 Maintenance of Mains. The first item is an increase in Maintenance of Exposed Main under Bridges. There have been certain mains identified that do not favor replacement due to difficult conditions such as rock and soil contamination. The wrapping of those remaining mains requires specialized equipment and contracted personnel. It will also involve the replacement of current main support devices or hangers. The Company projects a K&M increase of $200,000 for the 2025 test year.

The next item is the K&M expense regarding Right of Way ("ROW") clearing. MGUC will continue to perform ROW clearing for locations that continue to be identified as problem areas. Additionally, ROW that has been cleared in previous years continues to require ongoing maintenance. Current estimates for ROW clearing equate to approximately $25 thousand per week based on the specialized equipment and crew size required for this work. This would equate to approximately 24 weeks of contractor work. The Company projects a K&M increase of $600,000 for the 2025 test year.

The third item is the K&M expense regarding Large Tools Maintenance. MGUC continues to experience increasing expenses associated with large tools maintenance as required by the manufacturer. In some cases, this maintenance must be completed by a third-party, further increasing the overall cost of keeping these large tools in proper working order. Failing to comply with these manufacturer recommendations could result in voided warranties and unnecessary safety hazards. The Company projects a K&M increase of $150,000 for the 2025 test year.

The final item is the K&M expense regarding Small Tools Purchases. MGUC continues to see increasing costs for small tools purchases, driven by the replacement of worn tools with new technologies. Battery-operated options create increased efficiencies and provide employees with a safer option. The Company projects a K&M increase of $75,000 for the 2025 test year. In total, the Company projects a K&M increase of $1,025,000 for the 2025 test year for account 887.

Q. Please explain Schedule G17 of Exhibit A-17.

A. Schedule G17 of Exhibit A-17 calculates the K&M adjustment for account 891 Maintenance of Measuring and Regulating Station Equipment. MGUC continues to address atmospheric corrosion at regulation and city gate locations. The increased costs for sand blasting and painting, including the environments aspects of capturing and disposing of the old paint and primer, increase the cost of continued maintenance. Costs associated with this work are estimated at $8 to $10 thousand for regulator structures and $20 to $25 thousand for city gate stations. The Company projects a K&M increase of $150,000 for the 2025 test year.

Q. Please explain Schedule G18 of Exhibit A-17.

A. Schedule G18 of Exhibit A-17 calculates the K&M adjustment for account 892 Maintenance of Services. The first item is an increase in Cross Bores activity. In response to the MPSC-issued non-compliance letter NC-365527, MGUC has since developed and implemented a plan where customer sewer lines are inspected via camera in order to ensure that there are no conflicts with the Company's facilities. Given the rate at which inspections are being completed and rising contracted inspector costs, Cross Bore expenses are expected to increase beyond the 2025 test year's inflation. The Company projects a K&M increase of $215,000 for the 2025 test year.

The second item is the K&M expense regarding Small Tools Purchases. MGUC continues to see increased cost for small tools related to construction and underground work. Squeeze off tools, small stopping equipment, fusion tools, and pipe cutting tools all require continuous maintenance and repairs. Additionally, new battery-operated options create increased efficiencies and provide employees with a safer option. The Company projects a K&M increase of $60,000 for the 2025 test year. In total, the Company projects a K&M increase of $275,000 for the 2025 test year for account 892.

Q. Please explain Schedule G19 of Exhibit A-17.

A. Schedule G19 of Exhibit A-17 calculates the K&M adjustment for account 902 Meter Reading associated with meter reading expense. MGUC's 2023 O&M basis year includes one-time AMI vendor credit of $442,000 for a partnership credit that was offered during the competitive procurement process recognizing the continued expansion of certain AMI technologies across several WEC utilities. The difference between the $442,000 and the $463,279 of the adjustment are two years of non labor inflation to properly add back the dollars as the credit had inflation calculated on it for both 2024 and 2025.

Q. Please explain Schedule G20 of Exhibit A-17.

A. Schedule G20 of Exhibit A-17 calculates the K&M adjustment for account 903 Customer Records and Collection. MGUC's care center will increase due to higher outsourcing costs $185,000 and call center volumes $65,000. The new vendor cost was a lower cost option than had MGUC stayed with the current vendor. MGUC is executing on moving the dispatch function from an outside contractor to internal personnel. The move is for two primary reasons: first, because contractor pricing is increasing significantly for 2023, and second, MGUC believes it can provide more reliable and cost-effective service using its own resources versus those of the outside vendors. As mentioned above, the move results in a K&M decrease of $200,000 in account 903 and a simultaneous increase for proposed test year 2025 of $647,000 in account 880. As discribed above in relation to Schedule G14 of Exhibit A-17, insourcing this function is the least cost alternative in 2025.

Lastly, is an adjustment associated with one-time credits received in 2023 from an IT vendor we utilize for contracted services in the amount of $296,815. In total, the

Company projects a K&M increase of $346,815 for the 2025 test year for account 874.

Q. Please explain Schedule G21 of Exhibit A-17.

A. Schedule G21 of Exhibit A-17 page 1 of 2 calculates the K&M adjustment associated with uncollectible expense. To be consistent with past practice, MGUC has forecasted its 2025 projected test year uncollectible expense equal to its 5-year historic average of net write-offs, which is $1,887,441. This results in a total K&M decrease of $497,437 in Account 904.

Schedule G12 of Exhibit A-17, page 2 of 2, calculates the 2025 projected test year uncollectible expense of $1,887,441. As shown on this exhibit, for the 5-year period 2018-2022, MGUC's average net uncollectibles have equaled 1.046% of MGUC's tariff revenues. This percent was multiplied by MGUC's 2025 projected test year revenues of $180,399,335 to arrive at a 2025 projected test year uncollectible expense.

Q. Please explain Schedule G22 of Exhibit A-17.

A. Schedule G22 of Exhibit A-17 calculates the K&M adjustment for Account 920 Administrative and General Salaries. There are multiple headcount backfills in the corporate services area of WBS driving the increase in this account. Lastly, MGUC is removing a one-time adjustment related to a 2023 vacation accrual true-up. The Company projects a K&M increase of $189,487 for the 2025 test year.

Q. Please explain Schedule G23 of Exhibit A-17.

A. Schedule G23 of Exhibit A-17 calculates the K&M adjustment for Account 921 Office Supplies and Expense. The increase to this account is driven by an increase in Facilities Maintenance due to an increase in baseline work of $51,175 with inflation. The second item was to remove a credit from 2023 for the reversal of a charge from 2022 that was excluded from the 2024 test year of $1,049,088 in 2023 with inflation. Additionally, we have removed a one-time adjustment related to 2023 supply chain vendor credits received $16,435 with inflation. The Company projects a K&M increase of $1,116,698 for the 2025 test year.

Q. Please explain Schedule G24 of Exhibit A-17.

A. Schedule G24 of Exhibit A-17 calculates the K&M adjustment for Account 923 Outside Services Employed. Costs increases in excess of standard inflation rates are included for external services related to legal and IT software and hardware maintenance. Additionally, additional external services are expected in finance and legal associated with Climate Change, Regulatory Matters, and External Audit Services due to an increase in baseline services. The Company projects a K&M increase of $492,509 for the 2025 test year.

Q. Please explain Schedule G25 of Exhibit A-17.

A. Schedule G25 of Exhibit A-17 calculates the K&M adjustment for Account 924 Property Insurance. There has been a trend for property insurance premiums to increase due to increased claims activity as well as general inflationary pressures on the insurable values of existing property. The Company projects a K&M increase of $6,436 for the 2025 test year.

Q. Please explain Schedule G26 of Exhibit A-17.

A. Schedule G26 of Exhibit A-17 calculates the K&M adjustment for Account 925 Injuries and Damages Expense. There has been an unfavorable trend for liability insurance primarily due to the fact that we remain in the midst of a historically difficult property casualty insurance market cycle. Our liability insurers have cited an uptick in major plaintiff-friendly verdicts and third-party litigation financing as reasons liability claim outcomes have trended unfavorably in recent years. The Company projects a K&M increase of $124,723 for the 2024 test year.

Q. Please explain Schedule G27 of Exhibit A-17.

A. Schedule G27 of Exhibit A-17 calculates the Benefits K&M expenses for MGUC. MGUC is forecasting a K&M increase of $2,491,396 in Account 926, as shown on Line 31.

The 2025 MGUC forecast of employee benefit costs was developed utilizing three forecasting methods depending on the benefit being forecasted. The three methods are: MGUC estimate, inflationary, and actuarial analysis.

Lines 1-5 used MGUC's estimate. Self-insured medical costs, dental costs, and 401(k) costs for active employees were determined by calculating a cost per FTE. The rate per 2023 FTE was then applied to the number of FTE's in the test year and inflated as follows:

- Medical costs – 7.4% for 2024 and 7.42% for 2025, provided by Fidelity
- Dental costs – 2.7% for 2024 and 3.9% for 2025, provided by Delta Dental
- 401(k) benefit costs - general wage inflation factors of 4.53% for 2024 and 3.99% for 2025 were applied

Deferred Compensation was estimated using the July 31, 2023 balance and applying an asset return using assumptions that differ by investment type. Performance unit cost was estimated assuming target level payouts.

Actual costs from 2023 were inflated by the factors developed in Exhibit A-17 for the sub-accounts on lines 7 through 14. The 2025 employee benefit costs for the sub-accounts on lines 17 through 20 were determined by actuarial analysis.

WBS employee benefit cost projections relied on the same assumptions, actuarial analysis, and methodologies used for MGUC employee benefit costs, as described above. WBS total benefit costs and MGUC's share are calculated on page 2, MGUC's share is included on line 23 on page 1.

Q. **Please explain Schedule G28 of Exhibit A-17.**

A. Schedule G28 of Exhibit A-17 calculates the K&M adjustment associated with Account 928 Regulatory Commission Expense. The increase to this account is driven by External Services supporting increased state regulatory matters due to an increase in baseline work. The Company projects a K&M increase of $51,176 for the 2025 test year.

Q. Please explain Schedule G29 of Exhibit A-17.

A. Schedule G29 of Exhibit A-17 page 1 of 2 calculates the K&M adjustment associated with Account 930.2. MGUC has forecasted the projected test year Account 930.2 to be $672,634. That is a K&M increase of $67,339 from the 2023 costs inflated to 2025. This K&M adjustment is associated with MGUC's portion of the return on and of ("Return On/Of") WBS assets and net working capital as allowed in the shared service agreement between MGUC and WBS. The forecasted 2025 Service Company (WBS) Return On/Of is $431,242 as shown on line 14 of page 2. The 2023 actual amount was $346,965. The K&M increase largely represents the difference between the 2023 amount inflated using the inflation factors shown in Exhibit A-18 and the forecasted 2025 Service Company (WBS) Return On/Of amount. Schedule G29 of Exhibit A-17, page 2 calculates the 2025 Service Company (WBS) Return On/Of, which is a combination of Return on Assets and a Depreciation Charge to MGUC from the Service Company.

Depreciation Rates

Q. What depreciation rates were used in this rate case?

A. MGUC used depreciation rates and practices approved in Case No. U-21329.

Q. Does MGUC have a pending depreciation study filed with the MPSC?

A. No

Taxes other than Income Taxes

Q. Please explain Schedules C7 of Exhibit A-13

A. Exhibit A-13 schedule C7 calculates expenses associated with Account 408, MGUC has forecasted the projected test year to be $11.47 million. MGUC's personal property taxes are the main driver of the increase.

Q. How are Michigan Personal Property Taxes Calculated?

A. Michigan personal property taxes are based on the amount of taxable personal property reported in Michigan multiplied by an inflated composite jurisdictional specific mill rate.

Q. How does MGUC estimate personal property tax expense in the current forecasted test year?

A. For the current test year, MGUC forecasts its personal property tax expense by estimating the amount of taxable personal property reported in Michigan related to forecasted changes in gross book value. MGUC also uses the non-labor inflation rates to estimate changes in the composite jurisdiction mill rate. This resulted in the $10.17 million property tax expense forecast included in the projected test year.

Q. What are the year over year increases in Reported Personal Property in Michigan for MGUC?

Table 1 below shows historic (2016-2023) and forecasted (2024-2025) reported personal property for MGUC.

Table 1:

Year	Michigan Reported Personal Property	Year over Year increase
2025	$679 Million	6.4%
2024	$638 Million	8.0%
2023	$591 Million	5.9%
2022	$558 Million	7.5%
2021	$519 Million	5.0%
2020	$494 Million	11.3%
2019	$444 Million	7.8%
2018	$412 Million	5.1%
2017	$392 Million	6.2%
2016	$369 Million	6.0%

Q. How does actual property tax expense for MGUC compare to the tax expense reflected in historic base rates?

A. Table 2 below shows the historic increase in actual property tax expense at MGUC compared to the amount collected in base rates. Utilizing this approach, MGUC's property taxes for tax years 2017-2023 were underestimated by over $10 million.

Table 2: Differences between property tax expenses forecast and included in base rates and actual tax expenses.

Year	Actual Property Taxes Paid	Amount in Base Rates	Over/(Under) Collected Property Tax
2023	7.7 M	6.3 Million	(1.4) M
2022	7.3 M	6.3 Million	(1.0) M
2021	7.1 M	4.0 Million	(3.1) M
2020	6.0 M	4.0 Million	(2.0) M
2019	5.5 M	4.0 Million	(1.5) M
2018	5.1 M	4.0 Million	(1.1) M
2017	4.6 M	4.0 Million	(0.6) M

Matching of Gas Costs and Gas Cost Revenues

Q. Has MGUC matched gas costs and gas cost revenues in the calculation of the revenue deficiency in this general rate case proceeding?

A. Yes. The gas cost recovery factors used to calculate Revenues on Present Rates in the financial filing schedules supporting this application were calculated, such that gas costs equaled gas cost revenues, resulting in one-for-one recovery of gas costs.

2021 Capital Investment Deferral

Q. Does MGUC still have amortization associated with the 2021 capital investment deferral?

A. The 2022 test year included a $1.25 million amortization of a $5.0 million deferral of 2021 interest and depreciation expense associated with capital investments made in 2021 and previous years. This amortization is included in our projected 2025 test year and will continue until the end of 2025.

Incentive Compensation Overview

Q. Please describe MGUC's compensation philosophy.

A. Like most customer-focused businesses, MGUC maintains market-based compensation programs so it can attract and retain a qualified and motivated work force. In order for MGUC to provide the highest level of safe and reliable service to its customers, MGUC must be able to attract, retain, and motivate the talented employees who make it possible to achieve excellent overall utility operations that are safe and reliable. We compete for quality employees in a market that includes regulated and nonregulated energy companies as well as non-energy firms. MGUC's goal is to pay its employees a total cash compensation package designed to bring its employees' total cash compensation to the market median (i.e., 50th percentile) of total cash compensation paid to similarly-situated employees at comparable energy industry and general industry (non-energy) companies. The market median levels are primarily based on data provided by WTW (f/k/a Willis Towers Watson), an internationally recognized firm that specializes in both compensation and benefits consulting services.

MGUC's market-median total cash compensation package is comprised of both a base salary and an annual incentive target "pay at risk" component that depends upon not only individual performance but also certain operational performance goals being met. In other words, receiving MGUC's base pay alone without a payout from its incentive plans would result in MGUC's employees being paid at a level below the market median, because it is the combination of the base pay target and the annual incentive payout target that brings the total compensation of MGUC's employees to the 50th percentile median of comparable companies. Providing incentive pay at a target amount is not a "bonus" paid to employees over and above market levels, but a critical and expected component of a total compensation level that is set at the market median level.

MGUC's compensation programs are reviewed at least annually against the competitive data to ensure its compensation programs remain competitive to attract and retain a quality work force to serve its customers and remain at the market median. MGUC's total cash compensation costs are prudent expenditures that allow MGUC to continue to provide quality service at the level our customers expect while maintaining reasonable rates.

Q. What is the importance of including incentive pay as part of MGUC's total cash compensation package?

A. Incentive compensation is a critical component of total compensation. According to research from WorldatWork, a global nonprofit organization of compensation professionals, virtually all of the companies with which MGUC competes for quality employees have moved a portion of their total cash compensation to variable pay through annual incentive programs, also known as "pay at risk." For example, WorldatWork's 2023-2024 Salary Budget Survey (Exhibit A-19, both confidential and public) report found that 85% of organizations offer some sort of variable pay (WAW SBS 2023-24, page 48). Additionally, the Culpepper 2023-2024 Salary Budget Survey (Exhibit A-20) shows that 82.6% of survey respondents offer short-term cash incentives, with 85.7% of employers with between 2,501 and 10,000 employees (Culpepper SBS 2023-24 page 25). MGUC's "pay at risk" structure is an expected component of a total cash compensation package in today's talent marketplace.

Consequently, if MGUC offered only base pay plans without an incentive compensation pay at risk component, it would make it more difficult for MGUC to attract and retain the quality employees required to provide the level of service that its customers demand. Quality employees expect and demand this type of incentive compensation to recognize superior performance given the prevalence of "pay at risk" plans in the marketplace as demonstrated by the information discussed above. If MGUC went to a more fixed-expense basis for compensation in the form of increased base salaries, it would, without any benefit to the customer, put MGUC at a disadvantage in a market where incentive pay programs are prevalent, and would negatively impact MGUC's ability to attract and retain the quality workforce needed to deliver high levels of customer service.

Q. Is there any other reason why it is important for MGUC to include a "pay at risk" component in its total cash compensation package?

A. Yes. Including annual incentive plans in its compensation program enables MGUC to offer competitive compensation packages that incentivize employees to improve service levels and reduce costs that impact the rates paid by customers. The incentive plan design focuses employees on key goals and objectives that benefit our customers, as its design measures criteria concentrated on cost containment and operational goals that are aligned with the interests of customers rather than financial measures that might be more aligned with the interests of shareholders. By making a portion of its total cash compensation "at risk", MGUC is strengthening the link between pay and performance for its employees, thereby increasing MGUC's ability to engage and compensate its employees for superior performance. Indeed, MGUC's incentive plans are designed to incentivize employees to improve service levels and reduce costs that impact rates so as to directly benefit MGUC's customers. If MGUC were to eliminate incentive compensation and use only base pay to compensate its employees at market-median levels, this could reduce the efficiencies that result from MGUC's ability to engage and incentivize employee accomplishments toward objectives that benefit customers: improved safety, customer satisfaction, and cost control.

Moving incentive pay to base pay could also reduce MGUC's ability to motivate its employees towards further improvements in these areas, thereby denying customers the benefits they would receive from such improvements.

Q. Does a utility's ability to attract and retain a sufficient, qualified, and motivated work force benefit customers?

A. Yes. Attracting and retaining a sufficient, qualified, and motivated work force directly benefits customers, because it ensures there are enough highly proficient employees to perform needed customer work. In addition, customers benefit by MGUC maintaining and improving the productivity and quality of work performed, which reduces overall costs to customers. By retaining trained and experienced employees through a market-competitive compensation program, MGUC is able to avoid incurring the costs of hiring and training employees to replace workers who otherwise would choose to leave MGUC if such a market-competitive program were not in place.

Experienced employees who are familiar with MGUC systems and equipment are more efficient in their performance, further reducing MGUC's operating and maintenance expenses and capital expenditures.

<u>WEC's 2025 Incentive Compensation Plans</u>

Q. What incentive compensation plans will apply to MGUC in the 2025 test year?

A. While the incentive compensation plans for the year 2025 have not been finalized and approved, it is expected that compensation plans essentially identical to MGUC's current plans will remain in place through 2025. There are four different incentive compensation plans applicable to MGUC:

(a) the Short-Term Performance Plan ("STPP");

(b) the Omnibus Stock Incentive Plan ("OSIP");

(c) the Performance Unit Plan ("PUP"), and;

(d) the Non-Executive Annual Incentive Plan.

The first three of these are executive incentive plans.

Executive Incentive Plans

Q. Please give a brief overview of the executive incentive plans.

A. The STPP applies to executive officers of MGUC. It is anticipated that the 2025 plan will apply the same design as the current STPP. For those non-executive officers whose positions primarily relate to utility operations in Michigan, the 2025 annual incentive will apply the same design as the Non-Executive Plan (discussed below). The OSIP contains two parts that award WEC stock units or stock options to employees based on certain financial criteria. MGUC does not expect the metrics in the 2025 OSIP to differ in relevant part from those contained in the current plan. The PUP awards WEC performance stock units to employees based on certain financial criteria. MGUC does not expect the criteria to change in any relevant way in 2025.

The PUP plan is different from the stock unit component of the OSIP in that awards are determined based upon the value of WEC stock and are also contingent on performance measures established by the WEC Board of Directors' Compensation Committee. Such measures within the PUP may include WEC's rank with respect to the performance measures related to selected benchmark utilities, attainment of WEC stock reaching a certain price-to-earnings ratio at the end of a calendar year, or any additional performance measure(s) established by the WEC Board of Directors' Compensation Committee at the beginning of the performance period.

Non-Executive Incentive Plan

Q. Please describe the Non-Executive Incentive Plan.

A. The Non-Executive Incentive Plan sets different annual compensation levels for non-union, non-executive employees based on MGUC's performance against pre-determined goals in a number of areas that the Company believes are in our customers' best interests. A copy of the current Non Executive Incentive Plan is attached to my testimony as Exhibit A-21 (both confidential and public). The plan uses four specific performance measures to determine incentive payouts for MGUC employees as well as WBS employees that provide service to MGUC, all of which are focused on operational aspects of the business, including cost management. The plan does not contain any financial-specific measures that in previous rate cases the Commission has characterized as being of primary benefit to shareholders rather than customers. Instead, MGUC's measures assess cost control applying net income to measure non-fuel O&M expenses, which is weighted at 50% of the total. In addition, employee safety, customer service and supplier and workforce diversity are weighted at a combined 50% of the total. The plan design is summarized as follows and is included as Exhibit A-22 (both confidential and public):

Operational Performance Measure	Description	Weighting
Cost Management Net Income	Assess cost management via non-fuel Net Income, to help maintain or reduce expenses that may be charged to customers in future rate cases.	50%
Employee Safety	Employee safety is measured under two plan components: (1) DART (Days Away Restricted or Transfers) incidents and (2) Lost-Time Injuries. Each component is weighted equally. Performance is measured based on an annual improvement target for MGUC.	15%

Operational Performance Measure	Description	Weighting
Customer Satisfaction	Performance for customer satisfaction is determined by two measures: (1) Overall Satisfaction with Transactions and (2) Overall Satisfaction with MGUC. Each measure is weighted equally. The results for each of these measures are calculated by weighting the average results across the following transactions: Appointments, Billing, Care Center, Digital, Customer Contacts, Gas Emergencies, and Move Orders.	30%
Diversity	Diversity is a two-part, equally-weighted measure. Supplier diversity is based on the amount of spending against predetermined targets with qualified minority-, women-, service-disabled-, and veteran-owned businesses. Workforce diversity is based on evaluation against an agreed set of criteria including recruitment, promotion, and retention.	5%

Q. What is the focus of these operational measures?

A. Our operational measures are focused on improving the quality and safety of services delivered to customers, including cost control of expenses that impact rates. The measures are designed to motivate employees to maintain customer support at a high-quality level and at competitive rates.

Q. Who participates in the Non-Executive Incentive Plan?

A. Participants include non-union, non-executive employees of MGUC, as well as employees of WBS that provide support to MGUC. A portion of the non-executive incentive compensation costs for WBS employees incurred under the Non-Executive Incentive Plan is allocated to MGUC.

Q. Why is the current Non-Executive Incentive Pay Plan, attached as Exhibit A-21, relevant for the present rate case with a 2025 test year?

A. WEC approves its non-executive incentive compensation plans on an annual basis, establishing the metrics applicable to each of its utility affiliates and the targets to be met by those utility affiliates in order to earn payouts based on their performance during that year. If a utility's performance in those metrics meets or exceeds its targets, payout under the plan occurs the following year. The 2024 Non-Executive Incentive Plan is the plan that governs incentive pay for performance that occurs during calendar year 2024. The payouts under this plan will occur no later than March 15, 2025. See Exhibit A-21, page 1, for MGUC and Page 2 for WBS (confidential and public versions). The 2025 plan will be formally adopted in early 2025 and is expected to remain unchanged from 2024. MGUC expects that its non-executive incentive compensation for performance during calendar year 2025 will be governed by a substantially identical plan with the same metrics and weightings.

Q. How does the Cost Management Net Income metric benefit customers?

A. The Cost Management Net Income metric correlates to reductions in Non-Fuel O&M Expenses, benefitting customers by reducing the costs of service that must be recovered from customers in future rate cases. This metric encourages employees to maintain or reduce operational costs at or below the target level set for MGUC. The more O&M costs are reduced, the higher the associated payout for which employees may be eligible. This metric benefits customers because all else being equal, increased income via lowered expenses will reduce the amount of costs to be recovered in future rate cases. To the extent any cost savings are permanent, the result will be lower rates for MGUC customers for years to come.

Q. Is there evidence that the Cost Management Net Income metric has worked to control or reduce MGUC's costs so as to benefit customers?

A. Yes. The Company's recent performance demonstrates that the Net Income cost control metric successfully incentivizes employees to control operating expenses. The Company's performance for the most recent three years for which we have data is as follows:

- 2020 – Based on the 2020 incentive plan, the Company's goal was to achieve net income of $13.7 million. The Company beat that goal by $400 thousand, which resulted from reducing Total 2020 Non-fuel O&M Expense by an equivalent amount.
- 2021 – Based on the 2021 incentive plan, the Company's goal was to achieve net income of $14.8 million. The Company beat that goal by $400 thousand, which resulted from reducing Total 2021 Non-fuel O&M Expense by an equivalent amount.
- 2022 – Based on the 2022 incentive plan, the Company's goal was to achieve anet income of $16.1 million. The Company beat that goal by $500 thousand, which resulted from reducing Total 2022 Non-fuel O&M Expense by an equivalent amount.
- 2023 – Based on the 2023 incentive plan, the Company's goal was to achieve net income of $18.5 million. The Company finished $200 thousand under this goal but within our target performance range of $18.1 to $18.8 million.

In the absence of the cost control metric, MGUCs Non-Fuel O&M Expense from 2020 to present likely would have been higher than MGUC was able to achieve with that metric in place. Moreover, the O&M costs budgeted for the 2025 test year at issue in this rate case likely would have been higher in the absence of the Non-Executive Incentive Plan's cost control and reduction metric. When costs are reduced or controlled in one year, that reduction or control carries through to the basis used in planning the following years' budgets.

Q. Is recovery for the costs of the O&M cost control metric in this rate case consistent with and supported by the ratemaking treatment of such costs in prior rate cases of other utilities?

A. Yes. Recovery for the costs of the O&M cost control metric in this rate case would be consistent with and supported by the regulatory treatment of incentive compensation plan metrics that are designed to control or reduce O&M costs. In *Consumers Illinois Water Company, Docket No. 03-0403* (Order at 14–15), a case often cited by the Illinois Commerce Commission ("ICC") as establishing the standard for recovery of incentive compensation costs, the ICC approved the recovery of Consumers Illinois Water Company's incentive compensation expenses, which included a metric for "maintaining or reducing operating costs at or below budgeted levels."

Q. Is it your opinion that the Commission should allow MGUC to recover the costs associated with the cost control metric for the 2025 test year in this rate case?

A. Yes. Based on the specific evidence presented as to how the O&M cost control metric in the Non-Executive Incentive Plan benefits customers, the Commission should approve the recovery of MGUC's costs associated with the plan's O&M cost control metric in this proceeding.

Q. How does the Employee Safety metric benefit customers?

A. The Employee Safety metric benefits customers by reducing costs and inefficiencies associated with on-the-job accidents. The focus on employee safety is part of a larger effort to create a “Safety Culture” in which all aspects of safety – public safety, customer safety, and employee safety – become a daily part of what we do. By reviewing DART (Days Away Restricted or Transfers) and Lost Time Injuries, MGUC is able to identify the frequency and severity of injuries and illnesses impacting employees at each company and across the organization. Moreover, safer employees are more motivated and efficient than those who operate in a less safe environment. Thus, by encouraging increased safety for employees, this metric leads to more efficiency and lower costs, which are direct benefits to customers.

Q. How does the Customer Satisfaction metric benefit customers?

A. The Customer Satisfaction metric benefits customers by encouraging MGUC employees to improve MGUC’s performance in all of its interactions with customers: appointments, billing, care center, digital experience, customer contacts, move/transfer service, and gas emergencies. Customers are surveyed as to their satisfaction when they have one of these key transactions with the utility. The plan metric is based on the proportion of customers who are “very satisfied” (rating 8, 9 or 10 on a 10-point scale). Results are tracked on an annual basis. MGUC’s customers benefit from this metric because it helps ensure that they continue to receive high-quality service from MGUC employees and encourages further improvements in that service quality.

Q. How does the Diversity metric benefit customers?

A. Our customers represent a diverse population. To the degree that our workforce and our suppliers mirror that diversity, we can benefit our customers through a highly productive and engaged workforce. Our commitment to diversity promotes innovation, demonstrates MGUC’s commitment to and support of the economic and business growth of the communities we serve, and supports and cultivates our relationships with community leaders, advocacy groups, and external stakeholders.

Q. Do you have any comments concerning the interrelation between the Cost Management Non fuel O&M Expense metric and the other three metrics in the Non-Executive Incentive Plan?

A. Yes. The Employee Safety, Customer Satisfaction and Diversity metrics demonstrate that the cost control metric's target is not a one-dimensional goal, intended to be met solely by eliminating costs and neglecting investment in people and programs needed for the long-term sustainability of MGUC's operations. These metrics demonstrate MGUC's emphasis on providing safe and reliable gas distribution service to its customers, and the cost control metric demonstrates MGUC's emphasis on managing its operations to achieve these service goals in an efficient and cost-effective manner. In this way, the four metrics work together to encourage MGUC's non-executive employees to improve safety, reliability and service to customers, but in an efficient and non-wasteful manner. The result is that customers receive the benefits of both improved safety, reliability and service and the costs they pay for that service being controlled or reduced.

Q. Do you propose that MGUC recover, in rates, the costs of the Non-Executive Incentive Plan in their entirety?

A. Yes, for the reasons stated above.

Q. Does this conclude your pre-filed direct testimony at this time?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of	)	
MICHIGAN GAS UTILITIES CORPORATION	)	
for authority to increase retail natural gas rates	)	Case No. U-21540
and for other relief.	)	
	)	

DIRECT TESTIMONY AND EXHIBITS OF

JARED J. PECCARELLI

FOR

MICHIGAN GAS UTILITIES CORPORATION

March 1, 2024

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **MICHIGAN GAS UTILITIES CORPORATION** for authority to increase retail natural gas rates and for other relief.	)))))	Case No. U-21540

QUALIFICATIONS
OF
JARED J. PECCARELLI
PART I

Q. Please state your name, position and business address.

A. My name is Jared Peccarelli. My business address is 231 West Michigan St., Milwaukee, WI 53203. I am employed by WEC Business Services, LLC ("WBS"), a subsidiary of WEC Energy Group, Inc. ("WEC"), as Manager - Sales Forecasting

Q. For whom are you providing testimony?

A. I am providing testimony on behalf of Michigan Gas Utilities Corporation ("MGUC" or the "Company"), a subsidiary of WEC.

Q. Please describe briefly your educational, professional, and utility background

A. I received both a Bachelor of Science degree in Computer Science and a Master of Business Administration degree with a finance concentration from the University of Wisconsin – Milwaukee. In addition, I have completed all coursework required for a Master of Science degree in Applied Economics from Marquette University in Milwaukee, Wisconsin. I was hired by We Energies (a subsidiary of WEC Energy Group) in November 2002 and worked in various roles in several departments prior to my current position. I joined the Sales Forecasting team in Finance as a Principal Analyst in 2014 and have developed or assisted in the development of long-term electric and natural gas sales forecasts for multiple WEC operating utility subsidiaries since then. I am currently responsible for overseeing the development of the long-term sales forecasts for all of the electric, natural gas and steam utility operating subsidiaries of WEC, including MGUC.

Q. Have you previously testified before any regulatory agency?

A. Yes. I have submitted direct testimony concerning sales forecasting on behalf of MGUC's 2021-2022 GCR Plan and 2024-25 GCR Plan before the Michigan Public Service Commission ("MPSC" or the "Commission") in Case Nos. U-20818 and U-21441. I have also submitted direct, rebuttal and surrebuttal testimony related to sales forecasts for multiple operating utility subsidiaries of WEC and before the Public Service Commission of Wisconsin, the Minnesota Public Utilities Commission and the Illinois Commerce Commission in general rate case proceedings.

JARED J. PECCARELLI
DIRECT TESTIMONY
PART II

Q. What is the purpose of your pre-filed direct testimony?

A. The purpose of my direct testimony is to provide an explanation of the methodology used to develop MGUC's weather normalization procedure and resulting sales forecast for the 2025 projected Test Year.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-5	E1	Annual Service Sales by Major Customer Classes and System Output 5-Year Historical;
A-15	E1	Market Outlook: 5-Year Annual Calendar Year Gas Forecast by Class

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

A. Yes, they were.

Q. Please explain Exhibit A-5, Schedule E1.

A. Exhibit A-5, Schedule E1, is a summary of the five-year Historical Annual Service Area Sales by Major Customer Classes and System Output. This exhibit is filed in accordance with the Commission's rate case filing directive in Case No. U-18238.

Q. Please explain how the MGUC's 2025 projected Test Year sales forecast was developed.

A. The sales forecasts for the Residential, Small General Service ("SGS"), Large General Service ("LGS") and Transportation classes were developed using a combination of four methods.

The first method was a multiplicative approach used for the Residential and SGS classes. Regression models were developed in the Itron MetrixND forecasting application to forecast the number of customers and the average use per customer for each class. The total sales for each class were estimated by multiplying the customer count forecast by the average use per customer forecast. The supporting regression models[1] used historical monthly data covering the period January 2014 through October 2023. The regression models estimate the relationship between the dependent variables (e.g., average use per customer, number of customers) and independent variables such as economic, demographic, weather and seasonal factors, and then project future levels of average use per customer and number of customers. One of the economic variables used in the average use per customer models was the price of natural gas. The forecasted price of natural gas was based on the NYMEX Henry Hub as of November 15, 2023, with an average price of $4.12/dth for 2025.

Gas Cost Recovery ("GCR") and Gas Customer Choice ("GCC" or "Choice") customers were included in the same average use per customer and number of customers models for the Residential and SGS classes. For example, the Residential average use per customer model forecasted total residential usage whether the customers were GCR or Choice customers. The monthly estimates from the average use per customer models were multiplied by the monthly estimates from the number of customers model to forecast total sales volumes for each class.

[1] The historical time period of January 2014 through June 2023 was used for the SGS use per customer model. The adjustment in the ending month was made to address volatility in calendar sales from July 2023 through October 2023. This volatility consisted of several months of negative volumes and other months with higher than expected sales due to billing corrections / unbilled adjustments. The elimination of these 4 months resulted in more reasonable model estimates.

The forecasted sales for each class were then disaggregated into GCR and GCC sales forecasts based on recent historical Choice customer counts. In other words, the number of Choice customers in the forecast horizon was assumed to remain constant and the balance were assumed to be GCR customers.

The second method was used for the Medium General Service ("MGS") class. The average use-per-customer estimate was set equal to the actual use-per-customer for the 12-month period from November 2022 through October 2023 due to the minimal historical actual sales available when the forecast was prepared (approximately 18 months). The MGS customer forecast assumed a growth rate of 5 customers per year. The base year of this projection was 2023 which was estimated to average 8 customers using actuals through October. This resulted in an average of 18 customers forecasted in the Test Year. The annual estimates for the average use per customer were then multiplied by the annual estimates of customer counts to forecast total annual sales volumes.

The third method was used for the Large General Service ("LGS") class. The LGS customers were forecasted individually based on a rolling 12-month sum of billed sales through October 2023. One large customer was removed from this historical analysis because they switched to transportation service during the year. This customer accounted for approximately half of the sales in the LGS class in 2022.

The fourth method was used for the Commercial Transportation and Transportation Aggregation customers. These customers were forecasted individually based on customer-specific information provided by the account management team. These forecasts were then compared to the rolling 12-month sum of billed sales through October 2023. The forecast for one customer was adjusted (lowered) in the Test

Year to capture a substantial decrease in the most recent billed monthly sales which were not captured in the estimate from the account management team.

Q. Please explain how normal weather was defined when developing the sales forecast.

A. Normal weather was defined as the average of the 15 coldest years in the most recent 16-year historical period using heating degree days with a set point of 65 degrees Fahrenheit. This methodology was agreed upon in Case No. U-17273 in 2013 and has been used by MGUC in all rate case forecasts since. For the 2025 projected Test Year, the annual total of 6,176 heating degree days was based on the 16-year period of 2007 through 2022 with the warmest year, 2012, removed from the calculation.

Q. Please explain the development of the weather data.

A. Actual heating degree days were calculated on a daily basis by subtracting the average daily temperature from the set point of 65 degrees Fahrenheit. The calculation used a floor value of zero which meant that an average daily temperature equal to or greater than 65 degrees resulted in zero heating degree days for the day. Each day's average temperature was calculated by averaging all of the hourly temperature values for the day. The hourly temperatures were provided by DTN, a third-party data, analytics and technology service provider.

The Company used the weighted average weather data from four weather stations to calculate actual and normal heating degree days. The weightings for each distinct area of MGUC's service territory were:

1) Benton Harbor, MI: 37.4%
2) Monroe, MI: 31.3%

3) Coldwater, MI: 15.9%

4) Grand Rapids. MI: 15.4%

These weightings were based on the estimated number of customers in proximity to each weather station as a percentage of total company customers. The estimate was based on the number of residential, small general service, and large general service customers as of October 2015. The customers were grouped by zip code and then aggregated to counties to be assigned to the geographically closest weather station.

Q. What is the 2025 Test Year forecast of retail and transportation deliveries?

A. The 2025 Test Year forecast of retail and transportation deliveries, excluding company use and losses, is 34,294 MMcf as presented in Exhibit A-15, Schedule E1. System Output in the Test Year is projected to be 34,682 MMcf.

Q. How does the 2025 Test Year forecast compare to 2023 weather-normalized deliveries?

A. The 2025 Test Year forecast of total deliveries is 1.3% lower than 2023 weather-normalized deliveries. The 2025 Test Year forecast of Residential deliveries is 0.9% lower than 2023 weather-normalized deliveries. Residential deliveries include GCR and GCC customers. The 2025 Test Year forecast of Commercial deliveries is 2.6% higher than 2023 weather-normalized deliveries. Commercial deliveries include SGS GCR, SGS GCC, MGS GCR, MGS GCC and Commercial Lighting customers. The 2025 Test Year forecast of Industrial deliveries is 3.8% lower than 2023 weather-normalized deliveries. Industrial deliveries include LGS GCR, LGS GCC, Special Contract, and End-Use Transportation customers.

Q. Why is the 2025 Test Year forecast of Residential deliveries lower than 2023 weather-normalized deliveries?

A. The 2025 Test Year forecast of Residential deliveries are lower than 2023 weather-normalized deliveries because the average use per customer forecast for the 2025 Test Year are lower than the 2023 weather-normalized average use per customer. The primary driver of the lower forecasted use per customer is energy efficiency. The average use per customer regression model included a variable capturing the (decreasing) energy intensity of natural gas furnaces for residential consumers. The projection of falling energy intensity was provided by Itron, Inc., based on data from the U.S. Energy Information Administration.

Q. How does the 2025 Test Year forecast compare to the 2024 Test Year forecast used to set rates in the settlement agreement approved by the Final Order in Case No. U-21366?

A. All references to the 2024 Test Year forecast in this answer refer to the 2024 Test Year forecast which was used to set rates in Case No. U-21366. The 2025 Test Year forecast of total deliveries is 2.1% lower than the 2024 Test Year forecast. The 2025 Test Year forecast of Residential deliveries is 6.4% lower than the 2024 Test Year forecast and 1.3% lower than 2023 weather-normalized sales. The 2025 Test Year forecast of Residential deliveries is much lower than the 2024 Test Year forecast because it reflects more recent weather-normalized average-use-per customer trends than implied in the 2024 Test Year forecast. For example, the Residential weather-normalized average use-per-customer decreased by 5.7% between 2022 and 2023. The 2025 Test Year forecast assumes continued downward pressure on average use-per-customer primarily due to energy efficiency improvements in natural gas furnaces. In comparison, the 2024 Test Year forecast was 5.8% higher than 2023 weather-normalized sales. As a result, the 2025 Test

Year forecast is reasonable.

The 2025 Test Year forecast of Commercial deliveries is 1.1% higher than the 2024 Test Year forecast. The 2025 Test Year forecast of Industrial deliveries is 0.9% higher than the 2024 Test Year forecast.

Q. What is the impact of the 2025 Test Year forecast on the 2025 Test Year revenue deficiency?

A. The reduction in total sales of 2.1% noted above results in an increase in the revenue deficiency.

Q. Does this complete your pre-filed direct testimony at this time?

A. Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION
***

In the matter of the application of	)	
MICHIGAN GAS UTILITIES CORPORATION	)	
for authority to increase retail natural gas rates	)	Case No. U-21540
and for other relief	)	
	)	

DIRECT TESTIMONY AND EXHIBITS OF

ANN E. BULKLEY

ON BEHALF OF

MICHIGAN GAS UTILITIES CORPORATION

March 1, 2024

TABLE OF CONTENTS

EXHIBITS

Exhibit A-14, Schedule D6:	Summary of Results
Exhibit A-14, Schedule D7:	Proxy Group Selection
Exhibit A-14, Schedule D8:	Constant Growth DCF Model
Exhibit A-14, Schedule D9:	CAPM and ECAPM
Exhibit A-14, Schedule D10:	Long-term Average Beta
Exhibit A-14, Schedule D11:	Market Return
Exhibit A-14, Schedule D12:	Bond Yield Plus Risk Premium
Exhibit A-14, Schedule D13:	Capital Expenditures Analysis
Exhibit A-14, Schedule D14:	Regulatory Risk Analysis
Exhibit A-14, Schedule D15:	Size Premium Analysis
Exhibit A-14, Schedule D16:	Capital Structure Analysis

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the application of	)	
MICHIGAN GAS UTILITIES CORPORATION	)	
for authority to increase retail natural gas rates	)	Case No. U-21540
and for other relief	)	
	)	

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Ann E. Bulkley. I am a Principal at The Brattle Group ("Brattle"). My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this direct testimony before the Michigan Public Service Commission ("Commission") on behalf of Michigan Gas Utilities Corporation ("MGUC" or the "Company").

Q. Please describe your education and experience.

A. I hold a Bachelor's degree in Economics and Finance from Simmons College and a Master's degree in Economics from Boston University, with over 25 years of experience consulting to the energy industry. I have advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. My resume and a summary of testimony that I have filed in other proceedings is attached as Attachment A to this testimony.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to present evidence and provide a recommendation regarding the appropriate return on equity ("ROE") for MGUC, and to assess the reasonableness of its proposed capital structure for ratemaking purposes.

Q. Are you sponsoring any exhibits in support of your direct testimony?

A. Yes. I am sponsoring Exhibit A-14, Schedules D6 through D17, which were prepared by me or under my direction.

Q. Please provide a brief overview of the analyses that led to your ROE recommendation.

A. In developing my recommendation regarding the Company's proposed ROE in this proceeding, I have estimated the cost of equity by applying several traditional estimation methodologies to the proxy group, specifically the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Empirical Capital Asset Pricing Model ("ECAPM"), and a Bond Yield Risk Premium ("BYRP" or "Risk Premium") analysis. My recommendation also takes into consideration the Company's relative business and regulatory risk as compared with the proxy group, and the Company's proposed capital structure as compared with the capital structures of the operating utilities of the proxy group companies. While I do not make specific adjustments to my ROE recommendation for these factors, I did consider them in the aggregate when determining where my recommended ROE falls within the range of the analytical results.

Q. How is the remainder of your testimony organized?

A. The remainder of my direct testimony is organized as follows:

- Section II provides a summary of my analyses and conclusions.
- Section III reviews the regulatory guidelines pertinent to the development of the cost of capital.
- Section IV discusses current and projected capital market conditions and the effect of those conditions on MGUC's cost of equity.
- Section V explains my selection of the proxy group.
- Section VI describes my analyses and the analytical basis for my recommendation of the appropriate ROE for MGUC.
- Section VII provides a discussion of specific regulatory, business, and financial risks that have a direct bearing on the ROE to be authorized for MGUC in this case.
- Section VII provides an assessment of the reasonableness of MGUC's proposed capital structure.
- Section IX presents my conclusions and recommendations.

II. SUMMARY OF ANALYSIS AND CONCLUSION

Q. Please summarize the key factors considered in your analyses and upon which you base your recommended ROE.

A. The key factors that I considered in my cost of equity analyses and recommended ROE for the Company in this proceeding are:

- The United States Supreme Court's *Hope* and *Bluefield* decisions[1] established the standards for determining a fair and reasonable authorized ROE for public utilities, including consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and the requirement that the result lead to just and reasonable rates.

[1] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*"); *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*").

- The effect of current and prospective capital market conditions on the cost of equity estimation models and on investors' return requirements.

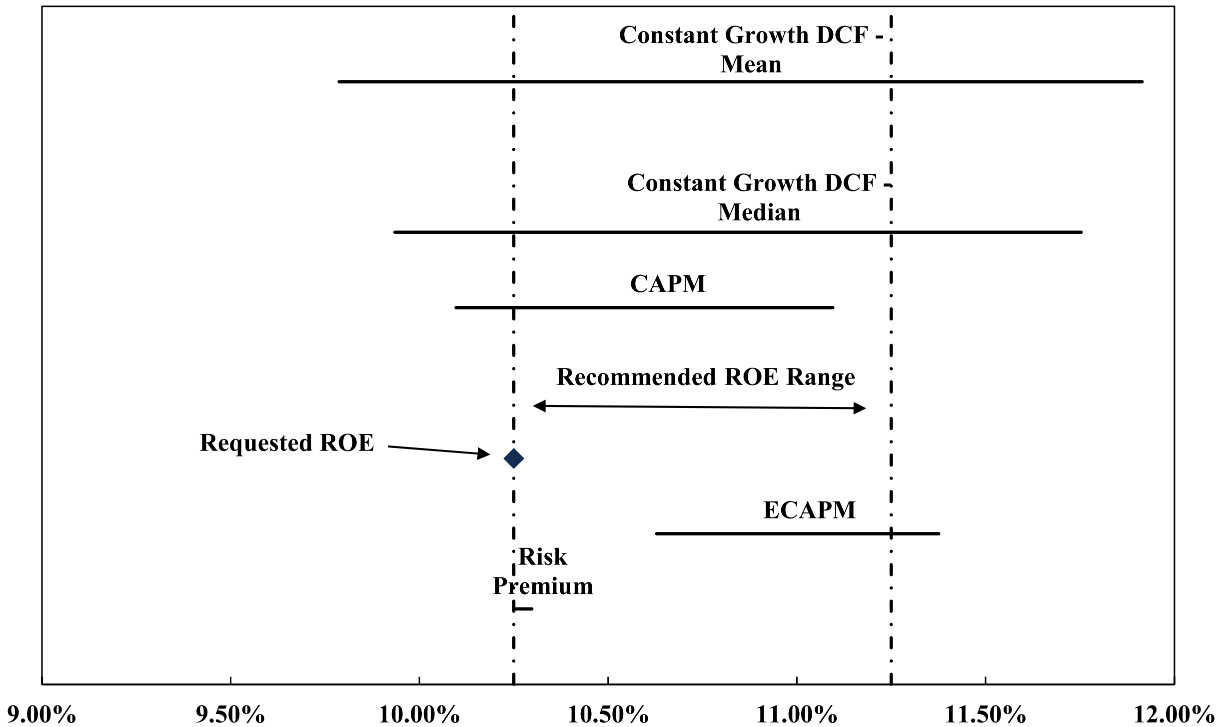
- The results of several analytical approaches that provide estimates of the Company's cost of equity. Because the Company's authorized ROE should be a forward-looking estimate over the period during which the rates will be in effect, these analyses rely on forward-looking inputs and assumptions (*e.g.*, projected analyst growth rates in the DCF model, forecasted risk-free rate and market risk premium in the CAPM analysis).

- Although the companies in my proxy group are generally comparable to MGUC, each company is unique, and no two companies have the exact same business and financial risk profiles. Accordingly, I considered the Company's regulatory, business, and financial risks relative to the proxy group of comparable companies in determining where the Company's ROE should fall within the reasonable range of analytical results to appropriately account for any residual differences in risk.

Q. What are the results of the models that you have used to estimate the cost of equity for the Company in this proceeding?

A. Figure 1 summarizes the range of results of my cost of equity analyses.

Figure 1: Summary of Cost of Equity Analytical Results



As shown, the range of results across all methodologies is wide. While it is common to consider multiple models to estimate the cost of equity, it is particularly important when the range of results varies considerably across methodologies.

Q. Are prospective capital market conditions expected to affect the results of the cost of equity for the Company during the period in which the rates established in this proceeding will be in effect?

A. Yes. Capital market conditions are expected to affect the results of the cost of equity estimation models. Specifically:

- Long-term interest rates have increased substantially in the past two years and are expected to remain relatively high at least over the next year in response to inflation.

- Since (i) utility dividend yields are less attractive than the risk-free rates of government bonds; (ii) interest rates are expected to remain near current levels over the next year, and (iii) utility stock prices are inversely related to changes in interest rates; utility share prices may remain depressed.
- Rating agencies have responded to the risks of the utility sector, citing factors including elevated capital expenditures, interest rates, and inflation that create pressures for customer affordability and prompt rate recovery, and have noted the importance of regulatory support in their current outlooks.
- Similarly, equity analysts have noted the increased risk for the utility sector as a result of rising interest rates and have expected the sector to underperform in 2024.
- Consequently, it is important to consider that if utility share prices decline, the results of the DCF model, which relies on current utility share prices, would understate the cost of equity during the period that the Company's rates will be in effect.

It is appropriate to consider all of these factors when estimating a reasonable range of the investor-required cost of equity and the recommended ROE for the Company.

Q. What is your recommended ROE for the Company in this proceeding?

A. Considering the analytical results of the cost of equity models, current and prospective capital market conditions, and the Company's regulatory, business, and financial risk relative to the proxy group, I conclude that an ROE in the range of 10.25 percent to 11.25 percent is reasonable. The Company's requested ROE of 10.25 percent is within, albeit at the low end of, the range.

Q. Is MGUC's requested capital structure reasonable and appropriate?

A. Yes. The Company's proposed capital structure of 50.9 percent equity and 49.1 percent long-term debt is within the range of the actual capital structures of the utility operating subsidiaries of the proxy group companies, and the Company's proposed equity ratio is below the average of the proxy group. Further, the Company's proposed equity ratio is reasonable considering credit rating agencies' continued concern with the negative effect on the cash flows and credit metrics associated relatively high interest rates and inflation, record levels of capital spending, and the need to fund capital spending in a credit supportive manner.

III. REGULATORY GUIDELINES

Q. Please describe the guiding principles to be used in establishing the cost of capital for a regulated utility.

A. The U.S. Supreme Court's precedent-setting *Hope* and *Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's authorized ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) the principle that the specific means of arriving at a fair return are not important, only that the end result (*i.e.*, an ROE that reflects investors' requirements for investments of comparable risks and supports a utility's credit quality and access to capital) leads to just and reasonable rates.[2]

Q. Has the Commission provided similar guidance in establishing the appropriate return on common equity?

A. Yes. For example, in its decision in Case No. U-20963, the Commission stated that:

> The criteria for establishing a fair ROR for public utilities is rooted in the language of the landmark United States (U.S.) Supreme Court cases

[2] *Bluefield*, 262 U.S. at 692-93; *Hope*, 320 U.S. at 603.

> *Bluefield Waterworks & Improvement Co v Public Serv Comm of West Virginia*, 262 US 679; 43 S Ct 675; 67 L Ed 1176 (1923), and *Federal Power Comm v Hope Natural Gas Co*, 320 US 591; 64 S Ct 281; 88 L Ed 333 (1944). The Supreme Court has made clear that, in establishing a fair ROR, consideration should be given to both investors and customers. As stated on page 12 of the December 23, 2008 order in U-15244 (December 23 order), "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." Nevertheless, the Commission observes that the determination of what is fair or reasonable, "is not subject to mathematical computation with scientific exactitude but depends upon a comprehensive examination of all factors involved, having in mind the objective sought to be attained in its use." Meridian Twp v City of East Lansing, 342 Mich 734, 749; 71 NW2d 234 (1955).[3]

This guidance is in accordance with my view that an authorized rate of return on equity must be sufficient to enable regulated companies, like MGUC, the ability to attract equity capital on reasonable terms.

Q. Is fixing a fair rate of return just about protecting the utility's interests?

A. No. As the court noted in *Bluefield*, a proper rate of return not only assures "confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit [but also] enable[s the utility] to raise the money necessary for the proper discharge of its public duties."[4] As the Court went on to explain in *Hope*, "[t]he rate-making process … involves balancing of the investor and consumer interests."[5]

[3] MPSC Case No. U-20963, 12/22/2021 Order, at 221-222.

[4] *Bluefield*, 262 U.S. at 679, 693.

[5] *Hope*, 320 U.S. at 591, 603.

Q. Why is it important for a utility to be allowed the opportunity to earn an ROE that is adequate to attract capital at reasonable terms?

A. An ROE that is adequate to attract capital at reasonable terms enables the Company to continue to provide safe, reliable natural gas service while maintaining its financial integrity. That return should be commensurate with returns expected elsewhere in the market for investments of equivalent risk. If it is not, debt and equity investors will seek alternative investment opportunities for which the expected return reflects the perceived risks, thereby inhibiting the Company's ability to attract capital at reasonable cost.

Q. Is a utility's ability to attract capital also affected by the ROEs authorized for other utilities?

A. Yes. Utilities compete directly for capital with other investments of similar risk, which include other utilities. Therefore, the ROE authorized for a utility sends an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk. The cost of capital represents an opportunity cost to investors. If higher returns are available for other investments of comparable risk, over the same time period, investors have an incentive to direct their capital to those alternative investments. Thus, an authorized ROE significantly below authorized ROEs for other utilities can inhibit the utility's ability to attract capital for investment.

Q. What is the standard for setting the ROE in a jurisdiction?

A. The stand-alone ratemaking principle is the foundation of jurisdictional ratemaking. This principle requires that the rates that are charged in any operating jurisdiction be for the costs incurred in that jurisdiction. The stand-alone ratemaking principle ensures that customers in each jurisdiction only pay for the costs of the service provided in that jurisdiction, which is not influenced by the business operations in other operating companies. In order to maintain this principle, the cost of equity analysis is performed for an individual operating company as a stand-alone entity. As such, I have evaluated the investor-required return for the Company's utility operations in Michigan.

Q. Does the fact that the Company is wholly-owned by WEC Energy Group, a publicly-traded company, affect your analysis?

A. No. In this proceeding, consistent with stand-alone ratemaking principles, it is appropriate to establish the cost of equity for MGUC, not its publicly-traded parent, WEC Energy Group, Inc. ("WEC Energy"). More importantly, however, it is appropriate to establish a cost of equity and capital structure that provide MGUC the ability to attract capital on reasonable terms, both on a stand-alone basis and within WEC Energy. While MGUC is committed to investing the required capital to provide safe and reliable service, because it is a subsidiary of WEC Energy, the Company competes with the other WEC Energy subsidiaries for discretionary investment capital. In determining how to allocate its finite discretionary capital resources, it would be reasonable for WEC Energy to consider the authorized ROE of each of its subsidiaries.

Q. Is the regulatory framework, including the authorized ROE and equity ratio, important to the financial community?

A. Yes. The regulatory framework is one of the most important factors in investors' assessments of the risk of utilities. Specifically, the authorized ROE and equity ratio for regulated utilities is very important for determining the degree of regulatory support for supporting a utility's creditworthiness and financial stability in the jurisdiction. To the extent that authorized returns in a jurisdiction are lower than the returns that have been authorized more broadly, such actions are considered by both debt and equity investors in the overall risk assessment of the regulatory jurisdiction in which the company operates.

Q. Are you aware of any utilities that have experienced a credit rating downgrade and/or market response related to the financial effects of a rate case decision?

A. Yes. There are numerous examples in which utilities have experienced a negative market response related to the financial effects of a rate decision, including credit rating downgrades and material stock price declines. For example, ALLETE, Inc.,[6] CenterPoint Energy Houston Electric,[7] and Pinnacle West Capital Corporation ("PNW")[8] each received credit rating downgrades following rate case decisions in the past few years for reasons that included below average authorized ROEs. The most recent example is the decision by the Illinois Commerce Commission ("ICC") in mid-December 2023 that rejected the multiyear grid plan proposals of Ameren Illinois Co. ("Ameren IL") and Commonwealth Edison Co. ("ComEd") and authorized lower-than-expected ROEs for both utilities. Specifically, the ICC authorized an ROE for Ameren IL of 8.72 percent and 8.905 percent

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[6] Moody's Investors Service, "Credit Opinion: ALLETE, Inc. Update following downgrade," April 3, 2019, at 3.

[7] Fitch Ratings, "Fitch Downgrades CenterPoint Energy Houston Electric to BBB+; Affirms CNP; Outlooks Negative," February 19, 2020.

[8] S&P Capital IQ Pro; Fitch Ratings, "Fitch Downgrades Pinnacle West Capital & Arizona Public Service to 'BBB+'; Outlooks Remain Negative," October 12, 2021; and Moody's Investors Service, "Rating Actions: Moody's downgrades Pinnacle West to Baa1 and Arizona Public Service to A3; outlook negative," November 17, 2021.

for ComEd, which was a significant reduction from the Administrative Law Judge's recommendations of 9.24 percent and 9.28 percent, respectively.[9]

Q. How did the market respond to the ICC's Decisions for these utilities?

A. While the Standard & Poor's ("S&P") 500 Index was increasing, the share prices of the parent companies of both Ameren IL and ComEd (*i.e*., Ameren Corp. and Exelon Corp., respectively) each dropped more than 7 percent on December 14, 2023 after the ICC's decision, and declined again by more than 4.4 percent and 6.4 percent the following day, respectively.[10] As of the close on January 5, 2023, Ameren and Exelon's stock prices were, respectively, 8.9 percent and 11.4 percent below where their stock prices closed on December 13, 2023, or the day immediately prior to the ICC's decisions.[11]

In addition, the reactions of equity analysts were universally negative, and questioned whether the parents of both Ameren IL and ComEd (*i.e*., Ameren Corp. and Exelon Corp., respectively) will shift their capital spending out of the jurisdiction as a result of the uncertainty associated with the multiyear rate plan and low authorized ROEs. For example:

- Barclays characterized the ICC's ROE authorizations as "draconian" and "one of the lowest awarded in recent memory, especially in an elevated interest rate and cost of capital environment."[12] Barclays also stated it found it hard to believe

9 Allison Good, "Ameren, Exelon shares fall after Illinois regulators reject grid plans," *Platts*, December 15, 2023.

10 Yahoo! Finance.

11 Ameren Corp.'s stock price closed at $81.32 on December 13, 2023 and $74.05 on January 5, 2023. Exelon Corp.'s stock price closed at $41.00 on December 13, 2023 and $36.31 on January 5, 2023.

12 Barclays, "AEE/EXC: Coal Stocking-Stuffer in Illinois," December 14, 2023.

utilities "can deploy capital under the same magnitude on the updated grid plans to be filed, especially under the current proposed ROE framework."

- In its assessment of the impact on Exelon, the parent of ComEd, UBS stated that, "[t]he actions taken by the ICC today call into question, in our view, the regulatory backdrop in which EXC operates."[13]

- Wells Fargo stated that it was not mincing words, and that the ICC's orders were "onerous" and that:

  > We now view IL as one of the worst regulatory jurisdictions in the U.S. (nipping at CT's heels). We think the totality of the recent orders suggest that the regulatory balancing act between customers and investors is currently heavily skewed toward customers. As a result, we wonder if AEE & EXC will allocate capital away from IL. Keep in mind, IL represents ~25% of both AEE's & EXC's total rate base."[14]

- In its evaluation of Ameren IL, BofA Securities characterized the ICC's decision as "punitive" and stated that it was a surprise based on numerous conversations with investors that believed the ICC may authorize an ROE above the ALJ's recommendation, not substantially lower, and that the downside surprise was one of the biggest in recent memory for their regulated utility coverage.[15] While BofA Securities acknowledged that Ameren IL represents less than 20 percent of Ameren Corp.'s consolidated rate base, it will nonetheless need offsets or capital expenditures elsewhere in order to hit its earnings growth rate targets.[16]

- After the decisions, Guggenheim questioned, "Is Illinois Becoming the Next Connecticut?" Guggenheim noted that investors questioned whether Illinois was "slowly becoming a CT-esque jurisdiction," and that equity and debt holders are going to be wary of Illinois as a jurisdiction going forward and that the ICC is "simply sending a negative message to investors."[17]

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[13] UBS, First Read Exelon Corp., "Negative Rate Case Outcome – Rating and PT Under Review," December 14, 2023.

[14] Wells Fargo, "The ICC Delivers a Lump of Coal for AEE & EXC," December 14, 2023.

[15] BofA Securities, Ameren Corporation, "Illinois delivers downside surprise," December 15, 2023.

[16] *Id*.

[17] Guggenheim, "IL: Is Illinois Becoming the Next Connecticut? To Be Determined, but Taking a Neutral Stance on the State," December 15, 2023.

Also, after the ICC's decisions, Regulatory Research Associates ("RRA") lowered its rating of the Illinois regulatory jurisdiction from Average/2 to Average/3 due to the "concerning pattern of restrictive" rate actions in the state.

Q. What are your conclusions regarding the regulatory principles to be used in establishing the cost of capital in this proceeding?

A. The ratemaking process is premised on the principle that, in order for investors and companies to commit the capital needed to provide safe and reliable utility services, a utility must have a reasonable opportunity to recover the return of, and the market-required return on, its invested capital. Accordingly, the Commission's order in this proceeding should establish rates that provide the Company with a reasonable opportunity to earn a ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises with similar risk. It is important for the ROE authorized in this proceeding to take into consideration current and projected capital market conditions, as well as investors' expectations and requirements for both risks and returns. Because utility operations are capital-intensive, regulatory decisions should enable the utility to attract capital at reasonable terms under a variety of economic and financial market conditions. Providing the opportunity to earn a market-based cost of capital supports the financial integrity of the Company, which is in the interest of both customers and shareholders.

IV. CAPITAL MARKET CONDITIONS

Q. Why is it important to analyze capital market conditions?

A. The models used to estimate the cost of equity rely on market data and thus the results of those models can be affected by prevailing market conditions at the time the analysis is performed. While the ROE established in a rate proceeding is intended to be forward-looking, the analysis uses current and projected market data, including stock prices, dividends, growth rates, and interest rates, in the cost of equity estimation models to estimate the investor-required return for the subject company.

Analysts and regulatory commissions recognize that current market conditions affect the results of the cost of equity estimation models. As a result, it is important to consider the effect of the market conditions on these models when determining an appropriate range for the ROE, and the reasonableness of an ROE to be used for ratemaking purposes for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that the cost of equity estimation models will not provide an accurate estimate of investors' required return during that rate period. Therefore, it is very important to consider projected market data to estimate the return for that forward-looking period.

Q. What factors are affecting the cost of equity for regulated utilities in the current and prospective capital markets?

A. The cost of equity for regulated utility companies is being affected by several factors in the current and prospective capital markets, including: (1) relatively high inflation; (2) changes in monetary policy; and (3) elevated interest rates that are expected to remain relatively high over the next few years. These factors affect the assumptions used in the cost of equity estimation models.

A. Inflation Expected to Remain Above Federal Reserve's Target Level for Near-Term

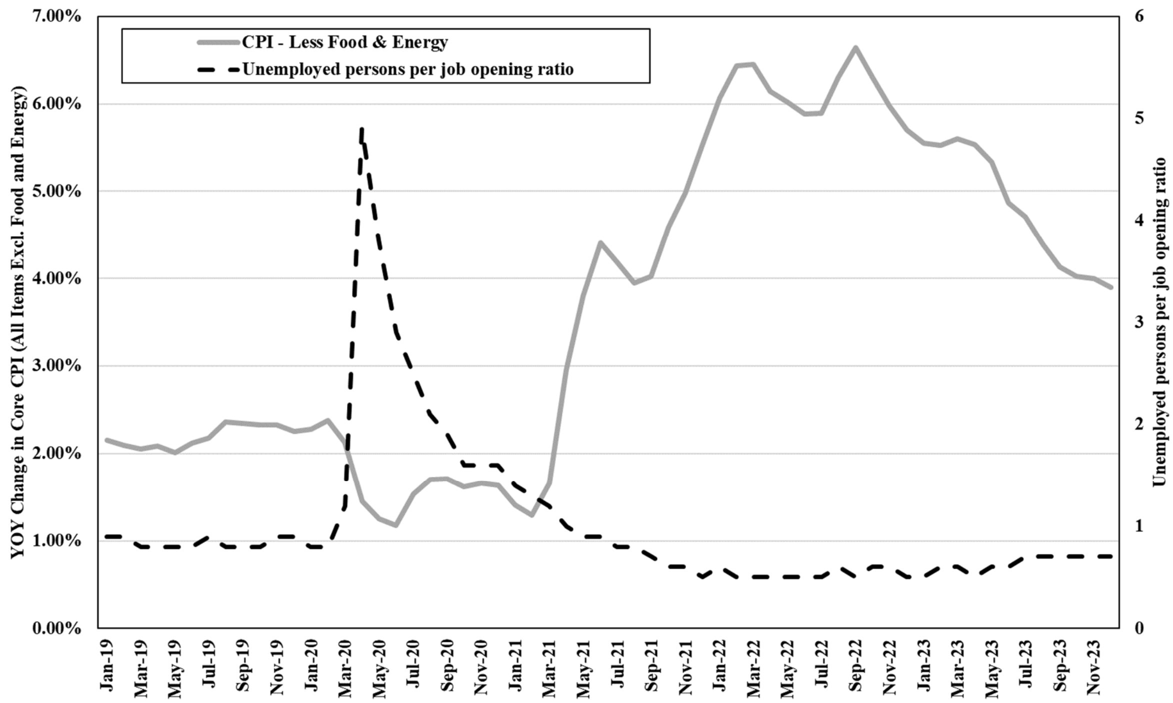
Q. What has the level of inflation been over the past few years?

A. As shown in Figure 2, core inflation increased steadily beginning in early 2021, rising from 1.41 percent in January 2021 to a high of 6.64 percent in September 2022, which was the largest 12-month increase since 1982.[18] Since that time, while core inflation has declined in response to the Federal Reserve's monetary policy, it continues to remain above the Federal Reserve's target level of 2.0 percent.

In addition, as shown in Figure 2, I have also considered the ratio of unemployed persons per job opening, which is currently 0.7 and has been consistently below 1.0 since 2021, despite the Federal Reserve's accelerated policy normalization. This metric indicates sustained strength in the labor market. Given the Federal Reserve's dual mandate of maximum employment and price stability, the continued increased levels of core inflation coupled with the strength in the labor market has resulted in the Federal Reserve's sustained focus on the priority of reducing inflation.

[18] The year-over-year ("YOY") change in core inflation, as measured by the Consumer Price Index ("CPI") excluding food and energy prices as published by the Bureau of Labor Statistics, is considered because it is the preferred inflation indicator of the Federal Reserve for determining the direction of monetary policy. Core inflation is preferred by the Federal Reserve because it removes the effect of food and energy prices, which can be highly volatile.

Figure 2: Core Inflation and Unemployed Persons-to-Job Openings, January 2019 to December 2023[19]



Q. What are the expectations for inflation over the near-term?

A. The Federal Reserve has indicated that it expects inflation will remain elevated above its target level until 2026 and that the extent to which it maintains the restrictive monetary policy will depend on market indicators going forward. For example, Federal Reserve Chair Jerome Powell at the Federal Open Market Committee ("FOMC") meeting on January 31, 2024 observed that while inflation is off of its recent highs, the progress towards the objective of 2 percent inflation is not assured and may require policy rates to

[19] Bureau of Labor Statistics.

remain elevated for longer and added that a March cut is "not the most likely" or "base case" scenario.[20]

> We believe that our policy rate is likely at its peak for this tightening cycle and that, if the economy evolves broadly as expected, it will likely be appropriate to begin dialing back policy restraint at some point this year. But the economy has surprised forecasters in many ways since the pandemic, and ongoing progress toward our 2 percent inflation objective is not assured. The economic outlook is uncertain, and we remain highly attentive to inflation risks. We are prepared to maintain the current target range for the federal funds rate for longer, if appropriate.[21]

In the December 13, 2023 FOMC meeting, Chair Powell reiterated that the FOMC was committed to bringing inflation down to the 2 percent target level, and that while the easing of inflation has been good news, it is currently projected to take until 2026 to reach the Federal Reserve's target of 2.0 percent:

> Inflation has eased over the past year but remains above our longer-run goal of 2 percent. Based on the Consumer Price Index and other data, we estimate that total PCE [*Personal Consumption Expenditures*] prices rose 2.6 percent over the 12 months ending in November; and that, excluding the volatile food and energy categories, core PCE prices rose 3.1 percent. The lower inflation readings over the past several months are welcome, but we will need to see further evidence to build confidence that inflation is moving down sustainably toward our goal. Longer-term inflation expectations appear to remain well anchored, as reflected in a broad range of surveys of households, businesses, and forecasters, as well as measures from financial markets. As is evident from the SEP [*Summary of Economic Projections*], we anticipate that the process of getting inflation all the way to 2 percent will take some time. The median projection in the SEP is 2.8 percent this year, falls to 2.4 percent next year, and reaches 2 percent in 2026.[22]

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[20] Federal Reserve, Transcript of Chair Powell's Press Conference, January 31, 2024, at 16.

[21] *Id*., at 3.

[22] Federal Reserve, Transcript of Chair Powell's Press Conference, December 13, 2023, at 2-3; clarification added

Q. Have there been economic indicators published since the FOMC published the SEP on December 13, 2023 that indicate strength in the US economy?

A. Yes. Since December 13, 2023, the following data has been released demonstrating the unexpected strength in the U.S. economy:

- GDP increased in the fourth quarter of 2023 by 3.3 percent, which exceeded the expectation of 2.0 percent. This followed an increase of 4.9 percent in the third quarter of the year.[23]
- U.S. employers added 353,000 jobs in January, far exceeding forecasts. Further, revised 2023 data indicated that 2023 was stronger than previously reported.[24]
- The unemployment rate remained at 3.7 percent, and has been below 4.0 percent for 24 months.[25]
- Average hourly earnings increased 0.6 percent in January 2024, up 4.5 percent year-over-year.[26]

Q. What has been the market's expectation about interest rate cuts since the recent economic data you referenced has been reported?

A. The market has recognized the strength in the economy and the labor market and has tempered its expectations that the FOMC will decrease interest rates in the first quarter of this year. The CME Group, which publishes a "FedWatch" probability chart of FOMC activity, is currently reporting less than a 20 percent probability that the FOMC will reduce rates in March.[27]

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[23] *See, e.g.*, Jeff Cox, "The U.S. economy grew at a blistering 3.3% pace in Q4 while inflation pulled back," CNBC, January 25, 2024.

[24] *See, e.g.*, Lydia DePillis, "Job Market Starts 2024 With a Bang," *The New York Times*, February 2, 2024.

[25] *Id.*

[26] *Id.*

[27] https://www.cmegroup.com/markets/interest-rates/cme-fedwatch-tool.htm; accessed February 8, 2023.

B. The Federal Reserve to Continue Use of Monetary Policy to Address Inflation

Q. What policy actions has the Federal Reserve enacted to respond to increased inflation?

A. The dramatic increase in inflation has prompted the Federal Reserve to pursue an aggressive normalization of monetary policy, removing the accommodative policy programs used to mitigate the economic effects of COVID-19. Beginning in March 2022 and through July 26, 2023, the Federal Reserve increased the target federal funds rate through a series of increases from a range of 0.00 – 0.50 percent to a range of 5.25 percent to 5.50 percent.[28] Further, as noted above, while the Federal Reserve acknowledges that inflation has declined from its peak, it still is well above the Federal Reserve's target of 2 percent. Therefore, the Federal Reserve anticipates the continued need to maintain the federal funds rate at a restrictive level in order to achieve its goal of 2 percent inflation over the long-run.

C. The Federal Reserve's Monetary Policy to Combat Inflation Has Increased Short- and Long-Term Interest Rates and the Investor-Required Return

Q. Have the yields on long-term government bonds increased in response to inflation and the Federal Reserve's normalization of monetary policy?

A. Yes. As the Federal Reserve has substantially increased the federal funds rate and decreased its holdings of Treasury bonds and mortgage-backed securities in response to

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[28] https://www.federalreserve.gov/monetarypolicy/openmarket.htm.

increased levels of inflation that have persisted for longer than originally projected, longer term interest rates have also increased. For example, as shown in Figure 3, since the Federal Reserve's December 2021 meeting, the yield on 10-year Treasury bonds have increasing from 1.47 percent on December 15, 2021 to 3.99 percent at the end of January 2024.

Figure 3: 10-Year Treasury Bond Yield, January 2021– January 2024[29]

Q. How have interest rates and inflation changed since the Company's last rate case?

A. As shown in Figure 4, both short-term and long-term interest rates have increased since the filing of the Company's last rate proceeding, where the data relied on to estimate the cost of equity was as of January 31, 2023. Specifically, long-term interest rates have increased

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29 S&P Capital IQ Pro.

nearly 50 basis points over this period, which is indicative of an increase in the cost of equity.[30] As discussed, as a result of the Federal Reserve's monetary policy of substantially increasing short-term interest rates, core inflation has declined since the last rate proceeding, although inflation remains above the Federal Reserve's long-term target value of 2.0 percent.

Figure 4: Change in Market Conditions Since the Company's Last Rate Case

Docket	Date	Federal Funds Rate	30-Day Avg of 30-Year Treasury Bond Yield	Core Inflation Rate
Case No. U-21366	1/31/2023	4.33%	3.73%	5.55%
Current	1/31/2024	5.33%	4.19%	3.90%

Q. What have equity analysts said about long-term government bond yields?

A. Leading equity analysts have noted that they expect the yields on long-term government bonds to remain elevated. For example, in the most recent Big Money poll released by *Barron's* in October 2023, which surveys money managers regarding the outlook for the next twelve months, two-thirds of the money managers surveyed expect the yield on the 10-year Treasury bond to be at least 4.50 percent in October 2024.[31] Similarly, according to the *Blue Chip Financial Forecasts* report, the consensus estimate of the average yields on the 10-year and 30-year Treasury bonds are approximately 4.00 percent and 4.30

[30] S&P Capital IQ Pro.

[31] Nicholas Jasinski, "Big Money Pros Are Split on the Outlook for Stocks. But They Are Fans of Bonds," October 27, 2023.

percent, respectively, through the first quarter of 2025.[32] Therefore, investors expect interest rates to remain elevated for at least the next 15 months.

D. Expected Performance of Utility Stocks and the Investor-Required Return on Utility Investments

Q. Are utility share prices correlated to changes in the yields on long-term government bonds?

A. Yes. Interest rates and utility share prices are inversely correlated, which means that increases in interest rates result in declines in the share prices of utilities and vice versa. For example, Goldman Sachs and Deutsche Bank examined the sensitivity of share prices of different industries to changes in interest rates over a five-year period. Both Goldman Sachs and Deutsche Bank found that utilities had one of the strongest negative relationships with bond yields (*i.e.*, increases in bond yields resulted in the decline of utility share prices).[33]

Q. In the Company's last rate proceeding, you discussed equity analysts' expected underperformance of the utility sector. Did that occur?

A. Yes. Since the filing of my direct testimony in the Company's last rate proceeding, utility stocks have significantly underperformed the broader market, as Treasury bond yields have increased to levels greater than the dividend yields of utility stocks. For example, as shown in Figure 5, since February 1, 2023, as noted, the yield on the 30-year Treasury bond has

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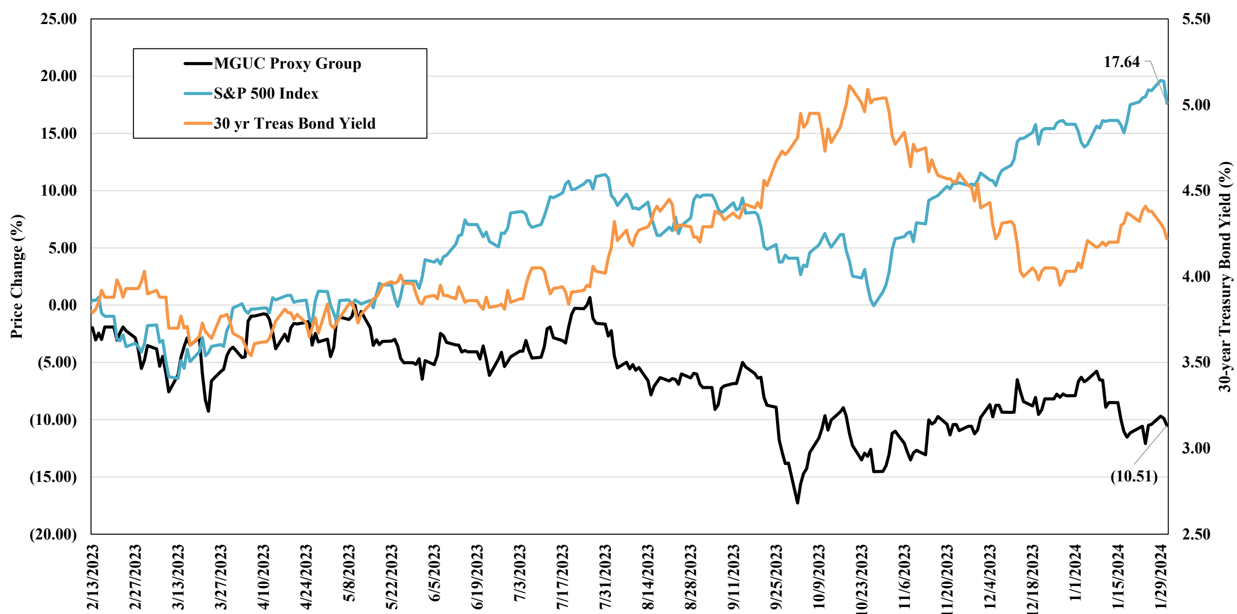
32 *Blue Chip Financial Forecasts*, Vol. 42, No. 12, December 1, 2023, at 2.

33 Justina Lee, "Wall Street Is Rethinking the Treasury Threat to Big Tech Stocks." Bloomberg.com, March 11, 2021.

increased by approximately 50 basis points, while the share prices for the natural gas utilities included in my proxy group (discussed in the following section) have *declined* by 10.5 percent and the S&P 500 Index has *increased* by more than 17.6 percent. In fact, on October 2, 2023, the utilities sector dropped by 4.7 percent, its single highest one-day percentage decline since April 2020.[34] The stock price under-performance for the utility sector indicates that the cost of equity has increased since the Company's last rate proceeding.

Figure 5: Relative Performance of the Proxy Group and the S&P 500 Index, February 2023 through January 2024[35]



34 Caroline Valetkevich, "S&P 500 ends near flat; utilities drop, focus on rate outlook," Reuters, October 2, 2023.

35 S&P Capital IQ Pro.

Q. How do equity analysts expect the utilities sector to perform in 2024?

A. Equity analysts have recently projected the continued underperformance of the utility sector, and have not changed their views on the sector. For example, Fidelity Investments classifies the utility sector as underweight,[36] and Bank of America recently noted that they are "not so constructive on [u]tilities" given that the dividend yields for utilities are below both the yields available on long- and short-term treasury bonds.[37] Moreover, the professional investors surveyed by *Barron's* in its most recent Big Money poll selected the utility sector as one of the four equity sectors that they liked the least over the next twelve months, indicating they are projecting that utilities will underperform the broader market in 2024.[38]

Q. Why do equity analysts expect the utility sector to underperform over the near-term?

A. Equity analyst expect the utility sector to continue to underperform given that utility dividend yields remain higher than the yields on long-term government bonds. To illustrate this point, I have examined the difference between the dividend yields of utility stocks and the yields on long-term government bonds from January 2010 through January 2024 ("yield spread"). I selected the dividend yield on the Standard & Poor's Utilities Index as the measure of the dividend yields for the utility sector and the yield on the 10-year Treasury bond as the estimate of the yield on long-term government bonds.

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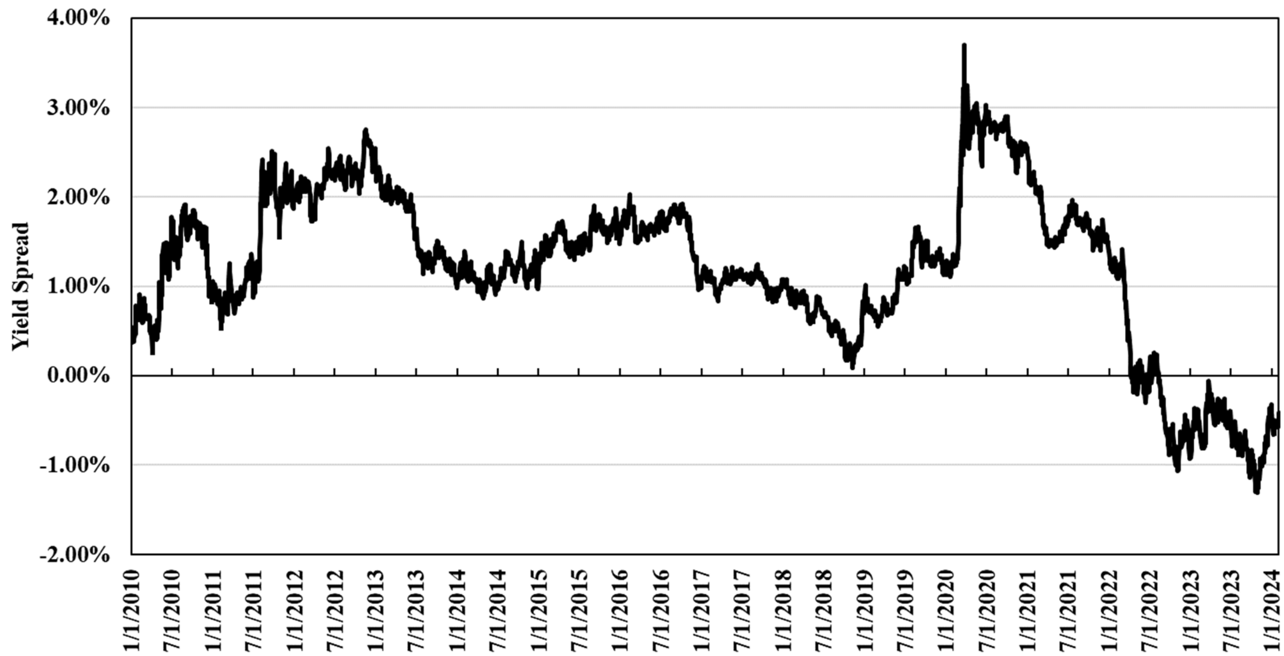
36 Fidelity Investments, "First Quarter 2024 Investment Research Update," January 30, 2024.

37 Julien Dumoulin-Smith, *et. al*., "US Electric Utilities & IPPs: As the leaves fall, preparing for Autumn utility outlook. Macro still has potholes," BofA Securities, September 6, 2023.

38 Nicholas Jasinski, "Big Money Pros Are Split on the Outlook for Stocks. But They Are Fans of Bonds," *Barron's*, October 27, 2023.

As shown in Figure 6, the recent significant increase in long-term government bonds yields has resulted in the yield on long-term government bonds exceeding the dividend yields of utilities. The yield spread as of January 31, 2024 was negative 0.42 percent, meaning that the yield on the 10-year Treasury bond exceeds the dividend yield for the S&P Utilities Index. However, the long-term average yield spread from 2010 to 2023 is 1.21 percent. Therefore, the current yield spread is well below the long-term average. Because of the fact that the yield spread is currently well below the long-term average, and the expectation that interest rates will remain relatively high through at least the next year, it is reasonable to conclude that the utility sector will most likely underperform over the near-term. This is because investors that purchased utility stocks as an alternative to the lower yields on long-term government bonds would otherwise be inclined to rotate back into government bonds, particularly as the yields on long-term government bonds remain elevated, thus resulting in a decrease in the share prices of utilities.

Figure 6: Spread between the S&P Utilities Index Dividend Yield and the 10-year Treasury Bond Yield, January 2010 – January 2024[39]



Q. Has the Commission previously considered capital market conditions in determining authorized ROEs?

A. Yes. For example, in its order in Case No. U-20697, the Commission noted that it is important to consider how a utility's access to capital could be affected in the near-term as a result of market reactions to global events like those that have occurred in the recent past. Specifically, the Commission noted that:

> [i]n setting the ROE at 9.90%, the Commission believes there is an opportunity for the company to earn a fair return during this period of atypical market conditions. This decision also reinforces the belief, as stated in the Commission's March 29 order, "that customers do not benefit from a lower ROE if it means the utility has difficulty accessing capital at attractive terms and in a timely manner." These conditions still hold true based on the evidence in the instant case. The fact that other utilities have

[39] S&P Capital IQ Pro and Bloomberg Professional.

> been able to access capital despite lower ROEs, as argued by many intervenors, is also a relevant consideration. *It is also important to consider how extreme market reactions to global events, as have occurred in the recent past, may impact how easily capital will be able to be accessed during the future test period should an unforeseen market shock occur. The Commission will continue to monitor a variety of market factors in future rate cases to gauge whether volatility and uncertainty continue to be prevalent issues that merit more consideration in setting the ROE.*[40]

E. Conclusion

Q. What are your conclusions regarding the effect of current market conditions on the cost of equity for MGUC?

A. Due to their effect on the estimated cost of equity, it is important that current and projected market conditions be considered in setting the forward-looking ROE in this proceeding. The combination of high inflation and the Federal Reserve's changes in monetary policy indicate that the cost of equity has increased since the Company's last rate proceeding given that (i) there is a strong historical inverse correlation between interest rates (*i.e.*, yields on long-term government bonds) and the share prices of utility stocks (*i.e.*, as interest rates increase, utility share prices decline, and thus utility dividend yields increase); and (ii) the yields on long-term government bonds currently exceed the dividend yields of utilities, when historically long-term government bond yields have been lower than the dividend yields of utilities. Because the cost of equity has increased since the Company's last rate proceeding, cost of equity estimates based in whole or in part on historical or current market conditions, as opposed to projected market conditions, may understate the cost of equity during the future period that the Company's rates will be in effect. Therefore,

[40] MPSC Case No. U-20697, 12/17/2020 Order, at 165-166; emphasis added.

these current and expected market conditions support consideration of forward-looking cost of equity estimation models such as the CAPM and ECAPM, which better reflect expected market conditions.

V. PROXY GROUP SELECTION

Q. Please provide a brief profile of MGUC.

A. MGUC is a natural gas distribution company that is a wholly-owned subsidiary of WEC Energy. MGUC distributes natural gas to approximately 183,000 customers in southern and western Michigan.[41] As of December 31, 2022, MGUC's net utility natural gas plant in Michigan was approximately $365 million.[42] In 2022, MGUC transported approximately 19.7 million Mcf to its sales customers and approximately 15.8 million Mcf for its customer choice and transportation customers.[43]

MGUC is not directly rated by either S&P or Moody's Investors Service ("Moody's"). WEC Energy has a long-term rating of A- (Outlook: Stable) from S&P, BBB+ (Outlook: Stable) from Fitch Ratings ("Fitch"), and Baa1 (Outlook: Stable) from Moody's.[44]

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41 MGUC website.

42 Michigan Gas Utilities Corporation, 2022 Annual LDC filing to the Michigan Public Service Commission, April 28, 2023, at 110.

43 *Id.*, at 305C, 306C, and 313.

44 S&P Global Market Intelligence; Fitch Ratings; Moody's Investors Service.

Q. Why have you used a proxy group of publicly traded companies to estimate the cost of equity for MGUC?

A. In this proceeding, I am estimating the cost of equity for MGUC, a rate-regulated subsidy of WEC Energy. Since the cost of equity is a market-based concept and given the fact that MGUC does not make up the entirety of a publicly-traded entity, it is necessary to establish a group of companies that is both publicly traded and comparable to MGUC in certain fundamental business and financial respects to serve as its "proxy" for purposes of estimating the cost of equity.

The overall purpose of developing a set of screening criteria is to select a proxy group of companies that aligns with the financial and operational characteristics of MGUC and that investors would view as comparable to the Company. I developed the screens and thresholds for each screen based on judgment with the intention of balancing the need to maintain a proxy group that is of sufficient size with the need to establish a proxy group of companies that are comparable in business and financial risk to MGUC.

Even if MGUC's regulated natural gas distribution business made up the entirety of a publicly-traded entity, it is possible that transitory events could bias its market value over a given time period. A significant benefit of using a proxy group is that it mitigates the effects of anomalous events that may be associated with any one company. The proxy companies used in my analyses all possess a set of operating and financial risk characteristics that are substantially comparable to MGUC, and, therefore, provide a reasonable basis to estimate the appropriate cost of equity for the Company.

Q. How did you select the companies included in your proxy group?

A. I began with the group of 10 companies that *Value Line Investment Survey* ("*Value Line*") classifies as Natural Gas Distribution Utilities and applied the following screening criteria to select companies that:

- pay consistent quarterly cash dividends, because companies that do not cannot be analyzed using the constant growth DCF model;
- have investment grade long-term issuer ratings from S&P and/or Moody's;
- are covered by more than one utility industry analyst;
- have positive long-term earnings growth forecasts from at least two equity analysts;
- derive more than 70.00 percent of their total operating income from regulated operations;
- derive more than 60.00 percent of regulated operating income from gas distribution operations; and,

  were not party to a merger or transformative transaction during the analytical period considered or had a material event that would have affected the market data for the company.

Q. What is the composition of your proxy group?

A. The screening criteria just discussed resulted in a proxy group consisting of the companies shown in Figure 7.

Figure 7: Proxy Group

Company	Ticker
Atmos Energy Corporation	ATO
NiSource	NI
Northwest Natural Gas Company	NWN
ONE Gas, Inc.	OGS
Spire, Inc.	SR

VI. COST OF EQUITY ESTIMATION

Q. Please briefly discuss the ROE in the context of the regulated rate of return.

A. The rate of return for a regulated utility is the weighted average cost of capital, in which the costs of the individual sources of capital are weighted by their respective proportion (*i.e.*, book values) in the utility's capital structure. The ROE is the cost rate applied to the equity capital in calculating the rate of return. While the costs of debt and preferred stock can be directly observed, the cost of equity is market-based and, therefore, must be estimated based on observable market data.

Q. How is the required cost of equity determined?

A. A range of the required cost of equity is estimated by using analytical techniques that rely on market-based data to quantify investor expectations regarding equity returns. Within that range, the ROE that is recommended is based on a review of the business, regulatory, and financial risks of the subject utility as compared with the proxy group, including the capital structure of the subject utility. A key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, as well as the subject company (in the context of the proxy group), in particular. Further, it is important that the ROE that is authorized takes into consideration the financial risk resulting from the authorized capital structure of the subject utility. An authorized capital structure that has a greater amount of leverage results in greater risk since equity is the last claimant in the event of the dissolution of a company. Therefore, as the leverage in the capital structure increases, it is necessary for the ROE to increase to recognize the incremental risk to equity holders.

Q. What methods do you use to establish your recommended ROE in this proceeding?

A. I consider the results of the constant growth DCF model, the CAPM, the ECAPM, and a BYRP analysis. A reasonable cost of equity estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results.

Q. Why is it important to use more than one analytical approach to estimate the cost of equity?

A. Because the cost of equity is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the cost of equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. Several models have been developed to estimate the cost of equity, and I use multiple approaches to estimate the cost of equity. As a practical matter, however, all of the models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints. Consequently, many well-regarded finance texts recommend using multiple approaches when estimating the cost of equity. For example, Copeland, Koller, and Murrin[45] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[46] recommend the CAPM, DCF, and BYRP approaches.

Further, the recent changes in market conditions discussed previously highlight the benefit of using multiple models since each model relies on different assumptions, certain

[45] Tom Copeland, Tim Koller and Jack Murrin, *Valuation: Measuring and Managing the Value of Companies*, New York, McKinsey & Company, Inc., 3rd Ed., 2000, at 214.

[46] Eugene Brigham and Louis Gapenski, *Financial Management: Theory and Practice*, Orlando, Dryden Press, 1994, at 341.

of which better reflect current and projected market conditions at different times. For example, the CAPM, ECAPM, and BYRP analyses rely directly on interest rates as an assumption in the models and therefore may more directly reflect the market conditions expected when the Company's rates are in effect. Accordingly, it is important to use multiple analytical approaches to ensure that the cost of equity results reflect market conditions that are expected during the period that the Company's rates will be in effect.

Q. Has the Commission recognized that it is important to consider the results of multiple models?

A. Yes. For example, in its order in Case No. U-18999 for DTE Gas Company, the Commission considered the results of each of the models presented by the witnesses, which included the DCF, CAPM, ECAPM and Risk Premium models, and also considered authorized ROEs in other states, increased volatility in capital markets, and the utility's specific business risks, ultimately authorizing a 10.00 percent ROE.[47]

A. Constant Growth DCF Model

Q. Please describe the DCF approach.

A. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

[47] MPSC Case No. U-18999, 9/13/2018 Order, at 45-47.

Where P_0 represents the current stock price, $D1 \ldots D\infty$ are all expected future dividends, and k is the discount rate, or required ROE. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g \qquad [2]$$

Equation [2] is often referred to as the constant growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate (*i.e.*, "*g*").

Q. What assumptions are required for the constant growth DCF model?

A. The constant growth DCF model requires the following four assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings ratio; and (4) a discount rate greater than the expected growth rate. To the extent that any of these assumptions are not objectively valid, considered judgment and/or specific adjustments should be applied to the results.

Q. What market data do you use to calculate the dividend yield in your constant growth DCF model?

A. The dividend yield in my constant growth DCF model is based on the proxy group companies' current annualized dividend and average closing stock prices over the most recent 30, 90, and 180 trading days ended January 31, 2024.

Q. Why do you use 30-, 90-, and 180-day averaging periods?

A. In my constant growth DCF model, I use an average of recent trading days to calculate the term P_0 in the DCF model to ensure that the cost of equity is not skewed by anomalous events that may affect stock prices on any given trading day. The averaging period should also be reasonably representative of expected capital market conditions over the long term.

Q. Do you make any adjustments to the dividend yield to account for periodic growth in dividends?

A. Yes. Since utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected first-year dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the aggregated dividends to be paid during that time.

Q. Why is it important to select appropriate measures of long-term growth in applying the DCF model?

A. In its constant growth form, the DCF model (*i.e.*, Equation [2]) assumes a single growth estimate in perpetuity. To reduce the long-term growth rate to a single measure, one must assume that the payout ratio remains constant and that earnings per share ("EPS"), dividends per share and book value per share all grow at the same constant rate. However, over the long run, dividend growth can only be sustained by earnings growth, meaning earnings are the fundamental driver of a company's ability to pay dividends. Therefore, projected EPS growth is the appropriate measure of a company's long-term growth. In contrast, changes in a company's dividend payments are based on management decisions related to cash management and other factors. For example, a company may decide to retain earnings rather than pay out a portion of those earnings to shareholders through dividends. Therefore, dividend growth rates are less likely than earnings growth rates to accurately reflect investor perceptions of a company's growth prospects. Accordingly, I have incorporated a number of sources of long-term EPS growth rates into the constant growth DCF model.

Q. Which sources of long-term earnings growth rates do you use in your DCF analysis?

A. I incorporate three sources of long-term earnings per share ("EPS") growth rates: (1) *Zacks Investment Research*; (2) Yahoo! Finance; and (3) *Value Line*.

Q. How do you calculate the range of results for the constant growth DCF Models?

A. I calculate the low-end result for the constant growth DCF model using the minimum growth rate of the three sources (*i.e.*, the lowest of the *Zacks*, Yahoo! Finance, and *Value Line* projected EPS growth rates) for each of the proxy group companies. I use a similar approach to calculate a high-end result, using the maximum growth rate of the three sources for each proxy group company. Lastly, I also calculate results using the average EPS growth rate from all three sources for each proxy group company.

Q. What are the results of your DCF analyses?

A. Figure 8 summarizes the results of my DCF analyses.

Figure 8: Summary of DCF Results

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.79%	10.71%	11.92%
90-Day Avg. Stock Price	9.87%	10.78%	11.99%
180-Day Avg. Stock Price	9.70%	10.62%	11.83%
Average	9.79%	10.70%	11.91%
Median Results:			
30-Day Avg. Stock Price	9.90%	10.17%	11.76%
90-Day Avg. Stock Price	9.98%	10.25%	11.85%
180-Day Avg. Stock Price	9.93%	10.20%	11.64%
Average	9.94%	10.21%	11.75%

Q. Have regulatory commissions acknowledged the reasonableness of considering multiple models to estimate the cost of equity given the current capital market conditions?

A. Yes. For example, in its May 2022 decision establishing the cost of equity for Aqua Pennsylvania, Inc., the Pennsylvania Public Utility Commission concluded that, based on high inflation and increased interest rates, weight should be placed on risk premium models, such as the CAPM, in addition to the DCF, in the determination of the ROE:

> To help control rising inflation, the Federal Open Market Committee has signaled that it is ending its policies designed to maintain low interest rates. Aqua Exc. at 9. Because the DCF model does not directly account for interest rates, consequently, it is slow to respond to interest rate changes. However, I&E's CAPM model uses forecasted yields on ten-year Treasury bonds, and accordingly, its methodology captures forward looking changes in interest rates.
>
> Therefore, our methodology for determining Aqua's ROE shall utilize both I&E's DCF and CAPM methodologies. As noted above, the Commission recognizes the importance of informed judgment and information provided by other ROE models. In the 2012 PPL Order, the Commission considered

> PPL's CAPM and RP methods, tempered by informed judgment, instead of DCF-only results. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. Historically, we have relied primarily upon the DCF methodology in arriving at ROE determinations and have utilized the results of the CAPM as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination. In light of the above, we shall determine an appropriate ROE for Aqua using informed judgement based on I&E's DCF and CAPM methodologies.[48]
>
> …..
>
> We have previously determined, above, that we shall utilize I&E's DCF and CAPM methodologies. I&E's DCF and CAPM produce a range of reasonableness for the ROE in this proceeding from 8.90% [DCF] to 9.89% [CAPM]. Based upon our informed judgment, which includes consideration of a variety of factors, including increasing inflation leading to increases in interest rates and capital costs since the rate filing, we determine that a base ROE of 9.75% is reasonable and appropriate for Aqua.[49]

B. CAPM and ECAPM Analyses

Q. Please briefly describe the CAPM.

A. The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or "systematic" risk of that security.[50] This second component is the product of the market risk premium and the beta coefficient, which measures the relative riskiness of the security being evaluated.

The CAPM is defined by four components:

[48] Pennsylvania Public Utility Commission, Docket Nos. R-2021-3027385 and R-2021-3027386, Opinion and Order, May 12, 2022, at 154-155.

[49] *Id*., at 177-178.

[50] Systematic risk is the risk inherent in the entire market or market segment, which cannot be diversified away using a portfolio of assets. Unsystematic risk is the risk of a specific company that can, theoretically, be mitigated through portfolio diversification.

$$K_e = r_f + \beta(r_m - r_f) \qquad [3]$$

Where:

K_e = the required market ROE;

β = beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market.

In this specification, the term ($r_m - r_f$) represents the market risk premium. According to the theory underlying the CAPM, because unsystematic risk can be diversified away, investors should only be concerned with systematic or non-diversifiable risk. Systematic risk is measured by beta, which is a measure of the volatility of a security as compared to the overall market. Beta is defined as:

$$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)} \qquad [4]$$

Variance (r_m) represents the variance of the market return, which is a measure of the uncertainty of the general market. *Covariance* (r_e, r_m) represents the covariance between the return on a specific security and the general market, which reflects the extent to which the return on that security will respond to a given change in the general market return. Thus, beta represents the risk of the security relative to the general market.

Q. What risk-free rate do you use in your CAPM analysis?

A. I rely on three sources for my estimate of the risk-free rate: (1) the current 30-day average yield on 30-yearTreasury bonds;[51] (2) the average projected 30-year Treasury bond yield

[51] Bloomberg Professional as of January 31, 2024.

for the second quarter of 2024 through the second quarter of 2025;[52] and (3) the average projected 30-year Treasury bond yield for 2025 through 2029.[53]

Q. What beta coefficients do you use in your CAPM analysis?

A. As shown on Schedule D9, I use the beta coefficients for the proxy group companies as reported by *Bloomberg Professional* ("*Bloomberg")* and *Value Line*. The beta coefficients reported by *Bloomberg* are calculated using ten years of weekly returns relative to the S&P 500 Index. The beta coefficients reported by *Value Line* are calculated based on five years of weekly returns relative to the New York Stock Exchange Composite Index. Additionally, as shown on Schedules D9 and D10, I also consider an additional CAPM analysis that relies on the long-term average beta coefficient reported by *Value Line* for the companies in my proxy group from 2013 through 2023.

Q. How do you estimate the market risk premium in the CAPM?

A. I estimate the market risk premium as the difference between the implied expected equity market return and the risk-free rate. As shown in Schedule D11, the expected market return is calculated using the constant growth DCF model discussed earlier in my testimony for the companies in the S&P 500 Index. Based on an estimated market capitalization-weighted dividend yield of 1.63 percent and a weighted long-term growth rate of 10.51 percent, the estimated required market return for the S&P 500 Index as of January 31, 2024 is 12.22 percent.

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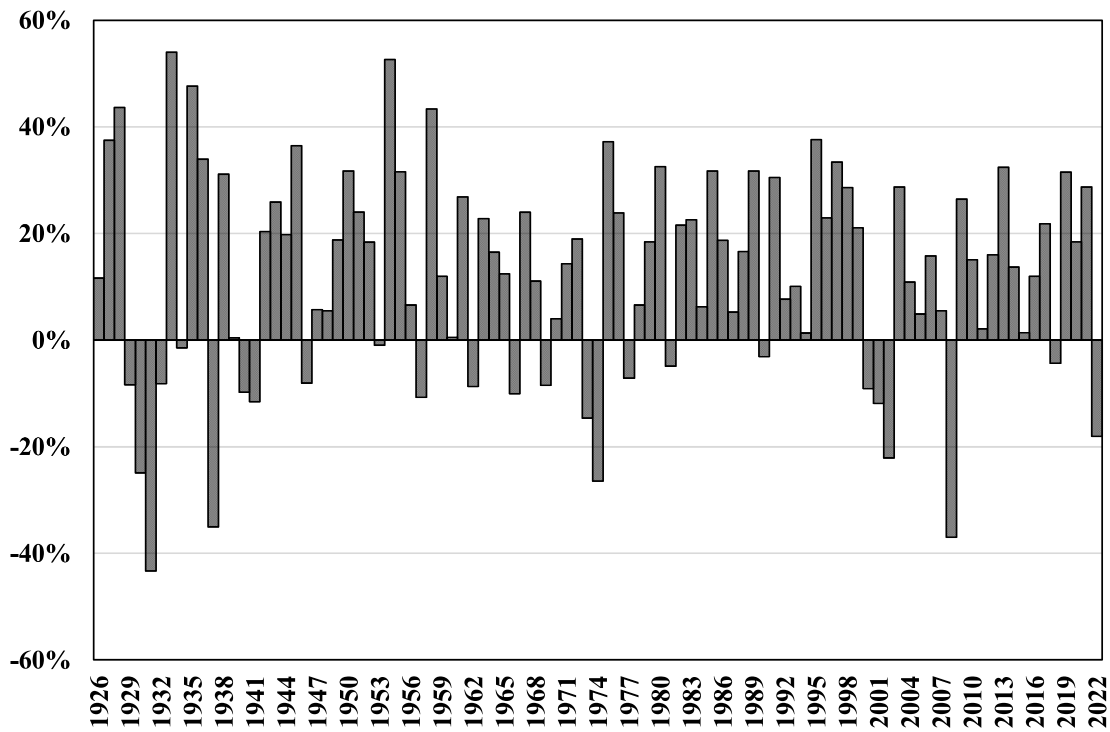
[52] *Blue Chip Financial Forecasts*, Vol. 43, No. 2, February 1, 2024, at 2.

[53] *Blue Chip Financial Forecasts*, Vol. 42, No. 12, December 1, 2023, at 14.

Q. How does the current expected market return compare to observed historical market returns?

A. As shown in Figure 9, given the range of annual equity returns that have been observed over the past century, a current expected market return of 12.22 percent is not unreasonable. As shown, in 51 out of the past 97 years (or roughly 53 percent of observations), the realized equity market return was 12.22 percent or greater.

Figure 9: Realized U.S. Equity Market Returns (1926-2022)[54]



[54] Depicts total annual returns on large company stocks, as reported in the 2022 *Kroll* SBBI Yearbook.

Q. Do you also consider another form of the CAPM in your analysis?

A. Yes. I have also considered the results of an ECAPM analysis in estimating the cost of equity for MGUC.[55] The ECAPM calculates the product of the adjusted beta coefficient and the market risk premium and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the market risk premium without any effect from the beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [5] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [5]$$

Where:

k_e = the required market ROE;
β = adjusted beta coefficient of an individual security;
r_f = the risk-free rate of return; and
r_m = the required return on the market as a whole.

The ECAPM addresses the tendency of the "traditional" CAPM to underestimate the cost of equity for companies with low beta coefficients such as regulated utilities. In that regard, the ECAPM is not redundant to the use of adjusted betas in the traditional CAPM; rather, it recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM underestimates the "alpha," or the constant return term.[56]

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55 *See, e.g.*, Roger A. Morin, *New Regulatory Finance*. Public Utilities Reports, Inc., 2006, at 189.

56 *Id.*, at 191.

Consistent with my CAPM, my application of the ECAPM uses the same three yields on the 30-year Treasury bonds as the risk-free rate, forward-looking market risk premium estimate, and beta coefficients.

Q. What are the results of your CAPM and ECAPM analyses?

A. The results of my CAPM and ECAPM analyses are summarized in Figure 10, as well as presented in Schedule D9.

Figure 10: Summary of CAPM and ECAPM Results

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.09%	11.08%	11.08%
Current Bloomberg Beta	10.31%	10.29%	10.29%
Long-term Avg. *Value Line* Beta	10.12%	10.10%	10.10%
ECAPM:			
Current *Value Line* Beta	11.38%	11.37%	11.37%
Current Bloomberg Beta	10.79%	10.77%	10.77%
Long-term Avg. *Value Line* Beta	10.64%	10.63%	10.63%

C. BYRP Analysis

Q. Please describe the BYRP analysis.

A. In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as bondholders. In other words, because returns to equity holders have greater risk than returns to bondholders, equity holders require a higher return for that incremental risk. Thus, risk premium approaches estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I use actual authorized returns for natural gas distribution utilities as the historical measure of the cost of equity to determine the risk premium.

Q. What is the fundamental relationship between the equity risk premium and interest rates?

A. It is important to recognize both academic literature and market evidence indicating that the equity risk premium (as used in this approach) is inversely related to the level of interest rates (*i.e.*, as interest rates increase, the equity risk premium decreases, and vice versa). Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. Such an analysis can be developed based on a regression of the risk premium as a function of U.S. Treasury bond yields. When the authorized ROEs for natural gas utilities serve as the measure of required equity returns and the yield on the long-term U.S. Treasury bond is defined as the relevant measure of interest rates, the risk premium is the difference between those two points.[57]

Q. Is the BYRP analysis relevant to investors?

A. Yes. Investors are aware of authorized ROEs in other jurisdictions and they consider those awards as a benchmark for a reasonable level of equity returns for utilities of comparable

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57 *See e.g.*, S. Keith Berry, "Interest Rate Risk and Utility Risk Premia during 1982-93," *Managerial and Decision Economics*, Vol. 19, No. 2, March, 1998 (the author used a similar methodology, including using authorized ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates). *See also* Robert S. Harris, "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return," *Financial Management*, Spring 1986, at 66.

risk operating in other jurisdictions. As discussed previously, utilities have experienced credit rating downgrades and been subject to a negative market reaction related to the financial effects of a rate case decision that included a below average authorized ROE. Because my BYRP analysis is based on authorized ROEs for utility companies relative to corresponding Treasury yields, it provides relevant information to assess the return expectations of investors in the current interest rate environment.

Q. What does your BYRP analysis reveal?

A. As shown in Figure 11, from 1980 through January 2024, there was a strong negative relationship between risk premia and interest rates. To estimate that relationship, I conducted a regression analysis using the following equation:

$$RP = a + b(T) \qquad [6]$$

Where:

RP = Risk Premium (difference between allowed ROEs and the yield on 30-year U.S. Treasury bonds)

a = intercept term

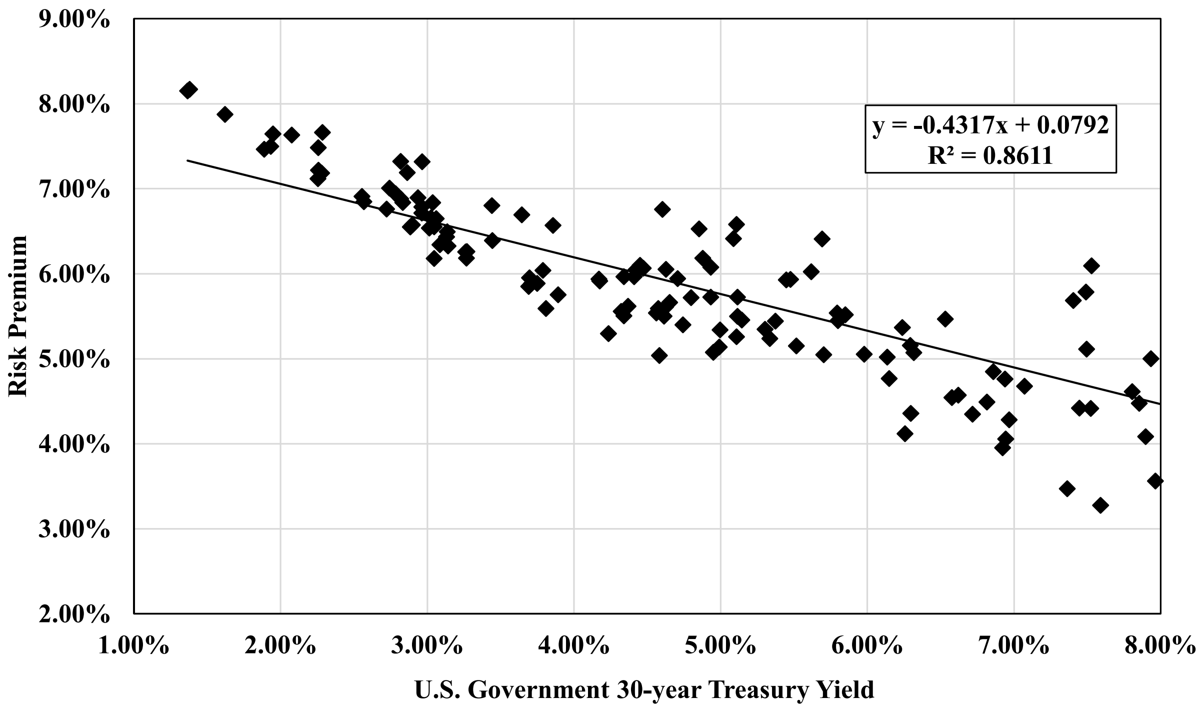
b = slope term

T = 30-year U.S. Treasury bond yield

Data regarding authorized ROEs are derived from all natural gas distribution rate cases over this period as reported by Regulatory Research Associates ("RRA").[58] This equation's coefficients were statistically significant at the 99.00 percent level.

[58] The data was screened to eliminate limited issue rider cases, pipeline transmission cases, and cases that were silent with respect to authorized ROE.

Figure 11: Risk Premium Regression Analysis



Q. What are the results of your BYRP analysis?

A. Figure 12 presents the results of my BYRP analysis, which are also presented in more detail in Schedule D12.

Figure 12: BYRP Results

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
Bond Yield Risk Premium:	10.35%	10.26%	10.25%

VII. REGULATORY AND BUSINESS RISKS

Q. Do the results of the cost of equity analyses alone provide an appropriate estimate of the cost of equity for the Company?

A. No. The model results provide only a range for the appropriate estimate of the Company's cost of equity. Several additional factors must be considered when determining where the Company's cost of equity falls within the range of analytical results. These risk factors, discussed below, should be considered with respect to their overall effect on the Company's risk profile relative to the proxy group.

A. Capital Expenditures

Q. Please summarize the Company's capital expenditure requirements.

A. As of December 31, 2023, the Company had net utility plant of approximately $392 million, and the Company currently projects capital expenditures for 2024 through 2028 of approximately $246 million.[59] Therefore, the Company's projected capital expenditures represent approximately 63 percent of its net utility plant as of December 31, 2023.

[59] Data provided by the Company.

Q. How do MGUC's capital expenditure requirements compare to those of the proxy group companies?

A. As shown on Schedule D13, I have calculated the ratio of expected capital expenditures to net utility plant for MGUC and each of the companies in the proxy group by dividing each company's projected capital expenditures for the period from 2024 through 2028 by its total net utility plant as of December 31, 2023. As shown, MGUC's ratio of capital expenditures as a percentage of net utility plant is higher than the median for the proxy group companies.

Q. How is the Company's risk profile affected by its substantial capital expenditure requirements?

A. As with any utility faced with substantial capital expenditure requirements, the Company's risk profile may be adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under-recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics.

Q. Do credit rating agencies recognize the risks associated with elevated levels of capital expenditures?

A. Yes. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, S&P explains the importance of regulatory support for a significant amount of capital projects:

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.[60]

Recently, S&P evaluated the capital expenditure trends in the utility sector, noting that the balance between operating with negative discretionary cash flow from operations offset by reliable access to capital markets for financing may be tested through ever-increasing capital expenditure requirements as a result of the transformation of the energy sector through the focus on low/no carbon generation, electrification, and the replacement of aging infrastructure:

> Some companies have been unable to support financial metrics consistent with former ratings as their discretionary cash flow deteriorated. This trend was a significant contributor to the sector seeing the median rating decline to 'BBB+' from 'A-' for the first time in 2022. What is less clear is whether or not management teams will take steps to forestall another step down in credit quality as high capital outlays persist. So far in 2023, we have not seen evidence that equity issuance is keeping pace with debt issuance to fill ever-deepening discretionary cash flow shortfalls, but time will tell.
>
> …..
>
> Despite the improvement in the economic outlook, we expect inflation, high interest rates, higher capital spending, and the strategic decision by many companies to operate with only minimal financial cushion from

60 S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.

> their downgrade thresholds to continue to pressure the industry's credit quality. We are cautious about the durability of the current stable ratings outlook given persistently high capital spending that now supports a trend of deterioration in discretionary cash flow. Without a commensurate focus on balance sheet preservation through equity support of discretionary cash flow deficits, limited financial cushions could give rise to another round of negative rating actions. The question then comes back to management priorities and financial policy decisions, or utilities may be faced with another step down in the median ratings.[61]

While MGUC is not currently rated by the credit rating agencies, the Company's business risk is also increased as a result of its elevated capital expenditures. Therefore, to the extent that MGUC's rates do not permit the opportunity to recover its capital investments on a regular and timely basis, the Company will face increased recovery risk and thus increased pressure on its credit metrics.

Q. Does the Company currently have a capital tracking mechanism to recover the costs associated with its capital expenditures plan between rate cases?

A. MGUC has a Main Replacement Program ("MRP") surcharge rider to recover the costs associated with qualifying gas infrastructure investments. However, it is important to note that, as part of the settlement of its last rate case, MGUC has paused the MRP surcharge from January 1, 2024 through December 31, 2024, and has authority to continue the implementation of the MRP through 2027. While the MRP provides for timely recovery of certain qualifying investments, the majority of the costs included in MGUC's capital expenditures plan do not qualify for cost recovery through the MRP. As a result, MGUC still depends on rate case filings for the majority of its capital cost recovery.

[61] S&P Global Ratings, "Record CapEx Fuels Growth Along With Credit Risk For North American Investor-Owned Utilities," September 12, 2023, at 5, 7-8.

Q. What are your conclusions regarding the effect of the Company's capital spending requirements on its risk profile and cost of capital?

A. The Company's capital expenditure requirements as a percentage of net utility plant are significant relative to the proxy group and are expected to continue over the next few years. While MGUC has an MRP to recover a portion of these expenditures, this mechanism does not provide for timely recovery of the majority of the Company's capital expenditures between rate cases.

B. Regulatory Risk

Q. How does the regulatory environment affect investors' risk assessments?

A. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility service, the subject utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory commissions recognize that because utility operations are capital intensive, their decisions should enable the utility to attract capital at reasonable terms, and that doing so balances the long-term interests of investors and customers. Utilities must finance their operations and thus require the opportunity to earn a reasonable return on their invested capital to maintain their financial profiles. The Company is no exception. Therefore, the regulatory environment is one of the most important factors considered in both debt and equity investors' risk assessments.

From the perspective of debt investors, the authorized return should enable the utility to generate the cash flow needed to meet its near-term financial obligations, make the capital investments needed to maintain and expand its systems, and maintain the necessary levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally generated funds, but also by efficient access to capital markets. Moreover, because fixed income investors have many investment alternatives, even within a given market sector, a utility's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions.

Equity investors require that the authorized return be adequate to provide a risk-comparable return on the equity portion of the utility's capital investments. Because equity investors are the residual claimants on the utility's cash flows (*i.e.*, the equity return is subordinate to interest payments), they are particularly concerned with the strength of regulatory support and its effect on future cash flows.

Q. Do credit rating agencies consider regulatory risk in establishing a company's credit rating?

A. Yes. Both S&P and Moody's consider the overall regulatory framework in establishing credit ratings. Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity and key financial metrics. Of these criteria, regulatory framework and the ability to recover costs and earn returns are each given a broad rating factor of 25.00 percent. Therefore, Moody's assigns regulatory risk a 50.00 percent weighting in the overall assessment of business and financial risk for regulated utilities.[62]

S&P also identifies the regulatory framework as an important factor in credit ratings for regulated utilities, stating: "One significant aspect of regulatory risk that influences credit quality is the regulatory environment in the jurisdictions in which a utility operates."[63] S&P identifies four specific factors that it uses to assess the credit implications of the regulatory jurisdictions of investor-owned regulated utilities: (1) regulatory stability; (2) tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.[64]

Q. How does the regulatory environment in which a utility operates affect its access to and cost of capital?

A. The regulatory environment can significantly affect both the access to and cost of capital in several ways. First, the proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. As noted by Moody's, for utilities, which are rate regulated, "the regulatory environment and how the utility adapts to that environment are the most important credit considerations."[65] Moody's further highlighted the relevance of a stable and predictable regulatory

[62] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 4.

[63] Standard & Poor's Global Ratings, Ratings Direct, "U.S. and Canadian Regulatory Jurisdictions Support Utilities' Credit Quality – But Some More So Than Others," June 25, 2018, at 2.

[64] *Id.*, at 1.

[65] Moody's Investors Service, "Rating Methodology: Regulated Electric and Gas Utilities," June 23, 2017, at 6.

environment to a utility's credit quality, noting: "[b]roadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation."[66]

Q. Have you conducted an analysis to compare the cost recovery mechanisms of MGUC to the cost recovery mechanisms approved in the jurisdictions in which the companies in your proxy group operate?

A. Yes. I have evaluated the regulatory framework in Michigan considering five factors that are important in terms of providing a regulated utility a reasonable opportunity to earn its authorized ROE: (1) test year convention (*i.e.*, forecast vs. historical); (2) use of rate design or other mechanisms that mitigate volumetric risk and stabilize revenue; and (3) prevalence of capital cost recovery between rate cases. Each are described below and are summarized in Schedule D14:

> <u>Test Year Convention</u>: MGUC uses a forecasted test year, and similarly, over half of the utility operating subsidiaries of the companies in the proxy group also use forecasted or partially forecasted test years.

> <u>Volumetric Risk:</u> MGUC does not have protection against volumetric risk through a decoupling or other revenue stabilization mechanism; however, approximately 91 percent of the utility operating subsidiaries of the proxy group companies have some form of revenue stabilization through either decoupling, formula-based rates, and/or straight-fixed variable rate design that allow them to break the link between customer usage and revenues.

> <u>Capital Cost Recovery:</u> As noted previously, MGUC has an MRP surcharge to recover capital costs for main replacement; however, the MRP does not provide for the timely recovery of the majority of MGUC's capital investments.

[66] *Id*.

> Approximately 71 percent of the utility operating subsidiaries of the proxy group companies have some form of capital cost recovery mechanism.

Q. What are your conclusions regarding the perceived risks related to the Michigan regulatory environment?

A. As discussed, MGUC has moderately greater regulatory risk as compared to the operating subsidiaries of the proxy group companies given the more timely cost recovery of the proxy group companies. Therefore, it is important that the cost of equity established for MGUC in this proceeding reflect the relative regulatory risk of the Company relative to the proxy group.

C. Small Size Risk

Q. Is there a risk to a firm associated with small size?

A. Yes. Both the financial and academic communities have long accepted the proposition that the cost of equity for small firms is subject to a "size effect." While empirical evidence of the size effect often is based on studies of industries other than regulated utilities, utility analysts also have noted the risk associated with small market capitalizations. Specifically, an analyst for Ibbotson Associates noted:

> For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return. [67]

[67] Michael Annin, "Equity and the Small-Stock Effect." Public Utilities Fortnightly, October 15, 1995.

Q. How does the smaller size of a utility affect its business risk?

A. In general, smaller companies are less able to withstand adverse events that affect their revenues and expenses. The impact of weather variability, the loss of large customers to bypass opportunities, or the destruction of demand as a result of general macroeconomic conditions or fuel price volatility will have a proportionately greater impact on the earnings and cash flow volatility of smaller utilities. Similarly, capital expenditures for non-revenue producing investments, such as system maintenance and replacements, will put proportionately greater pressure on customer costs, potentially leading to customer attrition or demand reduction. Taken together, these risks affect the return required by investors for smaller companies.

Q. How do MGUC's natural gas distribution operations in Michigan compare in size to the proxy group companies?

A. The Company's natural gas distribution operations are substantially smaller than the median for the proxy group companies in terms of market capitalization. While MGUC is not publicly-traded on a stand-alone basis, as shown on Schedule D15, MGUC's common equity based on its proposed test year rate base and equity ratio is substantially smaller than the median market capitalization of the proxy group companies.

Q. How do you estimate the size premium for MGUC?

A. Given this relative size information, it is possible to estimate the impact of size on the cost of equity for the Company using *Kroll* Cost of Capital Navigator data that estimates the stock risk premia based on the size of a company's market capitalization.[68] As shown in

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68 *Kroll* Cost of Capital Navigator – Size Premium.

Schedule D15, the median market capitalization of the proxy group is approximately $3.46 billion, which corresponds to the fifth decile of *Kroll's* market capitalization data.[69] Based on *Kroll's* analysis, that decile corresponds to a size premium of 0.93 percent (*i.e.*, 93 basis points). In comparison, MGUC's common equity of approximately $259 million falls within the ninth decile, which corresponds to a size premium of 2.15 percent (*i.e.*, 215 basis points). The difference between the size premium for the Company and the size premium for the proxy group is 122 basis points (*i.e.*, 2.15 percent minus 0.93 percent).

Q. Were utility companies included in the small size risk premium study conducted by *Kroll*?

A. Yes. As shown in Exhibit 7.2 of the *Kroll* (formerly *Duff & Phelps*) 2019 Valuation Handbook, OGE Energy Corp. had the largest market capitalization of the companies contained in the fourth decile, which indicates that Kroll has included utility companies in its size risk premium study.[70]

Q. Is the size premium applicable to companies in regulated industries such as natural gas utilities?

A. Yes. For example, Zepp (2003) provided the results of two studies that showed evidence of the required risk premium for small water utilities. The first study, which was conducted by the Staff of the California Public Utilities Commission, computed proxies for beta risk using accounting data from 1981 through 1991 for 58 water utilities and concluded that

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[69] *Id*.

[70] *Kroll*, Valuation Handbook: Guide to Cost of Capital, 2019, Exhibit 7.2.

smaller water utilities had greater risk and required higher returns on equity than larger water utilities.[71] The second study examined the differences in required returns over the period of 1987 through 1997 for two large and two small water utilities in California. As Zepp (2003) showed, the required return for the two small water utilities calculated using the DCF model was on average 99 basis points higher than the two larger water utilities.[72]

Additionally, Chrétien and Coggins (2011) studied the CAPM and its ability to estimate the risk premium for the utility industry, and in particular subgroups of utilities.[73] The article considered the CAPM, the Fama-French three-factor model, and a model similar to the ECAPM, which as previously discussed, I have also considered in estimating the cost of equity for the Company. In the study, the Fama-French three-factor model explicitly included an adjustment to the CAPM for risk associated with size. As Chrétien and Coggins (2011) show, the beta coefficient on the size variable for the U.S. natural gas utility group was positive and statistically significant indicating that small size risk was relevant for regulated natural gas utilities.[74]

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[71] Thomas M. Zepp, "Utility Stocks and the Size Effect—Revisited," *The Quarterly Review of Economics and Finance*. Vol. 43, No. 3, 2003, at 578–582.

[72] *Id*.

[73] Stéphane Chrétien and Frank Coggins, "Cost Of Equity For Energy Utilities: Beyond The CAPM," *Energy Studies Review*, Vol. 18, No. 2, 2011.

[74] *Id.*

Q. Have regulators in other jurisdictions made a specific risk adjustment to the cost of equity results based on a company's small size?

A. Yes. For example, in Order No. 15, the Regulatory Commission of Alaska ("RCA") concluded that Alaska Electric Light and Power Company ("AEL&P") was riskier than the proxy group companies due to small size as well as other business risks. The RCA did "not believe that adopting the upper end of the range of ROE analyses in this case, without an explicit adjustment, would adequately compensate AEL&P for its greater risk." [75] Thus, the RCA awarded AEL&P an ROE of 12.875 percent, which was 108 basis points above the highest cost of equity estimate from any model presented in the case.[76] Similarly, the RCA has also noted that small size, as well as other business risks such as structural regulatory lag, weather risk, alternative rate mechanisms, gas supply risk, geographic isolation and economic conditions, increased the risk of ENSTAR Natural Gas Company.[77] Ultimately, the RCA concluded that:

> Although we agree that the risk factors identified by ENSTAR increase its risk, we do not attempt to quantify the amount of that increase. Rather, we take the factors into consideration when evaluating the remainder of the record and the recommendations presented by the parties. After applying our reasoned judgment to the record, we find that 11.875% represents a fair ROE for ENSTAR.[78]

Additionally, the Minnesota Public Utilities Commission ("Minnesota PUC") authorized an ROE for Otter Tail Power Company ("Otter Tail") above the mean DCF

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[75] Regulatory Commission of Alaska, Docket No. U-10-29, Order No. 15, September 2, 2011, at 37.

[76] *Id.*, at 32 and 37.

[77] Regulatory Commission of Alaska, Docket No. U-16-066, Order No. 19, September 22, 2017, at 50-52.

[78] *Id.*

results as a result of multiple factors, including Otter Tail's small size. The Minnesota PUC stated:

> The record in this case establishes a compelling basis for selecting an ROE above the mean average within the DCF range, given Otter Tail's unique characteristics and circumstances relative to other utilities in the proxy group. These factors include the company's relatively smaller size, geographically diffuse customer base, and the scope of the Company's planned infrastructure investments. [79]

Finally, in Opinion Nos. 569 and 569-A, the Federal Energy Regulatory Commission ("FERC") adopted a size premium adjustment in its CAPM estimates for electric utilities. In those decisions, the FERC noted that "the size adjustment was necessary to correct for the CAPM's inability to fully account for the impact of firm size when determining the cost of equity."[80]

Q. How have you considered the smaller size of MGUC in your recommendation of the Company's ROE in this proceeding?

A. While I have estimated the effect of MGUC's small size on the cost of equity, I am not proposing a specific adjustment for this risk factor. Rather, I have considered the small size of the Company's utility operations in evaluating where within the range of analytical results that the Company's ROE should fall. All else equal, the additional risk associated

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[79] Minnesota Public Utilities Commission, Docket No. E017/GR-15-1033, Order, August 16, 2016, at 55.

[80] *Ass'n. of Businesses Advocating Tariff Equity, et. al., v. Midcontinent Indep. Sys. Operator, Inc., et. al.*, 171 FERC ¶ 61,154 (2020), at ¶ 75. The U.S. Court of Appeals recently vacated FERC Order No. 569 decisions that related to its risk premium model and remanded the case to FERC to reopen the proceedings. However, in its decision, the Court did not reject FERC's inclusion of the size premium to estimate the CAPM. (*See*, United States Court of Appeals Case No. 16-1325, Decision No. 16-1325, August 9, 2022 at 20).

with the Company's small size supports an ROE that is above the average of the range of results produced by the cost of equity estimation models.

VIII. CAPITAL STRUCTURE

Q. Is the capital structure of the Company an important consideration in the determination of the appropriate ROE?

A. Yes. The equity ratio is the primary indicator of financial risk for a regulated utility. All else equal, a higher debt ratio increases the risk to investors. For debt holders, higher debt ratios result in a greater portion of the available cash flow being required to meet debt service, thereby increasing the risk associated with the payments on debt. The result of increased risk is a higher interest rate. The incremental risk of a higher debt ratio is more significant for common equity shareholders, whose claim on the cash flow of the Company is secondary to debt holders. Therefore, the greater the debt service requirement, the less cash flow is available for common equity holders.

Q. What is the Company's proposed capital structure?

A. The Company proposes to establish a ratemaking capital structure consisting of 50.9 percent common equity and 49.1 percent long-term debt, which the Company notes will migrate towards 50 percent common equity and 50 percent long-term debt over time, as discussed in the direct testimony of Company witness Stasik.

Q. Did you conduct any analysis to determine if this requested equity ratio was reasonable?

A. Yes. I compared the Company's proposed capital structure relative to the actual capital structures of the utility operating subsidiaries of the companies in the proxy group. The cost of equity is estimated based on the return that is derived from companies in the proxy group that are deemed to be comparable in risk to the Company; however, those companies must be publicly-traded in order to apply the cost of equity models. The operating utility subsidiaries of the proxy group companies are most risk-comparable to the Company, and thus it is reasonable to look to the average capital structure of the operating utilities of the proxy group to benchmark the equity ratios for the Company. Specifically, I have calculated the average proportion of common equity, long-term debt, preferred equity and short-term debt for the most recent three years for each of the utility operating subsidiaries of the proxy group companies. As shown in Schedule D17, the common equity ratios for operating subsidiaries of the proxy group companies over the past three years ranged from 44.57 percent to 59.79 percent, with an average of 53.59 percent. Therefore, MGUC's proposed equity ratio is well within the range of equity ratios for the utility operating subsidiaries of the proxy group companies, and actually is well below the average.

Q. Are there other factors to be considered in setting the Company's capital structure?

A. Yes, there are other factors that should be considered in setting the Company's capital structure, namely the challenges that the credit rating agencies have highlighted as placing pressure on the credit metrics for utilities.

For example, while Moody's recently revised its outlook for the utility sector from "negative" to "stable", Moody's continues to note that high interest rates and increased capital spending will place pressure on credit metrics. Thus, Moody's highlights constructive regulatory outcomes that promote timely cost recovery as a key factor in supporting utility credit quality. [81]

Likewise, while S&P also recently revised its outlook for the industry from negative to stable,[82] S&P continues to see significant risks in 2024 for the industry as a result of, among other things, inflation and increased levels of capital spending, and specifically full electrification and natural gas bans for natural gas utilities.[83] S&P also recently found that the factors contributing to higher costs (*e.g.*, inflation; deferred commodity costs) and that it will be closely monitoring pressure on the industry's credit quality as a result of its ability to recover these costs on a timely basis and minimize regulatory lag, while at the same time effectively managing regulatory risk and customer rates. [84]

Fitch has stated that it is maintaining a "deteriorating outlook" on the U.S. utility sector in 2024 based on elevated capital spending and continuing higher interest rates that place pressure on credit metrics. Fitch noted that bill affordability will remain a major issue for the industry that could affect future regulatory outcomes, and that while it expects authorized ROEs to start trending up with the increase in interest rates, albeit with a lag,

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[81] Moody's Investors Service, Outlook, "Outlook turns stable on low prices and credit-supportive regulation," September 7, 2023.

[82] S&P Global Ratings, "The Outlook for North American Regulated Utilities Turns Stable," May 18, 2023, at 8.

[83] S&P Global Ratings, Industry Credit Outlook 2024 - North American Regulated Utilities, January 9, 2024.

[84] S&P Global Ratings, "Regulatory Friction Is Constraining Cost Recovery For North American Investor-Owned Utilities," November 6, 2023, at 8.

given the uncertain macroeconomic environment and bill pressure on customers, the lag could be longer than in previous cycles.[85]

The credit ratings agencies' continued concerns over the negative effects of inflation, higher interest rates, and increased capital expenditures underscore the importance of maintaining adequate cash flow metrics for the industry as a whole, and MGUC in particular in the context of this proceeding.

Q. Will the capital structure and ROE authorized in this proceeding affect the Company's access to capital at reasonable rates?

A. Yes. The level of earnings authorized by the Commission directly affects the Company's ability to fund its operations with internally generated funds. Both bond investors and rating agencies expect a significant portion of ongoing capital investments to be financed with internally-generated funds. In addition, it is important to recognize that because a utility's investment horizon is very long, investors require the assurance of a sufficiently high return to satisfy the long term financing requirements of the assets placed into service. Those assurances, which often are measured by the relationship between internally generated cash flows and debt (or interest expense), depend quite heavily on the capital structure. As a consequence, both the ROE and capital structure are very important to debt and equity investors, particularly given the capital market conditions discussed previously.

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85 Fitch Ratings, "North American Utilities, Power & Gas Outlook," S&P Market Intelligence, November 13, 2023.

IX. CONCLUSION AND RECOMMENDATION

Q. What is your conclusion regarding a fair ROE for MGUC?

A. Figure 13 summarizes the results of my cost of equity analyses. Based on the quantitative and qualitative analyses presented in my direct testimony, and the business and financial risks of the Company as compared to the proxy group, the Company's requested ROE of 10.25 percent is at the low end of my recommended range, and is reasonable.

Figure 13: Summary of Analytical Results

Constant Growth DCF	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.79%	10.71%	11.92%
90-Day Avg. Stock Price	9.87%	10.78%	11.99%
180-Day Avg. Stock Price	9.70%	10.62%	11.83%
Average	9.79%	10.70%	11.91%
Median Results:			
30-Day Avg. Stock Price	9.90%	10.17%	11.76%
90-Day Avg. Stock Price	9.98%	10.25%	11.85%
180-Day Avg. Stock Price	9.93%	10.20%	11.64%
Average	9.94%	10.21%	11.75%

CAPM / ECAPM / Bond Yield Risk Premium	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.09%	11.08%	11.08%
Current Bloomberg Beta	10.31%	10.29%	10.29%
Long-term Avg. *Value Line* Beta	10.12%	10.10%	10.10%
ECAPM:			
Current *Value Line* Beta	11.38%	11.37%	11.37%
Current Bloomberg Beta	10.79%	10.77%	10.77%
Long-term Avg. *Value Line* Beta	10.64%	10.63%	10.63%
Bond Yield Risk Premium:	10.30%	10.25%	10.25%

Q. What is your conclusion with respect to MGUC's proposed capital structure?

A. MGUC's proposal to establish a capital structure based on 50.9 percent common equity and 49.1 percent long-term debt is well within the range of actual capital structures of the proxy group companies, and is actually well below the average. Further, taking into consideration the impact of current and projected market conditions on the cash flows of utilities as raised by the credit rating agencies, I conclude that the Company's proposal is reasonable and should be adopted for ratemaking purposes.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of	)	
MICHIGAN GAS UTILITIES CORPORATION	)	
for authority to increase retail natural gas rates	)	Case No. U-21540
and for other relief.	)	
	)	

DIRECT TESTIMONY AND EXHIBITS OF

RILEY E O'BRIEN

FOR

MICHIGAN GAS UTILITIES CORPORATION

March 1, 2024

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of	)	
MICHIGAN GAS UTILITIES CORPORATION	)	
for authority to increase retail natural gas rates	)	Case No. U-21540
and for other relief.	)	
	)	

QUALIFICATIONS
OF
RILEY E O'BRIEN
PART I

Q. Please state your name, position and business address.

A. My name is Riley E. O'Brien. My business address is 231 West Michigan Street, Milwaukee, WI 53203. My position is Project Specialist 1 – State Regulatory Affairs. I am employed by WEC Business Services, LLC ("WBS"), serving all of the WEC Energy Group, Inc. ("WEC") utilities, including Michigan Gas Utilities Corporation ("MGUC" or the "Company"). WBS and MGUC are wholly-owned subsidiaries of WEC.

Q. For whom are you providing testimony?

A. I am providing testimony on behalf of MGUC.

Q. Please describe briefly your educational, professional, and utility background.

A. I received a Bachelor of Arts Degree with a major in Economics from Marquette University in 2020. I began my professional career in the compliance department of Robert W. Baird & Co before joining Refinitiv, a financial market data and infrastructure company, in 2020. From 2021 to 2023, I was employed by Rockwell Automation as an internal auditor. I then joined WEC Energy Group's State Regulatory Affairs in June of 2023. In this position, I am responsible for assisting in all of WEC Energy Group's operating utilities' regulatory matters in Wisconsin, Michigan, and Minnesota. I primarily support our natural gas and electric utilities' cost of service studies in Michigan and Wisconsin.

Q. Have you completed any seminars or other training courses?

Shortly after joining WEC Energy Group, I attended "The Basics: Practical Regulatory Training for the Electric Industry". This NARUC-endorsed course, hosted by the New Mexico State University Center for Public Utilities, included five days of curriculum designed to deliver an understanding of the industry and its regulation including, but not limited to, revenue requirements, class cost-of-service studies, and rate design.

RILEY E O'BRIEN
DIRECT TESTIMONY
PART II

Q. What is the purpose of your direct testimony?

A. My direct testimony and exhibits describe and present MGUC's class cost of service study ("COSS") for the 2025 projected test year. Company Witness Shannon Burzycki's direct testimony relies in part on the results of the class COSS for the 2025 projected test year to develop MGUC's proposed rate design intended to recover the Company's base rate revenue requirement.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-16	F1.1	Cost of service summary by rate class at present rates
A-16	F1.2	Cost of service summary by customer class at present rates
A-16	F1.3	Unbundled revenue requirement by customer class
A-16	F1.4	Unbundled rate base by customer class
A-16	F1.5	Unbundled unit cost by customer class

These exhibits present the 2025 projected class COSS prepared for MGUC. The accompanying workpaper (Workpaper REO-1) includes the associated allocation methodologies, supplemental analyses, and data. As required by the Rate Case Filing Requirements, MGUC is providing in native Microsoft Excel format with all formulas and links active the class COSS model. Workpaper REO-2 is MGUC's projected class COSS. The following testimony explains these studies.

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

A. Yes, they were.

Q. Can you provide an overview of your testimony and recommendations in this proceeding?

A. Yes, below is a summary of my testimony and recommendations:

1. As explained by Company Witness Reese in his direct testimony, MGUC's analysis of the test year ending December 31, 2025 indicates a need for an annual revenue increase of $17.6 million, or 9.74%; MGUC's class COSS for the 2025 projected test year is based on and uses the components from this analysis;

2. The customer class revenue requirements as determined by Exhibit A-16, Schedule F1.2, reasonably apportions the Company's proposed revenue increase among customer classes and should be approved as acceptable guidance for setting rates in this case.

Q. Please summarize the results of MGUC's proposed class COSS.

A. Table 1 summarizes the results of MGUC's class COSS with respect to revenue deficiency at present rates by customer class based on MGUC's requested revenue requirement consistent with Exhibit A-16, Schedule F1.2. Present rates are those that the Commission approved in MGUC's last general rate case, Case No. U-21366, ("2024 Rate Case").

Table 1
Michigan Gas Utilities Corporation
Class Revenue Deficiency at Present Rates

Line No.	Line Description	Present Revenue $	Revenue Deficiency $	Revenue Deficiency %	Revenue Requirement $
	Retail Sales and Transportation				
1					
2	General Service-Residential	115,699,922	13,883,498	12.0%	129,583,420
3	Customer Choice-Residential	6,369,864	1,484,543	23.3%	7,854,408
4	Agg Transport-Residential	10,323	10,954	106.1%	21,277
5	General Service-Small	43,264,455	(271,273)	-0.6%	42,993,182
6	Customer Choice-GS-Small	2,578,504	70,117	2.7%	2,648,621
7	Agg Transport-GS-Small	916,988	205,033	22.4%	1,122,022
8	Transport-TR-1	2,763,003	(397,988)	-14.4%	2,365,016
9	Agg Transport-GS-Medium	159,253	(23,298)	-14.6%	135,955
10	Customer Choice-GS-Medium	3,865	150	3.9%	4,015
11	General Service-Medium	204,417	(7,485)	-3.7%	196,933
12	General Service-Large	2,274,911	(173,631)	-7.6%	2,101,280
13	Transport-TR-2	4,165,063	1,640,629	39.4%	5,805,693
14	Customer Choice-GS-Large	40,206	12,801	31.8%	53,007
15	Agg Transport-GS-Large	86,914	(5,020)	-5.8%	81,895
16	Transport-TR-3	1,761,722	1,221,214	69.3%	2,982,936
17	Special Contract	99,923	(75,233)	-75.3%	24,689
18	Total Jurisdiction	**180,399,335**	**17,575,013**	**9.7%**	**197,974,348**

Q. How is the remainder of your testimony organized?

A. First, I will provide an overview of the cost of service study and the processes and procedures I relied on while developing MGUC's test year 2025 natural gas class COSS. Second, I will provide an overview of the allocation methods used in MGUC's 2025 test year class COSS. Finally, I will describe and summarize the results of MGUC's 2025 test year class COSS.

General Information

Q. What is the purpose of a class cost of service study?

A. The purpose of a class COSS is to identify the revenues, costs, and profitability for each customer class. It assists in determining the reasonableness of each class's present rates and provides a guide for the development of the proposed cost-based rates using an embedded cost methodology.

Q. How should a class COSS be performed?

A. Cost causation is the fundamental principle applicable to all cost studies for purposes of allocating costs to customer classes. The costs that customers become responsible to pay should be those costs that the particular customers cause the utility to incur because of the characteristics of the customers' usage of utility service. By performing a class COSS in this manner, the class COSS can be used to determine how costs should be recovered from customer classes through rate design.

Q. Please explain the procedures used to develop the class COSS shown in the schedules of Exhibit A-16 that you are sponsoring.

A. In general, there are three main steps to determining cost responsibility: 1) functionalization, 2) classification, and 3) class allocation. Each of these steps is performed on the Company's total cost of service.

Functionalization is the process of categorizing costs based on their function within the utility. Generally, natural gas costs are functionalized either as production, storage, transmission, or distribution.

Classification is the process of categorizing costs based on whether they are caused by demand, number of customers, or the commodity consumed.

Class allocation is the process of apportioning each cost item within each classification and for each function to classes of customers. Some costs, particularly general or indirect costs, cannot be directly functionalized or classified. In general, these costs are allocated to functions, classifications, and customer classes based upon the allocated results of other cost items within the class COSS.

Q. What is your process for functionalizing costs?

A. For the most part, the job of functionalizing plant costs is performed by the Plant Accounting Team, which operates in conformance with the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOA"). Similarly, operations and maintenance ("O&M") costs are functionalized by our Finance Department, also in conformance with the FERC USOA.

Q. What is your process for classifying costs?

A. Once costs are functionalized, all cost elements are classified by whether they are caused by demand, number of customers, or the commodity consumed. Demand-related costs are costs incurred to meet customer demand for natural gas. The cost of a peaking Liquefied Natural Gas ("LNG") facility is an example of a demand-related cost. Customer-related costs are costs associated with customers regardless of the amount of natural gas they demand or consume. These are costs incurred to extend service to and attach a customer to the distribution system, meter any natural gas usage, and bill and maintain the customer's account. The cost to install a meter is an example of a customer-related cost. Commodity-related costs are costs incurred as customers consume natural gas. The commodity cost of gas expense is an example of a commodity-related cost. However, when, as is the case with

MGUC, a gas utility's cost of gas is not recovered through its base rates, very little, if any, of its remaining delivery service cost structure is commodity related.

Q. What is your process for allocating costs to customer classes?

A. The purpose of cost allocation is to determine cost responsibility of each customer class. The prior steps consisting of functionalization and classification facilitate the allocation of costs to customer classes. In general, costs classified as demand-related are allocated to classes based upon a demand allocation factor, costs classified as commodity-related are allocated to classes based upon a commodity allocation factor, and costs classified as customer-related are allocated to classes based upon a customer allocation factor. Some costs, such as indirect or general costs, closely follow in proportion with other cost items. These costs are allocated using the allocated results of other cost items within the COSS, such as plant in service or the labor portion of O&M expense.

Q. Please explain the considerations relied upon in determining the cost allocation methodologies that are used to perform a class COSS.

A. As stated earlier, in order to allocate costs within any class COSS, the factors that cause the costs to be incurred must be identified and understood. Additionally, the cost analyst needs to develop data in a form that is compatible with, and supportive of, rate design proposals. The availability of data for use in developing alternative cost allocation factors is also a consideration. When evaluating any cost allocation methodology, appropriate consideration should be given to whether it provides a sound rationale or theoretical basis, whether the results reflect cost causation and are representative of the costs of serving different types of customers, as well as the stability of the results over time.

Q. What is the source of the cost data analyzed in MGUC's class COSS?

A. All cost of service data have been extracted from MGUC's revenue requirements and rate base contained in the instant filing as shown in Company Witness Reese's Exhibits A-11 through A-14 for the 2025 projected test year. Where more detailed information was required to perform various supplementary analyses related to certain plant and expense elements, the data was taken directly from MGUC's various software systems.

Q. Could you please describe the allocation factors used in MGUC's class COSS?

A. External allocation factors are developed using either historic or test year values that are known prior to performing the cost of service study. External allocation factors include data such as number of customers, total throughput, and other data being provided as part of the case filing in workpaper REO-1.

Q. Have you made any changes to the classes of customers included in the class COSS you prepared for the instant general rate case compared to the class COSS submitted in MGUC's 2024 Rate Case?

A. No, I have not.

Q. What classes of customers are included in MGUC's class COSS?

A. MGUC's class COSS includes the customer classes under which MGUC currently provides retail service in Michigan. A complete list of the customer classes used in MGUC's class COSS includes:

1. General Service–Residential, including residential heating, general, and lighting,

2. General Service–Small, including commercial lighting,

3. General Service–Medium

4. General Service–Large,

5. Transportation–TR-1,

6. Transportation–TR-2,

7. Transportation–TR-3,

8. Customer Choice–Residential,

9. Customer Choice–Small General Service,

10. Customer Choice–Medium General Service

11. Customer Choice–Large General Service,

12. Aggregated Transportation–Residential,

13. Aggregated Transportation–Small General Service,

14. Aggregated Transportation–Medium General Service ,

15. Aggregated Transportation–Large General Service, and

16. Special Contract, which consists of one customer who is currently served by MGUC under the terms of a special contract. This customer's rates are fixed by the terms of the contract and not subject to change in a general rate case proceeding. Therefore, the special contract customer is in a separate column solely to segregate its revenues and associated costs.

Test Year Natural Gas Cost of Service Study

Q. How many versions of the class COSS are you sponsoring in this case?

A. I am sponsoring one version of MGUC's natural gas class COSS. Schedules F1.1 through F1.5 present MGUC's class COSS with the allocation methods used in the 2024 Rate Case. Support for these schedules is provided in workpaper REO-1. Workpaper REO-2 contains the working Excel model for MGUC's COSS.

Overview of Allocation Methodologies

Q. How does MGUC allocate production-related costs to customer classes within the class COSS?

A. MGUC's production-related costs includes the commodity cost of gas, gas supply acquisition O&M expenses, and related general plant, common administrative and general expenses, depreciation, and taxes. MGUC also has O&M expenses relating to the deferred accounting of costs associated with the remediation of former manufactured gas plant sites, as discussed in Company Witness Reese's direct testimony. Since these production-related costs generally cannot be traced back to individual customers they are classified as either commodity- or demand-related. The commodity classification is further separated into sub-categories of purchased gas cost and gas supply acquisition.

The commodity cost of gas sold which is recovered via MGUC's Gas Cost Recovery ("GCR") plan are the only production costs classified as purchased gas costs.

Other commodity-related costs, not including the cost of gas sold, were assigned to the gas supply acquisition classification and allocated to the sales customer classes based on the throughput of those sales customer classes.

Production demand-related costs include those O&M expenses relating to the remediation of former manufactured gas plant sites in FERC Accounts 710-742. These production demand-related costs are allocated to customer classes based upon each class's maximum monthly volumes, or group peak demand, similar to MGUC's test year 2024 Rate Case.

Q. How does MGUC allocate storage-related costs to customer classes within the class COSS?

A. MGUC's storage-related costs are those relating to underground storage in FERC Accounts 350-357 and 814-842, and the rate base working capital component gas stored underground in FERC Account 164. These costs are classified as storage demand-related and are allocated to customer classes based upon the storage allocation factor, consistent with the Company's test year 2024 Rate Case.

Q. How does MGUC allocate transmission-related costs to customer classes within the COSS?

A. Transmission plant is high-pressure main typically used for transporting bulk quantities of gas from an interstate pipeline to the utility's distribution system load centers. A majority of the investment that is functionalized to transmission for MGUC is related to transmission main in Plant Account 367. Similar to MGUC's test year 2024 case, 100% of the balances in Plant Account 367 was assigned to the demand-related classification, which is consistent with the method recently utilized by other Michigan jurisdictional natural gas utilities, including MGUC, to allocate Plant Account 367. Transmission costs were then allocated to customer classes based upon average and peak demand.

Q. How are distribution-related costs classified in MGUC's class COSS?

A. The distribution system is built to meet two criteria: (i) it must connect to all customers and (ii) it must be capable of delivering the total gas volumes demanded from each of the customers connected to it during peak demand periods. Therefore, the distribution system should be classified as having both customer- and demand-related components. The costs for connecting customers to the distribution system are related to the number of customers and should be assigned to the customer-related classification. The theory is that there are costs associated with serving all customers even if they only use a minimal amount of natural gas (or even no natural gas at all). The remaining costs are considered to be demand-related and should be assigned to the demand-related classification. I will discuss the process of classifying MGUC's distribution-related costs in more detail later in my direct testimony.

Q. How are distribution-related costs allocated to customer classes in MGUC's class COSS?

A. In general, distribution customer-related costs are allocated to customer classes by the number of customers within each class, and distribution demand-related costs are allocated to classes by the group peak demand of each class. I will discuss a few instances where it is reasonable to incorporate a weighting factor into the allocation of certain distribution customer-related costs, such as service lines (Plant Account 380). A weighting factor is developed based on a detailed study of actual investment or costs by customer class. The weighting factor is used to account for differences in the average costs to serve each customer class.

Q. How are miscellaneous distribution plant costs (Plant Accounts 374 and 375) allocated to customer classes?

A. These two plant accounts are classified as 100% demand-related and allocated to customer classes based upon the group peak demand allocation factor.

Q. Please describe in more detail how distribution main (Plant Account 376) was allocated to customer classes.

A. Distribution main is booked to Plant Account 376 and consists of a network of smaller diameter pipe, typically ranging between 2 and 12 inches, which is used for delivering volumes of gas to a number of end-use locations. Similar to historical practice, distribution main investment in Plant Account 376 was allocated between the customer- and demand-related classifications using a zero-intercept regression analysis of the cost and size of distribution main in service at MGUC. The zero-intercept regression was performed using data supplied by property accounting as of November 30, 2023, and produced similar results to those last completed in Case No. U-17880 and subsequently carried forward and used in Case Nos. U-20718 and U-21366. In addition, and to assist with verifying the results of MGUC's distribution zero-intercept regression analysis, I completed a minimum-size study utilizing MGUC's 2-inch pipe diameter main for system minimum size because it is the standard sized pipe utilized by MGUC when installing new distribution mains. The regression based zero-intercept study assigns approximately 50.5% of distribution main costs as customer related and 49.5% as demand related. By comparison, the results of the minimum size study indicate approximately 60.9% of distribution main costs should be assigned as customer related and 39.1% as demand related, which supports that MGUC's zero-intercept results are reasonable.

Once classified, the customer-related portion of distribution main was allocated to customer classes based on the customer allocation factor and the demand-related portion of distribution main was allocated to customer classes based on the group peak demand allocation factor.

Q. How are distribution measuring and regulating station equipment (Plant Accounts 378 and 379) allocated to customer classes?

A. Gate stations represent the transfer point between the interstate pipeline and the local distribution company ("LDC"). Typically, these stations have measurement and odorizer equipment. Regulator stations regulate the pressure between two systems by controlling the flow of gas through the distribution system. Similar to historical practice, these two plant accounts were classified as 100% demand-related and allocated to customer classes based upon the group peak demand allocation factor.

Q. How are service lines (Plant Account 380) allocated to customer classes?

A. A service line is a lateral installed off distribution or high pressure main in order to serve a customer request for gas. In general, the larger the customer class the more costly the service lateral. Each service line can be traced back to a specific customer, or group of customers in the case of some residential and small commercial accounts. Therefore, service lines were classified as 100% customer-related and allocated to customer classes using a weighted customer allocation factor. Similar to historical practice, the weighted customer allocator represents an estimate of the service line replacement cost per customer.

Q. How are metering related costs (Plant Account 381) allocated to customer classes?

A. Meters measure the amount of gas used for billing. General practice is to install one meter per customer. There are three types of meters that can be installed depending on a customer class's requirements for gas: 1) diaphragm, for low flow; 2) rotary, for medium flow; and 3) turbine, for high flow. Meter costs (Plant Accounts 381 and 382) can be more directly assigned to customer classes because we know which meters serve which customers. Therefore, we can add up the number of meters serving each class. For this reason, metering costs were classified as 100% customer-related and allocated to customer classes by a weighted customer allocation factor. The weighted customer allocation factor represents an estimate of the current average meter cost per customer. Our metering department supplied estimates of the unit costs for meters. We derived allocation factors for each class by multiplying the number of meters in each class by the estimated unit cost of meters in each class. We then allocated these costs to customer classes proportionally to these allocation factors.

Q. Is the allocation methodology of house regulators in this case the same methodology utilized in the Company's 2022 and 2024 Rate Cases?

A. Yes, as explained in those cases, a meter set is typically accompanied by one or more regulators that can vary in size depending on the size and complexity of the metering configuration. Regulators adjust the delivery pressure and flow rate of natural gas to that which is required at the customers' premises. In MGUC's class COSS, and similar to past practice, regulators continue to be classified as 100% customer-related.

Larger meter sets require regulators that are more costly in material, design, and installation than regulators for smaller meter sets. For this reason, the class allocation of regulators reflects the average cost of regulators per customer class using a weighted customer allocation factor, similar to the methods used for Plant Accounts 380 and 381. Regulators and other accessories that accompany the largest meter installations, which I will discuss shortly, are booked to Plant Account 385, industrial measuring and regulating equipment. For this reason, these large, unique installations have been excluded from the regulators allocation factor.

Q. How are distribution industrial measuring and regulating equipment (Plant Account 385) allocated to customer classes?

A. Industrial measuring and regulating station equipment are large, unique installations of measuring and regulating equipment used by large commercial and industrial customers. This equipment has been defined as meter sets larger than 16,000 cubic feet per hour ("CFH"). The accessories that accompany these large, unique metering installations, such as regulators, piping, fittings, valves, etc. are booked to Plant Account 385. Similar to past practice, this account was allocated to those customer classes having customers with these unique installations. Since we know which meters serve which customers, we can identify the number of these large, unique meter sets per customer class. Therefore, industrial measuring and regulating station equipment were classified as 100% customer-related and allocated to customer classes using a weighted customer allocation factor. The weighted customer allocation factor represents an estimate of the current average industrial-sized meter cost per customer. MGUC's metering department supplied estimates of the unit costs for industrial-sized meters. I derived allocation factors for each class by multiplying the number of industrial-sized meters in each class by the estimated unit cost of industrial sized meters in each class. I then allocated these costs to customer classes proportionally to these allocation factors.

Q. Please explain how distribution O&M expenses were allocated to customer classes within MGUC's class COSS in this case.

A. Consistent with the methodology employed in MGUC's test year 2024 Rate Case in Case U-21366, these expenses were allocated in the same manner used for the gross plant values of each respective account.

Q. Please explain in more detail how distribution O&M expenses were allocated to customer classes in MGUC's class COSS.

A. In general, distribution O&M expenses are classified and allocated to customer classes based upon the allocated results of the gross plant values of each respective account. This includes mains, measuring and regulation equipment, service lines, and meters. Load dispatching costs (Account 871) are classified as 100% demand-related and allocated to customer classes based upon group peak demand, which was the allocation factor used in MGUC's test year 2024 Rate Case.

Customer installations (Account 879) are classified as 100% customer-related and allocated to customer classes based upon the allocated results of all other customer-related distribution O&M expenses, similar to the method used in MGUC's test year 2024 Rate Case. Supervision and engineering (Accounts 870 and 885) and other distribution (Accounts 880 and 894) are classified and allocated to customer classes based upon the allocated results of all other distribution O&M expenses, again, similar to the method used in MGUC's test year 2024 Rate Case.

Q. How are customer costs categorized?

A. FERC USOA defines customer costs as Accounts 901 through 917. MGUC categorizes Accounts 901, 902, 903 and 905 as customer accounting costs. Uncollectibles in Account 904 are categorized separately from customer accounting costs for allocation purposes. MGUC doesn't have any forecasted costs in Account 906. Accounts 907 through 910 are categorized as customer service costs. Accounts 911 through 917 are categorized as customer sales costs.

Q. How does MGUC allocate customer-related O&M costs to each customer class?

A. Customer accounting costs were allocated to customer classes based on the number of customers within each customer class. Costs that could be directly related and assigned to transportation customers were identified and allocated directly to those customers based on a specific transportation customer allocation factor. Expenses in Account 904 uncollectibles, as well as customer services and sales were allocated to customer classes based on a total margin revenue allocation factor, consistent with MGUC's past practice.

Q. How did MGUC allocate common administrative and general expenses to customer classes?

A. Common administrative and general ("A&G") expenses are defined as FERC Accounts 920 through 935. These expenses were allocated to customer classes based on the allocated results of other cost values within MGUC's class COSS. The underlying theory is that common A&G expenses are caused by, or follow in proportion to, other utility expenses and plant investments.

Q. Have you changed the allocation of A&G expenses to customer classes as compared to what was done in the 2024 Rate Case?

A. No, I have not.

Q. Please explain how A&G expenses were allocated in this case.

A. Each A&G related FERC Account was assigned to one of the following three categories (1) labor-related, consisting of Accounts 920, 925, and 926; (2) plant-related, consisting of Accounts 924 and 932; and (3) general O&M, consisting of Accounts 921–923 and 927–931. Once the A&G related FERC accounts were assigned to one of the three categories, each category used the allocated results from costs within the COSS to functionalize, classify, and allocate each A&G expense category to customer classes in the following manner:

1. The labor-related category of A&G expenses was functionalized, classified, and allocated to customer classes based upon the allocated results of the labor portion of O&M expenses, excluding other A&G expenses.

2. The plant-related category of A&G expenses was functionalized, classified, and allocated to customer classes based upon the allocated results of plant in service.

3. The general O&M-related category of A&G expenses was functionalized, classified, and allocated to customer classes based upon the allocated results of all other total O&M expenses, excluding other A&G expenses.

Q. How did MGUC allocate general and intangible plant to customer classes?

A. General and intangible plant consists of assets used to support MGUC's utility services but not readily categorized to a specific utility function. We would not be able to provide these services without the general plant assets. Communication devices, computer equipment, and vehicles supporting MGUC's utility functions are all examples of general plant. Similar to MGUC's test year 2024 Rate Case, general and intangible plant was allocated to customer classes based upon the allocated results of other gross plant in service. Plant costs related to the implementation of the Integrated Customer Experience ("ICE") systems were directly assigned to the customer-related classification.

Q. Please describe how income taxes are allocated to customer classes.

A. Current and deferred income taxes were allocated to customer classes based upon the allocated results of rate base, consistent with MGUC's test year 2024 Rate Case.

Q. Please describe the remaining components of the MGUC class COSS.

A. The remaining components of the MGUC class COSS include:

1. Taxes other than income relating to unemployment compensation, payroll, and retirement benefits were allocated to customer classes based upon the allocated results of the labor portion of O&M expenses, not including A&G expenses.

2. Rate base component cash working capital was allocated to customer classes based upon the allocated results of rate base.

3. Miscellaneous Revenues in Account 487 attributable to late payments were allocated to customer classes based on the total revenue allocation factor. Amounts booked to this account are based upon a percentage of customers'

total bill balances.

4. Rate base component materials and supplies in Account 154 was allocated to customer classes based on the allocated results of distribution plant in service.

5. Miscellaneous Revenues in Account 495 attributable to low income and senior assistance credits were directly assigned to general service residential customers.

<u>Natural Gas Class COSS for the 2025 Projected Test Year</u>

Q. Please describe Exhibit A-16, Schedule F1.1.

A. Schedule F1.1 summarizes the development of the allocated rate base, operating income, and revenue deficiency values by rate class at present rates for MGUC's 2025 projected test year Base Case class COSS. The rate classes presented on this schedule are categorized into 1) general service residential, 2) general service small commercial, 3) general service medium commercial, 4) general service large commercial, 5) transport, including customer choice and aggregated transport, and 6) special contract.

Q. Please describe Exhibit A-16, Schedule F1.2.

A. Schedule F1.2 summarizes the development of the allocated rate base, operating income, and revenue deficiency values by customer class at present rates for MGUC's 2025 projected test year Base Case class COSS. Schedule F1.2 presents the same information as Schedule F1.1 just at a more disaggregated customer class level using the classes of customers described earlier in this testimony.

Q. Please describe Exhibit A-16, Schedule F1.3.

A. Schedule F1.3 summarizes the unbundled revenue requirements by customer class resulting from MGUC's 2025 projected test year base case class COSS. Each of the class revenue requirements is summarized by function and classification.

Q. Please describe Exhibit A-16, Schedule F1.4.

A. Schedule F1.4 summarizes the unbundled rate base amounts by customer class resulting from MGUC's 2025 projected test year base case class COSS. Each of the class rate base amounts are summarized by function and classification.

Q. Please describe Exhibit A-16, Schedule F1.5.

A. Schedule F1.5 summarizes the unbundled unit costs by customer class resulting from MGUC's 2025 projected test year base case class COSS. The unit cost by function and classification was derived by dividing the unbundled revenue requirement data from Exhibit A-16, Schedule F1.3 by the related class determinant values (e.g., throughput, number of customers, etc.).

Q. In your opinion, does the MGUC class COSS provide a reasonable basis for establishing customer rates in this case?

A. Yes, it does. The class COSS for MGUC is a reasonable estimate of revenue requirements by customer class, given the total revenue requirement, and supports the rates requested in this case, as explained further in the direct testimony of Company Witness Burzycki.

Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **MICHIGAN GAS UTILITIES CORPORATION** for authority to increase retail natural gas rates and for other relief.	)))))	Case No. U-21540

DIRECT TESTIMONY AND EXHIBITS

OF SHANNON L. BURZYCKI

FOR

MICHIGAN GAS UTILITIES CORPORATION

March 1, 2024

DIRECT TESTIMONY AND EXHIBITS OF
SHANNON L. BURZYCKI

QUALIFICATIONS
OF
SHANNON L. BURZYCKI
PART I

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION.

A. My name is Shannon L. Burzycki. My business address is 899 S. Telegraph, Monroe, Michigan 48161. I am a State Regulatory Affairs Project Specialist supporting Michigan Gas Utilities Corporation (“MGUC” or the “Company”). MGUC is a wholly-owned subsidiary of WEC Energy Group Inc. (“WEC”).

Q. ON WHOSE BEHALF ARE YOU PROVIDING TESTIMONY?

A. I am providing testimony on behalf of MGUC.

Q. BRIEFLY DESCRIBE YOUR EDUCATIONAL, PROFESSIONAL, UTILITY BACKGROUND AND CURRENT JOB RESPONSIBILITIES.

A. I graduated from Eastern Michigan University in 1997 with a Bachelor of Business Administration, majoring in Accounting. In June of 2006, I was hired by Wisconsin Public Service Corporation (“WPS”) as a Senior Accountant for MGUC. In 2011, I became an employee of WBS Business Services (“WBS”), a subsidiary of WEC, after the acquisition of WPS by WEC, continuing to provide accounting services and support exclusively to MGUC. At the start of my career with MGUC, I calculated the cost of gas and provided support for the annual Gas Cost Recovery (“GCR”) Reconciliation Audit. My duties have included General Ledger accounting, providing data and analyses supporting the GCR Reconciliation, internal and external audits, and Michigan Public Service Commission (“MPSC” or the “Commission”) financial and operational reporting. My current position is State Regulatory Affairs Project Specialist. In this position, I am responsible for regulatory activities for MGUC, including: (1) ensuring MGUC’s compliance with all MPSC orders; and (2) acting as a liaison for the Company with the MPSC Staff and intervenors. In addition to these duties, I am responsible for preparing analyses related to and setting the Company's GCR factors, preparing the monthly 45-Day reports, GCR plan and reconciliation filings, as well as Energy Waste Reduction ("EWR") plan and reconciliation filings.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY AGENCY?

A, Yes. I sponsored testimony in previous MGUC GCR plan and reconciliation proceedings (Case Nos. U-20212, U-20240, U-20545, U-20546, U-20818, U-20819, U-21066, U-21067, U-21273 and U-21441). I also sponsored testimony in MGUC's EWR plan and reconciliation proceedings (Case Nos. U-20430, U-20709. U-20782, U-20882, U-21211 and U-21318), as well as in MGUC's certificate of public convenience and necessity proceedings (Case Nos. U-20853 and U-21292), Special Refund Credits proceeding (Case No. U-21517), and rate case proceedings, Case No. U-20718 and U-21366.

TESTIMONY
OF
SHANNON L. BURZYCKI
PART II

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my direct testimony is to support the development and presentation of MGUC's rate design and related proposed tariff changes, to propose surcharge revisions to MGUC's Main Replacement Program ("MRP") Rider approved in Case Nos. U-21366 and U-20718, to request an increase in the projected enrollment participation limits for the Senior Credit Assistance Program and request the continuation of the existing deferred accounting treatment for the Low Income and Senior Credit Assistance Programs, to request the continued waiver of Mich Admin. Rule 51, R 460.2351, to request the continuation of the Gas Demand Response Pilot Program, and to propose related and other tariff revisions. My testimony will include the calculation of the revised MRP revenue requirement and proposed MRP surcharges, a proposal for the 2023 MRP surcharges collected, as well as the evaluation and supplemental information for the continuation of Meter Testing Requirement Rule 51 waiver.

Q. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A. Yes, I am. I am sponsoring the following Schedules to Exhibit A-16:

1. Schedule F2.1, Summary of Present and Proposed Revenue by Rate Schedule Including Cost of Gas;
2. Schedule F2.2, Summary of Present and Proposed Revenue by Rate Schedule Excluding Cost of Gas;
3. Schedule F3.1, Present and Proposed Revenue Detail Including Cost of Gas;
4. Schedule F3.2, Present and Proposed Revenue Detail Excluding Cost of Gas;
5. Schedule F4, Comparison of Present and Proposed Monthly Bills; and
6. Schedule F5, Summary of Tariff Changes and Proposed Revised Tariff Sheets.

I am also sponsoring the following exhibits that relate to the MRP Rider and Meter Testing Requirement Waiver:

- Exhibit A-23 Proposed MRP Revenue Requirement;
- Exhibit A-24 Proposed MRP Customer Surcharges; and
- Exhibit A-25 Meter Testing Requirement Waiver.

Q. DID YOU PREPARE OR CAUSE THESE EXHIBITS TO BE PREPARED UNDER YOUR DIRECT SUPERVISION?

A. Yes, I did.

Q. PLEASE DESCRIBE SCHEDULE F2.1 OF EXHIBIT A-16.

A. Schedule F2.1 of Exhibit A-16 is a one page summary showing for each rate schedule the:

1. Revenues on Present Rates, including the cost of gas,
2. Revenues on Proposed Rates, including the cost of gas,
3. The proposed rate increase in dollars, including the cost of gas, and
4. The proposed rate increase in percent, including the cost of gas.

Q. PLEASE DESCRIBE SCHEDULE F2.2 EXHIBIT A-16.

A. Schedule F2.2 of Exhibit A-16 is a one page summary showing for each rate schedule the:

1. Revenues on Present Rates, excluding the cost of gas,
2. Revenues on Proposed Rates, excluding the cost of gas
3. The proposed rate increase in dollars, excluding the cost of gas, and
4. The proposed rate increase in percent, excluding the cost of gas.

Q. PLEASE DESCRIBE SCHEDULE F3.1 OF EXHIBIT A-16.

A. Schedule F3.1 of Exhibit A-16 shows a detailed computation by billing determinant for each rate schedule of the:

1. Revenues at Present Rates, including the cost of gas, and
2. Revenues at Proposed Rates, including the cost of gas.

Q. PLEASE DESCRIBE SCHEDULE F3.2 OF EXHIBIT A-16.

A. Schedule F3.2 of Exhibit A-16 shows a detailed computation by billing determinant for each rate schedule of the:

1. Revenues at Present Rates, excluding the cost of gas, and
2. Revenues at Proposed Rates, excluding the cost of gas.

Q. WHAT RATES WERE USED TO CALCULATE REVENUES AT PRESENT RATES FOR THE ABOVE- DESCRIBED SCHEDULES?

A. The Company used the rates approved by the Commission in MGUC's last rate case (Case No. U-21366) to the test year billing determinants to calculate revenues. The cost of gas component of $4.5312 per Mcf was derived from Company Witness Riley O'Brien's Cost of Service Study ("COSS") (total gas costs of $85,020,153 divided by sales of 18,763,259 Mcf).

Q. PLEASE DESCRIBE SCHEDULE F4 OF EXHIBIT A-16.

A. Schedule F4 of Exhibit A-16 is a comparison of typical monthly bills under present and proposed rates for each rate class.

Q. Please describe Schedule F5 of Exhibit A-16.

A. Schedule F5 of Exhibit A-16 is a Summary of Tariff Changes along with the proposed revised tariff sheets in redline format.

Summary of the Proposed Rate Increases

Q. PLEASE SUMMARIZE MGUC'S PROPOSED OVERALL RATE INCREASES BY SERVICE OFFERING.

A. The following table summarizes the proposed revenue increases in dollars and present rates. Revenues include the cost of gas.

	Revenue Increase $	Revenue Increase %
Residential	$13,941,762	12.1%
Gen Svc	991,239	2.2%
Special Contract	16	0.0%
Transport	958,648	11.0%
Aggregated - Residential	2,969	28.8%
Aggregated - Gen Service	32,338	2.8%
Choice - Residential	1,499,228	23.5%
Choice - General Service	148,265	5.7%
TOTAL MGUC	$17,575,013	9.7%

The detail underlying these proposed rates can be found in Schedule F3.1 of Exhibit A-16.

Q. IS MGUC PROPOSING TO MAINTAIN ITS EXISTING RATE STRUCTURE FOR EACH OF THESE SERVICE OFFERINGS?

A. Yes, each offering still includes a fixed monthly charge and a volumetric distribution charge. Monthly administrative charges also continue to apply to all customers, including those using transportation and aggregated services.

The Development and Presentation of the Proposed Rate Design

Q. WHAT FACTORS DID MGUC CONSIDER WHEN DEVELOPING ITS PROPOSED RATE DESIGN?

A. The following factors were considered when developing the proposed rate design:

1. The Cost of Service Study (COSS) sponsored by Company Witness O'Brien, specifically Exhibit A-16, Schedule F1.3;
2. The movement of customer rates toward the actual cost of service; and,
3. The minimization of cross-subsidizations between rate schedules.

Q. PLEASE EXPLAIN HOW THE COSS INFLUENCED THE PROPOSED RATE DESIGN.

A. Consistent with cost causation, and sound economic and ratemaking principles, MGUC is proposing to revise its rate structure to more closely reflect the actual cost of providing distribution service to the various customer classes, as calculated by the COSS sponsored by Company Witness O'Brien and shown in Exhibit A-16, Schedule F1.3. To that end, MGUC is proposing to change most of its monthly customer and volumetric charges to better match the monthly fixed costs incurred by MGUC in providing services to these customers. Specifically, MGUC is proposing changes to all customer charges except the Residential class as described in my testimony below.

Q. PLEASE EXPLAIN HOW THE COST SIMILARITIES AND DIFFERENCES INHERENT TO PROVIDING DISTRIBUTION SERVICES TO SYSTEM SALES, TRANSPORTATION AND CHOICE CUSTOMERS INFLUENCED THE PROPOSED RATE DESIGN.

A. MGUC's rate design is based upon the following conclusions from the COSS: First, the only significant fixed cost difference between providing distribution services to a transportation customer as compared to providing distribution services to a system sales customer with the same load characteristics is the cost associated with administering the more complicated transportation accounts and managing daily balancing.

Second, the only significant variable, "per Mcf,", or volumetric cost difference between providing distribution services to a system sales customer as compared to providing distribution services to transportation and Choice customers with the same load characteristics is the cost associated with administering the gas supply and procurement functions.

These assumptions are reflected in the grouping of rate schedules in Company Witness O'Brien's Exhibit A-16, Schedules F1.1 thru F1.5.

Q. ARE THE ASSUMPTIONS LISTED ABOVE REASONABLE?

A. Yes, because they lead to a reasonable match between cost causation and cost recovery.

<u>Monthly Customer Charges</u>

Q. PLEASE DESCRIBE THE CUSTOMER CHARGE.

A. The Customer Charge is designed to recover a portion of the fixed costs of delivering natural gas to customers using the MGUC distribution system. In the rate design proposed here, all customers in the same class have equal customer charge fees, as shown on Schedules F3.1 and F3.2 of Exhibit A-16.

Q. PLEASE DESCRIBE THE CUSTOMER CHARGE TO TRANSPORTATION CUSTOMERS.

A. Transportation customers pay a monthly meter Customer Charge. In addition, Transportation customers pay a monthly Administrative Charge. This fee recovers the costs associated with administering the more complicated transportation accounts. Since 2016, Transportation customers have been required to balance their deliveries and consumption on a daily basis. Customers that aggregate their accounts for billing purposes under the Aggregated Services also pay a monthly Administrative Charge in addition to the appropriate Customer Charge for their class. MGUC is proposing an increase to the Administrative Charge.

Q. ARE YOU PROPOSING CHANGES TO THE MONTHLY CUSTOMER CHARGES?

A. Yes, MGUC is proposing changes to all customer charges except the Residential class as described in my testimony below. The following table summarizes those changes.

MGUC Customer Class	Monthly Fixed Charge Current	Monthly Fixed Charge Proposed	Change $	Change %
Residential	$ 13.00	$ 13.00	$ -	0.0%
General Service - Small (incl. Comm. Lighting)	$ 35.00	$ 40.00	$ 5.00	14.3%
General Service - Medium	$ 50.00	$ 55.00	$ 5.00	10.0%
General Service - Large	$ 425.00	$ 450.00	$ 25.00	5.9%
Special Contract	$ 8,202.45	$ 8,202.45	N/A	N/A
TR-1 Transport	$ 925.00	$ 1,000.00	$ 75.00	8.1%
TR-2 Transport	$ 2,525.00	$ 2,600.00	$ 75.00	3.0%
TR-3 Transport	$ 3,205.00	$ 3,300.00	$ 95.00	3.0%
Aggregated - Residential to Residential	$ 13.00	$ 13.00	$ -	0.0%
Aggregated - Small to General Service - Small	$ 35.00	$ 40.00	$ 5.00	14.3%
Aggregated - Small to General Service - Medium	$ 50.00	$ 55.00	$ 5.00	10.0%
Aggregated - Large to General Service - Large	$ 425.00	$ 450.00	$ 25.00	5.9%
Choice - Residential	$ 13.00	$ 13.00	$ -	0.0%
Choice - General Service - Small	$ 35.00	$ 40.00	$ 5.00	14.3%
Choice - General Service - Medium	$ 50.00	$ 55.00	$ 5.00	10.0%
Choice - General Service - Large	$ 425.00	$ 450.00	$ 25.00	5.9%

Movement of the Customer Charge Toward Cost of Service

Q. WHAT IS MGUC'S PROPOSED CUSTOMER CHARGE FOR RESIDENTIAL SERVICE?

A. MGUC’s current Monthly Customer Charge is $13.00 for residential customers. The COSS, prepared by Company Witness O’Brien (specifically Schedule F1.5 of Exhibit A-16), however, supports a Monthly Customer Charge of $28.38 for a residential customer. In an effort to assist Residential customers in having more control over their monthly bill, MGUC is proposing that the Residential Monthly Customer Charge remain at $13.00 as it was set in the previous proceeding Case No. U-21366.

Distribution Rates

Q. PLEASE DESCRIBE THE PROPOSED DISTRIBUTION RATES.

A. The traditional distribution margin rate can be separated into two components – (i) distribution service volumetric fee and (ii) gas supply acquisition fee.

Q. PLEASE DESCRIBE THE DISTRIBUTION SERVICE VOLUMETRIC FEE COMPONENT IN THE DISTRIBUTION RATES.

A. The distribution service volumetric fee component recovers any remaining fixed costs that are not recovered through the customer charge as well as the variable costs of delivering natural gas to customers throughout MGUC's distribution system. In the rate design proposed here, all customers in the same class have equal distribution volumetric fees, as shown on Schedules F3.1 and F3.2 of Exhibit A-16.

Q. IS IT REASONABLE FOR SYSTEM SALES CUSTOMERS IN THE SAME CLASS TO PAY THE SAME DISTRIBUTION SERVICE VOLUMETRIC FEE?

A. Yes, it is. Due to the robust nature of MGUC's distribution system, the likelihood of interruption due to distribution system constraints is very small. Therefore, it is reasonable for all customers in the same class to pay the same distribution service volumetric fee.

Q. PLEASE DESCRIBE THE GAS SUPPLY ACQUISITION COMPONENT OF THE DISTRIBUTION RATES.

A. The Gas Supply Acquisition component is designed to recover the costs associated with administering MGUC's gas merchant function. MGUC has calculated the costs associated with administering the gas merchant function to be equal to $861,702 for the 2025 projected test year. Specifically, the gas merchant function costs primarily include the costs associated with the Gas Supply Department, along with the applicable taxes and Administrative and General ("A&G")

expense loadings. This equates to a charge of approximately $0.0459 per Mcf for GCR customers.

Q. IS IT REASONABLE FOR SYSTEM SALES CUSTOMERS TO PAY A GAS SUPPLY ACQUISITION COMPONENT WHILE TRANSPORTATION AND CHOICE CUSTOMERS DO NOT?

A. Yes, it is. System sales customers are directly benefiting from MGUC's gas merchant function, it is reasonable for these customers to pay the Gas Supply Acquisition costs for this service. Transportation and Choice customers receive this service from their own suppliers, not MGUC, and are charged accordingly by their suppliers. Therefore, it is not reasonable for these Transportation and Choice Customers to not pay this charge.

Q. PLEASE DISCUSS THE DISTRIBUTION PORTION OF THE TYPICAL RESIDENTIAL ANNUAL BILL.

A. The costs of providing natural gas distribution services including meter reading, billing, collections, depreciation and return on net rate base are practically 100% fixed and do not vary with the amount of gas actually consumed and purchased by customers. However, as discussed above in my direct testimony, while virtually all of the distribution costs are fixed, MGUC's current rate design does not reflect this: of the $383, only $156 is collected by the monthly Customer Charge, or approximately 41%, while 59% is recovered on a volumetric basis by the Distribution Charge and Gas Supply Acquisition Charge. Therefore, since there is a volumetric component in the current rate design, the collection of MGUC's base rate revenue requirement is affected by the weather, making the Company more seasonally or weather-dependent than the cost of service would substantiate. However, Under MGUC's proposal, taking into consideration the most recent rate case proceeding in Case No. U-21366, no annual increase to the Customer Charge is being proposed.

Current Residential Rate Structure and Cost Recovery

Q. PLEASE DESCRIBE MGUC'S CURRENT RESIDENTIAL RATE STRUCTURE AND COST RECOVERY.

A. Currently, the Residential rate class is subject to a monthly Customer Charge of $13/month ($0.4274/day) as well as a Distribution Charge of $3.8984/ Mcf. A typical residential customer uses 80.3 Mcf for a calendar year with "normal" weather. Under these rates a typical residential customer pays $156 a year in Customer Charges, $224 for Distribution Charges, and $3 for Gas Acquisition Charges, which totals $383 annually for local distribution services only. Residential sales customers are also subject to the GCR factor which recovers MGUC's actual costs of natural gas and the costs to transport the gas from the producers to the Company gate stations in its service territory. Using a GCR factor of $4.5312/Mcf, a customer using 80.3 Mcf would have an annual gas charge of $364. Adding the $383 for distribution service, and the $364 for the cost of gas, a typical Residential sales customer has an annual bill of $747.

Benefits of Higher Monthly Fixed Charges

Q. ARE THERE BENEFITS TO CUSTOMERS FOR MAINTAINING THE AMOUNT OF FIXED COSTS COLLECTED IN THE MONTHLY CUSTOMER CHARGE AND MAINTAINING THE AMOUNT COLLECTED BY THE VOLUMETRIC DISTRIBUTION CHARGE?

A. Yes. As previously discussed in my direct testimony and as reflected in the COSS, rates that are better aligned with cost causation provide more equitable or fair treatment to customers. Customers also will appreciate a higher degree of bill certainty and will have costs spread out more evenly during the year versus having higher costs during the winter months when their consumption is the highest.

Q. CAN YOU PROVIDE MORE INFORMATION ON HOW THIS RATE DESIGN IMPACTS CUSTOMERS WITH VARYING AMOUNTS OF ANNUAL CONSUMPTION?

A. Yes. Schedule F4 of Exhibit A-16 illustrates the impacts of this rate design for various consumption levels.

Cross-Subsidization Between Rate Schedules

Q. PLEASE EXPLAIN HOW MGUC'S ATTEMPT TO REDUCE THE AMOUNT OF CROSS-SUBSIDIZATION BETWEEN THE VARIOUS RATE SCHEDULES HAS INFLUENCED ITS PROPOSED RATE DESIGN.

A. Company Witness O'Brien's Schedule F1.2 of Exhibit A-16, MGUC's 2025 Projected COSS-Detailed Summary indicates that the Residential classes (General Service, Customer Choice, and Aggregated) plus Aggregated Transport Small, Customer Choice Large, Transport TR-2 and TR-3 classes are subsidized by the other rate schedules. With MGUC's proposed rate design, MGUC has attempted to reduce the amount of cross-subsidization between the rate schedules by increasing the amount of revenue collected from these rate schedules. Although MGUC's rate design does not eliminate all cross-subsidization between rate schedules, it provides appropriate movement toward that goal while considering rate stability, or avoiding rate shock, among other factors.

Q. PLEASE EXPLAIN WHAT IS MEANT BY A BREAKEVEN POINT.

A. The term "breakeven point" refers to the level of volumetric usage where the total amount of revenue collected from the customer at one rate class would equal the total revenue collected under another rate class. In the Company's last rate case, for instance, the breakeven point of 3,300 Mcf/year was approved in the rate design to distinguish between a small commercial and medium commercial customer.

Q. IN ADDITION TO REDUCING CROSS-SUBSIDIZATION BETWEEN RATE CLASSES, WHAT OTHER GOALS DID MGUC STRIVE FOR IN DEVELOPING ITS RATE DESIGN?

A. MGUC targeted existing breakeven points of 3,300 Mcf/year to move a customer from small to medium class and 8,300 Mcf/year to move a customer from medium to large class. Rates were designed to ensure that the total cost to the customer was the same under either class at those breakeven points. An additional goal used by MGUC was the concept of gradualism. While it would be reasonable to set both fixed and variable rates at exactly the cost of service for each class and service, it is not always desirable to promote what might be significant rate changes at one time. Accordingly, the Company attempted to minimize some of the rate adjustments in this proposal in some classes with the intention to reduce cross subsidization.[1]

Q. DID MGUC PERFORM A BREAKEVEN POINT ANALYSIS FOR ANY SERVICE OFFERINGS OTHER THAN THE GENERAL SERVICE CLASSES?

A. Yes. Breakeven point analysis was also used in the development of the three Transportation classes TR-1, TR-2, and TR-3. The breakeven point between the TR-1 and TR-2 class is 57,500 Mcf/year and the breakeven point between the TR-2 and TR-3 class is 571,400 Mcf/year. These breakeven points are the same as those approved in MGUC's last rate case (57,500 Mcf/year and 571,400 Mcf/year, respectively).

Q. IS IT NECESSARY IN CERTAIN CIRCUMSTANCES TO REALIGN BREAKEVEN POINTS FROM ONE RATE CASE TO ANOTHER?

A. Yes, realignments can be necessary in order to ensure that individual rate classes remain consistent with their cost basis per the COSS. However, in the rate design included in this rate case, MGUC is not proposing any changes.

[1] James C. Bonbright, Albert Danielson, and David Kamerschen, Principles of Public Utility Rates (Arlington, VA: Public Utilities Reports, Inc., 1988).

Q. WHY IS IT IMPORTANT TO INCORPORATE BREAKEVEN POINT ANALYSIS IN RATE DESIGN?

A. Incorporating economic breakeven points between rate classes is important for several reasons:

1. Provides transparency for customers, allowing them to know which rate is best for their usage requirement;
2. Reduces the administrative and contractual burden of moving customers between rate classes;
3. Stabilizes and minimizes rate shifting. Frequent shifts from rate class to rate class can cause volatility in the utility's revenue collection, making it difficult to accurately predict revenues for planning purposes and for future ratemaking purposes; and,
4. Allows for greater precision in designing rates and predicting revenue collections.

Modifications to Tariff Sheets

Q. IS MGU PROPOSING ANY MODIFICATIONS TO TARIFFS?

A. Yes. These modifications are discussed in pages 25-28 of my direct testimony.

Main Replacement Program (MRP) Rider Surcharge

Q. PLEASE EXPLAIN THE CHANGES PROPOSED TO THE COMPANY'S MAIN REPLACEMENT PROGRAM (MRP) RIDER.

A. There are two revisions to the MRP Rider that are being proposed. First, MGUC in this case has updated the list of projects that will be included in the MRP to reflect the projects that will be placed in service during 2024 and 2025. Because these projects will be included in base rates as part of our projected test year ending December 31, 2025, it would not be appropriate to continue to include these projects in the Rider. Company Witness Nathan Lee addresses the updated capital cost forecast of the remaining MRP projects in his direct testimony.

Lastly, MGUC is proposing to address the Regulatory Liability associated with the 2023 MRP Revenue Surcharges collected. Below, in my direct testimony, I provide testimony supporting the proposed MRP Rider surcharges for the periods of 2026 and 2027 using the forecasted capital costs provided in Company Witness Lee's testimony. In addition, it is important to note that the MRP Rider Surcharge Program will sunset in 2027.

Q. PLEASE PROVIDE AN OVERVIEW OF THE MRP RIDER.

A. The MRP Rider, as approved in Case Nos. U-21366 and U-20718, developed a per customer monthly surcharge that varies depending on customer class to collect the revenue requirement associated with the capital investment and associated property taxes for qualifying projects placed in service after the end of the current test year – December 31, 2025. The following section of my testimony describes the exhibits I am sponsoring that support the MRP surcharge for 2026 and 2027.

Q. PLEASE DESCRIBE PAGE 1 OF EXHIBIT A-23.

A. Exhibit A-23 calculates the 2026 and 2027 annual revenue requirement for each year that was used to develop the proposed annual customer surcharges for those same years. The yearly incremental investment associated with the MRP is illustrated on line 1 of the exhibit. Lines 2-6 calculate the average net rate base. The average net rate base is calculated by taking the cumulative capital investment on line 2 and subtracting out the accumulated depreciation and accumulated deferred taxes on lines 3 and 4. The result is the ending next rate bases on line 5 which is divided by two and results in the average net rate base for that year on line 6. The average annual net rate base is then multiplied by the capital rate of 9.10% to calculate the pre-tax return on net rate base shown on line 7. The depreciation expense and property taxes are then added to the return on net rate base to derive the total annual revenue requirements illustrated on line 10 for each year.

Q. WHAT IS THE BASIS FOR THE 9.10% CAPITAL CHARGE RATE?

A. The 9.10% capital charge rate is the Company's proposed pre-tax carrying cost and is based on the weighted rate of debt, preferred stock, equity and associated taxes reflected in the testimony of Company Witness Anthony Reese.

Q. WHAT IS THE BASIS FOR THE 2.96% BOOK DEPRECIATION RATE?

A. The 2.96% book depreciation rate is the weighted average depreciation rate for all of the capital investment in the MRP through December 2027.

Q. WHAT IS THE BASIS FOR THE PROPERTY TAX MILLAGE RATE?

A. The millage rate is the weighted average millage rate for the municipalities in which the forecasted projects will be located for all of the capital investment in the MRP through December 2027.

Q. PLEASE DESCRIBE PAGE 2 OF EXHIBIT A-23.

A. Page 2 of Exhibit A-23 is used to calculate the accumulated deferred taxes and the property taxes. The deferred taxes are calculated using the 20 year MACRS tax depreciation table and the weighted average 2.96% book depreciation rate for the MRP.

Q. PLEASE EXPLAIN EXHIBIT A-24.

A. Exhibit A-24 calculates the estimated annual MRP surcharges based on the forecasted annual revenue requirement from Line 10 of Exhibit A-23, page 1. All allocation factors on the exhibit are based on the 2025 Cost of Service Study supported by Company Witness O'Brien. The Company proposes that these surcharges remain in effect until the earlier of either: (i) base rates are addressed in a future contested case addressing the MRP, or (ii) December 31, 2027.

Q. IS THE COMPANY PROPOSING A REPORTING REQUIREMENT?

A. MGUC also proposes filing in this docket an annual MRP report by April 1st following the program year, detailing the annual capital spend of projects placed in service for the projects for which recovery through the MRP Rider occurs. The first report will be filed starting with the 2026 MRP projects placed in service and the report will be filed April 1, 2027.

Q. IS MGUC PROPOSING THAT THE MRP RIDER SURCHARGE BE UPDATED EACH YEAR?

A. Yes. As described above in my testimony, the MRP projects placed into service in 2025 have been included in the proposed base rates so there will be a pause in the 2025 surcharges, and as reflected in Exhibit A-24, the new MRP Rider surcharges will restart in 2026 and update again in 2027 on a bill rendered basis beginning in January. This approach is consistent with the approvals granted in Case Nos. U-21366 and U-20718.

Q. ARE YOU SPONSORING TARIFF SHEETS REFLECTIVE OF THE PROPOSED MRP RIDER?

A. Yes, see pages 20-21 of Exhibit A-16, Schedule F5 which reflect the MRP Rider and surcharges proposed for 2026 and 2027.

Q. PER RATE CASE PROCEEDING ORDER U-20718, MRP SURCHARGES WERE APPROVED TO BE COLLECTED IN 2023 AND ANY UNDERSPENT/OVERSPENT AMOUNT WILL BE PLACED INTO A REGULATORY LIABILITY/ASSET ACCOUNT, RESPECTIVELY, AND ADDRESSED IN MGUC'S NEXT GENERAL BASE RATE CASE. WHAT IS THE COMPANY PROPOSING REGARDING THE 2023 REVENUE SURCHARGES COLLECTED?

A. The 2023 revenue surcharges collected from customers totals $160,010 and resides in a regulatory liability account. In the 2024 test year rate case proceeding (Case No. U-21366), per the direct testimony of Richard F. Stasik, regarding the revenue requirement, "This includes the revenue requirement associated with capital projects that will be placed in service in 2023 that are currently included in the MRP rider being rolled into the Company's base rates." The Company is proposing to amortize the balance of $160,010 in the regulatory liability over two years, 2025 and 2026. This proposed amortization was included in the 2025 test year base rates. In addition, the projected 2023 MRP projects were delayed and are now expected to be put in-service in 2024.

Low Income and Senior Credit Assistance Programs

Q. PLEASE PROVIDE MGUC'S BACKGROUND WITH THE LOW INCOME AND SENIOR ASSISTANCE PROGRAMS.

A. MGUC implemented the Low Income and Senior Bill Assistance Programs in January 2022 per Settlement Agreement Order in Case No. U-20718, dated September 9, 2021. In Case No. U-21366, dated August 30, 2023, the Company was authorized deferred accounting treatment for the revenue impact if enrollment in the program was not the same as the projected customer participation level assumed when final rates were established in that proceeding.

Q. DOES THE COMPANY WANT TO MAINTAIN THE DEFERRED ACCOUNTING TREATMENT APPROVED IN CASE NO U-21366?

A. Yes, MGUC is requesting to maintain the deferred accounting treatment previously approved for the revenue impact if enrollment in the program does not match the projected customer participation level assumed when final rates are established in this proceeding. If authorized, this deferral would remain in effect until base rates are next established in a future MGUC rate case.

Q. IS THE COMPANY REQUESTING A CHANGE IN THE PROJECTED ENROLLMENT COUNT FOR THE SENIOR ASSISTANCE PROGRAM?

A. MGUC is requesting to increase the projected senior customer participation level to be more closely aligned with current participation levels and is requesting the number of projected enrollments be increased to 250 projected customers.

<u>Meter Testing Requirement Waiver</u>

Q. IN THE COMMISSION'S NOVEMBER 18, 2021 ORDER IN CASE NO. U-21114 AND THE EXTENSION OF THE ORDER IN AUGUST 30, 2023 IN CASE NO. U-21366, MGUC WAS AUTHORIZED TO (I) WAIVE TESTING REQUIREMENTS IN RULE 51 OF THE TECHNICAL STANDARDS FOR GAS SERVICE, MICH ADMIN CODE, R 460.2351 AND (II) USE MICH ADMIN CODE, R 460.2351A(3) FOR STATISTICAL SAMPLING AND APPLY THE NATURAL GAS DIAPHRAGM METER TESTING PROCEDURES USED BY THE AMERICAN NATIONAL STANDARDS INSTITUTE/AMERICAN SOCIETY FOR QUALITY CONTROL ANSI/ASQC Z1.4, UNTIL DECEMBER 31, 2028. SHOULD MGUC FILE A RATE CASE PRIOR TO DECEMBER 31, 2028 THE COMPANY WILL INCLUDE AN EVALUATION AND SUPPORTING INFORMATION ADDRESSING WHETHER THE APPROVALS GRANTED IN CASE NO U-21114 AND CONTINUED IN U-21366, CAN BE TERMINATED SOONER THAN DECEMBER 31, 2028 AND IF NOT, THE REASONS THEREFORE. IS THE COMPANY REQUESTING IN THIS CASE A CONTINUATION OF THE APPROVALS GRANTED IN CASE NOS. U-21114 AND U-21366?

A. Yes. As recognized in the Commission's Orders in Case Nos. U-21114 and U-21366, the Company is including an evaluation and supporting information addressing that the relief granted cannot be terminated sooner than December 31, 2028. The Company represents that the currently used testing procedures are effective. However, previously-experienced and currently on-going material shortages compounded with previous delays due to COVID-19 has made the Company reassess the anticipated timeframe needed to complete the removal of the failed lot meters. As such, I am sponsoring a revised Tariff Sheet No. B-2.00 which reflects the continued waiver of Rule 51, R 460.2351.

Q. EXPLAIN THE CIRCUMSTANCES THAT LEAD TO A REDUCED NUMBER OF METER EXCHANGES IN FAILED LOTS?

A. Initially, during COVID-19 MGUC did not exchange the gas meters unless they were "must eliminate" meters. During this time, some customers refused MGUC employees into their homes and MGUC employees would not go in to customer homes if the customer was sick or had COVID-19. The Company has also experienced various on-going material shortages since COVID-19. In addition, MGUC will not shut off customers who have not scheduled meter exchanges from November through March, due to cold weather. This limits the number of months that MGUC employees can complete all of their exchanges.

Q. WHAT MATERIAL SHORTAGES HAS THE COMPANY EXPERIENCED DUE TO SUPPLIER PRODUCTION ISSUES?

A. MGUC has experienced material shortages since Covid-19 and is continuing to experience material delays and shortages due to Supplier production issues.

<u>Current Supplier Production Issues</u>

a. 250 meters and meter loops

b. 1000 meter loops

c. ERT's for meters

Previous Supplier Production Issues

a. 630 meters

b. 425/630 meter bars

Q. HAS THE COMPANY EXPERIENCED LEAD TIME ISSUES WITH MATERIALS?

A. Yes, since the start of COVID-19 in early 2020, Hubbell (meter loops), Honeywell (meters), and Itron (ERT's) have not met their lead times. Today, lead times are still unpredictable, unreliable and not consistently being met and continue to be pushed back. In addition, an increase in material defects in product received has also impacted what is available for use. This has led to a Supplier beginning to implement in 2024 many new measures including new tooling for meter bar production, new tooling for forge equipment, new equipment to eliminate operator issues, increased inspection prior to air testing and shipping, recalibrating inspection gauges, and increased floor training.

Q. EXPLAIN WHAT OTHER FACTORS HAVE IMPACTED THE PROGESS THE COMPANY MADE IN ELIMINATING METERS IN FAILED LOTS?

A. During this time, MGUC has been transitioning to AMI technology. Meters were shipped without ERT's installed and this caused employees to spend multiple weeks throughout each year installing the ERT's on meters. In addition, the Bluetooth technology to connect to the meter set and program the ERT increased the time it takes to complete each meter exchange by roughly 20 minutes per meter. Also, MGUC has experienced employees retiring which reduces the number of qualified employees to conduct the work while training transfers or new hires. The training process for a new employee in this position can take between 6-9 months to become qualified.

Q. BRIEFLY EXPLAIN THE ANALYSIS MGUC USED TO DETERMINE WHY THE WAIVER CANNOT BE TERMINATED SOONER THAN DECEMBER 31, 2028?

A. The analysis performed was calculated with meter data for each of the five MGUC districts - Monroe, Coldwater, Benton Harbor, Grand Haven and Allegan. This data identified the number of meters exchanged per year since 2019 and the future average needed to complete all meters by the December 31, 2028 requirement, as shown on Exhibit A-25. Based on this analysis, three of the five districts will not meet the requirement. Please note, that because MGUC's service territory is spread out across the lower portion of Michigan, from Lake Erie to Lake Michigan, qualified employees from one district are unable to assist with the meter exchanges in other districts.

Q. IS THE COMPANY PROPOSING AN EXTENSION BEYOND DECEMBER 31, 2028?

A. Yes, as shown on Exhibit A-25, with current staffing levels the ability to complete this work by the required time in all districts is not possible. In order to manage cost increases to its customers, MGUC has determined that it is prudent to ask for a continuation of the relief granted in Case Nos. U-21114 and U-21366 and based on current calculations, barring any further unknown material delays, is requesting an extension to December 31, 2032.

Gas Demand Response Pilot Program

Q. PLEASE PROVIDE THE BACKGROUND OF THE GAS DEMAND RESPONSE PILOT PROGRAM.

A. In Case No. U-20464 the Commission ordered all Michigan utilities to include demand response offerings in their next filing of a rate case. MGUC filed rate case proceeding U-20718 on March 22, 2021 and proposed the Gas Demand Response Pilot Program. The Gas Demand Response

Pilot Program was approved to begin with the 2022-2023 heating season in the Order Approving Settlement Agreement. This pilot, as approved, uses the Company's Customer Notification System ("CNS") to notify enrolled Residential and C&I customers of a Gas Demand Response Event. The CNS system utilizes e-mail, text and / or telephone communication mechanisms to contact customers – based on the customer's preferred method of contact.

Q. IS MGUC PROPOSING ANY CHANGES TO THE PILOT GAS DEMAND RESPONSE PROGRAM?

A. No, the Company is not proposing any changes at this time and would like to remain with the current approved program.

Transportation

Q. IS MGUC PROPOSING LANGUAGE CHANGES TO THE TRANSPORTATION MAXIMUM DAILY QUANTITY (MDQ) DEFINITION AND SERVICE REQUIREMENTS QUANTITIES IN TARIFF?

A. Yes, the Company is currently utilizing system calculated MDQ quantities and wishes to align the tariff with the current operating process. Because the MDQ amount can fluctuate annually based on actual usage, the MDQ will be available on a secured internet-enabled portal, which MGUC expects to be available for the 2025 test year.

Tariff Revisions

Q. PLEASE EXPLAIN SCHEDULE F5 OF EXHIBIT A-16.

A. Schedule F5, summarizes the changes being proposed for MGUC's natural gas tariff. Pages 2-30 are redlined versions of the proposed tariff sheets.

Q. WHAT REVISION IS MGUC PROPOSING ON TARIFF SHEET NO. A-6.00?

A. MGUC is providing an updated Index.

Q. WHAT REVISION IS MGUC PROPOSING ON TARIFF SHEET NO. A-8.00 THROUGH A-11.00?

A. MGUC is providing an updated Table of Contents.

Q. WHAT REVISION IS MGUC PROPOSING ON TARIFF SHEET NO. B-2.00?

A. MGUC is requesting to continue the waiver of R 460.2351.

Q. WHAT REVISION IS MGUC PROPOSING ON TARIFF SHEET NO. C-36.00?

A. The Company is updating the Carrying Cost Rate per the proposed rate case reflected in the testimony of Witness Reese on Exhibit A-14, Schedule D-1.

Q. WHAT REVISION IS MGUC PROPOSING ON TARIFF SHEET NO. C-37.00?

A. The Company is updating the Discount Rate per the proposed rate case reflected in the testimony of Witness Reese on Exhibit A-14, Schedule D-1.

Q. WHAT REVISION IS MGUC PROPOSING ON TARIFF SHEET NO. C-38.00 TO C-45.00?

A. The Company is updating the Customer Attachment Program projects.

Q. WHAT REVISION IS MGUC PROPOSING ON TARIFF SHEET NO. D-1.01?

A. The Company is updating the respective Fixed Customer Charges, Distribution and Gas Supply Acquisition Charges in the Supplemental Charges schedule.

Q. WHAT REVISIONS ARE MGUC PROPOSING ON TARIFF SHEET NOS. D-1.04 THROUGH D-1.07?

A. The Company is reflecting the proposed MRP Rider changes for 2026 and 2027 as well as the removal of the 2025 surcharge.

Q. WHAT REVISION IS MGUC PROPOSING ON TARIFF SHEET NO. D-4.00?

A. The Company is removing the short-term Pipeline Refund Credit which expires in March 2024.

Q. WHAT REVISIONS ARE MGUC PROPOSING ON TARIFF SHEET NO. D-6.00?

A. The Company has updated its Distribution charges per its proposed rate design. The Company is proposing to increase the Distribution charge to $3.8984 per Mcf.

Q. WHAT REVISIONS ARE MGUC PROPOSING ON TARIFF SHEET NOS. D-9.00 THROUGH D-13.00?

A. For Small General Service, the Company is proposing a Customer Charge of $40.00, a Distribution charge of $1.8498 per Mcf, Medium General Service, the Company is proposing a Customer Charge of $55.00 per month, a Distribution charge of $1.7951 per Mcf, Large General Service, the Company is proposing a Customer Charge of $450.00 per month, a Distribution charge of $1.2214 per Mcf. In addition, for Small, Medium and Large General Service the Company is proposing a $0.0459 Gas Supply Acquisition charge.

Q. WHAT IS MGUC PROPOSING ON TARIFF SHEET NO. D-15.00?

A. The Company is proposing, for the Gas Lighting Rate, the Commercial Distribution Charges to be updated consistent with MGUC's proposed rate design and to include new language because the Company would like to stop offering service agreements for gas street lights when the existing contracts expire in 2026. The language has been added to the Commercial rate as gas street light contracts were renegotiated in 2016 under the Commercial rate. The new rate is $1.8498 per Mcf and $0.0459 for Gas Supply Acquisition per Mcf.

Q. WHAT REVISION IS MGUC PROPOSING ON TARIFF SHEET NO. E-1.00?

A. MGUC is proposing a revision to the definition in E1.1 (f) to include updated language regarding MDQ.

Q. WHAT REVISION IS MGUC PROPOSING ON TARIFF SHEET NO. E-7.00?

A. MGUC is proposing a revision to the definition in E4 (a) Quantities, (i) to include updated language regarding MDQ.

Q. WHAT REVISIONS IS MGUC PROPOSING ON TARIFF SHEET NO. E-13.00?

A. MGUC is proposing a revision to the Customer Charges for TR-1 $1,000, TR-2 $2,600, TR- 3 $,3,300. MGUC is also proposing changes to the Peak and Off-Peak rates for each class as shown on the proposed tariff sheet.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY AT THIS TIME?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **MICHIGAN GAS UTILITIES CORPORATION** for authority to increase retail natural gas rates and for other relief.	)))))	Case No. U-21540

DIRECT TESTIMONY AND EXHIBIT OF

NATHAN W. LEE

FOR

MICHIGAN GAS UTILITIES CORPORATION

March 1, 2024

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **MICHIGAN GAS UTILITIES CORPORATION** for authority to increase retail natural gas rates and for other relief.	)))))	Case No. U-21540

QUALIFICATIONS
OF
NATHAN W. LEE
PART I

Q. Please state your name, position and business address.

A. My name is Nathan Lee. My business address is 70 Sauk River Drive, Coldwater, Michigan, 49036. I am employed by Michigan Gas Utilities, a subsidiary of WEC Energy Group, Inc. ("WEC"), as Engineering Manager.

Q. For whom are you providing testimony?

A. I am providing testimony on behalf of Michigan Gas Utilities Corporation ("MGUC" or the "Company").

Q. Please describe briefly your educational, professional, and utility background

A. I received a Bachelor's degree in Math and Physics from the Spring Arbor University and a Bachelor's Degree in Civil Engineering from the University of Michigan. I was hired by MGUC (a subsidiary of WEC) in 2005 and worked in various roles in several departments prior to my current position. I became the Engineering Manager supporting MGUC in December 2019. I received my Professional Engineers License in 2008.

NATHAN W. LEE
DIRECT TESTIMONY
PART II

Q. What is the purpose of your pre-filed direct testimony?

A. The purpose of my direct testimony is to provide an update on several capital projects that were described in MGUC's most recent rate case (Case U-21366), which were put in service in 2023 or which are forcasted to be placed in service during 2024 or 2025.

I will also provide an update of the projects, including project costs for which MGUC received approval in Case U-21366 to implement a Main Replacement Program ("MRP") surcharge. These projects are projected to go in service for the years 2026 through 2027, which are all after the 2025 test year.

Finally, I will be discussing additional operations and maintenance ("O&M") expenses and capital costs related to PHMSA's Upcomning Leak Detection And Repair ("LDAR") Notice of Proposed Rulemaking ("NPRM").

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Exhibit A-26, the Forecasted Operations and Maintenance Costs and Capital Expenditures Summary from Proposed LDAR Rules.

Q. Was this exhibit prepared under your direct supervision?

A. Yes.

Update of Capital Investment Since Last Rate Case

Q. What is MGUC's capital spending plan in this rate case?

A. MGUC's 2025 test year revenue deficiency is mainly driven by its capital spending plan. Since its last rate case, MGUC placed $32.1 million into service in 2023 (within 2% of forecast) and forecasts placing $47.6 million into service in 2024 and $39.7 million into service in 2025. MGUC's investment in the natural gas delivery system continues to be focused on ensuring the Company is serving customers reliably and safely. Continuing from the Company's last rate case, there continues to be an increased focus on and investment in integrity transmission projects.

In 2024, MGUC capital spending on distribution system improvements amounts to $38.65 million, which includes system integrity, replacement of mains and services (including the MRP projects Marshall to Coldwater Project, South Grand Haven Station Relocate, Allegan Transmission Relocate, and County Line Road Station Relocate), road projects, line hits, and stations work and meters. MGUC also plans to spend $8.45 million related to system growth projects and an additional $7 million on the Partello Compressor project (discussed below).

In the section immediately below, I will provide greater detail of the significant capital projects that have been placed in service through the end of 2023 or will be placed in service during 2024 or the 2025 test year.

PRAGMA CAD Mobile Workforce Management

Q. What is the Pragma Cad Mobile Workforce Management Project?

A. CGI PragmaCAD ("PCAD")[1] is a workforce management system being implemented to replace MGUC's previous workforce management system known as G4/MobileField. The product is used to distribute and transmit orders to Field Technicians for completion and follow up. Fieldwork is grouped and sequenced into comprehensive work plans that address service work requiring multiple types of operations. By appropriately sequencing work, MGUC is able to ensure that work that must be completed first is done before subsequent and dependent work begins.

Q. When does MGUC plan to have PCAD implemented?

A. MGUC deployed PCAD in two phases in 2023 with initial roll out in March 2023 and additional enhancements deployed August 2023, and a final phase is planned for April of 2024.

Q. What is the cost of the PCAD project in this case?

A. Through 2023, the capital costs related to the PCAD project for MGUC were approximately $1.6 million, with an additional $1.2 million forecasted for the final phase forecasted to be implemented in April of 2024.

Q. Why is PCAD being implemented in place of the current dispatch system?

A. The prior dispatch software,G4/MobileField, was no longer supported by the manufacturer and was a standalone product used only by WEC's affiliates operating in Minnesota and Michigan. Continuing to use G4/MobileField would have required

[1] PCAD is the product name for an electronic dispatch suite of software.

MGUC to implement the new version of that software because what is currently being used is no longer supported.

This alternative was not pursued beyond an initial evalution because it would not have allowed for the realization of the inherent cost savings from multiple utilities using a common platform. Specifically, the capital costs would likely have been at least twice as much as the alternative pursued. Ongoing costs associated with maintaining a stand-alone tool for MGUC was estimated to be at least twice the amount forecasted under this preferred alternative, which allows for a sharing of these costs across multiple affiliated utilities, which is an on-going benefit of MGUC becoming part of the WEC Energy Group.

The other unselected alternative that was evaluated and not selected was to do nothing differently and continue to use the unsupported version of the G4/Mobile Field tool. However, this alternative was quickly eliminated because it would involve using unsupported software for the critical function of dispatching field personnel for activities including emergency response. Relying on software no longer supported by the vendor was deemed an imprudent course of action that would increase the likelihood of a long-term system outage that could impact reliability and impair field personnel, customer and public safety.

Implementing PCAD will put MGUC on the same platform as affiliates in other states, providing greater support. MGUC's implementation of PCAD is part of MGUC's larger efforts to standardize its software platforms and increase security.

Q. What benefits does PCAD provide?

A. As noted above, the largest benefit comes from the standardization across multiple WEC Energy Group utilities. PCAD is a current software with current support of its provider. Along with the software, Minnesota Energy Resources Corporation, an affiliated utility in Minnesota to which PCAD is being implemented simultaneously with MGUC, will also benefit from the existing internal support team. PCAD also offers enhanced scheduling and routing for field technicians. The implementation of PCAD also allows for consolidating operations into one dispatch center and eliminates the need for contracted dispatch services – resulting in additional savings for MGUC's customers.

<u>DTE Interconnection Project Update</u>

Q. What is the status of the DTE Interconnection project?

A. The DTE Interconnection project, which consisted of a new regulator station, referred to as the Scofield Carlton Station, and 1,200 ft of 12" steel gas main, is a new interconnection between DTE Gas Company ("DTEG") and MGUC located in Ash Township, Monroe County, that was put into service at the end of 2023. The total project cost was approximately \$4.5M.

<u>Partello Compressor Unit Replacement Update</u>

Q. Please describe the Partello Compressor Unit Replacement project.

A. The Partello Compressor Unit Replacement project will replace Unit 5, one of the two compressor units. Unit 5 was installed in 1980 and has a maximum allowable operating pressure ("MAOP") of 900 psig. Two of the three reservoirs at Partello have a 1300 psig MAOP. Unit 5 is only operated to compress gas below 900 psig. Unit 5 will be a twin to Unit 6 which was installed in 2005 and has updated fuel and emissions controls. This will create full redundancy, increase reliability throughout the entire injection cycle and give the facility the capability to operate at full pressure of 1300 psig. This will also standardize parts and maintenance procedures, reduce operations and maintenance repairs, and provide better accessibility to parts.

Q. Please discuss the cost of the Partello Compressor Unit Replacement project.

A. The cost for this project was projected to be $7.0 million.

Q. Is this project currently in service?

A. This project is scheduled to be placed in service in May of 2024.

Q. Please describe how this project benefits MGUC's customers.

A. The Partello Compressor project will benefit customers by increasing reliability, providing redundancy, and reducing operations and maintenance expenses.

<u>Capital Projects Undertaken to Reduce Gas Costs and Improve System Reliability and Redundancy for MGUC's Customers</u>

Q. Are there any projects you would like to discuss that will reduce gas costs and improve the reliability and redundancy of distribution assets?

A. Yes. A variety of projects were completed in 2023 that align with MGUC's Transmission Integrity Management Program ("TIMP") and Distribution Integrity Management Program ("DIMP"). These programs are designed to reduce pipeline risks and increase customer reliability. The TIMP category of projects includes gate station rebuilds to update telemetry, regulation, heaters, odorization, filters, and station protection and increasing system capacity.

Additional projects to be completed in 2024 are the South County Line Road Station and the South Grand Haven Station, which both consist of installing a new station to lower downstream pressure and eliminate transmission main. Each of these projects was scheduled to go into service in 2023 but is now scheduled to go into service around October 2024 due to permitting, land, and construction processes taking longer than initially estimated. Lastly, the Allegan Transmission Relocation Project and Phase 1 of the Marshall to Coldwater Project are also scheduled to go into service in the 4th quarter of 2024.

The DIMP cateogory of projects includes replacing regulator structures, replacing main with shorted casings, replacing exposed mains, eliminating Master Meter Systems and extending main, eliminating buried first cut regulators, replacing leak prone pipe, and adding valves to increase reliability and safety. Many of these initiatives will continue on beyond 2025.

Q: What projects are proposed to be added to the rate base during the 2025 test year?

A: Significant projects proposed to be added to the rate base during the 2025 test year are Phase 2 of the Coldwater to Marshall Project, continued DIMP spending centered mostly around replacement of vintage Aldyl A plastic main, and typical growth and conflict related work.

OVERVIEW OF PROJECTS IN SCOPE OF PROPOSED MRP SURCHARGE

Q. Are there any other capital projects that you would like to describe?

A. Yes. I will also provide an overview of two projects that the Company proposes be funded by the MRP rider surcharge that was first approved in Case U-20718 and continued in Case No. U-21366. MGUC is proposing to continue the MRP rider in this proceeding. These projects are included in the table below.

Project Name	Estimated Capital Costs	In Service Year(s)
Coldwater-Marshall Pipeline (Phase 3)	$ 11,431,000	2026
Otsego Paper Service Line	$ 625,000	2027

Q. Please provide a brief description of each of these projects and a brief description of the benefits for each.

A. The Coldwater-Marshall Pipeline project will replace approximately 20 miles of 10" transmission installed in 1952 with 12" pipe. This will allow MGUC to operate that pipeline at lower operating percent SMYS, increase system capacity, and eliminate Moderate Consequence and Class 3 areas.

The Otsego Paper Service Line Project will relocate 1200 feet of 8" transmission line to lower operating percent SMYS, which will eliminate a Class 3 location.

In addition to the specific benefits noted above for each project, completing those projects will also eliminate assessments, material verification, and MAOP reconfirmation that are required by the 2019 “Mega” Rule (84 FR 52180)..

Q. Please describe the changes to the Coldwater-Marshall Pipeline Replacement Project.

A. The Coldwater-Marshall Pipeline Replacement Project is starting construction in 2024 and each of the three phases is on schedule to be completed in 2024, 2025, and 2026, respectively. There have been no changes to the estimated cost of this project from the estimate provided in MGUC’s last rate case.

Leak Detection And Repair Notice of Proposed Rulemaking

Q. What is the LDAR NPRM?

A. PHMSA (Pipeline and Hazardous Materials Safety Administration) released its NPRM on LDAR on May 18, 2023. The rulemaking responds to the congressional mandate of the PIPES (Protecting our Infrastructure of Pipelines and Enhancing Safety) Act of 2020 which required PHMSA to establish a rule related to minimum requirements for leak detection and repair, and the use of advanced leak detection technologies and practices. The NPRM also codifies the mandate in the PIPES Act of 2020 that required operators to update their inspection and maintenance plans to include protection of the environment and replacement or remediation of pipe known to leak.

Q. When is the LDAR NPRM expected to become a final rule?

A. The LDAR Final Rule is expected to be published by PHMSA in the third quarter of 2024, and the effective date of the rule is currently six months from the final rule publication. Based on the rule being published on September 1, 2024, the effective date would be March 1, 2025.

Q. What changes are expected from the LDAR Final Rule that are expected to impact O&M costs and capital spending in the 2025 test year?

A. The LDAR Final Rule is expected to impact several areas of MGUC Operations:

1. Leak Grading and Repair
   - Projected doubling the number of found leaks and repair costs based on new leak repair and reassessment criteria.

2. Patrols and Leak Survey

- Projected doubling the amount of leak surveys based on shorter leak survey interval requirements.

3. Advance Leak Detection Program

- Projected doubling the number of found leaks and repair costs based on new leak criteria.

4. Transmission Blowdowns

- Projected incremental increase due to additional reporting and blowdown requirements.

5. Pressure Relief Devices

- Projected incremental increase due to increased investigation of relief device activation and associated repair/replacement costs.

6. Training

- Projected incremental increase in training due to additional requirements.

Q. How has MGUC forecasted the costs relating to the PHMSA's LDAR Final Rule?

A. As set forth in Exhibit A-26, MGUC has included forecasted costs related to compliance with the Final LDAR Rule in routine capital spending and O&M expenses for its projected 2025 test year.

Q, Does MGUC have an alternative proposal concerning the costs of complying with the new LDAR Rule?

A. Although MGUC believes it will be required to comply with the LDAR Rule in 2025, the Company has an alternative proposal to including such costs in the 2025 test year. The Company requests that MGUC be authorized in this case to create a regulatory deferral mechanism for all O&M costs and the revenue requirement associated with capital spending incurred to comply with the Final LDAR rule to be recoverable in MGUC's next general rate case..

Q. Why is MGUC alternatively recommending approval of a regulatory deferral mechanism?

A. MGUC is proposing this alternative because this rule is expected to result in meaningful changes to leak detection and repair compliance requirements and, therefore, the costs projected to be incurred in 2025. MGUC is aware that these regulatory changes are also expected to impact the forecasted O&M costs and capital spending of other utilities in the state.

The projected O&M and capital costs reflected in the Company's requested rate relief reflect the best information available at this time. In addition, incremental LDAR O&M compliance costs are anticipated to be approximately $6 million over the three-year period of 2025 – 2027, averaging out to approximately $2 million per year. A deferral mechanism could help mitigate the level of MGUC's needed rate relief in years beyond the projected test year.

<table>
<tr><th colspan="5">Final LDAR Rule Projected Expenditures Detail</th></tr>
<tr><th>Process</th><th>Before NPRM</th><th>After NPRM</th><th>O&M Projected Test Year</th><th>Capital Projected Test Year</th></tr>
<tr><td rowspan="5">Leak Grading and Repair</td><td>Distribution Only</td><td>Expanded to Transmission (Grade 1&2)</td><td rowspan="5"></td><td rowspan="5">$2.0M*</td></tr>
<tr><td>G1: Immediate Repair</td><td>G1: Immediate repair (no change)</td></tr>
<tr><td>G2: 6-month recheck, repair within 1 year</td><td>G2: 30-day rechecks, repair within 6 months</td></tr>
<tr><td>G3: Annual re-check, no required repair date</td><td>G3: 6 month rechecks, repair within 2 years</td></tr>
<tr><td></td><td>Rechecks to confirm 0 reads</td></tr>
<tr><td rowspan="7">Patrol and Leak Survey</td><td>Transmission Patrol: 1-4 times per year</td><td>Transmission Patrol: 12 times per year</td><td rowspan="7">$0.7M</td><td rowspan="7"></td></tr>
<tr><td>Transmission Leak Survey: 1-4 times per year</td><td>Transmission Leak Survey: 2-4 times per year</td></tr>
<tr><td>Distribution Leak Survey</td><td>Distribution leak survey</td></tr>
<tr><td>Business Districts - annual</td><td>Business District (no change)</td></tr>
<tr><td>Unprotected pipe - every 3 years</td><td>Unprotected pipe - annual</td></tr>
<tr><td>Leak Prone Pipe - no special requirement</td><td>Leak Prone Pipe - annual</td></tr>
<tr><td>All others - every 5 years</td><td>All others - every 3 years</td></tr>
<tr><td rowspan="2">Advance Leak Detection Program</td><td rowspan="2">No criteria regarding leak survey equipment</td><td>Leak survey equipment sensitivity: 5ppm sensitivity within 5' of pipeline or wall-to-wall pavement</td><td rowspan="2">$0.6M</td><td rowspan="2"></td></tr>
<tr><td>ALDP Program analysis and evaluation of program effectiveness</td></tr>
<tr><td>Transmission Blowdowns</td><td>No criteria regarding emissions</td><td>Requires strategies to reduce the intentional release of gas using approved methods</td><td>$0.4M</td><td></td></tr>
<tr><td rowspan="2">Pressure Relief Devices</td><td rowspan="2">No criteria regarding emissions</td><td>Requires an analysis of pressure relief devices</td><td rowspan="2">$0.15M</td><td rowspan="2"></td></tr>
<tr><td>Remediate existing/design new solutions to minimize release of gas</td></tr>
<tr><td>Training</td><td></td><td>OQ updates for all leak qualified employees</td><td>$0.1M</td><td></td></tr>
<tr><td colspan="3" align="right">Total:</td><td>$1.95M</td><td>$2.0M</td></tr>
</table>

*It is assumed that most of the increased leak repair costs will be capital expenses, however, some small portion will end of being O&M expenses

Q. Does that complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the application of **MICHIGAN GAS UTILITIES CORPORATION** for authority to increase its retail rates natural gas and for other relief.	)))))	Case No. U-21540

PROTECTIVE ORDER

This Protective Order governs the use and disposition of Protected Material that Michigan Gas Utilities Corporation ("Applicant") or any other Party discloses to another Party during the course of this proceeding. The Applicant or other Party disclosing Protected Material is referred to as the "Disclosing Party"; the recipient is the "Receiving Party" (defined further below). The intent of this Protective Order is to protect non-public, confidential information and materials so designated by the Applicant or by any other party, which information and materials contain confidential, proprietary, or commercially sensitive information. This Protective Order defines "Protected Material" and describes the manner in which Protected Material is to be identified and treated. Accordingly, it is ordered:

I. "Protected Material" and Other Definitions

A. For the purposes of this Protective Order, "Protected Material" consists of trade secrets or confidential, proprietary, or commercially sensitive information to be provided by Disclosing Party's materials responsive to Part III of the Commission's rate case filing requirements approved in Case No. U-18238 and any testimony, exhibits, workpapers, discovery, audit responses, any witness' related exhibits and testimony, and any arguments of counsel describing or relying upon the Protected Material. Subject to challenge under Paragraph IV.A, Protected Material shall consist of non-public confidential information and materials including, but not limited to, the following information disclosed during the course of this case if it is marked as required by this Protective Order:

1. Trade secrets or confidential, proprietary, or commercially sensitive information provided in response to discovery, in response to an order issued by the presiding officer or the Michigan Public Service Commission ("MPSC" or the "Commission"), in testimony or exhibits filed later in this case, or in arguments of counsel;

2. To the extent permitted, information obtained under license from a third-party licensor, to which the Disclosing Party or witnesses engaged by the Disclosing Party is a licensee, that is subject to any confidentiality or non-transferability clause. This information includes reports; analyses; models (including related inputs and outputs); trade secrets; and confidential, proprietary, or commercially sensitive information that the Disclosing Party or one of its witnesses receives as a licensee and is authorized by the third-party licensor to disclose consistent with the terms and conditions of this Protective Order;

3. Information that could identify the bidders and bids, including the winning bid, in a competitive solicitation for a natural gas purchase agreement or in a competitively bid engineering, procurement, or construction contract at any stage of the selection process (i.e., before the Disclosing Party has entered into a power purchase agreement or selected a contractor); and

4. Information that is protected as confidential in other jurisdictions that Applicant provides utility service.

B. The information subject to this Protective Order does not include:

1. Information that is or has become available to the public through no fault of the Receiving Party or Reviewing Representative and no breach of this Protective Order, or information that is otherwise lawfully known by the Receiving Party without any obligation to hold it in confidence;

2. Information received from a third party free to disclose the information without restriction;

3. Information that is approved for release by written authorization of the Disclosing Party, but only to the extent of the authorization;

4. Information that is required by law or regulation to be disclosed, but only to the extent of the required disclosure; or

5. Information that is disclosed in response to a valid, non-appealable order of a court of competent jurisdiction or governmental body, but only to the extent the order requires.

C. “Party” refers to the Applicant, MPSC Staff (“Staff”), the Michigan Attorney General, or any other person, company, organization, or association that is granted intervention in this Case No. U-21540 under the Commission’s Rules of Practice and Procedure, Mich Admin Code, R 792.10401 et al.

D. “Receiving Party” means any Party to this proceeding who requests or receives access to Protected Material, subject to the requirement that each Reviewing Representative sign a Nondisclosure Certificate attached to this Protective Order as Attachment 1.

E. “Reviewing Representative” means a person who has signed a Nondisclosure Certificate and who is:

1. an attorney who has entered an appearance in this proceeding for a Receiving Party;

2. an attorney, paralegal, or other employee associated, for the purpose of this case, with an attorney described in Paragraph I.E.1;

3. an expert or employee of an expert retained by a Receiving Party to advise, prepare for, or testify in this proceeding; or

4. an employee or other representative of a Receiving Party with significant responsibility in this case.

A Reviewing Representative is responsible for assuring that persons under his or her supervision and control comply with this Protective Order.

F. “Nondisclosure Certificate” means the certificate attached to this Protective Order as Attachment 1, which is signed by a Reviewing Representative who has been granted access to Protected Material and agreed to be bound by the terms of this Protective Order.

II. Access to and Use of Protected Material

A. This Protective Order governs the use of all Protected Material that is marked as required by Paragraph III.A and made available for review by the Disclosing Party to any Receiving Party or Reviewing Representative. This Protective Order protects: 1) the

Protected Material; 2) any copy or reproduction of the Protected Material made by any person; and 3) any memorandum, handwritten notes, or any other form of information that copies, contains, or discloses Protected Material. All Protected Material in the possession of a Receiving Party shall be maintained in a secure place. Access to Protected Material shall be limited to persons authorized to have access subject to the provisions of this Protective Order.

B. Protected Material shall be used and disclosed by the Receiving Party solely in accordance with the terms and conditions of this Protective Order. A Receiving Party may authorize access to and use of Protected Material by a Reviewing Representative identified by the Receiving Party, subject to Paragraphs III and V below, only as necessary to analyze the Protected Material; make or respond to discovery; present evidence; prepare testimony, argument, briefs, or other filings; prepare for cross-examination; consider strategy; and evaluate settlement. These individuals shall not release or disclose the content of Protected Material to any other person or use the information for any other purpose.

C. The Disclosing Party retains the right to object to any designated Reviewing Representative if the Disclosing Party has reason to believe that there is an unacceptable risk of misuse of confidential information. If a Disclosing Party objects to a Reviewing Representative, the Disclosing Party and the Receiving Party will attempt to reach an agreement to accommodate that Receiving Party's request to review Protected Material. If no agreement is reached, then either the Disclosing Party or the Receiving Party may submit the dispute to the presiding officer. If the Disclosing Party notifies a Receiving Party of an objection to a Reviewing Representative, then the Protected Material shall not be provided to that Reviewing Representative until the objection is resolved by agreement or by the presiding officer.

D. Before reviewing any Protected Material, including copies, reproductions, and copies of notes of Protected Material, a Receiving Party and Reviewing Representative shall sign a copy of the Nondisclosure Certificate (Attachment 1 to this Protective Order) agreeing to be bound by the terms of this Protective Order. The Reviewing Representative shall also provide a copy of the executed Nondisclosure Certificate to the Disclosing Party.

E. Even if no longer engaged in this proceeding, every person who has signed a Nondisclosure Certificate continues to be bound by the provisions of this Protective Order. The obligations under this Protective Order are not extinguished or nullified by entry of a final order in this case and are enforceable by the MPSC or a court of competent jurisdiction. To the extent Protected Material is not returned to a Disclosing Party, it remains subject to this Protective Order.

F. Members of the Commission, Commission staff assigned to assist the Commission with its deliberations, and the presiding officer and any other administrative law judge ("ALJ") or ALJ staff member working on this matter shall have access to all Protected Material that is submitted to the Commission under seal without the need to sign the Nondisclosure Certificate.

G. A Party retains the right to seek further restrictions on the dissemination of Protected Material to persons who have or may subsequently seek to intervene in this MPSC proceeding.

H. Nothing in this Protective Order precludes a Party from asserting a timely evidentiary objection to the proposed admission of Protected Material into the evidentiary record for this case.

III. Procedures

A. The Disclosing Party shall mark any information that it considers confidential as "CONFIDENTIAL: SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-21540." If the Receiving Party or a Reviewing Representative makes copies of any Protected Material, they shall conspicuously mark the copies as Protected Material. Notes of Protected Material shall also be conspicuously marked as Protected Material by the person making the notes.

B. If a Receiving Party wants to quote, refer to, or otherwise use Protected Material in pleadings, pre-filed testimony, exhibits, cross-examination, briefs, oral argument, comments, or in some other form in this proceeding (including administrative or judicial appeals), the Receiving Party shall do so consistent with procedures that will maintain the confidentiality of the Protected Material. For purposes of this Protective Order, the following procedures apply:

> 1. Written submissions using Protected Material shall be filed in a sealed record to be maintained by the MPSC's Docket Section, or by a court of competent jurisdiction, in envelopes clearly marked on the outside, "CONFIDENTIAL — SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-21540." Simultaneously, identical documents and materials, with the Protected Material redacted, shall be filed and disclosed the same way that evidence or briefs are usually filed;
>
> 2. Oral testimony, examination of witnesses, or argument about Protected Material shall be conducted on a separate record to be maintained by the MPSC's Docket Section or by a court of competent jurisdiction. These separate record proceedings shall be closed to all persons except those furnishing the Protected Material and persons otherwise subject to this Protective Order. The Receiving Party presenting the Protected Material during the course of the proceeding shall give the presiding officer or court sufficient notice to allow the presiding officer or court an opportunity to take measures to protect the confidentiality of the Protected Material; and
>
> 3. Copies of the documents filed with the MPSC or a court of competent jurisdiction, which contain Protected Material, including the portions of the exhibits, transcripts, or briefs that refer to Protected Material, must be sealed and maintained in the MPSC's or court's files with a copy of the Protective Order attached.

C. It is intended that the Protected Material subject to this Protective Order should be shielded from disclosure by a Receiving Party only to the extent permitted by law. If any person files a request under the Freedom of Information Act with a governmental agency participating in this proceeding, including, but not limited to, the MPSC, the MPSC Staff, and the Michigan Attorney General, seeking access to documents subject to this Protective Order, the governmental agency shall promptly notify the Disclosing Party, and the Disclosing Party may take whatever legal actions it deems appropriate to protect the Protected Material from disclosure. In light of Section 5 of the Freedom of Information Act, MCL 15.235, the notice must be given at least five (5) business days before the governmental agency grants the request in full or in part.

IV. Termination of Protected Status

A. A Receiving Party reserves the right to challenge whether a document or information is Protected Material and whether this information can be withheld under this Protective Order. In response to a motion, the Commission or the presiding officer in this case may revoke a document's protected status after notice and hearing. If the presiding officer revokes a document's protected status, then the document loses its protected status after 14 days unless a Party files an application for leave to appeal the ruling to the Commission within that time period. Any Party opposing the application for leave to appeal shall file an answer with the Commission no more than 14 days after the filing and service of the appeal. If an application is filed, then the information will continue to be protected from disclosure until either the time for appeal of the Commission's final order resolving the issue has expired under MCL 462.26 or, if the order is appealed, until judicial review is completed and the time to take further appeals has expired.

B. If a document's protected status is challenged under Paragraph IV.A, the Receiving Party challenging the protected status of the document shall explicitly state its reason for challenging the confidential designation. The Disclosing Party bears the burden of proving that the document should continue to be protected from disclosure.

V. Retention of Documents

A. Protected Material remains the property of the Disclosing Party. The Protected Material only remains available to the Receiving Party, unless the Receiving Party is an agency/public official of the State of Michigan subject to state documentation retention schedules, until the time expires for petitions for rehearing of a final MPSC order in this Case

No. U-21540 or until the MPSC has ruled on all petitions for rehearing in this case (if any). Should the Receiving Party be an agency/public official of the State of Michigan who retains the Protected Material to comply with applicable state documentation retention schedules, it is acknowledged that this Order will continue in effect and said Receiving Party will be required to retain the Protected Material in accordance with this Order. Furthermore, it is understood that an attorney for a Receiving Party who has signed a Nondisclosure Certificate and who is representing the Receiving Party in an appeal from an MPSC final order in this case may retain copies of Protected Material until either the time for appeal of the Commission's final order resolving the issue has expired under MCL 462.26 or, if the order is appealed, until judicial review is completed and the time to take further appeals has expired. On or before the time specified by the preceding sentences, the Receiving Party shall return to the Disclosing Party all Protected Material in its possession or in the possession of its Reviewing Representatives—including all copies and notes of Protected Material—or destroy the Protected Material and, at the request of the Disclosing Party, certify in writing that it has done so.

B. Notwithstanding the preceding paragraph, Counsel for a Receiving Party may maintain a single confidential file of Protected Material beyond the resolution of this proceeding, provided that this Order will continue in effect with respect to the Protected Material for so long as it is retained by counsel for any requesting Party. If the Protected Material is relevant or reasonably calculated to lead to admissible evidence in another Commission proceeding relating to and involving the Disclosing Party, then it may be used subject to the issuing of a new protective order in that case. The terms of this Paragraph shall apply until the later of (i) the resolution of Applicant's next general natural gas rate case conducted after the conclusion of Case No. U-21540, or (ii) the resolution of any and all Gas Cost Recovery ("GCR") plan or GCR reconciliation cases that may be filed before the resolution of the next general natural gas rate case. For purposes of this paragraph, the "resolution" of a case means the expiration of the period of judicial review of a final order of the Commission. Counsel for a Requesting Party shall have the right to retain copies of the pleadings, orders, transcripts, briefs, comments, and exhibits in these proceedings, but this protective order will continue in effect with respect to the Protected Material contained in these documents.

VI. Limitations and Disclosures

The provisions of this Protective Order do not apply to a particular document, or portion of a document, described in Paragraph II.A if a Receiving Party can demonstrate that it has been previously disclosed by the Disclosing Party on a non-confidential basis or meets the criteria set forth in Paragraphs I.B.l through I.B.5. A Receiving Party intending to disclose information taken directly from materials identified as Protected Material must—before actually disclosing the information do one of the following: 1) contact the Disclosing Party's counsel of record and obtain written permission to disclose the information, or 2) challenge the confidential nature of the Protected Material and obtain a ruling under Paragraph IV that the information is not confidential and may be disclosed in or on the public record.

VII. Remedies

If a Receiving Party violates this Protective Order by improperly disclosing or using Protected Material, the Receiving Party shall take all necessary steps to remedy the improper disclosure or use. This includes promptly notifying the MPSC, the presiding officer, and the Disclosing Party, in writing, of the identity of the person known or reasonably suspected to have obtained the Protected Material. A Party or person that violates this Protective Order remains subject to this paragraph regardless of whether the Disclosing Party could have discovered the violation earlier than it was discovered. This paragraph applies to both inadvertent and intentional violations. Nothing in this Protective Order limits the Disclosing Party's rights and remedies, at law or in equity, against a Party or person using Protected Material in a manner not authorized by this Protective Order, including the right to obtain injunctive relief in a court of competent jurisdiction to prevent violations of this Protective Order.

____
Administrative Law Judge

Attachment 1

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the application of **MICHIGAN GAS UTILITIES CORPORATION** for authority to increase its retail rates natural gas and for other relief. ____	)))))	Case No. U-21540

NONDISCLOSURE CERTIFICATE

By signing this Nondisclosure Certificate, I acknowledge that access to Protected Material is provided to me under the terms and restrictions of the Protective Order issued in Case No. U-21540, that I have been given a copy of and have read the Protective Order, and that I agree to be bound by the terms of the Protective Order. I understand that the substance of the Protected Material (as defined in the Protective Order), any notes from Protected Material, or any other form of information that copies or discloses Protected Material, shall be maintained as confidential and shall not be disclosed to anyone other than in accordance with the Protective Order.

Reviewing Representative

Date: ____________________ ____________________________________

Title:
Representing:

MICHIGAN DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS
PUBLIC SERVICE COMMISSION

ENTRY OF APPEARANCE IN AN ADMINISTRATIVE HEARING

This form is issued as provided for by 1939 PA 3, as amended, and by 1933 PA 254, as amended. The filing of this form, or an acceptable alternative, is necessary to ensure subsequent service of any hearing notices, Commission orders, and related hearing documents.

General Instructions:

Type or print legibly in ink. For assistance or clarification, please contact the Public Service Commission at 517-284-8090.

Please Note: *The Commission will provide* ***electronic*** *service of documents to all parties in this proceeding.*

THIS APPEARANCE TO BE ENTERED IN ASSOCIATION WITH THE ADMINISTRATIVE HEARING:

Case / Company Name: Michigan Gas Utilities Corporation (MGU) Docket No. U-21540

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name) Michigan Gas Utilities Corporation (MGU)
2. (Name)
3. (Name)
4. (Name)
5. (Name)
6. (Name)
7. (Name)

Name Sherri A. Wellman
Address Miller Canfield
One Michigan Avenue, Suite 900
City Lansing State MI
Zip 48933 Phone 517-483-4954
Email wellmans@millercanfield.com
Date 3/1/2024

Signature: ____________________

○ I am not an attorney

◉ I am an attorney whose:

Michigan Bar # is P-38989

__________ Bar # is: __________
(state)

EAHR1 - 09/29/2016

MICHIGAN DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS
PUBLIC SERVICE COMMISSION

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Case / Company Name: Michigan Gas Utilities Corporation (MGU) Docket No. U-21540

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name) Michigan Gas Utilities Corporation (MGU)
2. (Name)
3. (Name)
4. (Name)
5. (Name)
6. (Name)
7. (Name)

Name Paul M. Collins
Address Miller Canfield
One Michigan Avenue, Suite 900
City Lansing State MI
Zip 48933 Phone 517-483-4908
Email collinsp@millercanfield.com
Date 3/1/2024

Signature: ______________________

○ I am not an attorney
◉ I am an attorney whose:
Michigan Bar # is P-69719
__________ Bar # is: __________
(state)

EAHR1 - 09/29/2016

MICHIGAN DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS
PUBLIC SERVICE COMMISSION

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Case / Company Name: Michigan Gas Utilities Corporation (MGU) Docket No. U-21540

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name) Michigan Gas Utilities Corporation (MGU)
2. (Name)
3. (Name)
4. (Name)
5. (Name)
6. (Name)
7. (Name)

Name Benjamin J. Holwerda
Address Miller Canfield
One Michigan Avenue, Suite 900
City Lansing State MI
Zip 48933 Phone 517-483-4954
Email holwerda@millercanfield.com
Date 3/1/2024

Signature: ____________________

○ I am not an attorney
◉ I am an attorney whose:
Michigan Bar # is P-82110
____________ Bar # is: ____________
(state)

EAHR1 - 09/29/2016

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of	)	
MICHIGAN GAS UTILITIES CORPORATION	)	Case No. U-21540
for authority to increase retail natural gas rates	)	
and for other relief.	)	

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss
COUNTY OF INGHAM)

Kacey O'Neill, being first duly sworn, deposes and states that on March 1, 2024, she served Michigan Gas Utilities Corporation's direct case, as electronically filed on this date upon the parties listed below via electronic mail:

Michael E. Moody	moodym2@michigan.gov
Jennifer Utter Heston	jheston@fraserlawfirm.com
John R. Liskey	john@liskeypllc.com
Michael J. Pattwell	mpattwell@clarkhill.com
Stephen A. Campbell	scampbell@clarkhill.com
Lori Mayabb	MayabbL@michigan.gov

Kacey O'Neill

Subscribed and sworn to before me
on this 1st day of March, 2024.

Victoria J. Seyfried, Notary Public
State of Michigan, County of Clinton
My Commission Expires: 3/29/2030
Acting in the County of Ingham

MPSC Case No. U-21540
MGUC Index of Exhibits

Part	MGUC Exhibit No.	Schedule	Title	Witness
I	A-1	A1	Revenue Deficiency (Sufficiency)	Anthony Reese
I	A-1	A2	Historical Financial Metrics	Anthony Reese
I	A-2	B1	Rate Base	Anthony Reese
I	A-2	B2	Total Utility Plant	Anthony Reese
I	A-2	B3	Depreciation Reserve and Other Deductions	Anthony Reese
I	A-2	B4	Working Capital	Anthony Reese
I	A-3	C1	Adjusted Net Operating Income	Anthony Reese
I	A-3	C2	Revenue Conversion Factor	Anthony Reese
I	A-3	C3	Historical Operating Revenue	Anthony Reese
I	A-3	C4	Historical Cost of Gas Sold	Anthony Reese
I	A-3	C5	Historical Operation and Maintenance Expenses	Anthony Reese
I	A-3	C6	Depreciation and Amortization Expenses	Anthony Reese
I	A-3	C7	General Taxes	Anthony Reese
I	A-3	C8	Federal Income Taxes	Anthony Reese
I	A-3	C9	State Income Taxes	Anthony Reese
I	A-3	C10	Other (or Local) Taxes	Anthony Reese
I	A-3	C11	Allowance for Funds Used During Construction	Anthony Reese
I	A-4	D1	Rate of Return Summary	Anthony Reese
I	A-4	D2	Cost of Long-Term Debt	Anthony Reese
I	A-4	D3	Cost of Short-Term Debt	Anthony Reese
I	A-4	D4	Cost of Preferred Stock	Anthony Reese
I	A-4	D5	Cost of Common Shareholders' Equity	Anthony Reese
I	A-5	E1	Annual Service Area Sales by Major Customer Classes and System Output – 5-Year Historical	Jared J. Peccarelli
I	A-11	A1	Projected Revenue Deficiency (Sufficiency)	Anthony Reese
I	A-11	A2	Financial Metrics - Ratemaking Basis	Anthony Reese
I	A-12	B1	Projected Rate Base	Anthony Reese
I	A-12	B2	Total Utility Plant	Anthony Reese
I	A-12	B3	Depreciation Reserve and Other Deductions	Anthony Reese
I	A-12	B4	Projected Working Capital	Anthony Reese
I	A-12	B5	Projected Capital Expenditures	Anthony Reese
I	A-12	B5.1	Underground Gas Storage Capital Expenditures	Anthony Reese
I	A-12	B5.2	Transmission Capital Expenditures	Anthony Reese
I	A-12	B5.3	Distribution Plant Capital Expenditures	Anthony Reese
I	A-12	B5.4	General Capital Expenditures	Anthony Reese
I	A-12	B5.5	Intangible Capital Expenditures	Anthony Reese
I	A-13	C1	Adjusted Net Operating Income	Anthony Reese
I	A-13	C2	Projected Revenue Conversion Factor	Anthony Reese
I	A-13	C3	Projected Operating Revenue	Anthony Reese

I	A-13	C4	Projected Cost of Gas Sold	Anthony Reese
I	A-13	C5	Projected Operation and Maintenance Expenses	Anthony Reese
I	A-13	C6	Projected Depreciation and Amortization Expenses	Anthony Reese
I	A-13	C7	Projected General Taxes	Anthony Reese
I	A-13	C8	Projected Federal Income Taxes	Anthony Reese
I	A-13	C9	Projected State Income Taxes	Anthony Reese
I	A-13	C10	Other (or Local) Taxes	Anthony Reese
I	A-13	C11	Allowance for Funds Used During Construction	Anthony Reese
I	A-14	D1	Projected Rate of Return Summary	Anthony Reese
I	A-14	D2	Cost of Long-Term Debt	Anthony Reese
I	A-14	D3	Cost of Short-Term Debt	Anthony Reese
I	A-14	D4	Cost of Preferred Stock	Anthony Reese
I	A-14	D5	Cost of Common Shareholders' Equity	Anthony Reese
I	A-14	D6	Summary of ROE Analysis Results	Ann E. Bulkley
I	A-14	D7	Proxy Group Selection	Ann E. Bulkley
I	A-14	D8	Constant Growth DCF Model	Ann E. Bulkley
I	A-14	D9	CAPM and ECAPM	Ann E. Bulkley
I	A-14	D10	Long-Term Average Beta	Ann E. Bulkley
I	A-14	D11	Market Return	Ann E. Bulkley
I	A-14	D12	Bond Yield Plus Risk Premium	Ann E. Bulkley
I	A-14	D13	Capital Expenditures Analysis	Ann E. Bulkley
I	A-14	D14	Regulatory Risk Analysis	Ann E. Bulkley
I	A-14	D15	Size Premium Calculation	Ann E. Bulkley
I	A-14	D16	Capital Structure Analysis	Ann E. Bulkley
I	A-15	E1	Market Outlook: 5-Year Annual Calendar Gas Forecast by Class	Jared J. Peccarelli
I	A-16	F1.1	Cost of Service Summary by Rate Class at Present Rates	Riley E. O’Brien
I	A-16	F1.2	Cost of Service Summary by Customer Class at Present Rates	Riley E. O’Brien
I	A-16	F1.3	Unbundled Revenue Requirement by Customer Class	Riley E. O’Brien
I	A-16	F1.4	Unbundled Rate Base by Customer Class	Riley E. O’Brien
I	A-16	F1.5	Unbundled Unit Cost by Customer Class	Riley E. O’Brien
I	A-16	F2.1	Summary of Present and Proposed Revenue by Rate Schedule Including Cost of Gas	Shannon L. Burzycki
I	A-16	F2.2	Summary of Present and Proposed Revenue by Rate Schedule Excluding Cost of Gas	Shannon L. Burzycki
I	A-16	F3.1	Present and Proposed Revenue Detail Including Cost of Gas	Shannon L. Burzycki
I	A-16	F3.2	Present and Proposed Revenue Detail Excluding Cost of Gas	Shannon L. Burzycki

I	A-16	F4	Comparison of Present and Proposed Monthly Bills	Shannon L. Burzycki
I	A-16	F5	Summary of Tariff Changes and Proposed Revised Tariff Sheets	Shannon L. Burzycki
I	A-17	G1	Operation and Maintenance Expenses – Gas Utility Historical and Forecasted	Anthony Reese
I	A-17	G2	Known and Measurable Adjustment for Manufactured Gas Plant Remediation	Anthony Reese
I	A-17	G3	Known and Measurable Adjustment for Underground Storage Expenses – Maintenance of Reservoirs and Wells	Anthony Reese
I	A-17	G4	Known and Measurable Adjustment for Underground Storage Expenses – Operation Supervision and Engineering	Anthony Reese
I	A-17	G5	Known and Measurable Adjustment for Underground Storage Expenses – Maintenance of Compressor Equipment	Anthony Reese
I	A-17	G6	Known and Measurable Adjustment for Transmission Operations Mains Expense	Anthony Reese
I	A-17	G7	Known and Measurable Adjustment for Maintenance of Mains	Anthony Reese
I	A-17	G8	Known and Measurable Adjustment for Maintenance of Measuring and Regulating Station Equipment	Anthony Reese
I	A-17	G9	Known and Measurable Adjustment for Distribution Operations Operation Supervision and Engineering	Anthony Reese
I	A-17	G10	Known and Measurable Adjustment for Distribution Operations Mains and Services Expenses	Anthony Reese
I	A-17	G11	Known and Measurable Adjustment for Distribution Operations Measuring and Regulating Station Expenses - General	Anthony Reese
I	A-17	G12	Known and Measurable Adjustment for Distribution Operations Measuring and Regulating Station Expenses – City Gate Check Stations	Anthony Reese
I	A-17	G13	Known and Measurable Adjustment for Distribution Operations Meter and House Regulator Expenses	Anthony Reese
I	A-17	G14	Known and Measurable Adjustment for Distribution Operations Other Expenses	Anthony Reese
I	A-17	G15	Known and Measurable Adjustment for Distribution Maintenance Supervision and Engineering	Anthony Reese
I	A-17	G16	Known and Measurable Adjustment for Distribution Maintenance of Mains	Anthony Reese
I	A-17	G17	Known and Measurable Adjustment for Distribution Maintenance of Measuring and Regulating Gate Station Equipment – City Gate Check Stations	Anthony Reese
I	A-17	G18	Known and Measurable Adjustment for Distribution Maintenance of Services	Anthony Reese

I	A-17	G19	Known and Measurable Adjustment for Customer Accounts Expenses – Meter Reading	Anthony Reese
I	A-17	G20	Known and Measurable Adjustment for Customer Accounts Expenses – Customer Records and Collection	Anthony Reese
I	A-17	G21	Known and Measurable Adjustment for Customer Accounts Expenses – Uncollectible Accounts	Anthony Reese
I	A-17	G22	Known and Measurable Adjustment for Administrative and General – Administrative and General Salaries	Anthony Reese
I	A-17	G23	Known and Measurable Adjustment for Administrative and General – Office Supplies and Expense	Anthony Reese
I	A-17	G24	Known and Measurable Adjustment for Administrative and General – Outside Services Employed	Anthony Reese
I	A-17	G25	Known and Measurable Adjustment for Administrative and General – Property Insurance	Anthony Reese
I	A-17	G26	Known and Measurable Adjustment for Administrative and General – Injuries and Damages Expenses	Anthony Reese
I	A-17	G27	Known and Measurable Adjustment for Administrative and General – Employee Pensions and Benefits Expenses	Anthony Reese
I	A-17	G28	Known and Measurable Adjustment for Administrative and General – Regulatory Commission Expense	Anthony Reese
I	A-17	G29	Known and Measurable Adjustment for Administrative and General – Miscellaneous General Expenses	Anthony Reese
I	A-18		Estimate of Inflation for 2024 and 2025	Anthony Reese
I	A-19		WorldatWork Salary Budget Survey 2023-2024 (CONFIDENTIAL)	Anthony Reese
I	A-20		Culpepper Salary Budget Survey 2023-2024 (CONFIDENTIAL)	Anthony Reese
I	A-21		Annual Incentive Pay Plan for Non-Executives (CONFIDENTIAL)	Anthony Reese
I	A-22		2024 Annual Incentive Plan Overview (CONFIDENTIAL)	Anthony Reese
I	A-23		Proposed MRP Revenue Requirement	Shannon L. Burzycki
I	A-24		Proposed MRP Customer Surcharges 2026 and 2027	Shannon L. Burzycki
I	A-25		Necessity of Continuation of Waiver for Meter Testing Requirements Rule 51	Shannon L. Burzycki
I	A-26		Forecasted Costs Summary from Proposed LDAR Rules	Nathan W. Lee
II	N/A		2021 MGU Annual Report to MPSC P-522	
II	N/A		2022 MGU Annual Report to MPSC P-522	
II	N/A		2022 MGU Annual Report to the SEC Form 10-K (February 23, 2023) (link provided)	

II	N/A		Quarterly Report to Shareholders SEC Form 10-Q (November 3, 2022) (link provided)	
II	N/A		Quarterly Report to Shareholders SEC Form 10-Q (May 4, 2023) (link provided)	
II	N/A		Quarterly Report to Shareholders SEC Form 10-Q (August 3, 2023) (link provided)	
II	N/A		Quarterly Report to Shareholders SEC Form 10-Q (November 2, 2023) (link provided)	
II	N/A		Bond and Other Financial Prospectuses	
III	N/A		See "Part III Supplemental Data Index" (provided in link)	

Schedule A-1

Michigan Public Service Commission	Case No.: U-21540
Michigan Gas Utilities	Exhibit No.: A-1
Revenue Deficiency (Sufficiency)	Schedule: A-1
Historical 12 Month Period Ending December 31, 2022	Page: 1 of 1
	Witness: Anthony Reese

	(a)	(b)	(c)
Line No.	**Description**	**Source**	**Total ($000)**
1			
2	Rate Base	Exh. A-2, Sch. B1	$ 431,393
3			
4	Adjusted Net Operating Income	Exh. A-3, Sch. C1	22,286
5			
6	Overall Rate of Return	Line 4 ÷ Line 2	5.17%
7			
8	Required Rate of Return	Exh. A-4, Sch. D1	5.30%
9			
10	Income Requirements	Line 2 x Line 8	22,850
11			
12	Income Deficiency (Sufficiency)	Line 10 - Line 4	564
13			
14	Revenue Conversion Factor	Exh. A-3, Sch. C2	1.347
15			
16	Revenue Deficiency (Sufficiency)	Line 12 x Line 14	$ 760

($000)

Financial Metrics - Financial Basis

	[A]	[B]	[C]	[D]	[E]	[F]
Line	Description	2022	2021	2020	2019	2018
1	Operating Revenue	$ 216,229	$ 151,943	$ 128,211	$ 144,530	$ 148,416
2	Operating Expense	(188,928)	(133,697)	(106,184)	(118,178)	(122,219)
3	Pre-Tax Operating Income	27,302	18,246	22,027	26,352	26,197
4	Income Taxes	(4,450)	(3,635)	(3,611)	(4,305)	(5,530)
5	Net Operating Income	22,852	14,611	18,417	22,047	20,667
6	Other Income and Deductions	(207)	(252)	(202)	(277)	(200)
7	AFUDC	684	126	276	339	131
8	Interest Charges	(5,504)	(4,999)	(4,769)	(3,814)	(3,857)
9	Interest (2021 Deferral)	(1,225)	4,900	-	-	-
10	Preferred Stock Dividends	-	-	-	-	-
11	Net Income Available for Common	16,600	14,386	13,722	18,295	16,741
12	Year End Average Unadjusted Common Equity	195,886	175,368	178,795	177,774	154,745
13	Earned Rate of Return on Common Equity	8.47%	8.20%	7.67%	10.29%	10.82%
14	Authorized Return on Common Equity	9.85%	9.90%	9.90%	9.90%	9.90%

($000)

Schedule A-2

Financial Metrics - Financial Basis

Line	Description	2022	2021	2020	2019	2018
	[A]	[B]	[C]	[D]	[E]	[F]
	EBIT Interest Coverage Ratio					
15	Pre-Tax Operating Income	$ 27,302	$ 18,246	$ 22,027	$ 26,352	$ 26,197
16	Other Income and Deductions	(207)	(252)	(202)	(277)	(200)
17	AFUDC	684	126	276	339	131
18	Total EBIT	27,779	18,121	22,101	26,414	26,128
19	Interest Charges	5,504	4,999	4,769	3,814	3,857
20	EBIT Interest Coverage Ratio	5.05	3.62	4.63	6.93	6.77
	EBITDA Interest Coverage Ratio					
21	Total EBIT	$ 27,779	$ 18,121	$ 22,101	$ 26,414	$ 26,128
22	Depreciation and Amortization	18,450	17,189	15,524	12,885	12,539
23	Total EBITDA	46,229	35,310	37,625	39,299	38,667
24	Interest Charges	5,504	4,999	4,769	3,814	3,857
25	EBITDA Interest Coverage Ratio	8.40	7.06	7.89	10.30	10.03
	Funds Flow from Operations (FFO) Interest Coverage Ratio					
26	Net Operating Income	$ 22,852	$ 14,611	$ 18,417	$ 22,047	$ 20,667
27	Depreciation and Amortization	18,450	17,189	15,524	12,885	12,539
28	Deferred Income Tax	4,135	6,396	9,662	4,545	4,037
29	AFUDC	684	126	276	339	131
30	Other Major Recurring Non-Cash Items	(859)	(3,986)	610	1,390	425
31	Interest Paid	5,504	4,999	4,769	3,814	3,857
32	Less:					
33	Operating Lease Adjustment to Depreciation	-	-	-	-	-
34	Subtotal	50,765	39,335	49,257	45,020	41,655
35	Interest Charges	5,504	4,999	4,769	3,814	3,857
36	FFO Interest Coverage Ratio	9.22	7.87	10.33	11.80	10.80

Michigan Public Service Commission
Michigan Gas Utilities Corporation
($000)

Case No.: U-21540
Exhibit No.: A-1
Schedule: A-2

Witness: Anthony Reese

Financial Metrics - Financial Basis

	[A]	[B]	[C]	[D]	[E]	[F]
Line	Description	2022	2021	2020	2019	2018
	Overall Fixed Charge Coverage Ratio					
37	Net Income Available for Common	$ 16,600	$ 14,386	$ 13,722	$ 18,295	$ 16,741
38	Interest Charges	5,504	4,999	4,769	3,814	3,857
39	Subtotal Numerator	22,104	19,385	18,491	22,109	20,598
40	Interest Charges	5,504	4,999	4,769	3,814	3,857
41	Preferred Stock Dividends				-	-
42	Subtotal Denominator	5,504	4,999	4,769	3,814	3,857
43	Overall Fixed Charge Coverage Ratio	4.02	3.88	3.88	5.80	5.34
	Cash Flow Coverage of Dividends Ratio					
44	Net Income Available for Common	$ 16,600	$ 14,386	$ 13,722	$ 18,295	$ 16,741
45	Depreciation and Amortization	18,450	17,189	15,524	12,885	12,539
46	Deferred Taxes	4,135	6,396	9,662	4,545	4,037
47	Subtotal	39,185	37,971	38,907	35,725	33,317
48	Common Dividends	-	-	47,000	14,000	-
49	Cash Flow Coverage of Dividend Ratio	N/A	N/A	0.83	2.55	N/A
	Common Dividend Payout Ratio					
50	Common Dividends	$ -	$ -	$ 47,000	$ 14,000	$ -
51	Net Income Available for Common	16,600	14,386	13,722	18,295	16,741
52	Common Dividend Payout Ratio	N/A	N/A	343%	77%	N/A
	Permanent Capitalization					
53	Long-term Debt	$ 150,000	$ 150,000	$ 120,000	$ 90,000	$ 90,000
54	Preferred Stock				-	-
55	Common Equity	195,886	175,368	178,795	177,774	154,745
56	Total Permanent Capital	345,886	325,368	298,795	267,774	244,745
57	Long-term Debt Ratio	43.37%	46.10%	40.16%	33.61%	36.77%
58	Preferred Stock Ratio	-	-	-	-	-
59	Common Equity Ratio	56.63%	53.90%	59.84%	66.39%	63.23%
60	Total Permanent Capital	100.00%	100.00%	100.00%	100.00%	100.00%

($000)

Financial Metrics - Ratemaking Basis

	[A]	[B]	[C]	[D]	[E]	[F]
Line	Description	2022	2021	2020	2019	2018
61	Operating Revenue	$ 216,229	$ 151,943	$ 128,211	$ 144,530	$ 148,416
62	Operating Expense	(188,928)	(133,697)	(106,184)	(118,178)	(122,219)
63	Pre-Tax Operating Income	27,302	18,246	22,027	26,352	26,197
64	Income Taxes	(4,450)	(3,635)	(3,611)	(4,305)	(5,530)
65	Net Operating Income	22,852	14,611	18,417	22,047	20,667
66	Tax Impact of Pro-Forma Interest on NOI[1]	-	-	-	-	-
67	AFUDC	684	126	276	339	131
68	Interest Charges	(5,504)	(4,999)	(4,769)	(3,814)	(3,857)
69	Interest (2021 Deferral)	(1,225)	4,900	-	-	-
70	Preferred Stock Dividends	-	-	-	-	-
71	Net Income Available for Common and JDITC	16,807	14,638	13,924	18,571	16,940
72	Return Assignable to JDITC					
73	Net Income Available for Common	16,807	14,638	13,924	18,571	16,940
74	13 mo. Average Adjusted Common Equity	172,843	149,871	139,889	134,757	119,255
75	Earned Rate of Return on Common Equity	9.72%	9.77%	9.95%	13.78%	14.21%
76	Authorized Return on Common Equity	9.85%	9.90%	9.90%	9.90%	9.90%

Schedule A-2

Michigan Public Service Commission
Michigan Gas Utilities Corporation
($000)

Case No.: U-21540
Exhibit No.: A-1
Schedule: A-2

Witness: Anthony Reese

Financial Metrics - Ratemaking Basis

	[A]	[B]	[C]	[D]	[E]	[F]
Line	Description	2022	2021	2020	2019	2018
	EBIT Interest Coverage Ratio					
77	Pre-Tax Operating Income	$ 27,302	$ 18,246	$ 22,027	$ 26,352	$ 26,197
78	AFUDC	684	126	276	339	131
79	Total EBIT	27,985	18,372	22,303	26,690	26,328
80	Interest Charges	5,504	4,999	4,769	3,814	3,857
81	EBIT Interest Coverage Ratio	5.08	3.68	4.68	7.00	6.83
	EBITDA Interest Coverage Ratio					
82	Total EBIT	$ 27,985	$ 18,372	$ 22,303	$ 26,690	$ 26,328
83	Depreciation and Amortization	18,450	17,189	15,524	12,885	12,539
84	Total EBITDA	46,436	35,561	37,827	39,576	38,867
85	Interest Charges	5,504	4,999	4,769	3,814	3,857
86	EBITDA Interest Coverage Ratio	8.44	7.11	7.93	10.38	10.08
	Funds Flow from Operations (FFO) Interest Coverage Ratio					
87	Net Operating Income	$ 22,852	$ 14,611	$ 18,417	$ 22,047	$ 20,667
88	Depreciation and Amortization	18,450	17,189	15,524	12,885	12,539
89	Deferred Income Tax	4,135	6,396	9,662	4,545	4,037
90	AFUDC	684	126	276	339	131
91	Other Major Recurring Non-Cash Items	(859)	(3,986)	610	1,390	425
92	Interest Charges	5,504	4,999	4,769	3,814	3,857
93	Less:					
94	Operating Lease Adjustment to Depreciation	-	-	-	-	-
95	Subtotal	50,765	39,335	49,257	45,020	41,655
96	Interest Charges	5,504	4,999	4,769	3,814	3,857
97	FFO Interest Coverage Ratio	9.22	7.87	10.33	11.80	10.80

Schedule A-2

Michigan Public Service Commission
Michigan Gas Utilities Corporation
($000)

Case No.: U-21540
Exhibit No.: A-1
Schedule: A-2

Witness: Anthony Reese

Financial Metrics - Ratemaking Basis

	[A]	[B]	[C]	[D]	[E]	[F]
Line	Description	2022	2021	2020	2019	2018
	Overall Fixed Charge Coverage Ratio					
98	Net Income Available for Common	$ 16,807	$ 14,638	$ 13,924	$ 18,571	$ 16,940
99	Interest Charges	5,504	4,999	4,769	3,814	3,857
100	Subtotal Numerator	22,311	19,637	18,693	22,385	20,797
101	Interest Charges	5,504	4,999	4,769	3,814	3,857
102	Preferred Stock Dividends	-	-	-	-	-
103	Subtotal Denominator	5,504	4,999	4,769	3,814	3,857
104	Overall Fixed Charge Coverage Ratio	4.05	3.93	3.92	5.87	5.39
	Cash Flow Coverage of Dividends Ratio					
105	Net Income Available for Common	$ 16,807	$ 14,638	$ 13,924	$ 18,571	$ 16,940
106	Depreciation and Amortization	18,450	17,189	15,524	12,885	12,539
107	Deferred Taxes	4,135	6,396	9,662	4,545	4,037
108	Subtotal	39,392	38,223	39,109	36,002	33,517
109	Common Dividends	-	-	47,000	14,000	-
110	Cash Flow Coverage of Dividend Ratio	N/A	N/A	0.83	2.57	N/A
	Common Dividend Payout Ratio					
111	Common Dividends	$ -	$ -	$ 47,000	$ 14,000	$ -
112	Net Income Available for Common	16,807	14,638	13,924	18,571	16,940
113	Common Dividend Payout Ratio	N/A	N/A	338%	75%	N/A
	Permanent Capitalization					
114	Long-term Debt	$ 150,000	$ 150,000	$ 131,522	$ 89,415	$ 89,370
115	Preferred Stock	-	-	-	-	-
116	Common Equity	172,843	149,871	139,889	134,757	119,255
117	Total Permanent Capital	322,843	299,871	271,410	224,172	208,625
118	Long-term Debt Ratio	46.46%	50.02%	48.46%	39.89%	42.84%
119	Preferred Stock Ratio	-	-	-	-	-
120	Common Equity Ratio	53.54%	49.98%	51.54%	60.11%	57.16%
121	Total Permanent Capital	100.00%	100.00%	100.00%	100.00%	100.00%

[1] Data unavailable. Interest Charges on line 67 reflect total actual interest.

Schedule B-1

Michigan Public Service Commission	Case No.: U-21540
Michigan Gas Utilities	Exhibit No.: A-2
Rate Base	Schedule: B-1
Historical 13 Month Average, December 31, 2022	Page: 1 of 1
	Witness: Anthony Reese

		(b)	(c)
Line No.	**Description**	**Source**	**Rate Base ($000)**
1			
2	Plant in Service	Exh. A-2, Sch. B2	585,297
3	Plant Held for Future Use	Exh. A-2, Sch. B2	
4	Construction Work in Progress	Exh. A-2, Sch. B2	18,730
5	Total Utility Plant	Sum Lines 2-4	604,027
6			
7	Less: Depreciation Reserve	Exh. A-2, Sch. B3	251,319
8			
9	Net Utility Plant	Line 5 + Line 7	352,708
10			
11	Net Capital Lease Property		0
12			
13	Total Utility Property and Plant	Line 9 + Line 11	352,708
14			
15	Less: Capital Lease Obligations		0
16			
17	Net Plant	Line 13 + Line 15	352,708
18			
19	Allowance for Working Capital	Exh. A-2, Sch. B4	78,685
20			
21	Total Rate Base	Line 17 + Line 19	$ 431,393

Schedule B-2

Michigan Public Service Commission
Michigan Gas Utilities
Total Utility Plant
Historical 13 Month Average, December 31, 2022

Case No.: U-21540
Exhibit No.: A-2
Schedule: B-2
Page: 1 of 1
Witness: Anthony Reese

	(a)	(b)		
Line No.	Description	MPSC Account No.	Source	Utility Plant ($000)
1			Workpaper 3	
2	Plant in Service	101		$ 582,165
3	Plant purchased or sold	102		
4	Experimental plant unclassified	103		
5	Plant leased to others	104		
6	Completed construction not classified	106		
7	Gas Stored Base Gas	117		3,133
8	Plant in Service			$ 585,297
9				
10	Plant held for future use	105		
11				
12	Construction work in progress	107		$ 18,730
13				
14	Total Utility Plant			$ 604,027

Schedule B-3

Michigan Public Service Commission
Michigan Gas Utilities
Depreciation Reserve and Other Deductions
Historical 13 Month Average, December 31, 2022

Case No.: U-21540
Exhibit No.: A-2
Schedule: B-3
Page: 1 of 1
Witness: Anthony Reese

	(a)		(b)
Line No.	**Description**	**Source**	**Accumulated Provision for Depreciation ($000)**
1			
2	Total Projected Period Accumulated Provision for Depreciation	Workpaper 3	$ 251,319

Schedule B-4

Michigan Public Service Commission
Michigan Gas Utilities
Working Capital
Historical 13 Month Average, December 31, 2022

Case No.: U-21540
Exhibit No.: A-2
Schedule: B-4
Page: 1 of 1
Witness: Anthony Reese

Line No.	(a) Description	Source	(b) Projected Working Capital ($000)
1		Workpapers 3&4 2022	
2	Assets		
3	Utility Plant-ARO		1,140
4	Accumulated Depreciation-ARO		(854)
5	Investments - Pension & Other		23,559
6	Cash & Cash Equivalents		571
7	Net Accounts Receivable		23,710
8	Gas Accrued Revenue		11,711
9	Gas Storage		23,350
10	Materials and Supplies		1,391
11	Prepayments - Other		1,302
12	Derivative Assets		3,417
13	Other Current Assets		18,641
14	Regulatory Assets		40,949
15	Other Long-term		1,628
16	Total Assets		$ 150,517
17			
18	Liabilities		
19	Accounts Payable		22,751
20	Accrued Payroll, Vacation, Taxes, & Interest		3,524
21	Accrued Taxes		7,108
22	Customer Deposits		3
23	Miscellaneous Current and Accrued Liabilities		8,251
24	Regulatory Liabilities		8,222
25	Asset Removal Obligation		2,330
26	Post Retirement OPEB and Pension Liability		1,768
27	Other Deferred Credits		17,874
28			
29	Total Liabilities		$ 71,832
30			
31	Total Working Capital		$ 78,685

Schedule C-1

Michigan Public Service Commission
Michigan Gas Utilities
Adjusted Net Operating Income
For the Historical Year Ended December 31, 2022

Case No.: U-21540
Exhibit No.: A-3
Schedule: C-1
Page: 1 of 1
Witness: Anthony Reese

Line No.	(a) Description	Source	(b) Net Operating Income ($000)
1			
2	**Operating Revenues**	Exh. A-3, Sch. C3	$ 216,229
3			
4	**Operating Expenses**		
5	Cost of Gas	Exh. A-3, Sch. C4	124,779
6	Operations and Maintenance Expenses	Exh. A-3, Sch. C5	33,176
7	Depreciation and Amortization	Exh. A-3, Sch. C6	18,450
8	General Taxes	Exh. A-3, Sch. C7	12,523
9	Income Taxes	Exh. A-3, Sch. C8 & C9	4,450
10	Total Operating Expenses		$ 193,377
11			
12	**Operating Income**		$ 22,852
13			
14	**Operating Income Adjustments**		
15	Allowance For Funds Used During Construction	Exh. A-3, Sch. C11	684
16	Amortization of 2021 deferral ($5.0M over 4 Years)		(1,250)
17	Income Tax Effect of Interest		
18	Interest Synchronization Adjustment		
19	Total Operating Income Adjustments		$ (566)
20			
21	**Adjusted Net Operating Income**		$ 22,286

Schedule C-2

Michigan Public Service Commission		Case No.:	U-21540
Michigan Gas Utilities		Exhibit No.:	A-3
Revenue Conversion Factor		Schedule No.:	C-2
For the Historical Year Ended December 31, 2022		Page:	1 of 1
		Witness:	Anthony Reese

	(a)	(b)	(c)
Line No.	**Description**	**Calc. Logic/Source**	**Amount**
1			
2	Income Before Income Taxes		100.00%
3			
4	Michigan Corporate Income Tax Rate		6.00%
5			
6	Federal Income Tax Base	Ln 2 - Ln 4	94.00%
7			
8	Times Federal Income Tax Rate		21.00%
9			
10	Federal Income Tax	Ln 6 x Ln 8	19.74%
11			
12	Income After Taxes	Ln 6 - Ln 10	74.26%
13			
14	Gross Revenue Conversion Factor	Ln 2 / Ln 12	1.3466

Schedule C-3

Michigan Public Service Commission
Michigan Gas Utilities
Operating Revenue
For the Historical Year Ended December 31, 2022

Case No.: U-21540
Exhibit No.: A-3
Schedule No.: C-3
Page: 1 of 1
Witness: Anthony Reese

Line No.	(a) Description	(b) Source	(c) Sales Revenue ($000)
1			
2	Sales Revenue	Workpaper 5	$ 215,500
3			
4	Energy Optimization Revenue		$ -
5			
6	Other Revenues	Workpaper 5	$ 729
7			
8	Total Revenue		$ 216,229

Schedule C-4

Michigan Public Service Commission
Michigan Gas Utilities
Cost of Gas Sold
For the Historical Year Ened December 31, 2022

Case No.: U-21540
Exhibit No.: A-3
Schedule No.: C-4
Page: 1 of 1
Witness: Anthony Reese

	(a)	(b)	(c)
Line No.	**Description**	**Source**	**Cost of Gas ($000)**
1			
2	**Cost of Gas:**		
3	Energy	Workpaper 5	$ 124,779
4	Dem-Peak Day (D-1)		-
5	Other COG		-
6			
7	Total Cost of Gas		$ 124,779

Schedule C5

Michigan Public Service Commission
Michigan Gas Utilities
Operation and Maintenance Expenses
For the Historical Year Ened December 31, 2022

Case No.: U-21540
Exhibit No.: A-3
Schedule No.: C5
Page: 1 of 1
Witness: Anthony Reese

Line No.	(a) Description	(b) Source	Operation and Maintenance Expenses ($000)
1			
2	**Production - Other:**		
3	Energy		-
4	Dem-Peak Day (D-1)		-
5	Other Production		-
6	Manufactured Gas Production	*MPSC Report, p.320*	847
7	Gas Supply	Workpaper 5	250
8	Other COG		-
9			
10	**Total Production-Other**		$ 1,097
11			
12	**Operation and Maintenance Expenses:**		
13	Storage	*MPSC Report, p.322*	515
14	Transmission	*MPSC Report, p.324*	814
15	Distribution	*MPSC Report, p.324*	11,231
16	Customer Accounts	*MPSC Report, p.324*	6,595
17	Customer Service	*MPSC Report, p.325*	3,717
18	Sales	*MPSC Report, p.325*	1
19	Administration & General	*MPSC Report, p.325*	9,206
20			
21	**Total Operation and Maintenance Expenses**		$ 32,079
22			
23	Total Production-Other and Operation & Maintenance Expenses		$ 33,176

Schedule C-6

Michigan Public Service Commission	Case No.: U-21540
Michigan Gas Utilities	Exhibit No.: A-3
Depreciation and Amortization Expenses	Schedule No.: C-6
For the Historical Year Ened December 31, 2022	Page: 1 of 1
	Witness: Anthony Reese

	(a)	(b)	(c)
Line No.	**Description**	**Source**	**Depreciation & Amortization Expense ($000)**
1			
2	**Depreciation and Amortization Expense**		
3	Depreciation Expense	*MPSC Report, p.114*	$ 14,810
4	Amortization Expense	*MPSC Report, p.114*	3,640
5			
6	Total Depreciation and Amortization Expense		$ 18,450

Schedule C-7

Michigan Public Service Commission	Case No.: U-21540
Michigan Gas Utilities	Exhibit No.: A-3
General Taxes	Schedule No.: C-7
For the Historical Year Ened December 31, 2022	Page: 1 of 1
	Witness: Anthony Reese

	(a)	(b)	(c)
Line No.	**Description**	**Source**	**General Taxes ($000)**
1		Workpaper 6	
2	FEDERAL		
3	Payroll Taxes		$ 986
4	Unemployment Comp		6
5	PR Taxes Credited		(58)
6	Super Fund Tax		-
7	Highway Use Tax		-
8	Federal Excise Tax		-
9			
10	STATE		
11	Gross Receipts Tax		-
12	Unemployment Comp		7
13	Remain. Assessment		-
14	Use Tax		4,228
15	Unauthor Ins Tax		-
16	Wis Recycling Fee		-
17	Single Business Tax		-
18	Property		-
19			
20	LOCAL		
21	Real Est & Property		7,345
22			
23	WBS		
24	WBS Payroll Tax		9
25			
26	OTHER		
27	Franchise Tax Fees		-
28	State Unitary Fees		-
29			
30	Total General Taxes	*MPSC Report, p.114*	$ 12,523

Schedule C-8

Michigan Public Service Commission
Michigan Gas Utilities
Federal Income Taxes
For the Historical Year Ened December 31, 2022

Case No.: U-21540
Exhibit No.: A-3
Schedule No.: C-8
Page: 1 of 1
Witness: Anthony Reese

	(a)	(b)	(c)
Line No.	**Description**	**Source**	**Federal Income Taxes ($000)**
1			
2	Federal Income Taxes	Workpaper 7	$ 3,074

Schedule C-9

Michigan Public Service Commission	Case No.: U-21540
Michigan Gas Utilities	Exhibit No.: A-3
State Income Taxes	Schedule No.: C-9
For the Historical Year Ended December 31, 2022	Page: 1 of 1
	Witness: Anthony Reese

	(a)	(b)	(c)
Line No.	**Description**	**Source**	**State Income Taxes ($000)**
1			
2	State Income Taxes	Workpaper 7	$ 1,376

Schedule C10

Michigan Public Service Commission	Case No.: U-21540
Michigan Gas Utilities	Exhibit No.: A-3
Other (or Local) Taxes	Schedule No.: C10
For the Historical Year Ened December 31, 2022	Page: 1 of 1
	Witness: Anthony Reese

	(a)	(b)	(c)
Line No.	**Description**	**Source**	**TOTAL**
1			
2	All Taxes Other than Income are included on Exhibit A-3, Schedule C-7		

Schedule C11

Michigan Public Service Commission	Case No.: U-21540
Michigan Gas Utilities	Exhibit No.: A-3
Allowance for Funds Used During Construction	Schedule No.: C11
For the Historical Year Ened December 31, 2022	Page: 1 of 1
	Witness: Anthony Reese

	(a)	(b)	(c)	
Line No.	Description	Source	TOTAL	
1				
2	AFUDC Debt	MPSC Report, p.117	$	(173)
3	AFUDC Equity	MPSC Report, p.117		(511)
4				
5	Total AFUDC		$	(684)

Schedule D-1

Michigan Public Service Commission
Michigan Gas Utilities
Rate of Return Summary
Historical 13 Month Average, December 31, 2022

Case No.: U-21540
Exhibit No.: A-4
Schedule: D-1
Page: 1 of 1
Witness: Anthony Reese

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)	(i)
		Capital Structure					**Weighted Cost**			
Line No.	**Description**	**Amount ($000) (1)**	**Percent Permanent Capital (2)**	**Percent of Total Capital**	**Cost Rate %**		**Permanent Capital (2)**	**Total Cost %**	**Conversion Factor**	**Pre-Tax Return**
1										
2	Long-Term Debt	**$ 149,271**	46.34%	34.60%	**3.29%**	(3)	1.53%	1.14%		1.14%
3										
4	Preferred Stock	$ -	0.00%	0.00%	0.00%	(4)	0.00%	0.00%		0.00%
5										
6	Common Shareholders' Equity	**$ 172,843**	53.66%	40.07%	**9.85%**	(5)	5.29%	3.95%	1.347	5.31%
7										
8	Total Permanent Capital	$ 322,114	100.00%				6.81%			
9										
10	Short-Term Debt	**$ 28,675**		6.65%	**3.17%**	(6)		0.21%		0.21%
11										
12	Job Development - ITC - Debt									
13	Job Development - ITC Equity									
14	Total Job Development - ITC	$ -		0.00%	6.81%					
15										
16	Deferred Income Taxes (Net)	**$ 80,605**		18.68%	0.00%			0.00%		0.00%
17										
18	Deferred Tax Proration	$ 0		0.00%	6.51%			0.00%		0.00%
19										
20	Total	$ 431,393		100.00%				5.30%		6.66%

(1) See Exh. A-2, Sch. B1
(2) Excludes Short-Term Debt, Deferred Job Development Investment Tax Credit, Deferred Investment Tax Credit and Deferred Income Taxes to calculate the rate of return for Job Development Investment Tax Credit purposes in accordance with Internal Revenue Service Income Tax Regulation Section 1.46-6
(3) See Exh. A-4, Sch. D2
(4) Exh. A-4, Sch. D4 is not provided; MGU does not have preferred stock
(5) See Exh. A-4, Sch. D5
(6) See Exh. A-4, Sch. D3

Schedule D-2

Michigan Public Service Commission
Michigan Gas Utilities
Cost of Long-Term Debt
Historical 13 Month Average, December 31, 2022

Case No.: U-21540
Exhibit No.: A-4
Schedule: D-2
Page: 1 of 1
Witness: Anthony Reese

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Line No.	**Description**	**Original Issue Date**	**Stated Maturity Date**	**Interest Rate (%)**	**Amount of Offering ($000)**	**Price to Public (%)**	**Underwriting & Financing Expenses (%)**	**Net Proceeds to the Company (%)**	**Cost Based on Net Proceeds (%)**	**Amount Outstanding ($000)**	**Annual Cost ($000)**
1											
2	**Mortgage Bonds**										
3	Total Mortgage Bonds									$ -	
4											
5	**Other Long-Term Debt**										
6		May 01, 2020	May 01, 2025	2.69%	60,000	100%		100%	2.69%	60,000	1,614
7		June 27, 2017	July 15, 2027	3.11%	30,000	100%	-	100%	3.11%	30,000	933
8		June 27, 2017	June 27, 2032	3.41%	30,000	100%	-	100%	3.41%	30,000	1,023
9		June 27, 2017	June 27, 2047	4.01%	30,000	100%	-	100%	4.01%	30,000	1,203
10											
11											
12	Total Other Long-Term Debt									$ 150,000	$ 4,773
13											
14	Total Long-Term Debt									$ 150,000	
15											
16	Unamortized Debt Discount, Premium, and Expense									(729)	143
17											
18	Total Long-Term Debt Balance									$ 149,271	$ 4,916
19											
20	Cost of Long-Term Debt										3.29%

Schedule D-3

Michigan Public Service Commission	Case No.: U-21540
Michigan Gas Utilities	Exhibit No.: A-4
Cost of Short-Term Debt	Schedule: D-3
Historical 13 Month Average, December 31, 2022	Page: 1 of 1
	Witness: Anthony Reese

Line No.	(a) Month	(b) Balance Outstanding ($000)	(c) Total Cost ($000)
1			
2	Inter-Company Loans		
3	Dec	$ 18,800	
4	Jan	25,875	
5	Feb	24,325	
6	Mar	14,175	
7	Apr	7,900	
8	May	-	
9	Jun	10,700	
10	Jul	24,500	
11	Aug	29,800	
12	Sep	44,200	
13	Oct	56,900	
14	Nov	59,600	
15	Dec	56,000	
16	13 month Average/Total	$ 28,675	$ 744
17			
18	Credit Facility Fees and Amortization	-	131
19			
20	Guarantee Fees	-	33
21			
22	Other	-	-
23			
24	Total	$ 28,675	909
25			
26	Average Cost of Short-Term Debt		3.17%

Schedule D4

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Cost of Preferred Stock
Historical 13 Month Average, December 31, 2022

Case No.: U-21540
Exhibit No.: A-4
Schedule: D-4
Page: 1 of 1
Witness: Anthony Reese

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Description	Annual Dividend Required	Par Value	Discount or Premium	Finance Expenses	Net Proceeds Received	Number of Shares Outstanding	Total Value of Outstanding Proceeds	Cost Rate (%)	Annual Dollar Amount
1										
2	Michigan Gas Utilities Corporation has no preferred stock outstanding									

Schedule D-5

Michigan Public Service Commission	Case No.: U-21540
Michigan Gas Utilities	Exhibit No.: A-4
Cost of Common Shareholders' Equity	Schedule: D-5
Historical 13 Month Average, December 31, 2022	Page: 1 of 1
	Witness: Anthony Reese

Line No.		Adjusted Common Stock ($000)	
1			
2	Dec	156,067	
3	Jan	166,342	
4	Feb	171,189	
5	Mar	174,543	
6	Apr	177,050	
7	May	177,263	
8	Jun	176,507	
9	Jul	175,634	
10	Aug	174,875	
11	Sep	173,390	
12	Oct	173,022	
13	Nov	174,384	
14	Dec	176,690	
15			
16	Average	$172,843	9.85%

Schedule E1

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Annual Service Area Sales by Major Customer Classes and System Output
5-Year Historical
Units in MMcf

Case No.: U-21540
Exhibit No.: A-5
Schedule: E1
Page: 1 of 1
Witness: Jared J. Peccarelli

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	**Year**	**Residential**	**Commercial**	**Industrial**	**Other**	**Total**	**Losses and CU**	**% of Output**	**System Output**
1	2019	13,012	6,153	11,377	-	30,543	(323)	-1.1%	30,219
2	2020	11,184	5,271	10,362	-	26,817	891	3.3%	27,709
3	2021	13,251	6,173	12,904	-	32,329	231	0.7%	32,560
4	2022	14,917	7,503	13,077	-	35,497	514	1.4%	36,011
5	2023	12,437	6,588	13,394	-	32,420	572	1.8%	32,992

Notes:
1) Commercial includes Small General Service and Medium General Service
2) Industrial includes Large General Service and EUT volumes

Schedule A-1

Michigan Public Service Commission
Michigan Gas Utilities
Revenue Deficiency (Sufficiency)
Projected 12 Month Period Ending December 31, 2025

Case No.: U-21540
Exhibit No.: A-11
Schedule: A-1
Page: 1 of 1
Witness: Anthony Reese

	(a)	(b)	(c)
Line No.	**Description**	**Source**	**Total ($000)**
1			
2	Rate Base	Exh. A-12, Sch. B1	$ 509,067
3			
4	Adjusted Net Operating Income	Exh. A-13, Sch. C1	18,603
5			
6	Overall Rate of Return	Line 4 ÷ Line 2	3.65%
7			
8	Required Rate of Return	Exh. A-14, Sch. D1	6.22%
9			
10	Income Requirements	Line 2 x Line 8	31,655
11			
12	Income Deficiency (Sufficiency)	Line 10 - Line 4	13,051
13			
14	Revenue Conversion Factor	Exh. A-13, Sch. C2	1.347
15			
16	Revenue Deficiency (Sufficiency)	Line 12 x Line 14	$ 17,575

($000)

Schedule A-2

Michigan Public Service Commission
Michigan Gas Utilities
Ratios
Projected 12 Month Period Ending December 31, 2025

Line No.	[A] Description	[B] Projected 2025 No Rate Relief	[C] Projected 2025 Full Rate Relief
1	Operating Revenue	$ 181,912	$ 199,487
2	Operating Expense	(162,107)	(162,107)
3	Pre-Tax Operating Income	19,805	37,380
4	Income Taxes	(1,522)	(6,044)
5	Net Operating Income	18,283	31,337
6	Tax Impact of Pro-Forma Interest on NOI	-	-
7	AFUDC	318	318
8	Interest Charges	(10,921)	(10,930)
9	Preferred Stock Dividends	-	-
10	Net Income Available for Common and JDITC	7,680	20,725
11	Return Assignable to JDITC	-	-
12	Net Income Available for Common	7,680	20,725
13	Average Common Equity	202,137	202,137
14	Earned Rate of Return on Common Equity	3.80%	10.25%
15	Authorized / Requested Return on Common Equity	9.85%	10.25%
	EBIT Interest Coverage Ratio		
16	Pre-Tax Operating Income	$ 19,805	$ 37,380
17	AFUDC	318	318
18	Total EBIT	20,123	37,698
19	Interest Charges	10,921	10,930
20	EBIT Interest Coverage Ratio	1.84	3.45
	EBITDA Interest Coverage Ratio		
21	Total EBIT	$ 20,123	$ 37,698
22	Depreciation and Amortization	23,178	23,178
23	Total EBITDA	43,302	60,877
24	Interest Charges	10,921	10,930
25	EBITDA Interest Coverage Ratio	3.96	5.57
	Funds Flow from Operations (FFO) Interest Coverage Ratio		
26	Net Operating Income	$ 7,680	$ 20,725
27	Depreciation and Amortization	23,178	23,178
28	Deferred Income Tax	2,480	2,480
29	AFUDC	318	318
30	Other Major Recurring Non-Cash Items	-	-
31	Interest Paid	10,921	10,930
32	Less: Operating Lease Adjustment to Depreciation	-	-

($000)

Projected 12 Month Period Ending December 31, 2025

Page: 1 of 1
Witness: Anthony Reese

Line No.	[A] Description	[B] Projected 2025 No Rate Relief	[C] Projected 2025 Full Rate Relief
33	Subtotal	44,577	57,631
34	Interest Charges	10,921	10,930
35	FFO Interest Coverage Ratio	4.08	5.27
	Overall Fixed Charge Coverage Ratio		
36	Net Income Available for Common	$ 7,680	$ 20,725
37	Interest Charges	10,921	10,930
38	Subtotal Numerator	18,601	31,655
39	Interest Charges	10,921	10,930
40	Preferred Stock Dividends	-	-
41	Subtotal Denominator	10,921	10,930
42	Overall Fixed Charge Coverage Ratio	1.70	2.90
	Cash Flow Coverage of Dividends Ratio		
43	Net Income Available for Common	$ 7,680	$ 20,725
44	Depreciation and Amortization	23,178	23,178
45	Deferred Taxes	2,480	2,480
46	Subtotal	33,338	46,383
47	Common Dividends	-	3,142
48	Cash Flow Coverage of Dividend Ratio	-	0.07
	Common Dividend Payout Ratio		
49	Common Dividends	$ -	$ 3,142
50	Net Income Available for Common	7,680	20,725
51	Common Dividend Payout Ratio	0%	15%
	Permanent Capitalization		
52	Long-term Debt	$ 194,988	$ 194,988
53	Preferred Stock	-	-
54	Common Equity	202,137	202,137
55	Total Permanent Capital	397,125	397,125
56	Long-term Debt Ratio	49.1%	49.1%
57	Preferred Stock Ratio	0.0%	0.0%
58	Common Equity Ratio	50.9%	50.9%
59	Total Permanent Capital	100.0%	100.0%

Schedule B-1

Michigan Public Service Commission
Michigan Gas Utilities
Projected Rate Base
Projected 13 Month Average, December 31, 2025

Case No.: U-21540
Exhibit No.: A-12
Schedule: B-1
Page: 1 of 1
Witness: Anthony Reese

		(b)	(c)
Line No.	**Description**	**Source**	**Rate Base ($000)**
1			
2	Plant in Service	Exh. A-12, Sch. B2	735,320
3	Plant Held for Future Use	Exh. A-12, Sch. B2	-
4	Construction Work in Progress	Exh. A-12, Sch. B2	9,728
5	Total Utility Plant	Sum Lines 2-4	745,048
6			
7	Less: Depreciation Reserve	Exh. A-12, Sch. B3	292,061
8			
9	Net Utility Plant	Line 5 + Line 7	452,987
10			
11	Net Capital Lease Property		0
12			
13	Total Utility Property and Plant	Line 9 + Line 11	452,987
14			
15	Less: Capital Lease Obligations		0
16			
17	Net Plant	Line 13 + Line 15	452,987
18			
19	Allowance for Working Capital	Exh. A-12, Sch. B4	56,080
20			
21	Total Projected Test Period Rate Base	Line 17 + Line 19	$ 509,067

Schedule B-2

Michigan Public Service Commission	Case No.: U-21540
Michigan Gas Utilities	Exhibit No.: A-12
Total Utility Plant	Schedule: B-2
Projected 13 Month Average, December 31, 2025	Page: 1 of 1
	Witness: Anthony Reese

Line No.	(a) Description	(b) MPSC Account No.	Source	Projected Utility Plant ($000)
1				
2	Plant in Service	101		$ 732,187
3	Plant purchased or sold	102		
4	Experimental plant unclassified	103		
5	Plant leased to others	104		
6	Completed construction not classified	106		
7	Gas Stored Base Gas	117		$ 3,133
8	Plant in Service		Workpapers 2025 Page 1	$ 735,320
9				
10	Plant held for future use	105		
11				
12	Construction work in progress	107	Workpapers 2025 Page 1	$ 9,728
13				
14	Total Projected Period Utility Plant			$ 745,048

Schedule B-3

Michigan Public Service Commission
Michigan Gas Utilities
Depreciation Reserve and Other Deductions
Projected 13 Month Average, December 31, 2025

Case No.: U-21540
Exhibit No.: A-12
Schedule: B-3
Page: 1 of 1
Witness: Anthony Reese

	(a)		(b)
Line No.	**Description**	**Source**	**Projected Accumulated Provision for Depreciation ($000)**
1			
2	Total Projected Period Accumulated Provision for Depreciation	Workpapers 2025 Page 1	$ 292,061

Schedule B-4

Michigan Public Service Commission	Case No.: U-21540
Michigan Gas Utilities	Exhibit No.: A-12
Working Capital	Schedule: B-4
Projected 13 Month Average, December 31, 2025	Page: 1 of 1
	Witness: Anthony Reese

Line No.	(a) Description	Source	(b) Projected Working Capital ($000)
1		Workpapers 2025 Page 2	
2	Assets		
3	Utility Plant-ARO		(219)
4	Accumulated Depreciation-ARO		(838)
5	Other Investment and Special Funds		22,878
6	Cash & Cash Equivalents		(0)
7	Temporary Cash Investments		-
8	Customer A/R		26,590
9	Accumulated Provision Uncollectible Accounts		(2,388)
10	Accounts Receivable from Associated Companies		1,756
11	Prepayments		1,831
12	Gas Accrued Revenue		10,291
13	Gas Storage		20,181
14	Materials & Supplies		2,034
15	Derivative Assets		2,260
16	Other Current Assets		3,646
17	Other Long Term		798
18	Other Regulatory Assets		30,485
19			
20	Total Assets		$ 119,306
21			
22	Liabilities		
23	Accounts Payable		18,318
24	Accrued Payroll, Vacation, Taxes, & Interest		4,582
25	Accrued Taxes		4,551
26	Miscellaneous Current and Accrued Liabilities		14,401
27	Asset Retirement Obligation		1,083
28	Post Retirement OPEB and Pension Liability		1,480
29	Other Deferred Credits		14,533
30	Other Regulatory Liabilities		4,279
31			
32	Total Liabilities		$ 63,226
33			
34	Total Projected Working Capital		$ 56,080

Schedule B-5

Miscellaneous Utility
Case No. U-21540

Capital Expenditures Exhibit Index

	Title	Witness
hyperlinked	**Test Period Capital Expenditures**	
A-12 B5	Summary	
A-12 B5.1	Underground Gas Storage	
A-12 B5.2	Transmission	
A-12 B5.3	Distribution Plant	
A-12 B5.4	General	
A-12 B5.5	Intangible	

Schedule B-5

Michigan Public Service Commission
Michigan Gas Utilities
Summary of Actual and Projected Gas Capital Expenditures
for the years 2022 through December 2025
($000)

Case No.: U-21540
Exhibit No.: A-12
Schedule: B-5
Page: 1 of 1
Witness: Anthony Reese

(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Capital Expenditures									
					Projected Bridge Years			Projected Test Year			
Line No.	Description	Historical 12 mos. ended 12/31/2022	Histoical 9 mos. Ended 9/30/2023	3 mos. Ending 12/31/2023	12 mos. Ending 12/31/2023	12 mos. Ending 12/31/2023	15 mos. Ending 12/31/2024	12 mos. Ending 12/31/2025	Reference	Last Rate Case Approved Spending Plan U-21366 12 mos. Ended 12/31/2024 [1]	Actual Spending Test Year U-21366 12 mos. Ended 12/31/2024 [1]
1					*col. (c) + (d)*		*col. (d) + (F)*				
2											
3	Underground Gas Storage	937	2,490	2,979	5,470	2,472	5,451	567	Ex. A-12, Sch B5.1	xxxxx	xxxxx
4	Transmission	12,240	880	332	1,212	-	332	51	Ex. A-12, Sch B5.2	xxxxx	xxxxx
5	Distribution	27,643	22,271	8,084	30,355	51,973	60,057	40,576	Ex. A-12, Sch B5.3	xxxxx	xxxxx
6	General	3,037	1,718	2,406	4,124	3,657	6,063	11,906	Ex. A-12, Sch B5.4	xxxxx	xxxxx
7	Intangible	2,818	3,902	1,673	5,575	5,015	6,688	3,629	Ex. A-12, Sch B5.5	xxxxx	xxxxx
	Total Capital Expenditures	$ 46,675	$ 31,260	$ 15,475	$ 46,736	$ 63,116	$ 78,591	$ 56,730		$ -	$ -

[1] Note: The order issued for Case No. U-221366 approved a black box settlement agreement. The approved capital spending identified in the settlement agreement is unknown and inaccessible.

Schedule B-5.1

Michigan Public Service Commission	Case No.: U-21540
Michigan Gas Utilities Corporation	Exhibit No.: A-12
Underground Gas Storage Capital Expenditures	Schedule: B-5.1
for the years 2022 through December 2025	Page: 1 of 1
($000)	Witness: Anthony Reese

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Capital Expenditures						
			Projected Bridge Years					Projected Test Year
Line No.	Description	Historical 12 mos. ended 12/31/2022	Histoical 9 mos. Ended 9/30/2023	3 mos. Ending 12/31/2023	12 mos. Ending 12/31/2023	12 mos. Ending 12/31/2023	15 mos. Ending 12/31/2024	12 mos. Ending 12/31/2025
					col. (c) + (d)		*col. (d) + (F)*	
1	**Capital Expenditures**							
2	Underground Gas Storage							
3	MGU Gas MI 351, Natural Gas Underground Storage Structures and improvements	15	(1)	16	14	-	16	-
4	MGU Gas MI 352.4, Nat Gas Storage and Processing Plant - Wells-Wells	696	424	55	480	601	656	312
5	MGU Gas MI 354.2, NatGas Underground Storage Compressor station equipment	212	1,703	2,822	4,525	1,611	4,434	-
6	MGU Gas MI 355.2, Nat Underground Gas Storage Measuring and regulating Equip	14	364	86	450	260	346	255
7	Total Gas Storage	937	2,490	2,979	5,470	2,472	5,451	567

Schedule B-5.2

Michigan Public Service Commission
Michigan Gas Utilities
Transmission Capital Expenditures
for the years 2022 through December 2025
($000)

Case No.: U-21540
Exhibit No.: A-12
Schedule: B-5.2
Page: 1 of 1
Witness: Anthony Reese

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Capital Expenditures						
				Projected Bridge Years				Projected Test Year
Line No.	Description	Historical 12 mos. ended 12/31/2022	Histoical 9 mos. Ended 9/30/2023	3 mos. Ending 12/31/2023	12 mos. Ending 12/31/2023	12 mos. Ending 12/31/2024	15 mos. Ending 12/31/2024	12 mos. Ending 12/31/2025
					col. (c) + (d)		*col. (d) + (F)*	
1	Transmission							
2	MGU Gas MI 366.1, Gas Transmission Structures and improvements	-	1	-	1	-	-	-
3	MGU Gas MI 367.1, Gas Transmission Mains	11,286	799	332	1,131	-	332	1
4	MGU Gas MI 369.3, Gas Transmission Measuring & regulating equipment	954	81	-	81	-	-	50
5	Total Transmission	12,240	880	332	1,212	-	332	51

Schedule B-5.3

Michigan Public Service Commission
Michigan Gas Utilities
Distribution Plant Capital Expenditures
for the years 2022 through December 2025
($000)

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
					Projected Bridge Years	
Line No.	Description	Historical 12 mos. ended 12/31/2022	Histoical 9 mos. Ended 9/30/2023	3 mos. Ending 12/31/2023	12 mos. Ending 12/31/2023 *col. (c) + (d)*	12 mos. Ending 12/31/2024
1	Distribution Plant					
2	MGU Gas MI 376.1, Gas Distribution Mains-Gas Mains-Steel	1,431	2,137	1,225	3,362	8,201
3	MGU Gas MI 376.2, Gas Distribution Mains-Gas Mains-Plastic	11,167	5,570	1,468	7,038	7,200
4	MGU Gas MI 378, Gas Distribution Measuring & Reg equipment	1,536	1,068	805	1,873	700
5	MGU Gas MI 379, Gas Distribution City Gate Stations	50	2,186	-	2,186	-
6	MGU Gas MI 380.1, Gas Distribution Services-Gas Services-Steel	125	137	117	253	-
7	MGU Gas MI 380.2, Gas Distribution Services-Gas Services-Plastic	6,640	5,478	1,476	6,953	6,900
8	MGU Gas MI 381, Gas Distribution Meters	3,120	3,432	386	3,818	4,000
9	MGU Gas MI 381.2, Gas Distribution Meters-AMR Devices	2,327	569	550	1,119	4,895
10	MGU Gas MI 383, Gas Distribution House regulators	546	433	-	433	-
11	MGU Gas MI 385, Gas Distribution Industrial meas & regulating equp	36	13	24	37	100
12	MGU MI Gas Distribution - Main Replacement Rider (MRP)	665	1,249	2,034	3,283	19,977

Schedule B-5.4

Michigan Public Service Commission
Michigan Gas Utilities
General Capital Expenditures
for the years 2022 through December 2025
($000)

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
				Projected Bridge Years		
Line No.	Description	Historical 12 mos. ended 12/31/2022	Histoical 9 mos. Ended 9/30/2023	3 mos. Ending 12/31/2023	12 mos. Ending 12/31/2023 *col. (c) + (d)*	12 mos. Ending 12/31/2024
1	General					
2	MGU Gas MI 390, Gas General Structures and improvements	824	273	912	1,185	1,034
3	MGU Gas MI 391.1 Office Furniture and Equip	44	0	-	0	-
4	MGU Gas MI 391.2 Computer Equipment	191	71	291	362	340
5	MGU Gas MI 391.2 Server/Network Equipment	712	495	316	811	557
6	MGU Gas MI 392.1, Gas General Transportation equipment-Trans Equip	600	343	849	1,191	1,200
7	MGU Gas MI 392.2, Gas General Transportation Equipment-Trailers	43	-	-	-	-
8	MGU Gas MI 392.2, Gas General Transportation Equipment-Trailers Wheel Mounted Pw	157	2	-	2	-
9	MGU Gas MI 394, Gas General Tools, shop and garage equipment	218	443	39	482	415
10	MGU Gas MI 396, Gas General Power operated equipment	251	75	-	75	-
11	MGU Gas MI 397.1, Gas General Communication equipment-Comm Equip	(4)	16	-	16	111
12	Total General	3,037	1,718	2,406	4,124	3,657

Schedule B-5.5

Michigan Public Service Commission
Michigan Gas Utilities
Intangible Capital Expenditures
for the years 2022 through December 2025
($000)

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
					Projected Bridge Years	
Line No.	Description	Historical 12 mos. ended 12/31/2022	Histoical 9 mos. Ended 9/30/2023	3 mos. Ending 12/31/2023	12 mos. Ending 12/31/2023 *col. (c) + (d)*	12 mos. Ending 12/31/2024
1	Intangible					
2	MGU Gas MI Software 303 - 10 year	344	865	412	1,277	1,857
3	MGU Gas MI Software 303 - 15 year	294	615	634	1,250	1,379
4	MGU Gas MI Software 303 - 3 Year	97	87	-	87	92
5	MGU Gas MI Software 303 - 5 year	1,889	2,334	627	2,961	1,686
6	MGU Gas MI Software 303 - 6 Year	193	(0)	-	(0)	-
7	Total Intangible	2,818	3,902	1,673	5,575	5,015

Schedule C-1

Michigan Public Service Commission	Case No.: U-21540
Michigan Gas Utilities	Exhibit No.: A-13
Adjusted Net Operating Income	Schedule: C-1
Projected 12 Month Period Ending December 31, 2025	Page: 1 of 1
	Witness: Anthony Reese

	(a)		(b)
Line No.	**Description**	**Source**	**Net Operating Income ($000)**
1			
2	**Operating Revenues**	Exh. A-13, Sch. C3	$ 181,912
3			
4	**Operating Expenses**		
5	Cost of Gas	Exh. A-13, Sch. C4	85,020
6	Operations and Maintenance Expenses	Exh. A-13, Sch. C5	41,270
7	Depreciation and Amortization	Exh. A-13, Sch. C6	23,178
8	Regulatory Items, Debits and Credits		1,170
9	General Taxes	Exh. A-13, Sch. C7	11,468
10	Income Taxes	Exh. A-13, Sch. C8 & C9	1,520
11	Total Operating Expenses		$ 163,627
12			
13	**Operating Income**		$ 18,285
14			
15	**Operating Income Adjustments**		
16	Allowance For Funds Used During Construction	Exh. A-13, Sch. C11	318.06
17	Loss on Reacquired Securities		
18	Income Tax Effect of Interest		
19	Interest Synchronization Adjustment		
20	Total Operating Income Adjustments		$ 318
21			
22	**Adjusted Net Operating Income**		$ 18,603

Schedule C-2

	(a)	(b)	(c)
Line No.	**Description**	**Calc. Logic/Source**	**Amount**
1			
2	Income Before Income Taxes		100.00%
3			
4	Michigan Corporate Income Tax Rate		6.00%
5			
6	Federal Income Tax Base	Ln 2 - Ln 4	94.00%
7			
8	Times Federal Income Tax Rate		21.00%
9			
10	Federal Income Tax	Ln 6 x Ln 8	19.74%
11			
12	Income After Taxes	Ln 6 - Ln 10	74.26%
13			
14	Gross Revenue Conversion Factor	Ln 2 / Ln 12	1.347

Schedule C-3

Michigan Public Service Commission	Case No.: U-21540
Michigan Gas Utilities	Exhibit No.: A-13
Projected Operating Revenue	Schedule No.: C-3
Projected 12 Month Period Ending December 31, 2025	Page: 1 of 1
	Witness: Anthony Reese

Line No.	(a) Description	(b) Source	(c) Projected Sales Revenue ($000)
1			
2	Sales Revenue	Workpapers 2025 Page 4	$ 180,399
3			
4	Energy Optimization Revenue		$ 0
5			
6	Other Revenues	Workpapers 2025 Page 4	$ 1,513
7			
8	Total Revenue		$ 181,912

Schedule C-4

Michigan Public Service Commission
Michigan Gas Utilities
Cost of Gas Sold
Projected 12 Month Period Ending December 31, 2025

Case No.: U-21540
Exhibit No.: A-13
Schedule No.: C-4
Page: 1 of 1
Witness: Anthony Reese

	(a)	(b)	(c)
Line No.	**Description**	**Source**	**Cost of Gas ($000)**
1			
2	**Cost of Gas:**		
3	Energy	Workpapers 2025 Page 4	$ 85,020
4	Dem-Peak Day (D-1)		-
5	Other COG		-
6			
7	Total Cost of Gas		$ 85,020

Schedule C5

Michigan Public Service Commission	Case No.: U-21540
Michigan Gas Utilities	Exhibit No.: A-3
Projected Operation and Maintenance Expenses	Schedule No.: C5
Projected 12 Month Period Ending December 31, 2025	Page: 1 of 1
	Witness: Anthony Reese

	(a)	(b)	(c)
Line No.	Description	Source	Projected 2023 Operation and Maintenance Expenses ($000)
1			
2	**Production - Other:**		
3	Energy		-
4	Dem-Peak Day (D-1)		-
5	Other Production		-
6	Manufacture Gas Production	Exhibit A-17 Schedule C1	681
7	Gas Supply	Exhibit A-17 Schedule C1	306
8	Other COG		-
9			
10	**Total Production-Other**		$ 987
11			
12	**Operation and Maintenance Expenses:**		
13	Transmission	Exhibit A-17 Schedule C1	1,130
14	Distribution	Exhibit A-17 Schedule C1	15,372
15	Storage	Exhibit A-17 Schedule C1	734
16	Customer Accounts	Exhibit A-17 Schedule C1	8,342
17	Customer Service	Exhibit A-17 Schedule C1	520
18	Administration & General	Exhibit A-17 Schedule C1	14,186
19	Sales	Exhibit A-17 Schedule C1	-
20			
21	**Total Operation and Maintenance Expenses**		$ 40,283
22			
23	Total Production-Other and Operation & Maintenance Expenses		$ 41,270

Schedule C-6

Michigan Public Service Commission
Michigan Gas Utilities
Projected Depreciation and Amortization Expenses
Projected 12 Month Period Ending December 31, 2025

Case No.: U-21540
Exhibit No.: A-13
Schedule No.: C-6
Page: 1 of 1
Witness: Anthony Reese

	(a)	(b)	(c)
Line No.	**Description**	**Source**	**Projected Depreciation & Amortization Expense ($000)**
1			
2	**Depreciation and Amortization Expense**		
3	Depreciation Expense	Workpapers 2025 Page 5	$ 23,178
4	Amortization Expense		-
5			
6	Total Depreciation and Amortization Expense		$ 23,178

Schedule C-7

Michigan Public Service Commission
Michigan Gas Utilities
Projected General Taxes
Projected 12 Month Period Ending December 31, 2025

Case No.: U-21540
Exhibit No.: A-13
Schedule No.: C-7
Page: 1 of 1
Witness: Anthony Reese

Line No.	(a) Description	(b) Source	(c) Projected General Taxes ($000)
1			
2	FEDERAL		
3	Payroll Taxes	Workpapers 2025 Page 6	$ 1,269
4	Unemployment Comp		-
5	PR Taxes Credited		-
6	Super Fund Tax		-
7	Highway Use Tax		-
8	Federal Excise Tax		-
9			
10	STATE		
11	Gross Receipts Tax		$ -
12	Unemployment Comp		-
13	Remain. Assessment		-
14	Use Tax		-
15	Unauthor Ins Tax	Workpapers 2025 Page 6	$ 28
16	Wis Recycling Fee		-
17	Single Business Tax		-
18	Property	Workpapers 2025 Page 6	$ 10,171
19			
20	LOCAL		
21	Real Est & Property		$ -
22			
23	WBS		
24	WBS Payroll Tax		$ -
25			
26	OTHER		
27	Franchise Tax Fees		$ -
28	State Unitary Fees		-
29			
30	Total General Taxes		$ 11,468

Schedule C-8

Michigan Public Service Commission	Case No.:	U-21540
Michigan Gas Utilities	Exhibit No.:	A-13
Projected Federal Income Taxes	Schedule No.:	C-8
Projected 12 Month Period Ending December 31, 2025	Page:	1 of 1
	Witness:	Anthony Reese

	(a)	(b)	(c)
Line No.	**Description**	**Source**	**Projected Federal Income Taxes ($000)**
1			
2	Federal Income Taxes	Workpapers 2025 Page 7	$ 1,170

Schedule C-9

Michigan Public Service Commission	Case No.: U-21540
Michigan Gas Utilities	Exhibit No.: A-13
Projected State Income Taxes	Schedule No.: C-9
Projected 12 Month Period Ending December 31, 2025	Page: 1 of 1
	Witness: Anthony Reese

Line No.	(a) **Description**	(b) **Source**	(c) **Projected State Income Taxes ($000)**
1			
2	State Income Taxes	Workpapers 2025 Page 7	$ 350

Schedule C10

Michigan Public Service Commission	Case No.: U-21540
Michigan Gas Utilities	Exhibit No.: A-13
Other (or Local) Taxes	Schedule No.: C10
Projected 12 Month Period Ending December 31, 2025	Page: 1 of 1
	Witness: Anthony Reese

	(a)	(b)	(c)
Line No.	**Description**	**Source**	**TOTAL**
1			
2	None		

Schedule C11

Michigan Public Service Commission
Michigan Gas Utilities
Allowance for Funds Used During Construction
Projected 12 Month Period Ending December 31, 2025

Case No.: U-21540
Exhibit No.: A-13
Schedule No.: C11
Page: 1 of 1
Witness: Anthony Reese

	(a)	(b)	(c)
Line No.	**Description**	**Source**	**TOTAL**
1			
2	AFUDC Debt		$ 81
3	AFUDC Equity		$ 237
4			
5	Total AFUDC		$ 318

Schedule D-1

Michigan Public Service Commission
Michigan Gas Utilities
Projected Rate of Return Summary
Projected 13 Month Average, December 31, 2025

Case No.: U-21540
Exhibit No.: A-14
Schedule: D-1
Page: 1 of 1
Witness: Anthony Reese

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)	(i)
		Capital Structure					Weighted Cost			
Line No.	Description	Amount ($000) (1)	Percent Permanent Capital (2)	Percent of Total Capital	Cost Rate %		Permanent Capital (2)	Total Cost %	Conversion Factor	Pre-Tax Return
1										
2	Long-Term Debt	**$ 194,988**	49.10%	38.31%	**4.91%**	(3)	2.41%	1.88%		1.88%
3										
4	Preferred Stock	$ -	0.00%	0.00%	0.00%	(4)	0.00%	0.00%		0.00%
5										
6	Common Shareholders' Equity	**$ 202,137**	50.90%	39.72%	**10.25%**	(5)	5.22%	4.07%	1.347	5.48%
7										
8	Total Permanent Capital	$ 397,125	100.00%				7.63%			
9										
10	Short-Term Debt	**$ 29,695**		5.83485%	**4.56%**	(6)		0.27%		0.27%
11										
12	Job Development - ITC - Debt									
13	Job Development - ITC Equity									
14	Total Job Development - ITC	$ -		0.00%	7.63%					
15										
16	Deferred Income Taxes (Net) - Federal	**$ 82,102**		16.13%	0.00%			0.00%		0.00%
17										
18	Deferred Tax Proration	$ 0		0.00%	7.41%			0.00%		0.00%
19										
20	Capital Structure Adjustments	**$ 0**		0.00%	0.00%			0		0.00%
21										
22	Total	$ 508,922		100.00%				6.22%		7.63%
	Memo Only:									
	DITC	$ -								
	Liabilities & Equity	$ 508,922								

(1) See Exh. A-12, Sch. B1
(2) Excludes Short-Term Debt, Deferred Job Development Investment Tax Credit, Deferred Investment Tax Credit and Deferred Income Taxes to calculate the rate of return for Job Development Investment Tax Credit purposes in accordance with Internal Revenue Service Income Tax Regulation Section 1.46-6
(3) See Exh. A-14, Sch. D2
(4) Exh. A-14, Sch. D4 is not provided; MGU does not have preferred stock
(5) See Exh. A-14, Sch. D5
(6) See Exh. A-14, Sch. D3

Schedule D-2

Michigan Public Service Commission
Michigan Gas Utilities
Cost of Long-Term Debt
Projected 13 Month Average, December 31, 2025

Case No.: U-21540
Exhibit No.: A-14
Schedule: D-2
Page: 1 of 1
Witness: Anthony Reese

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Line No.	Description	Original Issue Date	Stated Maturity Date	Interest Rate (%)	Amount of Offering ($000)	Price to Public (%)	Underwriting & Financing Expenses (%)	Net Proceeds to the Company (%)	Cost Based on Net Proceeds (%)	Amount Outstanding ($000)	Annual Cost ($000)
1											
2	**Mortgage Bonds**										
3	Total Mortgage Bonds									$ -	
4											
5	**Other Long-Term Debt**										
6		June 27, 2017	July 15, 2027	3.11%	30,000	100%	-	100%	3.11%	30,000	933
7		June 27, 2017	July 15, 2032	3.41%	30,000	100%	-	100%	3.41%	30,000	1,023
8		June 27, 2017	July 15, 2047	4.01%	30,000	100%	-	100%	4.01%	30,000	1,203
9		April 2020	May 1, 2025	2.69%	60,000	100%	-	100%	2.69%	23,077	542
10		August 2024	August 2054	6.65%	40,000	100%	-	100%	6.65%	40,000	2,660
		May 2025	May 2055	6.65%	70,000	100%		100%	6.65%	43,077	3,103
11											
12	Total Other Long-Term Debt									$ 196,154	$ 9,465
13											
14	Total Long-Term Debt									$ 196,154	
15											
16	Unamortized Debt Discount, Premium, and Expense									(1,165)	107
17											
18	Total Long-Term Debt Balance									$ 194,988	$ 9,572
19											
20	Cost of Long-Term Debt										4.91%

Schedule D-3

Michigan Public Service Commission
Michigan Gas Utilities
Cost of Short-Term Debt
Projected 13 Month Average, December 31, 2025

Case No.: U-21540
Exhibit No.: A-14
Schedule: D-3
Page: 1 of 1
Witness: Anthony Reese

	(a)	(b)	(c)
Line No.	**Month**	**Projected Balance Outstanding ($000)**	**Total Cost ($000)**
1			
2	Inter-Company Loans		
3	Dec	$ 33,281	
4	Jan	40,107	$ 138
5	Feb	34,356	$ 140
6	Mar	31,438	$ 123
7	Apr	17,482	$ 87
8	May	2,444	$ 35
9	Jun	8,113	$ 19
10	Jul	29,799	$ 63
11	Aug	25,833	$ 93
12	Sep	34,160	$ 100
13	Oct	45,265	$ 124
14	Nov	48,120	$ 146
15	Dec	35,636	$ 131
16	13 month Average	$ 29,695	$ 1,198
17			
18	Credit Facility Fees and Amortization	-	120
19			
20	Guarantee Fees	-	20
21			
22	Other	-	18
23			
24	Total	$ 29,695	$ 1,355
25			
26	Average Cost of Short-Term Debt		4.56%

Schedule D4

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Cost of Preferred Stock
Projected 13 Month Average, December 31, 2025

Case No.: U-21540
Exhibit No.: A-14
Schedule: D-4
Page: 1 of 1
Witness: Anthony Reese

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Description	Annual Dividend Required	Par Value	Discount or Premium	Finance Expenses	Net Proceeds Received	Number of Shares Outstanding	Total Value of Outstanding Proceeds	Cost Rate (%)	Annual Dollar Amount
1										
2	None									

Michigan Public Service Commission
Michigan Gas Utilities
Cost of Common Shareholders' Equity
Projected 13 Month Average, December 31, 2025

Case No.: U-21540
Exhibit No.: A-14
Schedule: D-5
Page: 1 of 1
Witness: Anthony Reese

Line No.		Adjusted Common Stock ($000)	
1			
2	Dec	193,794	
3	Jan	197,287	
4	Feb	204,508	
5	Mar	209,561	
6	Apr	211,070	
7	May	209,352	
8	Jun	205,807	
9	Jul	202,011	
10	Aug	198,180	
11	Sep	195,121	
12	Oct	194,478	
13	Nov	197,548	
14	Dec	209,061	
15			
16	Average	$202,137	10.25%

SUMMARY OF RESULTS

Constant Growth DCF			
	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.79%	10.71%	11.92%
90-Day Avg. Stock Price	9.87%	10.78%	11.99%
180-Day Avg. Stock Price	9.70%	10.62%	11.83%
Average	9.79%	10.70%	11.91%
Median Results:			
30-Day Avg. Stock Price	9.90%	10.17%	11.76%
90-Day Avg. Stock Price	9.98%	10.25%	11.85%
180-Day Avg. Stock Price	9.93%	10.20%	11.64%
Average	9.94%	10.21%	11.75%

CAPM / ECAPM / Bond Yield Risk Premium			
	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.09%	11.08%	11.08%
Current Bloomberg Beta	10.31%	10.29%	10.29%
Long-term Avg. *Value Line* Beta	10.12%	10.10%	10.10%
ECAPM:			
Current *Value Line* Beta	11.38%	11.37%	11.37%
Current Bloomberg Beta	10.79%	10.77%	10.77%
Long-term Avg. *Value Line* Beta	10.64%	10.63%	10.63%
Bond Yield Risk Premium:	10.30%	10.25%	10.25%

PROXY GROUP SCREENING DATA AND RESULTS - FINAL PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
Company	Ticker	Dividends	S&P or Moody's Investment Grade Credit Rating	Covered by More Than 1 Analyst	Positive Growth Rates from at least two sources (Value Line, Yahoo! First Call, and Zacks)	% Regulated Operating Income > 70%	% Regulated Natural Gas Operating Income > 60%	Announced Merger
Atmos Energy Corporation	ATO	Yes	A-	Yes	Yes	100.00%	66.03%	No
NiSource Inc.	NI	Yes	BBB+	Yes	Yes	100.00%	65.58%	No
Northwest Natural Gas Company	NWN	Yes	A+	Yes	Yes	99.84%	91.01%	No
ONE Gas, Inc.	OGS	Yes	A-	Yes	Yes	100.00%	100.00%	No
Spire, Inc.	SR	Yes	A-	Yes	Yes	86.84%	100.00%	No

Notes:
[1] Bloomberg Professional
[2] Bloomberg Professional
[3] Yahoo! Finance, Value Line Investment Survey, and Zacks
[4]-[5]: Form 10-K's for 2022, 2020, and 2021
[6] S&P Capital IQ news releases

30-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Yahoo! Finance Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	$3.22	$115.04	2.80%	2.90%	7.00%	7.50%	7.30%	7.27%	9.90%	10.17%	10.40%
NiSource Inc.	NI	$1.00	$26.31	3.80%	3.96%	9.50%	8.30%	7.20%	8.33%	11.14%	12.29%	13.48%
Northwest Natural Gas Company	NWN	$1.95	$38.25	5.10%	5.21%	6.50%	2.80%	3.70%	4.33%	7.97%	9.54%	11.76%
ONE Gas, Inc.	OGS	$2.60	$62.39	4.17%	4.28%	6.50%	5.00%	5.00%	5.50%	9.27%	9.78%	10.80%
Spire, Inc.	SR	$3.02	$61.03	4.95%	5.11%	8.00%	6.36%	5.60%	6.65%	10.69%	11.77%	13.15%
Mean										9.79%	10.71%	11.92%
Median										9.90%	10.17%	11.76%

Notes:
[1] Bloomberg Professional as of January 31 2024
[2] Bloomberg Professional 30-day average as of January 31, 2024
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

90-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Yahoo! Finance Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	$3.22	$111.87	2.88%	2.98%	7.00%	7.50%	7.30%	7.27%	9.98%	10.25%	10.49%
NiSource Inc.	NI	$1.00	$25.76	3.88%	4.04%	9.50%	8.30%	7.20%	8.33%	11.22%	12.38%	13.57%
Northwest Natural Gas Company	NWN	$1.95	$37.60	5.19%	5.30%	6.50%	2.80%	3.70%	4.33%	8.06%	9.63%	11.85%
ONE Gas, Inc.	OGS	$2.60	$63.04	4.12%	4.24%	6.50%	5.00%	5.00%	5.50%	9.23%	9.74%	10.76%
Spire, Inc.	SR	$3.02	$59.22	5.10%	5.27%	8.00%	6.36%	5.60%	6.65%	10.84%	11.92%	13.30%
Mean										9.87%	10.78%	11.99%
Median										9.98%	10.25%	11.85%

Notes:
[1] Bloomberg Professional as of January 31 2024
[2] Bloomberg Professional 90-day average as of January 31, 2024
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

180-DAY CONSTANT GROWTH DCF

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Projected EPS Growth Rate	[6] Yahoo! Finance Projected EPS Growth Rate	[7] Zacks Projected EPS Growth Rate	[8] Average Projected EPS Growth Rate	[9] Cost of Equity: Minimum Growth Rate	[10] Cost of Equity: Mean Growth Rate	[11] Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	$3.22	$113.76	2.83%	2.93%	7.00%	7.50%	7.30%	7.27%	9.93%	10.20%	10.44%
NiSource Inc.	NI	$1.00	$26.27	3.81%	3.97%	9.50%	8.30%	7.20%	8.33%	11.14%	12.30%	13.49%
Northwest Natural Gas Company	NWN	$1.95	$39.17	4.98%	5.09%	6.50%	2.80%	3.70%	4.33%	7.85%	9.42%	11.64%
ONE Gas, Inc.	OGS	$2.60	$69.55	3.74%	3.84%	6.50%	5.00%	5.00%	5.50%	8.83%	9.34%	10.36%
Spire, Inc.	SR	$3.02	$60.12	5.02%	5.19%	8.00%	6.36%	5.60%	6.65%	10.76%	11.84%	13.22%
Mean										9.70%	10.62%	11.83%
Median										9.93%	10.20%	11.64%

Notes:
[1] Bloomberg Professional as of January 31 2024
[2] Bloomberg Professional 180-day average as of January 31, 2024
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	4.19%	0.85	12.22%	8.03%	11.01%	11.32%
NiSource Inc.	NI	4.19%	0.90	12.22%	8.03%	11.42%	11.62%
Northwest Natural Gas Company	NWN	4.19%	0.85	12.22%	8.03%	11.01%	11.32%
ONE Gas, Inc.	OGS	4.19%	0.85	12.22%	8.03%	11.01%	11.32%
Spire, Inc.	SR	4.19%	0.85	12.22%	8.03%	11.01%	11.32%
Mean						11.09%	11.38%
Median						11.01%	11.32%

Notes:
[1] Bloomberg Professional 30-day average as of January 31, 2024
[2] Value Line
[3] MGUC Schedule D11
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q1 2024 - Q2 2025)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	4.10%	0.85	12.22%	8.12%	11.00%	11.31%
NiSource Inc.	NI	4.10%	0.90	12.22%	8.12%	11.41%	11.61%
Northwest Natural Gas Company	NWN	4.10%	0.85	12.22%	8.12%	11.00%	11.31%
ONE Gas, Inc.	OGS	4.10%	0.85	12.22%	8.12%	11.00%	11.31%
Spire, Inc.	SR	4.10%	0.85	12.22%	8.12%	11.00%	11.31%
Mean						11.08%	11.37%
Median						11.00%	11.31%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 43, No. 2, February 1, 2024, at 2
[2] Value Line
[3] MGUC Schedule D11
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA

K = Rf + β (Rm − Rf)
K = Rf + 0.25 x (Rm - Rf) + 0.75 x β x (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2025 - 2029)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	4.10%	0.85	12.22%	8.12%	11.00%	11.31%
NiSource Inc.	NI	4.10%	0.90	12.22%	8.12%	11.41%	11.61%
Northwest Natural Gas Company	NWN	4.10%	0.85	12.22%	8.12%	11.00%	11.31%
ONE Gas, Inc.	OGS	4.10%	0.85	12.22%	8.12%	11.00%	11.31%
Spire, Inc.	SR	4.10%	0.85	12.22%	8.12%	11.00%	11.31%
Mean						11.08%	11.37%
Median						11.00%	11.31%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023, at 14
[2] Value Line
[3] MGUC Schedule D11
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND BLOOMBERG BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	4.19%	0.75	12.22%	8.03%	10.23%	10.72%
NiSource Inc.	NI	4.19%	0.81	12.22%	8.03%	10.66%	11.05%
Northwest Natural Gas Company	NWN	4.19%	0.70	12.22%	8.03%	9.83%	10.42%
ONE Gas, Inc.	OGS	4.19%	0.78	12.22%	8.03%	10.47%	10.91%
Spire, Inc.	SR	4.19%	0.77	12.22%	8.03%	10.37%	10.83%
Mean						10.31%	10.79%
Median						10.37%	10.83%

Notes:
[1] Bloomberg Professional 30-day average as of January 31, 2024
[2] Bloomberg Professional
[3] MGUC Schedule D11
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR TERM PROJECTED RISK-FREE RATE AND BLOOMBERG BETA

$$K = Rf + \beta\,(Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q1 2024 - Q2 2025)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	4.10%	0.75	12.22%	8.12%	10.21%	10.71%
NiSource Inc.	NI	4.10%	0.81	12.22%	8.12%	10.65%	11.04%
Northwest Natural Gas Company	NWN	4.10%	0.70	12.22%	8.12%	9.80%	10.40%
ONE Gas, Inc.	OGS	4.10%	0.78	12.22%	8.12%	10.45%	10.90%
Spire, Inc.	SR	4.10%	0.77	12.22%	8.12%	10.35%	10.82%
Mean						10.29%	10.77%
Median						10.35%	10.82%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 43, No. 2, February 1, 2024, at 2
[2] Bloomberg Professional
[3] MGUC Schedule D11
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK-FREE RATE AND BLOOMBERG BETA

$$K = Rf + \beta\,(Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2025 - 2029)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	4.10%	0.75	12.22%	8.12%	10.21%	10.71%
NiSource Inc.	NI	4.10%	0.81	12.22%	8.12%	10.65%	11.04%
Northwest Natural Gas Company	NWN	4.10%	0.70	12.22%	8.12%	9.80%	10.40%
ONE Gas, Inc.	OGS	4.10%	0.78	12.22%	8.12%	10.45%	10.90%
Spire, Inc.	SR	4.10%	0.77	12.22%	8.12%	10.35%	10.82%
Mean						10.29%	10.77%
Median						10.35%	10.82%

Notes:

[1] Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023, at 14
[2] Bloomberg Professional
[3] MGUC Schedule D11
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND LONG-TERM VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	4.19%	0.75	12.22%	8.03%	10.21%	10.71%
NiSource Inc.	NI	4.19%	0.76	12.22%	8.03%	10.26%	10.75%
Northwest Natural Gas Company	NWN	4.19%	0.71	12.22%	8.03%	9.88%	10.47%
ONE Gas, Inc.	OGS	4.19%	0.74	12.22%	8.03%	10.11%	10.64%
Spire, Inc.	SR	4.19%	0.74	12.22%	8.03%	10.14%	10.66%
Mean						10.12%	10.64%
Median						10.14%	10.66%

Notes:
[1] Bloomberg Professional 30-day average as of January 31, 2024
[2] MGUC Schedule D10
[3] MGUC Schedule D11
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q1 2024 - Q2 2025)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	4.10%	0.75	12.22%	8.12%	10.19%	10.70%
NiSource Inc.	NI	4.10%	0.76	12.22%	8.12%	10.23%	10.73%
Northwest Natural Gas Company	NWN	4.10%	0.71	12.22%	8.12%	9.86%	10.45%
ONE Gas, Inc.	OGS	4.10%	0.74	12.22%	8.12%	10.09%	10.62%
Spire, Inc.	SR	4.10%	0.74	12.22%	8.12%	10.12%	10.64%
Mean						10.10%	10.63%
Median						10.12%	10.64%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 43, No. 2, February 1, 2024, at 2
[2] MGUC Schedule D10
[3] MGUC Schedule D11
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA

$$K = Rf + \beta (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2025 - 2029)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] CAPM ROE (K)	[6] ECAPM ROE (K)
Atmos Energy Corporation	ATO	4.10%	0.75	12.22%	8.12%	10.19%	10.70%
NiSource Inc.	NI	4.10%	0.76	12.22%	8.12%	10.23%	10.73%
Northwest Natural Gas Company	NWN	4.10%	0.71	12.22%	8.12%	9.86%	10.45%
ONE Gas, Inc.	OGS	4.10%	0.74	12.22%	8.12%	10.09%	10.62%
Spire, Inc.	SR	4.10%	0.74	12.22%	8.12%	10.12%	10.64%
Mean						10.10%	10.63%
Median						10.12%	10.64%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023, at 14
[2] MGUC Schedule D10
[3] MGUC Schedule D11
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

HISTORICAL VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021	12/31/2022	12/31/2023	Average
Atmos Energy Corporation	ATO	0.80	0.80	0.80	0.70	0.70	0.60	0.60	0.80	0.80	0.80	0.85	0.75
NiSource Inc.	NI	0.85	0.85	NMF	NMF	0.60	0.50	0.55	0.85	0.85	0.85	0.90	0.76
Northwest Natural Gas Company	NWN	0.65	0.7	0.65	0.65	0.70	0.60	0.60	0.80	0.85	0.80	0.80	0.71
ONE Gas, Inc.	OGS	NA	NA	NA	0.70	0.70	0.65	0.65	0.80	0.80	0.80	0.80	0.74
Spire, Inc.	SR	0.65	0.7	0.7	0.70	0.70	0.65	0.65	0.85	0.85	0.85	0.85	0.74
Mean		0.74	0.76	0.72	0.69	0.68	0.60	0.61	0.82	0.83	0.82	0.84	0.74

Notes:
[1] Value Line, dated December 26, 2013.
[2] Value Line, dated December 31, 2014.
[3] Value Line, dated December 30, 2015.
[4] Value Line, dated December 29, 2016.
[5] Value Line, dated December 28, 2017.
[6] Value Line, dated December 27, 2018.
[7] Value Line, dated December 26, 2019.
[8] Value Line, dated December 30, 2020.
[9] Value Line, dated December 29, 2021.
[10] Value Line, dated December 30, 2022.
[11] Value Line, Dated December 29, 2023.
[12] Average ([1] - [11]).

MARKET RISK PREMIUM DERIVED FROM S&P 500 INDEX

[1] Estimate of the S&P 500 Dividend Yield	1.63%
[2] Estimate of the S&P 500 Growth Rate	10.51%
[3] S&P 500 Estimated Required Market Return	12.22%

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Bloomberg Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
LyondellBasell Industries NV	LYB	324.36	94.12	30,528.95	0.10%	5.31%	0.01%	8.00%	0.01%
American Express Co	AXP	723.00	200.74	145,135.02	0.46%	1.20%	0.01%	14.17%	0.06%
Verizon Communications Inc	VZ	4,204.00	42.35	178,039.40		6.28%		-4.10%	
Broadcom Inc	AVGO	468.14	1,180.00	552,406.38	1.75%	1.78%	0.03%	13.90%	0.24%
Boeing Co/The	BA	610.14	211.04	128,762.89					
Caterpillar Inc	CAT	509.09	300.31	152,883.32	0.48%	1.73%	0.01%	20.00%	0.10%
JPMorgan Chase & Co	JPM	2,891.01	174.36	504,076.15	1.59%	2.41%	0.04%	2.00%	0.03%
Chevron Corp	CVX	1,887.75	147.43	278,310.84	0.88%	4.10%	0.04%	7.27%	0.06%
Coca-Cola Co/The	KO	4,323.41	59.49	257,199.90	0.81%	3.09%	0.03%	6.58%	0.05%
AbbVie Inc	ABBV	1,765.54	164.40	290,254.28	0.92%	3.77%	0.03%	9.09%	0.08%
Walt Disney Co/The	DIS	1,830.32	96.05	175,801.85	0.56%	0.62%	0.00%	18.88%	0.10%
FleetCor Technologies Inc	FLT	72.20	289.93	20,934.11	0.07%			12.79%	0.01%
Extra Space Storage Inc	EXR	211.28	144.44	30,516.99	0.10%	4.49%	0.00%	1.20%	0.00%
Exxon Mobil Corp	XOM	4,006.13	102.81	411,870.53	1.30%	3.70%	0.05%	13.21%	0.17%
Phillips 66	PSX	439.96	144.31	63,490.05		2.91%		-7.56%	
General Electric Co	GE	1,088.39	132.42	144,124.07	0.46%	0.24%	0.00%	7.00%	0.03%
HP Inc	HPQ	990.90	28.71	28,448.80	0.09%	3.84%	0.00%	3.00%	0.00%
Home Depot Inc/The	HD	995.26	352.96	351,287.68	1.11%	2.37%	0.03%	1.82%	0.02%
Monolithic Power Systems Inc	MPWR	47.91	602.72	28,877.52	0.09%	0.66%	0.00%	8.00%	0.01%
International Business Machines Corp	IBM	913.12	183.66	167,703.44	0.53%	3.62%	0.02%	5.14%	0.03%
Johnson & Johnson	JNJ	2,407.28	158.90	382,516.63	1.21%	3.00%	0.04%	3.76%	0.05%
Lululemon Athletica Inc	LULU	121.08	453.82	54,946.26	0.17%			17.00%	0.03%
McDonald's Corp	MCD	725.34	292.72	212,322.11	0.67%	2.28%	0.02%	9.53%	0.06%
Merck & Co Inc	MRK	2,534.02	120.78	306,059.30	0.97%	2.55%	0.02%	17.33%	0.17%
3M Co	MMM	552.32	94.35	52,111.11	0.16%	6.36%	0.01%	5.50%	0.01%
American Water Works Co Inc	AWK	194.71	124.02	24,147.31	0.08%	2.28%	0.00%	7.76%	0.01%
Bank of America Corp	BAC	7,895.50	34.01	268,525.96		2.82%		-7.00%	
Pfizer Inc	PFE	5,646.41	27.08	152,904.86		6.20%		33.35%	
Procter & Gamble Co/The	PG	2,353.02	157.14	369,753.72	1.17%	2.39%	0.03%	7.56%	0.09%
AT&T Inc	T	7,150.00	17.69	126,483.50		6.27%		-4.61%	
Travelers Cos Inc/The	TRV	228.20	211.36	48,232.35	0.15%	1.89%	0.00%	19.03%	0.03%
RTX Corp	RTX	1,437.90	91.12	131,021.54	0.41%	2.59%	0.01%	10.14%	0.04%
Analog Devices Inc	ADI	495.84	192.36	95,379.78	0.30%	1.79%	0.01%	4.50%	0.01%
Walmart Inc	WMT	2,692.23	165.25	444,891.67	1.41%	1.38%	0.02%	3.00%	0.04%
Cisco Systems Inc	CSCO	4,063.48	50.18	203,905.23	0.64%	3.11%	0.02%	10.00%	0.06%
Intel Corp	INTC	4,228.00	43.08	182,142.24		1.16%		31.13%	
General Motors Co	GM	1,154.43	38.80	44,792.00	0.14%	1.24%	0.00%	15.71%	0.02%
Microsoft Corp	MSFT	7,430.44	397.58	2,954,192.74	9.33%	0.75%	0.07%	16.62%	1.55%
Dollar General Corp	DG	219.50	132.07	28,988.97		1.79%		-5.94%	
Cigna Group/The	CI	292.62	300.95	88,063.99	0.28%	1.63%	0.00%	9.80%	0.03%
Kinder Morgan Inc	KMI	2,222.77	16.92	37,609.34	0.12%	6.68%	0.01%	3.00%	0.00%
Citigroup Inc	C	1,903.10	56.17	106,897.13		3.77%		21.67%	
American International Group Inc	AIG	702.04	69.51	48,798.80	0.15%	2.07%	0.00%	10.00%	0.02%
Altria Group Inc	MO	1,768.65	40.12	70,958.12	0.22%	9.77%	0.02%	4.50%	0.01%
HCA Healthcare Inc	HCA	267.66	304.90	81,609.84	0.26%	0.87%	0.00%	7.72%	0.02%
International Paper Co	IP	346.02	35.83	12,397.79		5.16%		-2.00%	
Hewlett Packard Enterprise Co	HPE	1,300.00	15.29	19,877.00	0.06%	3.40%	0.00%	2.64%	0.00%
Abbott Laboratories	ABT	1,736.06	113.15	196,435.08	0.62%	1.94%	0.01%	8.00%	0.05%
Aflac Inc	AFL	584.38	84.34	49,286.61	0.16%	2.37%	0.00%	6.85%	0.01%
Air Products and Chemicals Inc	APD	222.23	255.71	56,825.92	0.18%	2.77%	0.00%	12.06%	0.02%
Royal Caribbean Cruises Ltd	RCL	256.24	127.50	32,669.96					
Hess Corp	HES	307.15	140.53	43,164.07	0.14%	1.25%	0.00%	13.50%	0.02%
Archer-Daniels-Midland Co	ADM	533.38	55.58	29,645.32		3.60%		-7.81%	
Automatic Data Processing Inc	ADP	410.70	245.78	100,941.85	0.32%	2.28%	0.01%	16.00%	0.05%
Verisk Analytics Inc	VRSK	144.99	241.53	35,018.71	0.11%	0.56%	0.00%	11.70%	0.01%
AutoZone Inc	AZO	17.29	2,762.13	47,762.75	0.15%			14.29%	0.02%
Linde PLC	LIN	484.89	404.83	196,298.02	0.62%	1.26%	0.01%	14.00%	0.09%
Avery Dennison Corp	AVY	80.53	199.45	16,061.91	0.05%	1.62%	0.00%	7.00%	0.00%
Enphase Energy Inc	ENPH	136.55	104.13	14,219.06				28.57%	
MSCI Inc	MSCI	79.10	598.62	47,350.84	0.15%	1.07%	0.00%	12.12%	0.02%
Ball Corp	BALL	315.30	55.45	17,483.44	0.06%	1.44%	0.00%	9.50%	0.01%
Axon Enterprise Inc	AXON	74.93	249.06	18,663.06					
Dayforce Inc	DAY	156.13	69.52	10,853.95					
Carrier Global Corp	CARR	897.66	54.71	49,110.76	0.16%	1.39%	0.00%	10.94%	0.02%
Bank of New York Mellon Corp/The	BK	759.34	55.46	42,113.22	0.13%	3.03%	0.00%	10.00%	0.01%
Otis Worldwide Corp	OTIS	409.26	88.44	36,194.87	0.11%	1.54%	0.00%	9.00%	0.01%
Baxter International Inc	BAX	507.32	38.69	19,628.37		3.00%		-3.00%	
Becton Dickinson & Co	BDX	289.54	238.81	69,145.53		1.59%		-2.02%	
Berkshire Hathaway Inc	BRK/B	1,308.41	383.74	502,090.79					
Best Buy Co Inc	BBY	215.40	72.49	15,614.06	0.05%	5.08%	0.00%	3.08%	0.00%
Boston Scientific Corp	BSX	1,464.98	63.26	92,674.82	0.29%			12.10%	0.04%
Bristol-Myers Squibb Co	BMY	2,034.76	48.87	99,438.62	0.31%	4.91%	0.02%	2.78%	0.01%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Brown-Forman Corp	BF/B	306.48	54.90	16,825.48	0.05%	1.59%	0.00%	4.85%	0.00%
Coterra Energy Inc	CTRA	752.19	24.88	18,714.54		3.22%		55.04%	
Campbell Soup Co	CPB	298.10	44.63	13,304.20	0.04%	3.32%	0.00%	2.81%	0.00%
Hilton Worldwide Holdings Inc	HLT	256.44	190.96	48,969.78	0.15%	0.31%	0.00%	17.14%	0.03%
Carnival Corp	CCL	1,119.45	16.58	18,560.40					
Qorvo Inc	QRVO	97.35	99.74	9,709.29	0.03%			18.15%	0.01%
Builders FirstSource Inc	BLDR	123.35	173.73	21,429.07				-1.67%	
UDR Inc	UDR	328.93	36.02	11,847.99	0.04%	4.66%	0.00%	6.08%	0.00%
Clorox Co/The	CLX	124.06	145.25	18,019.57	0.06%	3.30%	0.00%	11.90%	0.01%
Paycom Software Inc	PAYC	60.23	190.24	11,457.77	0.04%	0.79%	0.00%	15.19%	0.01%
CMS Energy Corp	CMS	291.76	57.16	16,677.23	0.05%	3.41%	0.00%	7.75%	0.00%
Colgate-Palmolive Co	CL	823.37	84.20	69,327.92	0.22%	2.28%	0.00%	8.18%	0.02%
EPAM Systems Inc	EPAM	57.70	278.11	16,046.95	0.05%			4.87%	0.00%
Comerica Inc	CMA	131.87	52.58	6,933.88		5.40%		31.00%	
Conagra Brands Inc	CAG	478.01	29.15	13,933.85	0.04%	4.80%	0.00%	2.08%	0.00%
Airbnb Inc	ABNB	434.75	144.14	62,664.14	0.20%			18.20%	0.04%
Consolidated Edison Inc	ED	344.92	90.90	31,353.59	0.10%	3.65%	0.00%	6.00%	0.01%
Corning Inc	GLW	853.18	32.49	27,719.88	0.09%	3.45%	0.00%	9.34%	0.01%
Cummins Inc	CMI	141.75	239.30	33,919.58	0.11%	2.81%	0.00%	7.01%	0.01%
Caesars Entertainment Inc	CZR	215.71	43.87	9,463.24				127.12%	
Danaher Corp	DHR	739.20	239.91	177,341.47	0.56%	0.40%	0.00%	5.83%	0.03%
Target Corp	TGT	461.66	139.08	64,207.95	0.20%	3.16%	0.01%	15.29%	0.03%
Deere & Co	DE	279.99	393.58	110,198.46	0.35%	1.49%	0.01%	3.96%	0.01%
Dominion Energy Inc	D	836.77	45.72	38,257.26	0.12%	5.84%	0.01%	6.90%	0.01%
Dover Corp	DOV	139.89	149.78	20,952.72	0.07%	1.36%	0.00%	10.00%	0.01%
Alliant Energy Corp	LNT	252.72	48.66	12,297.31	0.04%	3.95%	0.00%	6.16%	0.00%
Steel Dynamics Inc	STLD	161.82	120.69	19,529.57		1.41%		-13.01%	
Duke Energy Corp	DUK	771.00	95.83	73,884.93	0.23%	4.28%	0.01%	6.34%	0.01%
Regency Centers Corp	REG	184.58	62.67	11,567.38	0.04%	4.28%	0.00%	3.46%	0.00%
Eaton Corp PLC	ETN	399.30	246.08	98,259.74	0.31%	1.40%	0.00%	15.00%	0.05%
Ecolab Inc	ECL	285.14	198.22	56,520.45	0.18%	1.15%	0.00%	14.33%	0.03%
Revvity Inc	RVTY	123.41	107.18	13,226.76		0.26%		-7.32%	
Emerson Electric Co	EMR	570.10	91.73	52,295.27	0.17%	2.29%	0.00%	12.01%	0.02%
EOG Resources Inc	EOG	583.15	113.79	66,356.64	0.21%	3.20%	0.01%	17.83%	0.04%
Aon PLC	AON	200.22	298.43	59,750.46	0.19%	0.82%	0.00%	10.03%	0.02%
Entergy Corp	ETR	211.46	99.76	21,094.85	0.07%	4.53%	0.00%	6.51%	0.00%
Equifax Inc	EFX	123.22	244.34	30,106.84	0.10%	0.64%	0.00%	13.64%	0.01%
EQT Corp	EQT	411.33	35.40	14,561.15		1.78%		21.41%	
IQVIA Holdings Inc	IQV	182.50	208.23	38,001.98	0.12%			9.67%	0.01%
Gartner Inc	IT	77.95	457.44	35,656.99	0.11%			8.24%	0.01%
FedEx Corp	FDX	249.89	241.29	60,296.68	0.19%	2.09%	0.00%	13.50%	0.03%
FMC Corp	FMC	124.76	56.20	7,011.46		4.13%		-4.00%	
Brown & Brown Inc	BRO	284.60	77.43	22,036.58	0.07%	0.67%	0.00%	7.91%	0.01%
Ford Motor Co	F	3,932.10	11.72	46,084.24		5.12%		-2.52%	
NextEra Energy Inc	NEE	2,023.71	58.63	118,650.35	0.37%	3.19%	0.01%	8.10%	0.03%
Franklin Resources Inc	BEN	526.56	26.63	14,022.24		4.66%		-7.00%	
Garmin Ltd	GRMN	191.33	119.49	22,862.14	0.07%	2.44%	0.00%	5.60%	0.00%
Freeport-McMoRan Inc	FCX	1,433.98	39.69	56,914.55		1.51%		-15.66%	
Dexcom Inc	DXCM	386.37	121.35	46,886.48				26.89%	
General Dynamics Corp	GD	272.90	264.99	72,314.98	0.23%	1.99%	0.00%	11.30%	0.03%
General Mills Inc	GIS	567.89	64.91	36,861.74	0.12%	3.64%	0.00%	8.00%	0.01%
Genuine Parts Co	GPC	140.20	140.23	19,659.83	0.06%	2.71%	0.00%	9.26%	0.01%
Atmos Energy Corp	ATO	150.83	113.94	17,186.03	0.05%	2.83%	0.00%	7.26%	0.00%
WW Grainger Inc	GWW	49.63	895.64	44,454.20		0.83%			
Halliburton Co	HAL	895.05	35.65	31,908.60	0.10%	1.91%	0.00%	16.34%	0.02%
L3Harris Technologies Inc	LHX	189.54	208.42	39,503.93	0.12%	2.19%	0.00%	5.53%	0.01%
Healthpeak Properties Inc	PEAK	547.07	18.50	10,120.87	0.03%	6.49%	0.00%	1.21%	0.00%
Insulet Corp	PODD	69.83	190.87	13,328.07				39.34%	
Catalent Inc	CTLT	180.64	51.64	9,328.30				26.24%	
Fortive Corp	FTV	351.43	78.18	27,475.11	0.09%	0.41%	0.00%	9.29%	0.01%
Hershey Co/The	HSY	149.89	193.54	29,008.74	0.09%	2.46%	0.00%	9.00%	0.01%
Synchrony Financial	SYF	406.90	38.87	15,816.20		2.57%			
Hormel Foods Corp	HRL	546.84	30.37	16,607.53	0.05%	3.72%	0.00%	1.08%	0.00%
Arthur J Gallagher & Co	AJG	216.69	232.16	50,305.82	0.16%	1.03%	0.00%	12.38%	0.02%
Mondelez International Inc	MDLZ	1,360.90	75.27	102,434.64	0.32%	2.26%	0.01%	8.83%	0.03%
CenterPoint Energy Inc	CNP	629.43	27.94	17,586.33	0.06%	2.86%	0.00%	8.02%	0.00%
Humana Inc	HUM	122.22	378.06	46,208.01		0.94%		-3.07%	
Willis Towers Watson PLC	WTW	103.26	246.30	25,432.94	0.08%	1.36%	0.00%	10.94%	0.01%
Illinois Tool Works Inc	ITW	300.89	260.90	78,501.16	0.25%	2.15%	0.01%	3.86%	0.01%
CDW Corp/DE	CDW	133.96	226.72	30,371.41	0.10%	1.09%	0.00%	13.10%	0.01%
Trane Technologies PLC	TT	227.56	252.05	57,355.74	0.18%	1.19%	0.00%	13.04%	0.02%
Interpublic Group of Cos Inc/The	IPG	383.00	32.99	12,635.30	0.04%	3.76%	0.00%	6.29%	0.00%
International Flavors & Fragrances Inc	IFF	255.28	80.68	20,595.91	0.07%	4.02%	0.00%	5.67%	0.00%
Generac Holdings Inc	GNRC	61.43	113.67	6,982.98	0.02%			5.00%	0.00%
NXP Semiconductors NV	NXPI	257.76	210.57	54,277.15		1.93%		34.00%	
Kellanova	K	342.52	54.76	18,756.40		4.09%		-2.42%	
Broadridge Financial Solutions Inc	BR	117.65	204.20	24,023.52		1.57%			
Kimberly-Clark Corp	KMB	337.94	120.97	40,880.72	0.13%	4.03%	0.01%	4.42%	0.01%
Kimco Realty Corp	KIM	671.72	20.20	13,568.78	0.04%	4.75%	0.00%	4.75%	0.00%
Oracle Corp	ORCL	2,748.92	111.70	307,054.59	0.97%	1.43%	0.01%	15.00%	0.15%
Kroger Co/The	KR	719.42	46.14	33,194.18	0.10%	2.51%	0.00%	4.21%	0.00%

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Lennar Corp	LEN	247.16	149.85	37,037.38	0.12%	1.33%	0.00%	9.02%	0.01%
Eli Lilly & Co	LLY	949.31	645.61	612,882.09		0.81%		24.60%	
Bath & Body Works Inc	BBWI	225.94	42.66	9,638.64	0.03%	1.88%	0.00%	6.51%	0.00%
Charter Communications Inc	CHTR	147.92	370.71	54,835.42	0.17%			12.44%	0.02%
Loews Corp	L	223.25	72.86	16,266.07		0.34%			
Lowe's Cos Inc	LOW	575.11	212.84	122,407.05	0.39%	2.07%	0.01%	4.43%	0.02%
Hubbell Inc	HUBB	53.62	335.57	17,993.93	0.06%	1.45%	0.00%	18.00%	0.01%
IDEX Corp	IEX	75.63	211.50	15,994.90	0.05%	1.21%	0.00%	11.00%	0.01%
Marsh & McLennan Cos Inc	MMC	493.07	193.84	95,577.08	0.30%	1.47%	0.00%	8.27%	0.02%
Masco Corp	MAS	224.50	67.29	15,106.67	0.05%	1.69%	0.00%	6.17%	0.00%
S&P Global Inc	SPGI	316.80	448.35	142,037.28	0.45%	0.81%	0.00%	13.58%	0.06%
Medtronic PLC	MDT	1,329.65	87.54	116,397.91	0.37%	3.15%	0.01%	4.33%	0.02%
Viatris Inc	VTRS	1,199.67	11.77	14,120.13		4.08%		-2.58%	
CVS Health Corp	CVS	1,286.90	74.37	95,706.53	0.30%	3.58%	0.01%	6.24%	0.02%
DuPont de Nemours Inc	DD	430.04	61.80	26,576.60	0.08%	2.33%	0.00%	10.20%	0.01%
Micron Technology Inc	MU	1,103.91	85.75	94,660.20		0.54%		-7.00%	
Motorola Solutions Inc	MSI	165.97	319.50	53,026.78	0.17%	1.23%	0.00%	10.82%	0.02%
Cboe Global Markets Inc	CBOE	105.56	183.85	19,406.47	0.06%	1.20%	0.00%	12.81%	0.01%
Laboratory Corp of America Holdings	LH	84.90	222.30	18,873.27		1.30%		-7.29%	
Newmont Corp	NEM	1,152.49	34.51	39,772.50	0.13%	4.64%	0.01%	6.21%	0.01%
NIKE Inc	NKE	1,217.23	101.53	123,584.85	0.39%	1.46%	0.01%	14.65%	0.06%
NiSource Inc	NI	413.42	25.97	10,736.39	0.03%	4.08%	0.00%	7.65%	0.00%
Norfolk Southern Corp	NSC	225.68	233.89	52,784.53	0.17%	2.31%	0.00%	0.61%	0.00%
Principal Financial Group Inc	PFG	238.41	79.10	18,858.39	0.06%	3.39%	0.00%	8.77%	0.01%
Eversource Energy	ES	349.09	54.22	18,927.44	0.06%	5.27%	0.00%	5.21%	0.00%
Northrop Grumman Corp	NOC	150.04	446.76	67,030.08	0.21%	1.67%	0.00%	16.03%	0.03%
Wells Fargo & Co	WFC	3,598.90	49.83	179,333.19	0.57%	2.81%	0.02%	13.41%	0.08%
Nucor Corp	NUE	245.84	186.93	45,954.68		1.16%		-10.80%	
Occidental Petroleum Corp	OXY	877.58	57.57	50,522.34		1.25%			
Omnicom Group Inc	OMC	197.93	90.38	17,889.27	0.06%	3.10%	0.00%	4.83%	0.00%
ONEOK Inc	OKE	582.55	68.25	39,759.11	0.13%	5.80%	0.01%	7.65%	0.01%
Raymond James Financial Inc	RJF	208.70	110.18	22,994.57	0.07%	1.63%	0.00%	13.15%	0.01%
PG&E Corp	PCG	2,133.51	16.87	35,992.28	0.11%	0.24%	0.00%	6.26%	0.01%
Parker-Hannifin Corp	PH	128.48	464.50	59,677.10	0.19%	1.27%	0.00%	15.28%	0.03%
Rollins Inc	ROL	484.04	43.31	20,963.69	0.07%	1.39%	0.00%	14.86%	0.01%
PPL Corp	PPL	737.12	26.20	19,312.65	0.06%	3.66%	0.00%	8.00%	0.00%
ConocoPhillips	COP	1,187.41	111.87	132,835.33	0.42%	0.52%	0.00%	12.00%	0.05%
PulteGroup Inc	PHM	215.60	104.56	22,542.61	0.07%	0.77%	0.00%	5.41%	0.00%
Pinnacle West Capital Corp	PNW	113.31	68.90	7,807.20	0.02%	5.11%	0.00%	6.98%	0.00%
PNC Financial Services Group Inc/The	PNC	398.00	151.21	60,181.58	0.19%	4.10%	0.01%	14.67%	0.03%
PPG Industries Inc	PPG	235.80	141.04	33,257.23	0.11%	1.84%	0.00%	11.71%	0.01%
Progressive Corp/The	PGR	585.30	178.25	104,329.73		0.22%		29.97%	
Veralto Corp	VLTO	246.31	76.69	18,889.36		0.47%			
Public Service Enterprise Group Inc	PEG	499.11	57.99	28,943.45	0.09%	3.93%	0.00%	5.47%	0.01%
Robert Half Inc	RHI	105.90	79.54	8,422.89		2.41%			
Cooper Cos Inc/The	COO	49.53	373.03	18,474.68	0.06%			9.41%	0.01%
Edison International	EIX	383.57	67.48	25,883.17	0.08%	4.62%	0.00%	6.00%	0.00%
Schlumberger NV	SLB	1,427.40	48.70	69,514.14		2.26%		20.37%	
Charles Schwab Corp/The	SCHW	1,771.68	62.92	111,474.23		1.59%			
Sherwin-Williams Co/The	SHW	255.97	304.38	77,910.93	0.25%	0.80%	0.00%	10.94%	0.03%
West Pharmaceutical Services Inc	WST	73.99	373.03	27,600.49	0.09%	0.21%	0.00%	18.89%	0.02%
J M Smucker Co/The	SJM	106.14	131.55	13,963.24	0.04%	3.22%	0.00%	6.91%	0.00%
Snap-on Inc	SNA	52.78	289.93	15,302.51	0.05%	2.57%	0.00%	4.85%	0.00%
AMETEK Inc	AME	230.80	162.05	37,400.98	0.12%	0.62%	0.00%	6.87%	0.01%
Uber Technologies Inc	UBER	2,057.86	65.27	134,316.39				68.00%	
Southern Co/The	SO	1,091.52	69.52	75,882.12	0.24%	4.03%	0.01%	4.50%	0.01%
Truist Financial Corp	TFC	1,333.74	37.06	49,428.52	0.16%	5.61%	0.01%	7.33%	0.01%
Southwest Airlines Co	LUV	596.12	29.89	17,817.88	0.06%	2.41%	0.00%	15.74%	0.01%
W R Berkley Corp	WRB	256.55	81.88	21,005.90	0.07%	0.54%	0.00%	15.00%	0.01%
Stanley Black & Decker Inc	SWK	153.31	93.30	14,303.92	0.05%	3.47%	0.00%	9.00%	0.00%
Public Storage	PSA	175.83	283.19	49,793.01	0.16%	4.24%	0.01%	3.77%	0.01%
Arista Networks Inc	ANET	311.10	258.68	80,475.35	0.25%			19.72%	0.05%
Sysco Corp	SYY	497.83	80.93	40,289.38	0.13%	2.47%	0.00%	14.00%	0.02%
Corteva Inc	CTVA	704.88	45.48	32,057.94	0.10%	1.41%	0.00%	16.42%	0.02%
Texas Instruments Inc	TXN	909.00	160.12	145,549.08	0.46%	3.25%	0.01%	10.00%	0.05%
Textron Inc	TXT	196.01	84.71	16,603.58		0.09%			
Thermo Fisher Scientific Inc	TMO	386.37	538.98	208,246.78		0.26%			
TJX Cos Inc/The	TJX	1,139.68	94.91	108,166.74	0.34%	1.40%	0.00%	6.38%	0.02%
Globe Life Inc	GL	94.12	122.82	11,559.70		0.73%			
Johnson Controls International plc	JCI	681.48	52.69	35,907.02	0.11%	2.81%	0.00%	9.77%	0.01%
Ulta Beauty Inc	ULTA	48.56	502.05	24,380.55	0.08%			6.26%	0.00%
Union Pacific Corp	UNP	609.60	243.93	148,699.00	0.47%	2.13%	0.01%	11.00%	0.05%
Keysight Technologies Inc	KEYS	175.05	153.26	26,827.40	0.08%			2.61%	0.00%
UnitedHealth Group Inc	UNH	924.93	511.74	473,321.12	1.50%	1.47%	0.02%	10.61%	0.16%
Blackstone Inc	BX	719.36	124.45	89,524.10	0.28%	3.02%	0.01%	8.58%	0.02%
Marathon Oil Corp	MRO	585.25	22.85	13,372.89	0.04%	1.93%	0.00%	8.00%	0.00%
Bio-Rad Laboratories Inc	BIO	24.06	320.89	7,720.29					
Ventas Inc	VTR	402.38	46.39	18,666.45	0.06%	3.88%	0.00%	8.66%	0.01%
VF Corp	VFC	388.88	16.46	6,401.01	0.02%	2.19%	0.00%	3.10%	0.00%
Vulcan Materials Co	VMC	132.87	226.01	30,030.63		0.76%		22.79%	
Weyerhaeuser Co	WY	730.00	32.77	23,922.13		0.43%			

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Whirlpool Corp	WHR	55.00	109.52	6,023.60		6.39%		-1.36%	
Williams Cos Inc/The	WMB	1,216.50	34.66	42,163.86	0.13%	5.48%	0.01%	3.50%	0.00%
Constellation Energy Corp	CEG	319.38	122.00	38,964.60		0.92%		27.95%	
WEC Energy Group Inc	WEC	315.44	80.76	25,474.53	0.08%	4.14%	0.00%	6.39%	0.01%
Adobe Inc	ADBE	452.00	617.78	279,236.56	0.88%			16.91%	0.15%
AES Corp/The	AES	669.63	16.68	11,169.41	0.04%	4.14%	0.00%	10.14%	0.00%
Expeditors International of Washington Inc	EXPD	145.39	126.33	18,366.99		1.09%		-16.00%	
Amgen Inc	AMGN	535.18	314.26	168,185.04	0.53%	2.86%	0.02%	4.23%	0.02%
Apple Inc	AAPL	15,461.90	184.40	2,851,173.62	9.01%	0.52%	0.05%	13.00%	1.17%
Autodesk Inc	ADSK	213.92	253.81	54,293.77	0.17%			12.48%	0.02%
Cintas Corp	CTAS	101.37	604.57	61,285.87	0.19%	0.89%	0.00%	11.35%	0.02%
Comcast Corp	CMCSA	3,962.41	46.54	184,410.70	0.58%	2.66%	0.02%	9.65%	0.06%
Molson Coors Beverage Co	TAP	200.96	61.79	12,417.01	0.04%	2.65%	0.00%	12.08%	0.00%
KLA Corp	KLAC	135.23	594.04	80,334.41	0.25%	0.98%	0.00%	9.06%	0.02%
Marriott International Inc/MD	MAR	293.69	239.73	70,406.54	0.22%	0.87%	0.00%	17.45%	0.04%
Fiserv Inc	FI	600.19	141.87	85,148.39	0.27%			15.20%	0.04%
McCormick & Co Inc/MD	MKC	251.44	68.16	17,138.22	0.05%	2.46%	0.00%	5.40%	0.00%
PACCAR Inc	PCAR	523.30	100.39	52,534.09	0.17%	1.08%	0.00%	12.00%	0.02%
Costco Wholesale Corp	COST	443.73	693.86	307,885.11	0.97%	0.59%	0.01%	7.64%	0.07%
Stryker Corp	SYK	379.90	335.48	127,447.17	0.40%	0.95%	0.00%	8.20%	0.03%
Tyson Foods Inc	TSN	286.35	54.76	15,680.58		3.58%		46.71%	
Lamb Weston Holdings Inc	LW	144.37	102.08	14,737.49	0.05%	1.41%	0.00%	15.46%	0.01%
Applied Materials Inc	AMAT	832.06	164.30	136,707.79	0.43%	0.78%	0.00%	5.50%	0.02%
American Airlines Group Inc	AAL	653.54	14.23	9,299.89				-7.46%	
Cardinal Health Inc	CAH	246.47	109.19	26,911.84	0.09%	1.83%	0.00%	13.66%	0.01%
Cincinnati Financial Corp	CINF	156.91	110.80	17,385.41	0.05%	2.92%	0.00%	15.15%	0.01%
Paramount Global	PARA	610.70	14.59	8,910.17		1.37%		-21.36%	
DR Horton Inc	DHI	331.82	142.91	47,419.97	0.15%	0.84%	0.00%	4.49%	0.01%
Electronic Arts Inc	EA	268.97	137.58	37,004.34	0.12%	0.55%	0.00%	11.07%	0.01%
Fair Isaac Corp	FICO	24.85	1,198.83	29,793.32				22.00%	
Fastenal Co	FAST	571.98	68.23	39,026.33		2.29%			
M&T Bank Corp	MTB	166.15	138.10	22,945.18	0.07%	3.77%	0.00%	8.08%	0.01%
Xcel Energy Inc	XEL	551.82	59.87	33,037.22	0.10%	3.47%	0.00%	6.21%	0.01%
Fifth Third Bancorp	FITB	681.13	34.24	23,321.72		4.09%		25.00%	
Gilead Sciences Inc	GILD	1,246.04	78.26	97,515.25	0.31%	3.83%	0.01%	3.06%	0.01%
Hasbro Inc	HAS	138.76	48.95	6,792.50		5.72%		-3.49%	
Huntington Bancshares Inc/OH	HBAN	1,448.00	12.73	18,433.04		4.87%		-5.65%	
Welltower Inc	WELL	556.09	86.51	48,107.69	0.15%	2.82%	0.00%	9.22%	0.01%
Biogen Inc	BIIB	144.90	246.66	35,740.54	0.11%			10.50%	0.01%
Northern Trust Corp	NTRS	205.13	79.64	16,336.23	0.05%	3.77%	0.00%	2.57%	0.00%
Packaging Corp of America	PKG	89.62	165.88	14,866.83	0.05%	3.01%	0.00%	3.00%	0.00%
Paychex Inc	PAYX	359.82	121.73	43,801.13	0.14%	2.92%	0.00%	7.00%	0.01%
QUALCOMM Inc	QCOM	1,116.00	148.51	165,737.16	0.52%	2.15%	0.01%	10.81%	0.06%
Ross Stores Inc	ROST	336.67	140.28	47,227.51	0.15%	0.96%	0.00%	10.00%	0.01%
IDEXX Laboratories Inc	IDXX	83.05	515.08	42,778.42	0.14%			16.36%	0.02%
Starbucks Corp	SBUX	1,132.20	93.03	105,328.57	0.33%	2.45%	0.01%	15.41%	0.05%
KeyCorp	KEY	936.56	14.53	13,608.27		5.64%		-1.67%	
Fox Corp	FOXA	247.23	32.30	7,985.43	0.03%	1.61%	0.00%	12.00%	0.00%
Fox Corp	FOX	235.58	30.01	7,069.79	0.02%	1.73%	0.00%	12.00%	0.00%
State Street Corp	STT	301.94	73.87	22,304.60	0.07%	3.74%	0.00%	7.85%	0.01%
Norwegian Cruise Line Holdings Ltd	NCLH	425.43	17.80	7,572.57					
US Bancorp	USB	1,558.00	41.54	64,719.32	0.20%	4.72%	0.01%	6.00%	0.01%
A O Smith Corp	AOS	122.83	77.61	9,532.68		1.65%			
Gen Digital Inc	GEN	640.72	23.48	15,043.99	0.05%	2.13%	0.00%	12.98%	0.01%
T Rowe Price Group Inc	TROW	223.47	108.45	24,235.32		4.57%		-1.21%	
Waste Management Inc	WM	402.78	185.63	74,767.12	0.24%	1.51%	0.00%	10.39%	0.02%
Constellation Brands Inc	STZ	182.80	245.08	44,799.64	0.14%	1.45%	0.00%	10.63%	0.02%
DENTSPLY SIRONA Inc	XRAY	211.86	34.75	7,362.14	0.02%	1.61%	0.00%	7.93%	0.00%
Zions Bancorp NA	ZION	148.15	41.90	6,207.61		3.91%		-9.40%	
Invesco Ltd	IVZ	449.50	15.83	7,115.59	0.02%	5.05%	0.00%	4.00%	0.00%
Intuit Inc	INTU	279.94	631.33	176,731.99	0.56%	0.57%	0.00%	18.96%	0.11%
Morgan Stanley	MS	1,641.31	87.24	143,188.06	0.45%	3.90%	0.02%	5.28%	0.02%
Microchip Technology Inc	MCHP	541.05	85.18	46,086.21		2.06%		-1.85%	
Chubb Ltd	CB	405.27	245.00	99,291.15	0.31%	1.40%	0.00%	6.00%	0.02%
Hologic Inc	HOLX	234.72	74.44	17,472.63	0.06%			8.86%	0.00%
Citizens Financial Group Inc	CFG	466.42	32.70	15,251.87		5.14%		-6.96%	
Jabil Inc	JBL	127.55	125.29	15,980.24	0.05%	0.26%	0.00%	12.00%	0.01%
O'Reilly Automotive Inc	ORLY	59.16	1,023.05	60,525.68	0.19%			11.80%	0.02%
Allstate Corp/The	ALL	261.69	155.25	40,626.91		2.29%		-7.00%	
Equity Residential	EQR	379.29	60.19	22,829.53	0.07%	4.40%	0.00%	4.75%	0.00%
BorgWarner Inc	BWA	235.06	33.90	7,968.36	0.03%	1.30%	0.00%	4.81%	0.00%
Keurig Dr Pepper Inc	KDP	1,398.34	31.44	43,963.68	0.14%	2.74%	0.00%	6.81%	0.01%
Host Hotels & Resorts Inc	HST	705.40	19.22	13,557.79		4.16%			
Incyte Corp	INCY	224.11	58.77	13,170.89				37.00%	
Simon Property Group Inc	SPG	326.25	138.61	45,221.10	0.14%	5.48%	0.01%	1.71%	0.00%
Eastman Chemical Co	EMN	118.56	83.55	9,906.02	0.03%	3.88%	0.00%	5.02%	0.00%
AvalonBay Communities Inc	AVB	142.02	179.01	25,422.11	0.08%	3.80%	0.00%	5.95%	0.00%
Prudential Financial Inc	PRU	361.00	104.93	37,879.73	0.12%	4.77%	0.01%	10.55%	0.01%
United Parcel Service Inc	UPS	723.26	141.90	102,630.17		4.59%		-0.39%	
Walgreens Boots Alliance Inc	WBA	862.38	22.57	19,463.83	0.06%	4.43%	0.00%	0.31%	0.00%
STERIS PLC	STE	98.80	218.95	21,632.26		0.95%			

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McKesson Corp	MCK	133.06	499.89	66,516.36	0.21%	0.50%	0.00%	10.04%	0.02%
Lockheed Martin Corp	LMT	241.64	429.41	103,763.92	0.33%	2.93%	0.01%	5.39%	0.02%
Cencora Inc	COR	199.48	232.68	46,415.47	0.15%	0.88%	0.00%	8.66%	0.01%
Capital One Financial Corp	COF	380.40	135.32	51,475.73		1.77%		50.24%	
Waters Corp	WAT	59.13	317.71	18,785.24	0.06%			4.87%	0.00%
Nordson Corp	NDSN	57.02	251.72	14,352.07		1.08%		45.00%	
Dollar Tree Inc	DLTR	217.87	130.62	28,458.44	0.09%			7.77%	0.01%
Darden Restaurants Inc	DRI	119.41	162.58	19,413.84	0.06%	3.22%	0.00%	3.78%	0.00%
Evergy Inc	EVRG	229.58	50.77	11,655.93	0.04%	5.06%	0.00%	4.35%	0.00%
Match Group Inc	MTCH	271.81	38.38	10,432.14				28.33%	
Domino's Pizza Inc	DPZ	34.88	426.22	14,866.98	0.05%	1.14%	0.00%	12.71%	0.01%
NVR Inc	NVR	3.20	7,075.29	22,605.55	0.07%			4.41%	0.00%
NetApp Inc	NTAP	206.03	87.20	17,965.90	0.06%	2.29%	0.00%	6.00%	0.00%
Old Dominion Freight Line Inc	ODFL	109.11	391.02	42,665.76	0.13%	0.53%	0.00%	9.31%	0.01%
DaVita Inc	DVA	91.30	108.16	9,875.01	0.03%			19.69%	0.01%
Hartford Financial Services Group Inc/The	HIG	300.77	86.96	26,154.96	0.08%	2.16%	0.00%	7.00%	0.01%
Iron Mountain Inc	IRM	291.99	67.52	19,715.16	0.06%	3.85%	0.00%	4.00%	0.00%
Estee Lauder Cos Inc/The	EL	232.31	131.99	30,661.94	0.10%	2.00%	0.00%	10.88%	0.01%
Cadence Design Systems Inc	CDNS	272.06	288.46	78,479.00	0.25%			17.03%	0.04%
Tyler Technologies Inc	TYL	42.12	422.75	17,807.92					
Universal Health Services Inc	UHS	61.01	158.81	9,688.52	0.03%	0.50%	0.00%	11.38%	0.00%
Skyworks Solutions Inc	SWKS	160.23	104.46	16,737.21	0.05%	2.60%	0.00%	9.03%	0.00%
Quest Diagnostics Inc	DGX	112.44	128.43	14,440.03		2.21%		-1.18%	
Rockwell Automation Inc	ROK	114.59	253.28	29,023.86	0.09%	1.97%	0.00%	11.06%	0.01%
Kraft Heinz Co/The	KHC	1,226.54	37.13	45,541.39	0.14%	4.31%	0.01%	4.46%	0.01%
American Tower Corp	AMT	466.17	195.65	91,205.18	0.29%	3.48%	0.01%	11.81%	0.03%
Regeneron Pharmaceuticals Inc	REGN	107.13	942.78	100,999.08	0.32%			5.33%	0.02%
Amazon.com Inc	AMZN	10,334.03	155.20	1,603,841.61				35.10%	
Jack Henry & Associates Inc	JKHY	72.83	165.83	12,077.07	0.04%	1.25%	0.00%	7.06%	0.00%
Ralph Lauren Corp	RL	39.75	143.67	5,711.17	0.02%	2.09%	0.00%	10.25%	0.00%
Boston Properties Inc	BXP	156.94	66.50	10,436.58		5.89%		-1.26%	
Amphenol Corp	APH	598.31	101.10	60,489.14	0.19%	0.87%	0.00%	9.02%	0.02%
Howmet Aerospace Inc	HWM	411.74	56.26	23,164.72		0.36%		20.41%	
Pioneer Natural Resources Co	PXD	233.62	229.83	53,693.57	0.17%	5.57%	0.01%	2.00%	0.00%
Valero Energy Corp	VLO	340.45	138.90	47,288.92	0.15%	3.08%	0.00%	8.16%	0.01%
Synopsys Inc	SNPS	152.52	533.35	81,347.08	0.26%			17.68%	0.05%
Etsy Inc	ETSY	119.75	66.56	7,970.29	0.03%			8.47%	0.00%
CH Robinson Worldwide Inc	CHRW	116.65	84.09	9,809.18		2.90%		-10.00%	
Accenture PLC	ACN	666.51	363.88	242,530.39	0.77%	1.42%	0.01%	10.00%	0.08%
TransDigm Group Inc	TDG	55.59	1,092.68	60,746.45	0.19%			15.56%	0.03%
Yum! Brands Inc	YUM	280.31	129.49	36,297.08	0.11%	2.07%	0.00%	11.49%	0.01%
Prologis Inc	PLD	923.97	126.69	117,057.89	0.37%	2.75%	0.01%	8.60%	0.03%
FirstEnergy Corp	FE	573.82	36.68	21,047.53		4.47%		-0.33%	
VeriSign Inc	VRSN	102.10	198.88	20,305.65	0.06%			11.50%	0.01%
Quanta Services Inc	PWR	145.29	194.05	28,192.55	0.09%	0.19%	0.00%	8.00%	0.01%
Henry Schein Inc	HSIC	130.59	74.84	9,772.98	0.03%			3.44%	0.00%
Ameren Corp	AEE	262.95	69.57	18,293.08	0.06%	3.62%	0.00%	6.40%	0.00%
ANSYS Inc	ANSS	86.92	327.83	28,494.00	0.09%			9.00%	0.01%
FactSet Research Systems Inc	FDS	38.09	475.92	18,125.89	0.06%	0.82%	0.00%	10.60%	0.01%
NVIDIA Corp	NVDA	2,470.00	615.27	1,519,716.90		0.03%		43.97%	
Cognizant Technology Solutions Corp	CTSH	501.41	77.12	38,668.97	0.12%	1.50%	0.00%	12.00%	0.01%
Intuitive Surgical Inc	ISRG	352.33	378.22	133,256.74	0.42%			12.00%	0.05%
Take-Two Interactive Software Inc	TTWO	170.07	164.93	28,049.32				35.02%	
Republic Services Inc	RSG	314.64	171.12	53,840.68	0.17%	1.25%	0.00%	10.11%	0.02%
eBay Inc	EBAY	519.00	41.07	21,315.33	0.07%	2.43%	0.00%	0.32%	0.00%
Goldman Sachs Group Inc/The	GS	326.11	384.01	125,230.27	0.40%	2.86%	0.01%	8.36%	0.03%
SBA Communications Corp	SBAC	107.89	223.86	24,151.58	0.08%	1.52%	0.00%	8.00%	0.01%
Sempra	SRE	629.33	71.56	45,034.71	0.14%	3.33%	0.00%	4.95%	0.01%
Moody's Corp	MCO	183.00	392.04	71,743.32	0.23%	0.79%	0.00%	13.59%	0.03%
ON Semiconductor Corp	ON	430.70	71.13	30,635.55	0.10%			1.60%	0.00%
Booking Holdings Inc	BKNG	34.89	3,507.47	122,375.63	0.39%			15.00%	0.06%
F5 Inc	FFIV	58.80	183.70	10,801.01	0.03%			7.09%	0.00%
Akamai Technologies Inc	AKAM	150.83	123.23	18,587.03	0.06%			7.87%	0.00%
Charles River Laboratories International Inc	CRL	51.30	216.28	11,094.52	0.04%			14.00%	0.00%
MarketAxess Holdings Inc	MKTX	37.91	225.51	8,547.96		1.31%			
Devon Energy Corp	DVN	640.70	42.02	26,922.21		7.33%		21.68%	
Alphabet Inc	GOOGL	5,893.00	140.10	825,609.30	2.61%			10.05%	0.26%
Bio-Techne Corp	TECH	158.15	70.32	11,121.11	0.04%	0.46%	0.00%	5.00%	0.00%
Teleflex Inc	TFX	46.99	242.83	11,411.31	0.04%	0.56%	0.00%	7.00%	0.00%
Allegion plc	ALLE	87.79	123.89	10,876.06	0.03%	1.45%	0.00%	5.14%	0.00%
Netflix Inc	NFLX	432.76	564.11	244,124.24				31.81%	
Warner Bros Discovery Inc	WBD	2,438.57	10.02	24,434.43				91.04%	
Agilent Technologies Inc	A	293.00	130.10	38,119.82		0.73%			
Trimble Inc	TRMB	248.77	50.86	12,652.34					
Elevance Health Inc	ELV	234.96	493.44	115,938.17	0.37%	1.32%	0.00%	10.83%	0.04%
CME Group Inc	CME	359.99	205.84	74,100.34	0.23%	2.14%	0.01%	8.54%	0.02%
Juniper Networks Inc	JNPR	318.87	36.96	11,785.36	0.04%	2.38%	0.00%	7.96%	0.00%
BlackRock Inc	BLK	148.76	774.31	115,187.90	0.36%	2.63%	0.01%	9.00%	0.03%
DTE Energy Co	DTE	206.11	105.42	21,728.01	0.07%	3.87%	0.00%	7.00%	0.00%
Celanese Corp	CE	108.86	146.29	15,924.40	0.05%	1.91%	0.00%	2.16%	0.00%
Nasdaq Inc	NDAQ	576.97	57.77	33,331.27	0.11%	1.52%	0.00%	9.08%	0.01%

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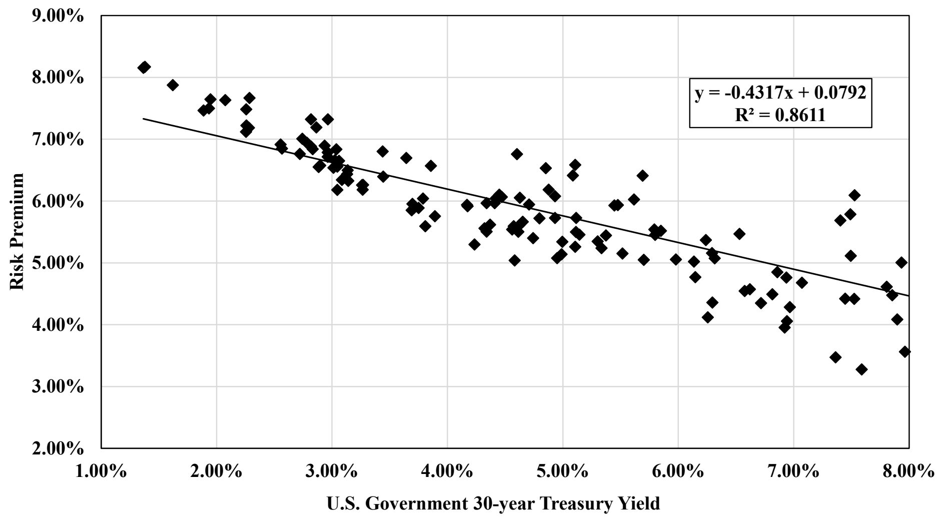
Philip Morris International Inc	PM	1,552.41	90.85	141,036.09	0.45%	5.72%	0.03%	6.49%	0.03%
Ingersoll Rand Inc	IR	404.80	79.86	32,327.09	0.10%	0.10%	0.00%	14.00%	0.01%
Salesforce Inc	CRM	968.00	281.09	272,095.12				22.50%	
Roper Technologies Inc	ROP	106.82	537.00	57,363.41	0.18%	0.56%	0.00%	8.00%	0.01%
Huntington Ingalls Industries Inc	HII	39.72	258.92	10,285.08		2.01%		40.00%	
MetLife Inc	MET	740.19	69.32	51,309.97	0.16%	3.00%	0.00%	9.84%	0.02%
Tapestry Inc	TPR	229.19	38.79	8,890.12	0.03%	3.61%	0.00%	11.00%	0.00%
CSX Corp	CSX	1,976.13	35.70	70,547.88	0.22%	1.23%	0.00%	6.75%	0.02%
Edwards Lifesciences Corp	EW	606.50	78.47	47,592.06	0.15%			8.75%	0.01%
Ameriprise Financial Inc	AMP	101.20	386.83	39,145.65		1.40%			
Zebra Technologies Corp	ZBRA	51.36	239.55	12,303.29					
Zimmer Biomet Holdings Inc	ZBH	208.98	125.60	26,248.01	0.08%	0.76%	0.00%	7.19%	0.01%
Camden Property Trust	CPT	106.77	93.84	10,019.39	0.03%	4.26%	0.00%	5.67%	0.00%
CBRE Group Inc	CBRE	304.79	86.31	26,306.68					
Mastercard Inc	MA	930.44	449.23	417,980.66	1.32%	0.59%	0.01%	16.64%	0.22%
CarMax Inc	KMX	157.92	71.18	11,240.82				29.90%	
Intercontinental Exchange Inc	ICE	572.36	127.33	72,879.11	0.23%	1.32%	0.00%	9.64%	0.02%
Fidelity National Information Services Inc	FIS	592.48	62.26	36,888.05	0.12%	3.34%	0.00%	11.42%	0.01%
Chipotle Mexican Grill Inc	CMG	27.45	2,408.77	66,108.69				24.78%	
Wynn Resorts Ltd	WYNN	112.95	94.43	10,665.49		1.06%		140.51%	
Live Nation Entertainment Inc	LYV	230.33	88.85	20,464.38					
Assurant Inc	AIZ	52.59	167.95	8,832.66	0.03%	1.71%	0.00%	11.66%	0.00%
NRG Energy Inc	NRG	225.76	53.04	11,974.52	0.04%	3.07%	0.00%	8.88%	0.00%
Monster Beverage Corp	MNST	1,040.44	55.02	57,245.06	0.18%			15.46%	0.03%
Regions Financial Corp	RF	930.07	18.67	17,364.31	0.05%	5.14%	0.00%	1.41%	0.00%
Baker Hughes Co	BKR	1,006.23	28.50	28,677.67	0.09%	2.81%	0.00%	17.00%	0.02%
Mosaic Co/The	MOS	326.84	30.71	10,037.10		2.74%		24.50%	
Expedia Group Inc	EXPE	133.33	148.33	19,776.10	0.06%			17.50%	0.01%
CF Industries Holdings Inc	CF	191.06	75.51	14,426.71		2.65%		46.00%	
APA Corp	APA	306.72	31.33	9,609.51	0.03%	3.19%	0.00%	2.00%	0.00%
Leidos Holdings Inc	LDOS	137.51	110.47	15,190.29	0.05%	1.38%	0.00%	8.12%	0.00%
Alphabet Inc	GOOG	5,671.00	141.80	804,147.80	2.54%			10.05%	0.26%
First Solar Inc	FSLR	106.84	146.30	15,631.28				43.22%	
TE Connectivity Ltd	TEL	308.80	142.19	43,908.13	0.14%	1.66%	0.00%	5.27%	0.01%
Discover Financial Services	DFS	250.06	105.52	26,386.12	0.08%	2.65%	0.00%	17.16%	0.01%
Visa Inc	V	1,581.59	273.26	432,185.28	1.37%	0.76%	0.01%	13.41%	0.18%
Mid-America Apartment Communities Inc	MAA	116.69	126.38	14,747.03	0.05%	4.65%	0.00%	1.86%	0.00%
Xylem Inc/NY	XYL	241.08	112.44	27,106.81		1.17%			
Marathon Petroleum Corp	MPC	379.70	165.60	62,877.82		1.99%		-11.89%	
Tractor Supply Co	TSCO	108.11	224.60	24,282.40	0.08%	1.83%	0.00%	3.42%	0.00%
Advanced Micro Devices Inc	AMD	1,615.79	167.69	270,951.32				29.35%	
ResMed Inc	RMD	147.09	190.20	27,976.33	0.09%	1.01%	0.00%	8.67%	0.01%
Mettler-Toledo International Inc	MTD	21.68	1,197.19	25,959.87	0.08%			5.96%	0.00%
VICI Properties Inc	VICI	1,034.53	30.12	31,160.10	0.10%	5.51%	0.01%	4.78%	0.00%
Copart Inc	CPRT	960.23	48.04	46,129.50					
Jacobs Solutions Inc	J	126.32	134.77	17,023.61	0.05%	0.86%	0.00%	12.31%	0.01%
Albemarle Corp	ALB	117.35	114.74	13,465.08		1.39%		35.15%	
Fortinet Inc	FTNT	767.91	64.49	49,522.52	0.16%			14.37%	0.02%
Moderna Inc	MRNA	381.28	101.05	38,528.75				-29.33%	
Essex Property Trust Inc	ESS	64.18	233.27	14,971.97	0.05%	3.96%	0.00%	5.71%	0.00%
CoStar Group Inc	CSGP	408.36	83.48	34,090.14	0.11%			20.00%	0.02%
Realty Income Corp	O	831.79	54.39	45,240.89	0.14%	5.66%	0.01%	1.39%	0.00%
Westrock Co	WRK	256.51	40.26	10,327.01	0.03%	3.01%	0.00%	5.70%	0.00%
Westinghouse Air Brake Technologies Corp	WAB	179.16	131.57	23,571.95	0.07%	0.52%	0.00%	14.08%	0.01%
Pool Corp	POOL	38.68	371.25	14,359.58		1.19%		-0.25%	
Western Digital Corp	WDC	324.24	57.25	18,562.91				-13.91%	
PepsiCo Inc	PEP	1,374.86	168.53	231,705.83	0.73%	3.00%	0.02%	8.62%	0.06%
Diamondback Energy Inc	FANG	178.99	153.74	27,517.15	0.09%	8.77%	0.01%	8.47%	0.01%
Palo Alto Networks Inc	PANW	315.30	338.51	106,732.20				30.00%	
ServiceNow Inc	NOW	205.00	765.40	156,907.00				30.00%	
Church & Dwight Co Inc	CHD	246.38	99.85	24,601.24	0.08%	1.09%	0.00%	6.28%	0.00%
Federal Realty Investment Trust	FRT	81.62	101.73	8,303.00	0.03%	4.29%	0.00%	4.42%	0.00%
MGM Resorts International	MGM	341.58	43.37	14,814.45					
American Electric Power Co Inc	AEP	515.18	78.14	40,255.85	0.13%	4.50%	0.01%	5.11%	0.01%
Invitation Homes Inc	INVH	611.96	32.93	20,151.78	0.06%	3.40%	0.00%	2.83%	0.00%
PTC Inc	PTC	119.44	180.65	21,576.29	0.07%			19.53%	0.01%
JB Hunt Transport Services Inc	JBHT	103.14	200.98	20,729.68	0.07%	0.86%	0.00%	15.00%	0.01%
Lam Research Corp	LRCX	131.10	825.17	108,182.26	0.34%	0.97%	0.00%	11.37%	0.04%
Mohawk Industries Inc	MHK	63.68	104.25	6,638.85				-2.33%	
GE HealthCare Technologies Inc	GEHC	455.24	73.36	33,396.63	0.11%	0.16%	0.00%	12.70%	0.01%
Pentair PLC	PNR	165.30	73.17	12,094.93	0.04%	1.26%	0.00%	7.53%	0.00%
Vertex Pharmaceuticals Inc	VRTX	257.68	433.38	111,674.66	0.35%			13.40%	0.05%
Amcor PLC	AMCR	1,445.34	9.43	13,629.58	0.04%	5.30%	0.00%	2.20%	0.00%
Meta Platforms Inc	META	2,219.61	390.14	865,957.47				20.79%	
T-Mobile US Inc	TMUS	1,195.81	161.23	192,799.96	0.61%	1.61%	0.01%	5.25%	0.03%
United Rentals Inc	URI	67.19	625.40	42,021.88	0.13%	1.04%	0.00%	6.85%	0.01%
Alexandria Real Estate Equities Inc	ARE	174.97	120.90	21,153.63	0.07%	4.20%	0.00%	5.28%	0.00%
Honeywell International Inc	HON	659.25	202.26	133,340.11	0.42%	2.14%	0.01%	7.87%	0.03%
Delta Air Lines Inc	DAL	643.46	39.14	25,185.14	0.08%	1.02%	0.00%	8.37%	0.01%
United Airlines Holdings Inc	UAL	328.02	41.38	13,573.34				49.56%	
Seagate Technology Holdings PLC	STX	209.51	85.68	17,950.90		3.27%		-4.90%	

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Bloomberg Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
News Corp	NWS	191.39	25.57	4,893.71		0.78%			
Centene Corp	CNC	534.20	75.31	40,230.68	0.13%			9.26%	0.01%
Martin Marietta Materials Inc	MLM	61.81	508.42	31,423.91		0.58%		20.66%	
Teradyne Inc	TER	152.88	96.59	14,766.58	0.05%	0.50%	0.00%	6.00%	0.00%
PayPal Holdings Inc	PYPL	1,078.14	61.35	66,143.89	0.21%			6.26%	0.01%
Tesla Inc	TSLA	3,184.79	187.29	596,479.32	1.88%			2.00%	0.04%
Arch Capital Group Ltd	ACGL	373.17	82.43	30,760.57	0.10%			15.00%	0.01%
Dow Inc	DOW	702.29	53.60	37,642.90		5.22%		23.26%	
Everest Group Ltd	EG	43.39	384.97	16,703.85		1.82%		33.50%	
Teledyne Technologies Inc	TDY	47.19	418.47	19,745.51	0.06%			8.03%	0.01%
News Corp	NWSA	380.67	24.64	9,379.71		0.81%			
Exelon Corp	EXC	994.30	34.81	34,611.55	0.11%	4.14%	0.00%	4.69%	0.01%
Global Payments Inc	GPN	260.39	133.23	34,691.63	0.11%	0.75%	0.00%	13.05%	0.01%
Crown Castle Inc	CCI	434.00	108.25	46,980.50	0.15%	5.78%	0.01%	7.00%	0.01%
Aptiv PLC	APTV	282.86	81.33	23,005.17	0.07%			11.44%	0.01%
Align Technology Inc	ALGN	76.59	267.32	20,473.77	0.06%			12.52%	0.01%
Illumina Inc	ILMN	158.80	143.01	22,709.99				-9.88%	
Kenvue Inc	KVUE	1,915.00	20.76	39,755.30		3.85%			
Targa Resources Corp	TRGP	222.98	84.96	18,944.04	0.06%	2.35%	0.00%	14.00%	0.01%
Bunge Global SA	BG	161.43	88.09	14,220.28		3.01%		-5.94%	
LKQ Corp	LKQ	267.60	46.67	12,488.80	0.04%	2.57%	0.00%	11.50%	0.00%
Zoetis Inc	ZTS	459.11	187.81	86,226.20	0.27%	0.92%	0.00%	10.91%	0.03%
Equinix Inc	EQIX	93.88	829.77	77,901.30	0.25%	2.05%	0.01%	14.63%	0.04%
Digital Realty Trust Inc	DLR	302.85	140.46	42,537.75	0.13%	3.47%	0.00%	6.80%	0.01%
Molina Healthcare Inc	MOH	58.30	356.44	20,780.45	0.07%			11.24%	0.01%
Las Vegas Sands Corp	LVS	764.49	48.92	37,398.90		1.64%			

Notes:
[1] Equals sum of Col. [9]
[2] Equals sum of Col. [11]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Source: Bloomberg Professional as of January 31 2024
[5] Source: Bloomberg Professional as of January 31 2024
[6] Equals [4] x [5]
[7] Equals weight in S&P 500 based on market capitalization [6] if Growth Rate >0% and ≤20%
[8] Source: Bloomberg Professional, as of January 31 2024
[9] Equals [7] x [8]
[10] Source: Bloomberg, as of January 31 2024
[11] Equals [7] x [10]



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.927975
R Square	0.861137
Adjusted R Square	0.860321
Standard Error	0.005397
Observations	172.000000

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1.000000	0.030710	0.030710	1,054.231629	0.000000
Residual	170.000000	0.004952	0.000029		
Total	171.000000	0.035663			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0792	0.0009	87.3018	0.0000	0.0774	0.0810	0.0774	0.0810
U.S. Govt. 30-year Treasury	(0.4317)	0.0133	(32.4689)	0.0000	(0.4580)	(0.4055)	(0.4580)	(0.4055)

	[7]	[8]	[9]
	U.S. Govt. 30-year Treasury	Risk Premium	Cost of Equity
Current 30-day average of 30-year U.S. Treasury bond yield [4]	4.19%	6.11%	10.30%
Blue Chip Near-Term Projected Forecast (Q2 2024 - Q2 2025) [5]	4.10%	6.15%	10.25%
Blue Chip Long-Term Projected Forecast (2025-2029) [6]	4.10%	6.15%	10.25%
AVERAGE			10.27%

Notes:
[1] Source: Regulatory Research Associates, rate cases through December 31, 2023
[2] Source: S&P Capital IQ Pro, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] Source: S&P Capital IQ Pro, 30-day average as of December 31, 2023
[5] Source: Blue Chip Financial Forecasts, Vol. 43, No. 1, December 28, 2023, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.079192 + (-0.431720 x Column [7])
[9] Equals Column [7] + Column [8]

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Average Authorized Natual Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
1980.1	13.45%	11.66%	1.79%
1980.2	14.38%	10.52%	3.85%
1980.3	13.87%	10.85%	3.02%
1980.4	14.35%	12.10%	2.25%
1981.1	14.71%	12.53%	2.18%
1981.2	14.61%	13.24%	1.36%
1981.3	14.86%	14.13%	0.72%
1981.4	15.70%	13.85%	1.86%
1982.1	15.55%	13.96%	1.59%
1982.2	15.62%	13.52%	2.10%
1982.3	15.77%	12.79%	2.97%
1982.4	15.63%	10.75%	4.89%
1983.1	15.41%	10.71%	4.71%
1983.2	14.84%	10.65%	4.19%
1983.3	15.24%	11.62%	3.62%
1983.4	15.40%	11.74%	3.66%
1984.1	15.39%	12.04%	3.35%
1984.2	15.07%	13.18%	1.89%
1984.3	15.46%	12.69%	2.77%
1984.4	15.33%	11.70%	3.63%
1985.1	15.03%	11.58%	3.45%
1985.2	15.44%	11.00%	4.45%
1985.3	14.64%	10.55%	4.08%
1985.4	14.37%	10.04%	4.33%
1986.1	14.05%	8.77%	5.28%
1986.2	13.28%	7.49%	5.79%
1986.3	13.09%	7.40%	5.69%
1986.4	13.62%	7.53%	6.09%
1987.1	12.61%	7.49%	5.11%
1987.2	13.04%	8.53%	4.51%
1987.3	12.70%	9.06%	3.64%
1987.4	12.69%	9.23%	3.46%
1988.1	12.94%	8.63%	4.31%
1988.2	12.48%	9.06%	3.41%
1988.3	12.79%	9.18%	3.61%
1988.4	12.98%	8.97%	4.00%
1989.1	12.99%	9.04%	3.96%
1989.2	13.25%	8.70%	4.55%
1989.3	12.56%	8.12%	4.44%
1989.4	12.94%	7.93%	5.00%
1990.1	12.68%	8.44%	4.24%
1990.2	12.81%	8.65%	4.16%
1990.3	12.36%	8.79%	3.57%
1990.4	12.78%	8.56%	4.22%
1991.1	12.69%	8.20%	4.49%
1991.2	12.53%	8.31%	4.22%
1991.3	12.43%	8.19%	4.24%
1991.4	12.33%	7.85%	4.48%
1992.1	12.42%	7.81%	4.61%
1992.2	11.98%	7.90%	4.09%
1992.3	11.87%	7.45%	4.42%
1992.4	11.94%	7.52%	4.42%
1993.1	11.75%	7.07%	4.68%
1993.2	11.71%	6.86%	4.85%
1993.3	11.39%	6.32%	5.07%
1993.4	11.16%	6.14%	5.02%
1994.1	11.12%	6.58%	4.54%
1994.2	10.84%	7.36%	3.47%
1994.3	10.87%	7.59%	3.28%
1994.4	11.53%	7.96%	3.56%
1995.2	11.00%	6.94%	4.06%
1995.3	11.07%	6.72%	4.35%
1995.4	11.61%	6.24%	5.37%
1996.1	11.45%	6.29%	5.16%

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Average Authorized Natual Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
1996.2	10.88%	6.92%	3.95%
1996.3	11.25%	6.97%	4.28%
1996.4	11.19%	6.62%	4.57%
1997.1	11.31%	6.82%	4.49%
1997.2	11.70%	6.94%	4.76%
1997.3	12.00%	6.53%	5.47%
1997.4	10.92%	6.15%	4.77%
1998.2	11.37%	5.85%	5.52%
1998.3	11.41%	5.48%	5.93%
1998.4	11.69%	5.11%	6.58%
1999.1	10.82%	5.37%	5.44%
1999.2	11.25%	5.80%	5.45%
1999.4	10.38%	6.26%	4.12%
2000.1	10.66%	6.30%	4.36%
2000.2	11.03%	5.98%	5.05%
2000.3	11.33%	5.79%	5.54%
2000.4	12.10%	5.69%	6.41%
2001.1	11.38%	5.45%	5.93%
2001.2	10.75%	5.70%	5.05%
2001.4	10.65%	5.30%	5.35%
2002.1	10.67%	5.52%	5.15%
2002.2	11.64%	5.62%	6.03%
2002.3	11.50%	5.09%	6.41%
2002.4	11.01%	4.93%	6.08%
2003.1	11.38%	4.85%	6.53%
2003.2	11.36%	4.60%	6.76%
2003.3	10.61%	5.11%	5.50%
2003.4	10.84%	5.11%	5.73%
2004.1	11.06%	4.88%	6.18%
2004.2	10.57%	5.34%	5.24%
2004.3	10.37%	5.11%	5.26%
2004.4	10.66%	4.93%	5.73%
2005.1	10.65%	4.71%	5.94%
2005.2	10.54%	4.47%	6.07%
2005.3	10.47%	4.42%	6.05%
2005.4	10.32%	4.65%	5.66%
2006.1	10.68%	4.63%	6.05%
2006.2	10.60%	5.14%	5.46%
2006.3	10.34%	5.00%	5.34%
2006.4	10.14%	4.74%	5.40%
2007.1	10.52%	4.80%	5.72%
2007.2	10.13%	4.99%	5.14%
2007.3	10.03%	4.95%	5.08%
2007.4	10.12%	4.61%	5.50%
2008.1	10.38%	4.41%	5.97%
2008.2	10.17%	4.57%	5.59%
2008.3	10.55%	4.45%	6.10%
2008.4	10.34%	3.64%	6.69%
2009.1	10.24%	3.44%	6.80%
2009.2	10.11%	4.17%	5.94%
2009.3	9.88%	4.32%	5.56%
2009.4	10.31%	4.34%	5.97%
2010.1	10.24%	4.62%	5.61%
2010.2	9.99%	4.37%	5.62%
2010.3	10.43%	3.86%	6.57%
2010.4	10.09%	4.17%	5.92%
2011.1	10.10%	4.56%	5.54%
2011.2	9.85%	4.34%	5.51%
2011.3	9.65%	3.70%	5.95%
2011.4	9.88%	3.04%	6.84%
2012.1	9.63%	3.14%	6.50%

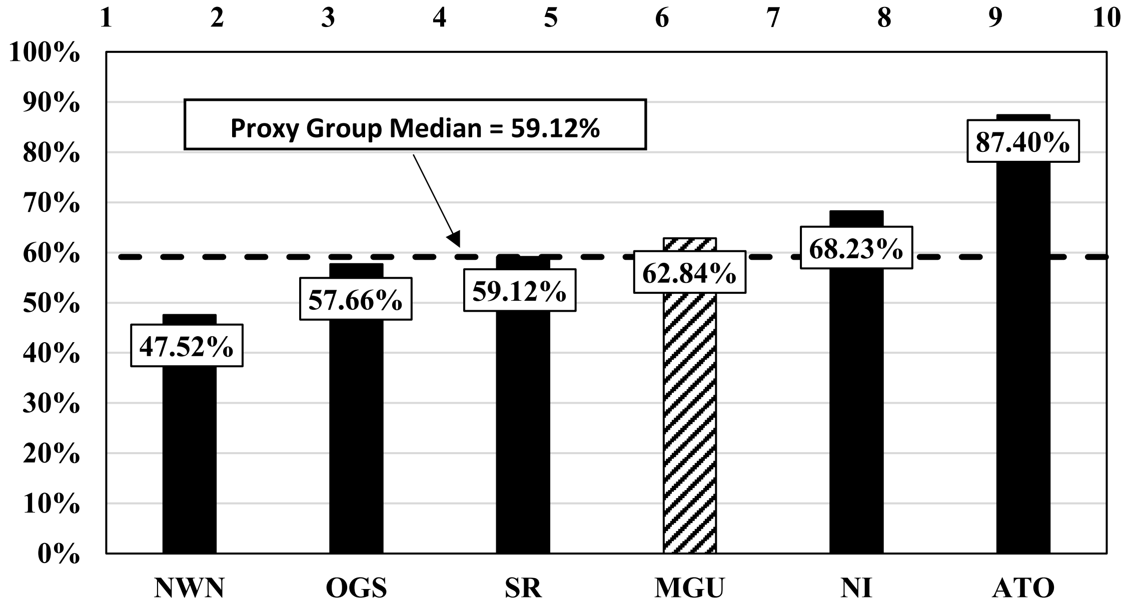
BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Average Authorized Natual Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
2012.2	9.83%	2.94%	6.89%
2012.3	9.75%	2.74%	7.01%
2012.4	10.06%	2.86%	7.19%
2013.1	9.57%	3.13%	6.44%
2013.2	9.47%	3.14%	6.33%
2013.3	9.60%	3.71%	5.89%
2013.4	9.83%	3.79%	6.04%
2014.1	9.54%	3.69%	5.85%
2014.2	9.84%	3.44%	6.39%
2014.3	9.45%	3.27%	6.18%
2014.4	10.28%	2.96%	7.32%
2015.1	9.47%	2.55%	6.91%
2015.2	9.43%	2.88%	6.55%
2015.3	9.75%	2.96%	6.79%
2015.4	9.68%	2.96%	6.71%
2016.1	9.48%	2.72%	6.76%
2016.2	9.42%	2.57%	6.85%
2016.3	9.47%	2.28%	7.19%
2016.4	9.67%	2.83%	6.84%
2017.1	9.60%	3.05%	6.55%
2017.2	9.47%	2.90%	6.57%
2017.3	10.14%	2.82%	7.32%
2017.4	9.70%	2.82%	6.88%
2018.1	9.68%	3.02%	6.66%
2018.2	9.43%	3.09%	6.34%
2018.3	9.71%	3.06%	6.65%
2018.4	9.53%	3.27%	6.26%
2019.1	9.55%	3.01%	6.54%
2019.2	9.73%	2.78%	6.94%
2019.3	9.95%	2.29%	7.67%
2019.4	9.74%	2.26%	7.48%
2020.1	9.35%	1.89%	7.46%
2020.2	9.55%	1.38%	8.17%
2020.3	9.52%	1.37%	8.15%
2020.4	9.50%	1.62%	7.87%
2021.1	9.71%	2.07%	7.63%
2021.2	9.48%	2.26%	7.22%
2021.3	9.43%	1.93%	7.50%
2021.4	9.59%	1.95%	7.65%
2022.1	9.38%	2.25%	7.12%
2022.2	9.23%	3.05%	6.18%
2022.3	9.52%	3.26%	6.26%
2022.4	9.65%	3.89%	5.75%
2023.1	9.64%	3.75%	5.89%
2023.2	9.40%	3.81%	5.59%
2023.3	9.53%	4.23%	5.30%
2023.4	9.62%	4.58%	5.04%
AVERAGE	11.37%	6.08%	5.29%
MEDIAN	10.83%	5.22%	5.50%

2024-2028 CAPITAL EXPENDITURES AS A PERCENTAGE OF 2023 NET PLANT
($ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2023	2024	2025	2026	2027	2028	2024-2028 Cap. Ex. / 2023 Net Plant
Atmos Energy Corporation	ATO							
Capital Spending per Share			$ 18.70	$ 20.10	$ 21.50	$ 21.50	$ 21.50	
Common Shares Outstanding			$ 155.00	$ 162.50	$ 170.00	$ 170.00	$ 170.00	
Capital Expenditures			$ 2,898.50	$ 3,266.25	$ 3,655.00	$ 3,655.00	$ 3,655.00	87.40%
Net Plant		$ 19,600						
NiSource Inc.	NI							
Capital Spending per Share			$ 7.95	$ 7.35	$ 6.75	$ 6.75	$ 6.75	
Common Shares Outstanding			$ 415.00	$ 427.50	$ 440.00	$ 440.00	$ 440.00	
Capital Expenditures			$ 3,299.25	$ 3,142.13	$ 2,970.00	$ 2,970.00	$ 2,970.00	68.23%
Net Plant		$ 22,500						
Northwest Natural Gas Company	NWN							
Capital Spending per Share			$ 7.75	$ 7.63	$ 7.50	$ 7.50	$ 7.50	
Common Shares Outstanding			$ 38.00	$ 40.00	$ 42.00	$ 42.00	$ 42.00	
Capital Expenditures			$ 294.50	$ 305.00	$ 315.00	$ 315.00	$ 315.00	47.52%
Net Plant		$ 3,250						
ONE Gas, Inc.	OGS							
Capital Spending per Share			$ 11.95	$ 12.23	$ 12.50	$ 12.50	$ 12.50	
Common Shares Outstanding			$ 55.50	$ 56.25	$ 57.00	$ 57.00	$ 57.00	
Capital Expenditures			$ 663.23	$ 687.66	$ 712.50	$ 712.50	$ 712.50	57.66%
Net Plant		$ 6,050						
Spire, Inc.	SR							
Capital Spending per Share			$ 12.85	$ 12.60	$ 12.35	$ 12.35	$ 12.35	
Common Shares Outstanding			$ 53.00	$ 54.00	$ 55.00	$ 55.00	$ 55.00	
Capital Expenditures			$ 681.05	$ 680.40	$ 679.25	$ 679.25	$ 679.25	59.12%
Net Plant		$ 5,750						
Michigan Gas Utilities Corporation	MGU							
Capital Expenditures [8]			$ 63.12	$ 56.73	$ 48.88	$ 42.38	$ 35.27	62.84%
Net Plant [9]		$ 392.06						

Notes:
[1] - [6] Value Line, dated November 24, 2023
[7] Equals (Column [2] + [3] + [4] + [5] + [6]) / Column [1]
[8] Source: Company Provided Data
[9] Source: Company Provided Data



Projected CAPEX/2023 Net Plant

	Company	Ticker	Projected CAPEX / 2023 Net Plant
1	Northwest Natural Gas Company	NWN	47.52%
2	ONE Gas, Inc.	OGS	57.66%
3	Spire, Inc.	SR	59.12%
4	Michigan Gas Utilities Corporation	MGU	62.84%
5	NiSource Inc.	NI	68.23%
6	Atmos Energy Corporation	ATO	87.40%
	Proxy Group Median		59.12%
	Michigan Gas Utilities Corporation in % of Median		1.15

Notes:
MGU Schedule D13, pg. 1 col. [7]

COMPARISON OF
REGULATORY RISK ASSESSMENT

				[1]	[2]	[3]	[4]	[
					Revenue Stabilization			
Company	Operating Subsidiary	State	Utility Type	Test Year Convention	Revenue Decoupling	Formula-Based Rates	Straight Fixed Variable Rate Design	Overall Stabil
Atmos Energy Corporation								
	Atmos Energy Corporation	Kansas	Gas	Historical	Partial	No	No	
	Atmos Energy Corporation	Kentucky	Gas	Fully Forecast	Partial	No	No	
	Atmos Energy Corporation	Louisiana	Gas	Historical	Partial	Yes	No	
	Atmos Energy Corporation	Mississippi	Gas	Historical	Partial	Yes	No	
	Atmos Energy Corporation	Tennessee	Gas	Historical	Partial	Yes	No	
	Atmos Energy Corporation	Texas	Gas	Historical	Partial	Yes	No	
NiSource Inc.								
	Northern Indiana Public Service Co.	Indiana	Electric	Fully Forecast	Partial	No	No	
	Northern Indiana Public Service Co.	Indiana	Gas	Fully Forecast	No	No	No	
	Columbia Gas of Kentucky Inc.	Kentucky	Gas	Fully Forecast	Partial	No	No	
	Columbia Gas of Maryland Inc.	Maryland	Gas	Partially Forecast	Partial	No	No	
	Columbia Gas of Ohio Inc.	Ohio	Gas	Partially Forecast	No	No	Yes	
	Columbia Gas of Pennsylvania Inc.	Pennsylvania	Gas	Fully Forecast	Partial	No	No	
	Columbia Gas of Virginia Inc.	Virginia	Gas	Historical	Partial	No	No	
Northwest Natural Gas Company								
	Northwest Natural Gas Co.	Oregon	Gas	Fully Forecast	Partial	No	No	
	Northwest Natural Gas Co.	Washington	Gas	Historical	No	No	No	
ONE Gas, Inc.								
	Kansas Gas Service Co.	Kansas	Gas	Historical	Partial	No	No	
	Oklahoma Natural Gas Co.	Oklahoma	Gas	Historical	Partial	Yes	No	
	Texas Gas Service Co. Inc.	Texas	Gas	Historical	Partial	Yes	No	
Spire, Inc.								
	Spire Alabama Inc.	Alabama	Gas	Fully Forecast	Partial	Yes	No	
	Spire Gulf Inc.	Alabama	Gas	Fully Forecast	Partial	Yes	No	
	Spire Missouri Inc.	Missouri	Gas	Partially Forecast	Partial	No	No	
Proxy Group Totals			Fully Forecast	8				
			Partially Forecast	3				Yes
			Historical	10				No
			% Forecast	52.4%				% Yes
MGUC [7]		Michigan	Gas	Fully Forecast	No	No	No	

Notes:
[1] Regulatory Research Associates, Rate Case History, Company Tariffs, Company Form 10-K.

SIZE PREMIUM CALCULATION

Proxy Group Market Capitalization and Market-to-Book Ratio

Company	Ticker	[1] Market Capitalization ($ billions)
Atmos Energy Corporation	ATO	17.28
NiSource Inc.	NI	10.88
Northwest Natural Gas Company	NWN	1.42
ONE Gas Inc.	OGS	3.46
Spire, Inc.	SR	3.25
Median		3.46

Michigan Gas Utilities Corporation			
Test Year Rate Base ($millions)	[2]	$	509.07
Company-Projected Common Equity Ratio	[3]		50.90%
Common Equity ($millions)	[4]	$	259.12
Market Capitalization of Proxy Group (median) ($millions)	[5]	$	3,460.02

Kroll Cost of Capital Navigator -- Size Premium

Breakdown of Deciles 1-10			[6] Market Capitalization of Largest Company ($ millions)	[7] Size Premium
1-Largest			2,662,326.05	-0.26%
2			36,391.11	0.45%
3			14,820.05	0.57%
4			7,461.28	0.58%
5			4,621.79	0.93%
6			3,010.81	1.16%
7			1,862.49	1.37%
8			1,046.04	1.18%
9			554.52	2.15%
10-Smallest			212.64	4.83%
Michigan Gas Common Equity	[4]	$	259.12	2.15%
Proxy Group Market Capitalization (median)	[5]	$	3,460.02	0.93%
Size Premium	[8]			1.22%

Notes:
[1] S&P Capital IQ Pro, equals 30-day average as of January 31, 2024
[2] Data provided by the Company
[3] Data provided by the Company
[4] Equals [2] x [3]
[5] Equals median market capitalization of proxy group x 1000
[6]-[7] Kroll Cost of Capital Navigator - Size Premium: Annual Data as of 12/31/2023
[8] Size Premium of Michigan Gas less Size Premium of Proxy Group

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO [1]

Proxy Group Company	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	60.01%	59.88%	58.31%	59.40%
NiSource Inc.	NI	54.17%	54.85%	54.43%	54.48%
Northwest Natural Gas Company	NWN	47.72%	44.08%	41.92%	44.57%
One Gas Inc.	OGS	58.24%	61.09%	60.04%	59.79%
Spire Inc.	SR	47.30%	49.08%	52.75%	49.71%

Proxy Group					
MEAN		53.49%	53.80%	53.49%	53.59%
LOW		47.30%	44.08%	41.92%	44.57%
HIGH		60.01%	61.09%	60.04%	59.79%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	60.01%	59.88%	58.31%	59.40%
Northern Indiana Public Service Company LLC	NI	56.92%	58.59%	58.01%	57.84%
Columbia Gas of Kentucky, Inc.	NI	54.91%	53.87%	54.68%	54.49%
Columbia Gas of Maryland, Inc.	NI	51.96%	55.26%	54.95%	54.06%
Columbia Gas of Ohio, Inc.	NI	50.67%	50.79%	50.45%	50.64%
Columbia Gas of Pennsylvania, Inc.	NI	56.64%	56.05%	55.68%	56.12%
Columbia Gas of Virginia, Inc.	NI	44.25%	44.52%	43.69%	44.15%
Northwest Natural Gas Company	NWN	47.72%	44.08%	41.92%	44.57%
Kansas Gas Service Company, Inc.	OGS	58.37%	61.37%	60.33%	60.02%
Oklahoma Natural Gas Company	OGS	58.26%	60.99%	59.85%	59.70%
Texas Gas Service Company, Inc.	OGS	58.13%	60.98%	59.99%	59.70%
Spire Alabama Inc.	SR	52.01%	56.67%	58.82%	55.84%
Spire Gulf Inc.	SR	41.35%	41.14%	39.49%	40.66%
Spire Mississippi Inc.	SR		39.18%	38.74%	38.96%
Spire Missouri Inc.	SR	45.49%	46.20%	50.65%	47.45%

Notes:

[1] Ratios are weighted by actual common capital, preferred equity, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas, Electric and Water operating subsidiaries where data was unable to be obtained for 2022, 2021 and 2020 were removed from the analysis.

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	39.99%	40.12%	41.69%	40.60%
NiSource Inc.	NI	45.83%	45.15%	45.57%	45.52%
Northwest Natural Gas Company	NWN	45.46%	44.85%	46.45%	45.59%
One Gas Inc.	OGS	41.76%	38.91%	39.96%	40.21%
Spire Inc.	SR	39.78%	39.42%	37.24%	38.82%
Proxy Group					
MEAN		42.56%	41.69%	42.18%	42.14%
LOW		39.78%	38.91%	37.24%	38.82%
HIGH		45.83%	45.15%	46.45%	45.59%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	39.99%	40.12%	41.69%	40.60%
Northern Indiana Public Service Company LLC	NI	43.08%	41.41%	41.99%	42.16%
Columbia Gas of Kentucky, Inc.	NI	45.09%	46.13%	45.32%	45.51%
Columbia Gas of Maryland, Inc.	NI	48.04%	44.74%	45.05%	45.94%
Columbia Gas of Ohio, Inc.	NI	49.33%	49.21%	49.55%	49.36%
Columbia Gas of Pennsylvania, Inc.	NI	43.36%	43.95%	44.32%	43.88%
Columbia Gas of Virginia, Inc.	NI	55.75%	55.48%	56.31%	55.85%
Northwest Natural Gas Company	NWN	45.46%	44.85%	46.45%	45.59%
Kansas Gas Service Company, Inc.	OGS	41.63%	38.63%	39.67%	39.98%
Oklahoma Natural Gas Company	OGS	41.74%	39.01%	40.15%	40.30%
Texas Gas Service Company, Inc.	OGS	41.87%	39.02%	40.01%	40.30%
Spire Alabama Inc.	SR	33.01%	40.18%	32.80%	35.33%
Spire Gulf Inc.	SR	38.77%	42.00%	57.90%	46.22%
Spire Mississippi Inc.	SR		0.00%	0.00%	0.00%
Spire Missouri Inc.	SR	42.91%	39.42%	38.72%	40.35%

Notes:

[1] Ratios are weighted by actual common capital, preferred equity, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas, Electric and Water operating subsidiaries where data was unable to be obtained for 2022, 2021 and 2020 were removed from the analysis.

CAPITAL STRUCTURE ANALYSIS

PREFERRED EQUITY RATIO [1]

Proxy Group Company	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%	0.00%
NiSource Inc.	NI	0.00%	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	0.00%	0.00%	0.00%	0.00%
One Gas Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Spire Inc.	SR	0.00%	0.00%	0.00%	0.00%
Proxy Group					
MEAN		0.00%	0.00%	0.00%	0.00%
LOW		0.00%	0.00%	0.00%	0.00%
HIGH		0.00%	0.00%	0.00%	0.00%

PREFERRED EQUITY RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%	0.00%
Northern Indiana Public Service Company LLC	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Kentucky, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Maryland, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Ohio, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Pennsylvania, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Virginia, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	0.00%	0.00%	0.00%	0.00%
Kansas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Oklahoma Natural Gas Company	OGS	0.00%	0.00%	0.00%	0.00%
Texas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Spire Alabama Inc.	SR	0.00%	0.00%	0.00%	0.00%
Spire Gulf Inc.	SR	0.00%	0.00%	0.00%	0.00%
Spire Mississippi Inc.	SR		0.00%	0.00%	0.00%
Spire Missouri Inc.	SR	0.00%	0.00%	0.00%	0.00%

Notes:

[1] Ratios are weighted by actual common capital, preferred equity, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas, Electric and Water operating subsidiaries where data was unable to be obtained for 2022, 2021 and 2020 were removed from the analysis.

Schedule E1

Michigan Public Service Commission
Michigan Gas Utilities
Market Outlook: 5-Year Annual Calendar Gas Forecast by Class
Units in MMcf

Case No.: U-21540
Exhibit No.: A-15
Schedule: E1

Witness: Jared J. Peccarelli

Line No.	(a) Year	(b) Residential	(c) Commercial	(d) Industrial	(e) Other	(f) Total	(g) Losses and CU	(h) % of Output	(i) System Output
1	2024	14,410	7,161	13,523	-	35,093	397	1.1311%	35,490
2	2025	13,793	7,434	13,067	-	34,294	388	1.1311%	34,682
3	2026	13,821	7,516	13,249	-	34,586	391	1.1311%	34,977
4	2027	13,882	7,600	13,378	-	34,861	394	1.1311%	35,255
5	2028	13,951	7,633	13,508	-	35,092	397	1.1311%	35,489

Notes:
1) Commercial includes Small General Service and Medium General Service
2) Industrial includes Large General Service and EUT volumes

Michigan Gas Utilities Corporation
Gas Cost of Service Study
Test Year Ending December 31, 2025
Level 7 Revenue Requirements
Return Summary by Rate Class

Case No.: U-21540
Exhibit No.: A-16
Schedule: F1.1

Witness: Riley O'Brien

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Line Description	Total MGU Natural Gas	Total GS Residential	Total GS Small Commercial	Total GS Medium Commercial	Total GS Large Commercial	Total Transport	Total Special Contract
1	Development of Rate Base							
2	Net Plant							
3	Total-Utility Plant in Service	735,319,808	475,406,105	104,525,853	377,517	3,626,572	151,209,852	173,909
4	Total-Construction Work in Progress	9,728,030	5,751,655	1,464,676	6,002	58,497	2,445,506	1,694
5	Total-Accumulated Depreciation	(292,060,735)	(195,771,260)	(38,092,350)	(137,017)	(1,308,758)	(56,663,149)	(88,202)
6	Net Plant	452,987,103	285,386,500	67,898,179	246,502	2,376,311	96,992,210	87,402
7	Other Rate Base Components							
8	Total-Gas Stored Underground	20,181,385	12,087,157	5,545,432	29,128	295,255	2,223,584	829
9	Total-Material and Supplies	2,033,967	1,379,035	263,570	828	7,733	382,247	554
10	Total-Prepayments	1,831,048	1,130,976	289,288	1,122	10,832	398,504	326
11	Total-Working Capital	32,033,312	14,449,739	6,431,103	34,275	321,460	10,795,249	1,485
12	Total-Other Rate Base Components	56,079,712	29,046,908	12,529,394	65,353	635,280	13,799,584	3,193
13	Total Rate Base							
14	Total Rate Base	509,066,815	314,433,408	80,427,573	311,855	3,011,591	110,791,794	90,595
15	Operating Income							
16	Operating Revenues							
17	Total-Sales Revenue	180,399,335	115,699,922	43,264,455	204,417	2,274,911	18,855,708	99,923
18	Total-Other Operating Revenues	1,512,805	1,009,053	316,958	1,417	15,497	169,206	674
19	Total-Other Misc Revenues	0	0	0	0	0	0	0
20	Total-Operating Revenues	181,912,140	116,708,975	43,581,413	205,834	2,290,408	19,024,914	100,597
21	Operating Expenses							
22	Total-Operation & Maintenance	126,290,238	84,329,916	32,203,163	156,890	1,717,922	7,871,361	10,986
23	Total-Book Depreciation Expense	23,178,254	15,270,826	3,241,597	11,075	105,512	4,543,860	5,384
24	Total-Taxes Other than Income Taxes	11,468,271	7,162,843	1,776,780	6,796	65,586	2,454,145	2,121
25	Total-State Income Taxes	(326,859)	(201,890)	(51,640)	(200)	(1,934)	(71,137)	(58)
26	Total-Federal Income Taxes	(622,260)	(384,349)	(98,311)	(381)	(3,681)	(135,427)	(111)
27	Total-Deferred Income Taxes	2,479,711	1,531,634	391,770	1,519	14,670	539,677	441
28	Total-Regulatory Debits and Credits	1,169,995	740,279	182,863	689	6,619	239,325	220
29	Total-Investment Tax Credits	(10,569)	(6,528)	(1,670)	(6)	(63)	(2,300)	(2)
30	Total-Operating Expenses	163,626,781	108,442,731	37,644,552	176,381	1,904,631	15,439,505	18,981
31	Revenue Deficiency							
32	Revenue Deficiency at Present Rates							
33	Total-Adjustments to Operating Income	318,055	196,452	50,250	195	1,882	69,221	57
34	Adjusted Operating Income	18,603,414	8,462,696	5,987,110	29,648	387,659	3,654,629	81,672
35	Earned Rate of Return	0.0365	0.0269	0.0744	0.0951	0.1287	0.0330	0.9015
36	Required Rate of Return	0.0622	0.0622	0.0622	0.0622	0.0622	0.0622	0.0622
37	Income Deficiency (Sufficiency) %	0.0256	0.0353	(0.0123)	(0.0329)	(0.0665)	0.0292	(0.8393)
38	Income Deficiency (Sufficiency) $	13,051,204	11,089,294	(985,990)	(10,256)	(200,393)	3,234,588	(76,039)
39	Tax Gross-up Factor	0.34662						
40	Additional Taxes on Income Deficiency	4,523,808	2,794,204	714,717	2,771	26,762	984,548	805
41	Revenue Deficiency (Sufficiency) $	17,575,013	13,883,498	(271,273)	(7,485)	(173,631)	4,219,136	(75,233)
42	Revenue Deficiency (Sufficiency) %	0.0974	0.1200	(0.0063)	(0.0366)	(0.0763)	0.2238	(0.7529)
43	Adjustments to Revenue Deficiency	0	0	0	0	0	0	0
44	Revenue Deficiency After Specified Adjustments $	17,575,013	13,883,498	(271,273)	(7,485)	(173,631)	4,219,136	(75,233)
45	Revenue Deficiency After Specified Adjustments %	0.0974	0.1200	(0.0063)	(0.0366)	(0.0763)	0.2238	(0.7529)
46	Adjustments to Requested Revenue	0	0	0	0	0	0	0
47	Revenue Deficiency For 2025 Rate Design $	17,575,013	13,883,498	(271,273)	(7,485)	(173,631)	4,219,136	(75,233)
48	Revenue Deficiency For 2025 Rate Design %	0.0974	0.1200	(0.0063)	(0.0366)	(0.0763)	0.2238	(0.7529)
49	Utility Sales (from above)	180,399,335	115,699,922	43,264,455	204,417	2,274,911	18,855,708	99,923
50	Revenue Requirement	197,974,348	129,583,420	42,993,182	196,933	2,101,280	23,074,844	24,689
51	Cost of Gas	85,020,153	56,385,665	26,947,551	138,850	1,546,907	0	1,179
52	Revenue Requirement excl Gas Costs	112,954,194	73,197,754	16,045,631	58,083	554,373	23,074,844	23,510

Michigan Gas Utilities Corporation
Gas Cost of Service Study
Test Year Ending December 31, 2025
Level 7 Revenue Requirements
Balances by Rate Schedule

Case No.: U-21540
Exhibit No.: A-16
Schedule: F1.2

Witness: Riley O'Brien

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
			Residential			Small			
Line No.	Line Description	Total MGU Natural Gas	General Service-Residential	Customer Choice-Residential	Agg Transport-Residential	General Service-Small	Customer Choice-GS-Small	Agg Transport-GS-Small	Transport-TR-1
1	Development of Rate Base								
2	Net Plant								
3	Total-Utility Plant in Service	735,319,808	475,406,105	51,060,503	66,092	104,525,853	17,291,525	5,138,763	15,101,748
4	Total-Construction Work in Progress	9,728,030	5,751,655	609,881	832	1,464,676	233,195	80,929	280,080
5	Total-Accumulated Depreciation	(292,060,735)	(195,771,260)	(21,083,637)	(21,236)	(38,092,350)	(6,228,698)	(1,798,628)	(5,363,606)
6	Net Plant	452,987,103	285,386,500	30,586,747	45,688	67,898,179	11,296,021	3,421,064	10,018,223
7	Other Rate Base Components								
8	Total-Gas Stored Underground	20,181,385	12,087,157	1,308,808	0	5,545,432	886,721	0	0
9	Total-Material and Supplies	2,033,967	1,379,035	148,417	196	263,570	44,336	13,717	35,910
10	Total-Prepayments	1,831,048	1,130,976	121,304	174	289,288	47,832	13,830	41,599
11	Total-Working Capital	32,033,312	14,449,739	1,559,662	2,405	6,431,103	1,023,386	396,272	1,469,523
12	Total-Other Rate Base Components	56,079,712	29,046,908	3,138,191	2,775	12,529,394	2,002,276	423,818	1,547,031
13	Total Rate Base								
14	Total Rate Base	509,066,815	314,433,408	33,724,938	48,463	80,427,573	13,298,297	3,844,882	11,565,254
15	Operating Income								
16	Operating Revenues								
17	Total-Sales Revenue	180,399,335	115,699,922	6,369,864	10,323	43,264,455	2,578,504	916,988	2,763,003
18	Total-Other Operating Revenues	1,512,805	1,009,053	75,354	85	316,958	21,874	6,823	19,528
19	Total-Other Misc Revenues	0	0	0	0	0	0	0	0
20	Total-Operating Revenues	181,912,140	116,708,975	6,445,218	10,408	43,581,413	2,600,378	923,812	2,782,531
21	Operating Expenses								
22	Total-Operation & Maintenance	126,290,238	84,329,916	2,973,113	14,206	32,203,163	836,339	589,153	819,379
23	Total-Book Depreciation Expense	23,178,254	15,270,826	1,634,267	2,157	3,241,597	534,834	156,568	437,222
24	Total-Taxes Other than Income Taxes	11,468,271	7,162,843	766,618	1,328	1,776,780	292,524	92,369	254,778
25	Total-State Income Taxes	(326,859)	(201,890)	(21,654)	(31)	(51,640)	(8,538)	(2,469)	(7,426)
26	Total-Federal Income Taxes	(622,260)	(384,349)	(41,224)	(59)	(98,311)	(16,255)	(4,700)	(14,137)
27	Total-Deferred Income Taxes	2,479,711	1,531,634	164,277	236	391,770	64,777	18,729	56,335
28	Total-Regulatory Debits and Credits	1,169,995	740,279	79,367	113	182,863	30,315	8,427	23,937
29	Total-Investment Tax Credits	(10,569)	(6,528)	(700)	(1)	(1,670)	(276)	(80)	(240)
30	Total-Operating Expenses	163,626,781	108,442,731	5,554,064	17,949	37,644,552	1,733,718	857,998	1,569,848
31	Revenue Deficiency								
32	Revenue Deficiency at Present Rates								
33	Total-Adjustments to Operating Income	318,055	196,452	21,071	30	50,250	8,309	2,402	7,226
34	Adjusted Operating Income	18,603,414	8,462,696	912,225	(7,510)	5,987,110	874,968	68,215	1,219,909
35	Earned Rate of Return	0.0365	0.0269	0.0270	(0.1550)	0.0744	0.0658	0.0177	0.1055
36	Required Rate of Return	0.0622	0.0622	0.0622	0.0622	0.0622	0.0622	0.0622	0.0622
37	Income Deficiency (Sufficiency) %	0.0256	0.0353	0.0351	0.2171	(0.0123)	(0.0036)	0.0444	(0.0433)
38	Income Deficiency (Sufficiency) $	13,051,204	11,089,294	1,184,848	10,523	(985,990)	(48,058)	170,866	(500,762)
39	Tax Gross-up Factor	0.34662							
40	Additional Taxes on Income Deficiency	4,523,808	2,794,204	299,696	431	714,717	118,175	34,167	102,774
41	Revenue Deficiency (Sufficiency) $	17,575,013	13,883,498	1,484,543	10,954	(271,273)	70,117	205,033	(397,988)
42	Revenue Deficiency (Sufficiency) %	0.0974	0.1200	0.2331	1.0611	(0.0063)	0.0272	0.2236	(0.1440)
43	Adjustments to Revenue Deficiency	0	0	0	0	0	0	0	0
44	Revenue Deficiency After Specified Adjustments $	17,575,013	13,883,498	1,484,543	10,954	(271,273)	70,117	205,033	(397,988)
45	Revenue Deficiency After Specified Adjustments %	0.0974	0.1200	0.2331	1.0611	(0.0063)	0.0272	0.2236	(0.1440)
46	Adjustments to Requested Revenue	0	0	0	0	0	0	0	0
47	Revenue Deficiency For 2024 Rate Design $	17,575,013	13,883,498	1,484,543	10,954	(271,273)	70,117	205,033	(397,988)
48	Revenue Deficiency For 2025 Rate Design %	0.0974	0.1200	0.2331	1.0611	(0.0063)	0.0272	0.2236	(0.1440)
49	Utility Sales (from above)	180,399,335	115,699,922	6,369,864	10,323	43,264,455	2,578,504	916,988	2,763,003
50	Revenue Requirement	197,974,348	129,583,420	7,854,408	21,277	42,993,182	2,648,621	1,122,022	2,365,016
51	Cost of Gas	85,020,153	56,385,665	0	0	26,947,551	0	0	0
52	Revenue Requirement excl Gas Costs	112,954,194	73,197,754	7,854,408	21,277	16,045,631	2,648,621	1,122,022	2,365,016
53									
54	Company Use: Company Use	0							
55	Gas-in-Kind: Gas-in-Kind	0							
56	Lost Gas: Lost Gas	0							

Michigan Gas Utilities Corporation
Gas Cost of Service Study
Test Year Ending December 31, 2025
Level 7 Revenue Requirements
Balances by Rate Schedule

Case No.: U-21540
Exhibit No.: A-16
Schedule: F1.2

Witness: Riley O'Brien

	(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
			Medium			Large			
Line No.	Line Description	Total MGU Natural Gas	Agg Transport-GS-Medium	Customer Choice-GS-Medium	General Service-Medium	General Service-Large	Transport-TR-2	Customer Choice-GS-Large	Agg Transport-GS-Large
1	Development of Rate Base								
2	Net Plant								
3	Total-Utility Plant in Service	735,319,808	748,146	26,329	377,517	3,626,572	40,121,974	348,906	496,125
4	Total-Construction Work in Progress	9,728,030	13,082	391	6,002	58,497	789,555	5,141	8,240
5	Total-Accumulated Depreciation	(292,060,735)	(275,707)	(9,403)	(137,017)	(1,308,758)	(14,272,566)	(127,408)	(187,030)
6	Net Plant	452,987,103	485,522	17,317	246,502	2,376,311	26,638,963	226,639	317,335
7	Other Rate Base Components								
8	Total-Gas Stored Underground	20,181,385	0	1,849	29,128	295,255	0	26,205	0
9	Total-Material and Supplies	2,033,967	1,874	61	828	7,733	90,318	810	1,298
10	Total-Prepayments	1,831,048	2,023	78	1,122	10,832	110,984	1,044	1,336
11	Total-Working Capital	32,033,312	72,893	2,248	34,275	321,460	4,015,475	35,554	51,474
12	Total-Other Rate Base Components	56,079,712	76,789	4,235	65,353	635,280	4,216,777	63,612	54,108
13	Total Rate Base								
14	Total Rate Base	509,066,815	562,310	21,552	311,855	3,011,591	30,855,739	290,251	371,444
15	Operating Income								
16	Operating Revenues								
17	Total-Sales Revenue	180,399,335	159,253	3,865	204,417	2,274,911	4,165,063	40,206	86,914
18	Total-Other Operating Revenues	1,512,805	1,135	29	1,417	15,497	30,372	297	620
19	Total-Other Misc Revenues	0	0	0	0	0	0	0	0
20	Total-Operating Revenues	181,912,140	160,388	3,895	205,834	2,290,408	4,195,435	40,503	87,534
21	Operating Expenses								
22	Total-Operation & Maintenance	126,290,238	59,941	1,174	156,890	1,717,922	1,695,956	15,019	31,632
23	Total-Book Depreciation Expense	23,178,254	21,820	773	11,075	105,512	1,143,296	10,046	14,483
24	Total-Taxes Other than Income Taxes	11,468,271	12,849	468	6,796	65,586	668,885	6,274	8,320
25	Total-State Income Taxes	(326,859)	(361)	(14)	(200)	(1,934)	(19,812)	(186)	(238)
26	Total-Federal Income Taxes	(622,260)	(687)	(26)	(381)	(3,681)	(37,717)	(355)	(454)
27	Total-Deferred Income Taxes	2,479,711	2,739	105	1,519	14,670	150,301	1,414	1,809
28	Total-Regulatory Debits and Credits	1,169,995	1,191	48	689	6,619	62,214	652	805
29	Total-Investment Tax Credits	(10,569)	(12)	(0)	(6)	(63)	(641)	(6)	(8)
30	Total-Operating Expenses	163,626,781	97,479	2,526	176,381	1,904,631	3,662,483	32,858	56,349
31	Revenue Deficiency								
32	Revenue Deficiency at Present Rates								
33	Total-Adjustments to Operating Income	318,055	351	13	195	1,882	19,278	181	232
34	Adjusted Operating Income	18,603,414	63,260	1,382	29,648	387,659	552,230	7,827	31,417
35	Earned Rate of Return	0.0365	0.1125	0.0641	0.0951	0.1287	0.0179	0.0270	0.0846
36	Required Rate of Return	0.0622	0.0622	0.0622	0.0622	0.0622	0.0622	0.0622	0.0622
37	Income Deficiency (Sufficiency) %	0.0256	(0.0503)	(0.0019)	(0.0329)	(0.0665)	0.0443	0.0352	(0.0224)
38	Income Deficiency (Sufficiency) $	13,051,204	(28,295)	(42)	(10,256)	(200,393)	1,366,431	10,221	(8,320)
39	Tax Gross-up Factor	0.34662							
40	Additional Taxes on Income Deficiency	4,523,808	4,997	192	2,771	26,762	274,199	2,579	3,301
41	Revenue Deficiency (Sufficiency) $	17,575,013	(23,298)	150	(7,485)	(173,631)	1,640,629	12,801	(5,020)
42	Revenue Deficiency (Sufficiency) %	0.0974	(0.1463)	0.0388	(0.0366)	(0.0763)	0.3939	0.3184	(0.0578)
43	Adjustments to Revenue Deficiency	0	0	0	0	0	0	0	0
44	Revenue Deficiency After Specified Adjustments $	17,575,013	(23,298)	150	(7,485)	(173,631)	1,640,629	12,801	(5,020)
45	Revenue Deficiency After Specified Adjustments %	0.0974	(0.1463)	0.0388	(0.0366)	(0.0763)	0.3939	0.3184	(0.0578)
46	Adjustments to Requested Revenue	0	0	0	0	0	0	0	0
47	Revenue Deficiency For 2024 Rate Design $	17,575,013	(23,298)	150	(7,485)	(173,631)	1,640,629	12,801	(5,020)
48	Revenue Deficiency For 2025 Rate Design %	0.0974	(0.1463)	0.0388	(0.0366)	(0.0763)	0.3939	0.3184	(0.0578)
49	Utility Sales (from above)	180,399,335	159,253	3,865	204,417	2,274,911	4,165,063	40,206	86,914
50	Revenue Requirement	197,974,348	135,955	4,015	196,933	2,101,280	5,805,693	53,007	81,895
51	Cost of Gas	85,020,153	0	0	138,850	1,546,907	0	0	0
52	Revenue Requirement excl Gas Costs	112,954,194	135,955	4,015	58,083	554,373	5,805,693	53,007	81,895
53									
54	Company Use: Company Use	0							
55	Gas-in-Kind: Gas-in-Kind	0							
56	Lost Gas: Lost Gas	0							

Michigan Gas Utilities Corporation
Gas Cost of Service Study
Test Year Ending December 31, 2025
Level 8 Revenue Requirements
Unbundled Revenue Requirement

Case No.: U-21540
Exhibit No.: A-16
Schedule: F1.3

Witness: Riley O'Brien

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
			Residential			Small			
Line No.	Line Description	Total MGU Natural Gas	General Service-Residential	Customer Choice-Residential	Agg Transport-Residential	General Service-Small	Customer Choice GS-Small	Agg Transport-GS-Small	Transport-TR-1
1	Units								
2	Throughput total	34,294,114	12,443,860	1,346,322	2,666	5,947,106	951,896	420,113	2,129,704
3	Customers average	186,733	154,964	16,799	7	12,485	2,008	223	98
4	Commodity total	18,763,259	12,443,860	0	0	5,947,106	0	0	0
5									
6	Revenue Requirement								
7	Cost of Gas								
8	Demand	$0	$0	$0	$0	$0	$0	$0	$0
9	Customer	$0	$0	$0	$0	$0	$0	$0	$0
10	Commodity	$85,020,153	$56,385,665	$0	$0	$26,947,551	$0	$0	$0
11	Sub-total	**$85,020,153**	**$56,385,665**	**$0**	**$0**	**$26,947,551**	**$0**	**$0**	**$0**
12	Production								
13	Demand	$786,475	$347,107	$37,615	$66	$152,800	$24,407	$10,939	$39,342
14	Customer	$0	$0	$0	$0	$0	$0	$0	$0
15	Commodity	$861,702	$571,484	$0	$0	$273,121	$0	$0	$0
16	Sub-total	**$1,648,177**	**$918,591**	**$37,615**	**$66**	**$425,921**	**$24,407**	**$10,939**	**$39,342**
17	Storage								
18	Demand	$6,721,024	$4,025,396	$435,874	$0	$1,846,800	$295,306	$0	$0
19	Customer	$0	$0	$0	$0	$0	$0	$0	$0
20	Commodity	$0	$0	$0	$0	$0	$0	$0	$0
21	Sub-total	**$6,721,024**	**$4,025,396**	**$435,874**	**$0**	**$1,846,800**	**$295,306**	**$0**	**$0**
22	Transmission								
23	Demand	$10,134,163	$4,028,625	$436,204	$803	$1,852,491	$296,232	$128,387	$565,112
24	Customer	$0	$0	$0	$0	$0	$0	$0	$0
25	Commodity	$0	$0	$0	$0	$0	$0	$0	$0
26	Sub-total	**$10,134,163**	**$4,028,625**	**$436,204**	**$803**	**$1,852,491**	**$296,232**	**$128,387**	**$565,112**
27	Distribution								
28	Demand	$26,106,830	$11,455,794	$1,252,778	$2,202	$5,057,049	$815,745	$366,060	$1,317,474
29	Customer	$57,071,409	$44,445,630	$4,791,284	$7,483	$5,867,851	$1,058,044	$258,452	$219,175
30	Commodity	$0	$0	$0	$0	$0	$0	$0	$0
31	Sub-total	**$83,178,239**	**$55,901,424**	**$6,044,061**	**$9,684**	**$10,924,900**	**$1,873,790**	**$624,512**	**$1,536,649**
32	Customer								
33	Demand	$0	$0	$0	$0	$0	$0	$0	$0
34	Customer	$11,272,591	$8,323,718	$900,654	$10,724	$995,519	$158,887	$358,183	$223,912
35	Commodity	$0	$0	$0	$0	$0	$0	$0	$0
36	Sub-total	**$11,272,591**	**$8,323,718**	**$900,654**	**$10,724**	**$995,519**	**$158,887**	**$358,183**	**$223,912**
37	Grand Total								
38	Demand	$43,748,492	$19,856,922	$2,162,470	$3,071	$8,909,140	$1,431,690	$505,386	$1,921,928
39	Customer	$68,344,000	$52,769,348	$5,691,938	$18,207	$6,863,370	$1,216,931	$616,635	$443,088
40	Commodity	$85,881,856	$56,957,150	$0	$0	$27,220,672	$0	$0	$0
41	Sub-total	**$197,974,348**	**$129,583,420**	**$7,854,408**	**$21,277**	**$42,993,182**	**$2,648,621**	**$1,122,022**	**$2,365,016**

Michigan Gas Utilities Corporation
Gas Cost of Service Study
Test Year Ending December 31, 2025
Level 8 Revenue Requirements
Unbundled Revenue Requirement

	(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
			Medium			Large			
Line No.	Line Description	Total MGU Natural Gas	Agg Transport-GS-Medium	Customer Choice-GS-Medium	General Service-Medium	General Service-Large	Transport-TR-2	Customer Choice-GS-Large	Agg Transport-GS-Large
1	Units								
2	Throughput total	34,294,114	82,398	1,849	30,643	341,390	6,715,089	21,316	48,401
3	Customers average	186,733	16	1	17	62	40	3	6
4	Commodity total	18,763,259	0	0	30,643	341,390	0	0	0
5									
6	Revenue Requirement								
7	Cost of Gas								
8	Demand	$0	$0	$0	$0	$0	$0	$0	$0
9	Customer	$0	$0	$0	$0	$0	$0	$0	$0
10	Commodity	$85,020,153	$0	$0	$138,850	$1,546,907	$0	$0	$0
11	Sub-total	**$85,020,153**	**$0**	**$0**	**$138,850**	**$1,546,907**	**$0**	**$0**	**$0**
12	Production								
13	Demand	$786,475	$2,007	$55	$819	$7,465	$105,131	$906	$1,463
14	Customer	$0	$0	$0	$0	$0	$0	$0	$0
15	Commodity	$861,702	$0	$0	$1,407	$15,678	$0	$0	$0
16	Sub-total	**$1,648,177**	**$2,007**	**$55**	**$2,226**	**$23,143**	**$105,131**	**$906**	**$1,463**
17	Storage								
18	Demand	$6,721,024	$0	$616	$9,701	$98,329	$0	$8,727	$0
19	Customer	$0	$0	$0	$0	$0	$0	$0	$0
20	Commodity	$0	$0	$0	$0	$0	$0	$0	$0
21	Sub-total	**$6,721,024**	**$0**	**$616**	**$9,701**	**$98,329**	**$0**	**$8,727**	**$0**
22	Transmission								
23	Demand	$10,134,163	$24,013	$615	$9,720	$98,285	$1,716,547	$7,713	$13,604
24	Customer	$0	$0	$0	$0	$0	$0	$0	$0
25	Commodity	$0	$0	$0	$0	$0	$0	$0	$0
26	Sub-total	**$10,134,163**	**$24,013**	**$615**	**$9,720**	**$98,285**	**$1,716,547**	**$7,713**	**$13,604**
27	Distribution								
28	Demand	$26,106,830	$67,169	$1,828	$27,146	$246,765	$3,526,461	$30,380	$49,031
29	Customer	$57,071,409	$14,526	$750	$6,718	$64,768	$280,577	$4,024	$6,922
30	Commodity	$0	$0	$0	$0	$0	$0	$0	$0
31	Sub-total	**$83,178,239**	**$81,695**	**$2,578**	**$33,864**	**$311,533**	**$3,807,039**	**$34,404**	**$55,953**
32	Customer								
33	Demand	$0	$0	$0	$0	$0	$0	$0	$0
34	Customer	$11,272,591	$28,241	$152	$2,572	$23,083	$176,976	$1,257	$10,875
35	Commodity	$0	$0	$0	$0	$0	$0	$0	$0
36	Sub-total	**$11,272,591**	**$28,241**	**$152**	**$2,572**	**$23,083**	**$176,976**	**$1,257**	**$10,875**
37	Grand Total								
38	Demand	$43,748,492	$93,189	$3,113	$47,385	$450,844	$5,348,139	$47,725	$64,098
39	Customer	$68,344,000	$42,766	$902	$9,290	$87,850	$457,553	$5,281	$17,797
40	Commodity	$85,881,856	$0	$0	$140,257	$1,562,586	$0	$0	$0
41	Sub-total	**$197,974,348**	**$135,955**	**$4,015**	**$196,933**	**$2,101,280**	**$5,805,693**	**$53,007**	**$81,895**

Michigan Gas Utilities Corporation
Gas Cost of Service Study
Test Year Ending December 31, 2025
Level 8 Revenue Requirements
Unbundled Revenue Requirement

Case No.: U-21540
Exhibit No.: A-16
Schedule: F1.3

Witness: Riley O'Brien

	(A)	(B)	(Q)	(R)
			Super Large	Other
Line No.	Line Description	Total MGU Natural Gas	Transport-TR-3	Special Contract
1	Units			
2	Throughput total	34,294,114	3,811,100	260
3	Customers average	186,733	4	1
4	Commodity total	18,763,259	0	260
5				
6	Revenue Requirement			
7	Cost of Gas			
8	Demand	$0	$0	$0
9	Customer	$0	$0	$0
10	Commodity	$85,020,153	$0	$1,179
11	Sub-total	**$85,020,153**	**$0**	**$1,179**
12	Production			
13	Demand	$786,475	$56,313	$40
14	Customer	$0	$0	$0
15	Commodity	$861,702	$0	$12
16	Sub-total	**$1,648,177**	**$56,313**	**$52**
17	Storage			
18	Demand	$6,721,024	$0	$276
19	Customer	$0	$0	$0
20	Commodity	$0	$0	$0
21	Sub-total	**$6,721,024**	**$0**	**$276**
22	Transmission			
23	Demand	$10,134,163	$955,548	$266
24	Customer	$0	$0	$0
25	Commodity	$0	$0	$0
26	Sub-total	**$10,134,163**	**$955,548**	**$266**
27	Distribution			
28	Demand	$26,106,830	$1,889,793	$1,156
29	Customer	$57,071,409	$26,264	$18,940
30	Commodity	$0	$0	$0
31	Sub-total	**$83,178,239**	**$1,916,057**	**$20,096**
32	Customer			
33	Demand	$0	$0	$0
34	Customer	$11,272,591	$55,018	$2,821
35	Commodity	$0	$0	$0
36	Sub-total	**$11,272,591**	**$55,018**	**$2,821**
37	Grand Total			
38	Demand	$43,748,492	$2,901,654	$1,738
39	Customer	$68,344,000	$81,282	$21,760
40	Commodity	$85,881,856	$0	$1,191
41	Sub-total	**$197,974,348**	**$2,982,936**	**$24,689**

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
			Residential			Small			
Line No.	Line Description	Total MGU Natural Gas	General Service-Residential	Customer Choice-Residential	Agg Transport-Residential	General Service-Small	Customer Choice GS-Small	Agg Transport-GS-Small	Transport-TR-1
1	Units								
2	Throughput total	34,294,114	12,443,860	1,346,322	2,666	5,947,106	951,896	420,113	2,129,704
3	Customers average	186,733	154,964	16,799	7	12,485	2,008	223	98
4	Commodity total	18,763,259	12,443,860	0	0	5,947,106	0	0	0
5									
6	Rate Base								
7	Cost of Gas								
8	Demand	$0	$0	$0	$0	$0	$0	$0	$0
9	Customer	$0	$0	$0	$0	$0	$0	$0	$0
10	Commodity	$0	$0	$0	$0	$0	$0	$0	$0
11	Sub-total	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
12	Production								
13	Demand	$0	$0	$0	$0	$0	$0	$0	$0
14	Customer	$0	$0	$0	$0	$0	$0	$0	$0
15	Commodity	$1,305,391	$865,740	$0	$0	$413,750	$0	$0	$0
16	Sub-total	**$1,305,391**	**$865,740**	**$0**	**$0**	**$413,750**	**$0**	**$0**	**$0**
17	Storage								
18	Demand	$48,847,969	$29,256,321	$3,167,901	$0	$13,422,424	$2,146,262	$0	$0
19	Customer	$0	$0	$0	$0	$0	$0	$0	$0
20	Commodity	$0	$0	$0	$0	$0	$0	$0	$0
21	Sub-total	**$48,847,969**	**$29,256,321**	**$3,167,901**	**$0**	**$13,422,424**	**$2,146,262**	**$0**	**$0**
22	Transmission								
23	Demand	$69,133,705	$27,482,659	$2,975,713	$5,477	$12,637,410	$2,020,851	$875,835	$3,855,105
24	Customer	$0	$0	$0	$0	$0	$0	$0	$0
25	Commodity	$0	$0	$0	$0	$0	$0	$0	$0
26	Sub-total	**$69,133,705**	**$27,482,659**	**$2,975,713**	**$5,477**	**$12,637,410**	**$2,020,851**	**$875,835**	**$3,855,105**
27	Distribution								
28	Demand	$133,513,796	$58,925,724	$6,385,638	$11,214	$25,939,670	$4,143,432	$1,857,107	$6,678,861
29	Customer	$256,013,493	$197,706,314	$21,174,485	$31,680	$27,992,149	$4,984,097	$1,108,784	$1,028,804
30	Commodity	$0	$0	$0	$0	$0	$0	$0	$0
31	Sub-total	**$389,527,289**	**$256,632,039**	**$27,560,123**	**$42,894**	**$53,931,818**	**$9,127,529**	**$2,965,891**	**$7,707,665**
32	Customer								
33	Demand	$0	$0	$0	$0	$0	$0	$0	$0
34	Customer	$252,461	$196,649	$21,201	$92	$22,170	$3,654	$3,156	$2,485
35	Commodity	$0	$0	$0	$0	$0	$0	$0	$0
36	Sub-total	**$252,461**	**$196,649**	**$21,201**	**$92**	**$22,170**	**$3,654**	**$3,156**	**$2,485**
37	Grand Total								
38	Demand	$251,495,470	$115,664,704	$12,529,252	$16,692	$51,999,504	$8,310,545	$2,732,942	$10,533,966
39	Customer	$256,265,954	$197,902,963	$21,195,686	$31,772	$28,014,319	$4,987,752	$1,111,940	$1,031,289
40	Commodity	$1,305,391	$865,740	$0	$0	$413,750	$0	$0	$0
41	Sub-total	**$509,066,815**	**$314,433,408**	**$33,724,938**	**$48,463**	**$80,427,573**	**$13,298,297**	**$3,844,882**	**$11,565,254**

Michigan Gas Utilities Corporation
Gas Cost of Service Study
Test Year Ending December 31, 2025
Level 8 Revenue Requirements
Unbundled Rate Base

	(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
			Medium			Large			
Line No.	Line Description	Total MGU Natural Gas	Agg Transport-GS-Medium	Customer Choice-GS-Medium	General Service-Medium	General Service-Large	Transport-TR-2	Customer Choice-GS-Large	Agg Transport-GS-Large
1	Units								
2	Throughput total	34,294,114	82,398	1,849	30,643	341,390	6,715,089	21,316	48,401
3	Customers average	186,733	16	1	17	62	40	3	6
4	Commodity total	18,763,259	0	0	30,643	341,390	0	0	0
5									
6	Rate Base								
7	Cost of Gas								
8	Demand	$0	$0	$0	$0	$0	$0	$0	$0
9	Customer	$0	$0	$0	$0	$0	$0	$0	$0
10	Commodity	$0	$0	$0	$0	$0	$0	$0	$0
11	Sub-total	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
12	Production								
13	Demand	$0	$0	$0	$0	$0	$0	$0	$0
14	Customer	$0	$0	$0	$0	$0	$0	$0	$0
15	Commodity	$1,305,391	$0	$0	$2,132	$23,751	$0	$0	$0
16	Sub-total	**$1,305,391**	**$0**	**$0**	**$2,132**	**$23,751**	**$0**	**$0**	**$0**
17	Storage								
18	Demand	$48,847,969	$0	$4,475	$70,503	$714,649	$0	$63,428	$0
19	Customer	$0	$0	$0	$0	$0	$0	$0	$0
20	Commodity	$0	$0	$0	$0	$0	$0	$0	$0
21	Sub-total	**$48,847,969**	**$0**	**$4,475**	**$70,503**	**$714,649**	**$0**	**$63,428**	**$0**
22	Transmission								
23	Demand	$69,133,705	$163,812	$4,197	$66,307	$670,483	$11,710,023	$52,614	$92,802
24	Customer	$0	$0	$0	$0	$0	$0	$0	$0
25	Commodity	$0	$0	$0	$0	$0	$0	$0	$0
26	Sub-total	**$69,133,705**	**$163,812**	**$4,197**	**$66,307**	**$670,483**	**$11,710,023**	**$52,614**	**$92,802**
27	Distribution								
28	Demand	$133,513,796	$340,680	$9,266	$138,986	$1,267,281	$17,847,206	$153,790	$248,412
29	Customer	$256,013,493	$57,644	$3,611	$33,888	$335,132	$1,296,416	$20,401	$30,144
30	Commodity	$0	$0	$0	$0	$0	$0	$0	$0
31	Sub-total	**$389,527,289**	**$398,324**	**$12,877**	**$172,874**	**$1,602,413**	**$19,143,622**	**$174,191**	**$278,556**
32	Customer								
33	Demand	$0	$0	$0	$0	$0	$0	$0	$0
34	Customer	$252,461	$174	$3	$39	$295	$2,094	$19	$86
35	Commodity	$0	$0	$0	$0	$0	$0	$0	$0
36	Sub-total	**$252,461**	**$174**	**$3**	**$39**	**$295**	**$2,094**	**$19**	**$86**
37	Grand Total								
38	Demand	$251,495,470	$504,492	$17,939	$275,796	$2,652,412	$29,557,229	$269,832	$341,214
39	Customer	$256,265,954	$57,818	$3,614	$33,927	$335,427	$1,298,510	$20,419	$30,230
40	Commodity	$1,305,391	$0	$0	$2,132	$23,751	$0	$0	$0
41	Sub-total	**$509,066,815**	**$562,310**	**$21,552**	**$311,855**	**$3,011,591**	**$30,855,739**	**$290,251**	**$371,444**

Michigan Gas Utilities Corporation
Gas Cost of Service Study
Test Year Ending December 31, 2025
Level 8 Revenue Requirements
Unbundled Rate Base

Case No.: U-21540
Exhibit No.: A-16
Schedule: F1.4
Page: 3 of 3
Witness: Riley O'Brien

	(A)	(B)	(Q)	(R)
			Super Large	Other
Line No.	Line Description	Total MGU Natural Gas	Transport-TR-3	Special Contract
1	Units			
2	Throughput total	34,294,114	3,811,100	260
3	Customers average	186,733	4	1
4	Commodity total	18,763,259	0	260
5				
6	Rate Base			
7	Cost of Gas			
8	Demand	$0	$0	$0
9	Customer	$0	$0	$0
10	Commodity	$0	$0	$0
11	Sub-total	**$0**	**$0**	**$0**
12	Production			
13	Demand	$0	$0	$0
14	Customer	$0	$0	$0
15	Commodity	$1,305,391	$0	$18
16	Sub-total	**$1,305,391**	**$0**	**$18**
17	Storage			
18	Demand	$48,847,969	$0	$2,006
19	Customer	$0	$0	$0
20	Commodity	$0	$0	$0
21	Sub-total	**$48,847,969**	**$0**	**$2,006**
22	Transmission			
23	Demand	$69,133,705	$6,518,603	$1,813
24	Customer	$0	$0	$0
25	Commodity	$0	$0	$0
26	Sub-total	**$69,133,705**	**$6,518,603**	**$1,813**
27	Distribution			
28	Demand	$133,513,796	$9,559,762	$6,767
29	Customer	$256,013,493	$129,983	$79,961
30	Commodity	$0	$0	$0
31	Sub-total	**$389,527,289**	**$9,689,744**	**$86,728**
32	Customer			
33	Demand	$0	$0	$0
34	Customer	$252,461	$315	$30
35	Commodity	$0	$0	$0
36	Sub-total	**$252,461**	**$315**	**$30**
37	Grand Total			
38	Demand	$251,495,470	$16,078,365	$10,586
39	Customer	$256,265,954	$130,297	$79,991
40	Commodity	$1,305,391	$0	$18
41	Sub-total	**$509,066,815**	**$16,208,662**	**$90,595**

Michigan Gas Utilities Corporation
Gas Cost of Service Study
Test Year Ending December 31, 2025
Level 8 Revenue Requirements
Unbundled Unit Costs

Case No.: U-21540
Exhibit No.: A-16
Schedule: F1.5
Page: 1 of 3
Witness: Riley O'Brien

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
			Residential			Small			
Line No.	Line Description	Total MGU Natural Gas	General Service-Residential	Customer Choice-Residential	Agg Transport-Residential	General Service-Small	Customer Choice GS-Small	Agg Transport-GS-Small	Transport-TR-1
1	Units								
2	Throughput total	34,294,114	12,443,860	1,346,322	2,666	5,947,106	951,896	420,113	2,129,704
3	Customers average	186,733	154,964	16,799	7	12,485	2,008	223	98
4	Commodity total	18,763,259	12,443,860	0	0	5,947,106	0	0	0
5									
6	Cost per Unit								
7	Cost of Gas								
8	Demand	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
9	Customer	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
10	Commodity	$4.5312	$4.5312	$0.0000	$0.0000	$4.5312	$0.0000	$0.0000	$0.0000
11	Production								
12	Demand	$0.0229	$0.0279	$0.0279	$0.0248	$0.0257	$0.0256	$0.0260	$0.0185
13	Customer	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
14	Commodity	$0.0459	$0.0459	$0.0000	$0.0000	$0.0459	$0.0000	$0.0000	$0.0000
15	Storage								
16	Demand	$0.3188	$0.3235	$0.3238	$0.0000	$0.3105	$0.3102	$0.0000	$0.0000
17	Customer	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
18	Commodity	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
19	Transmission								
20	Demand	$0.2955	$0.3237	$0.3240	$0.3011	$0.3115	$0.3112	$0.3056	$0.2653
21	Customer	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
22	Commodity	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
23	Distribution								
24	Demand	$0.7613	$0.9206	$0.9305	$0.8257	$0.8503	$0.8570	$0.8713	$0.6186
25	Customer	$25.4693	$23.9011	$23.7677	$89.0793	$39.1672	$43.9095	$96.5816	$186.3737
26	Commodity	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
27	Customer								
28	Demand	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
29	Customer	$5.0306	$4.4762	$4.4678	$127.6649	$6.6450	$6.5939	$133.8502	$190.4017
30	Commodity	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
31	Grand Total								
32	Demand	$1.3985	$1.5957	$1.6062	$1.1517	$1.4981	$1.5040	$1.2030	$0.9024
33	Customer	$30.4999	$28.3773	$28.2355	$216.7441	$45.8121	$50.5035	$230.4318	$376.7754
34	Commodity	$4.5771	$4.5771	$0.0000	$0.0000	$4.5771	$0.0000	$0.0000	$0.0000

Michigan Gas Utilities Corporation
Gas Cost of Service Study
Test Year Ending December 31, 2025
Level 8 Revenue Requirements
Unbundled Unit Costs

	(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
			Medium			Large			
Line No.	Line Description	Total MGU Natural Gas	Agg Transport-GS-Medium	Customer Choice-GS-Medium	General Service-Medium	General Service-Large	Transport-TR-2	Customer Choice-GS-Large	Agg Transport-GS-Large
1	Units								
2	Throughput total	34,294,114	82,398	1,849	30,643	341,390	6,715,089	21,316	48,401
3	Customers average	186,733	16	1	17	62	40	3	6
4	Commodity total	18,763,259	0	0	30,643	341,390	0	0	0
5									
6	Cost per Unit								
7	Cost of Gas								
8	Demand	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
9	Customer	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
10	Commodity	$4.5312	$0.0000	$0.0000	$4.5312	$4.5312	$0.0000	$0.0000	$0.0000
11	Production								
12	Demand	$0.0229	$0.0244	$0.0295	$0.0267	$0.0219	$0.0157	$0.0425	$0.0302
13	Customer	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
14	Commodity	$0.0459	$0.0000	$0.0000	$0.0459	$0.0459	$0.0000	$0.0000	$0.0000
15	Storage								
16	Demand	$0.3188	$0.0000	$0.3331	$0.3166	$0.2880	$0.0000	$0.4094	$0.0000
17	Customer	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
18	Commodity	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
19	Transmission								
20	Demand	$0.2955	$0.2914	$0.3328	$0.3172	$0.2879	$0.2556	$0.3618	$0.2811
21	Customer	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
22	Commodity	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
23	Distribution								
24	Demand	$0.7613	$0.8152	$0.9886	$0.8859	$0.7228	$0.5252	$1.4252	$1.0130
25	Customer	$25.4693	$75.6552	$62.5224	$32.7511	$87.1689	$584.5362	$111.7844	$101.7100
26	Commodity	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
27	Customer								
28	Demand	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
29	Customer	$5.0306	$147.0860	$12.6346	$12.5403	$31.0664	$368.7003	$34.9208	$159.7973
30	Commodity	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
31	Grand Total								
32	Demand	$1.3985	$1.1310	$1.6840	$1.5464	$1.3206	$0.7964	$2.2389	$1.3243
33	Customer	$30.4999	$222.7412	$75.1570	$45.2913	$118.2353	$953.2364	$146.7052	$261.5074
34	Commodity	$4.5771	$0.0000	$0.0000	$4.5771	$4.5771	$0.0000	$0.0000	$0.0000

Michigan Gas Utilities Corporation
Gas Cost of Service Study
Test Year Ending December 31, 2025
Level 8 Revenue Requirements
Unbundled Unit Costs

Case No.: U-21540
Exhibit No.: A-16
Schedule: F1.5
Page: 3 of 3
Witness: Riley O'Brien

	(A)	(B)	(Q)	(R)
			Super Large	Other
Line No.	Line Description	Total MGU Natural Gas	Transport-TR-3	Special Contract
1	Units			
2	Throughput total	34,294,114	3,811,100	260
3	Customers average	186,733	4	1
4	Commodity total	18,763,259	0	260
5				
6	Cost per Unit			
7	Cost of Gas			
8	Demand	$0.0000	$0.0000	$0.0000
9	Customer	$0.0000	$0.0000	$0.0000
10	Commodity	$4.5312	$0.0000	$4.5312
11	Production			
12	Demand	$0.0229	$0.0148	$0.1532
13	Customer	$0.0000	$0.0000	$0.0000
14	Commodity	$0.0459	$0.0000	$0.0459
15	Storage			
16	Demand	$0.3188	$0.0000	$1.0607
17	Customer	$0.0000	$0.0000	$0.0000
18	Commodity	$0.0000	$0.0000	$0.0000
19	Transmission			
20	Demand	$0.2955	$0.2507	$1.0212
21	Customer	$0.0000	$0.0000	$0.0000
22	Commodity	$0.0000	$0.0000	$0.0000
23	Distribution			
24	Demand	$0.7613	$0.4959	$4.4439
25	Customer	$25.4693	$547.1724	$1,578.3135
26	Commodity	$0.0000	$0.0000	$0.0000
27	Customer			
28	Demand	$0.0000	$0.0000	$0.0000
29	Customer	$5.0306	$1,146.2103	$235.0495
30	Commodity	$0.0000	$0.0000	$0.0000
31	Grand Total			
32	Demand	$1.3985	$0.7614	$6.6789
33	Customer	$30.4999	$1,693.3827	$1,813.3630
34	Commodity	$4.5771	$0.0000	$4.5771

Schedule F2.1

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Summary of Present and Proposed Revenue by Rate Schedule
Including Cost of Gas

Case No.:	U-21540
Exhibit No.:	A-16
Schedule:	F2.1
Page:	1 of 1
Witness:	S. L. Burzycki
Date:	March 1, 2024

Line No.	MGUC Rate Schedule	Current Revenue $	Proposed Revenue $	Revenue Increase $	Revenue Increase %
1	Residential	$115,634,942	$129,576,704	$13,941,762	12.06%
2	General Service - Small (incl. Comm. Lighting)	43,264,250	44,214,377	950,127	2.20%
3	General Service - Medium	204,417	206,539	2,122	1.04%
4	General Service - Large	2,274,910	2,313,900	38,990	1.71%
5	Special Contract	99,923	99,938	16	0.02%
6	TR-1 Transport	2,763,034	2,989,403	226,369	8.19%
7	TR-2 Transport	4,164,919	4,641,786	476,867	11.45%
8	TR-3 Transport	1,761,718	2,017,129	255,411	14.50%
9	Aggregated - Residential to Residential	10,323	13,292	2,969	28.76%
10	Aggregated - Small to General Service - Small	916,976	941,699	24,723	2.70%
11	Aggregated - Small to General Service - Medium	159,251	162,601	3,350	2.10%
12	Aggregated - Large to General Service - Large	86,914	91,180	4,265	4.91%
13	Choice - Residential	6,369,882	7,869,110	1,499,228	23.54%
14	Choice - General Service - Small	2,578,055	2,724,176	146,121	5.67%
15	Choice - General Service - Medium	3,865	3,979	114	2.94%
16	Choice - General Service - Large	40,206	42,236	2,030	5.05%
17	Inc Assistance Cr in Misc Rev (COSS Sched 13)	65,100	66,300	1,200	1.84%
18	Rounding	651		(651)	0.00%
19	**TOTAL MGUC**	$180,399,335	$197,974,348	$17,575,013	9.74%

Note: Gas costs are included in both the Current Revenues or the Proposed Revenues above.

Schedule F2.2

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Summary of Present and Proposed Revenue by Rate Schedule
Excluding Cost of Gas

Case No.: U-21540
Exhibit No.: A-16
Schedule: F2.2
Page: 1 of 1
Witness: S. L. Burzycki
Date: March 1, 2024

Line No.	MGUC Rate Schedule	Current Revenue $	Proposed Revenue $	Revenue Increase $	Revenue Increase %
1	Residential	$59,249,323	$73,191,085	$13,941,762	23.5%
2	General Service - Small (incl. Comm. Lighting)	16,316,722	17,266,849	950,127	5.8%
3	General Service - Medium	65,567	67,689	2,122	3.2%
4	General Service - Large	728,003	766,993	38,990	5.4%
5	Special Contract	98,744	98,759	16	0.0%
6	TR-1 Transport	2,763,034	2,989,403	226,369	8.2%
7	TR-2 Transport	4,164,919	4,641,786	476,867	11.4%
8	TR-3 Transport	1,761,718	2,017,129	255,411	14.5%
9	Aggregated - Residential to Residential	10,323	13,292	2,969	28.8%
10	Aggregated - Small to General Service - Small	916,976	941,699	24,723	2.7%
11	Aggregated - Small to General Service - Medium	159,251	162,601	3,350	2.1%
12	Aggregated - Large to General Service - Large	86,914	91,180	4,265	4.9%
13	Choice - Residential	6,369,882	7,869,110	1,499,228	23.5%
14	Choice - General Service - Small	2,578,055	2,724,176	146,121	5.7%
15	Choice - General Service - Medium	3,865	3,979	114	2.9%
16	Choice - General Service - Large	40,206	42,236	2,030	5.0%
17	Inc Assistance Cr in Misc Rev (COSS Sched 13)	65,100	66,300	1,200	5.0%
18	Rounding	651		(651)	
19	**TOTAL MGUC**	$95,379,254	$112,954,266	$17,575,013	18.3%

Note: No gas costs are included in either the Current Revenues or the Proposed Revenues above.

Schedule F3.1

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Present and Proposed Revenue Detail Including Cost of Gas

Case No.: U-21540
Exhibit No.: A-16
Schedule: F3.1
Page: 1 of 6
Witness: S. L. Burzycki
Date: March 1, 2024

	(a)	(b)		(c)	(d)	(e)	(f)
		Billing Determinants		**Present**		**Proposed**	
Line No.	**Description**	**Quantity**	**Units**	**Rate**	**Revenue**	**Rate**	**Revenue**
1	**Residential***						
2	Monthly Customer Charge	1,859,554	Bills	$13.00	$24,174,207	$13.00	$24,174,207
3	Distribution Charge	12,443,860	Mcf	2.7848	34,653,661	3.8984	48,510,805
4	Gas Supply Acquisition Charge	12,443,860	Mcf	0.0391	486,555	0.0459	571,173
5	Cost of Gas	12,443,860	Mcf	4.5312	56,385,618	4.5312	56,385,618
6	**Provisions**						
7	Income Assistance - RIA	1,200	Bills	$ (13.00)	($15,600)	$ (13.00)	($15,600)
8	Income Assistance - SIA	3,000	Bills	$ (6.50)	(19,500)	$ (6.50)	(19,500)
9	Income Assistance - LIAC	1,000	Bills	$ (30.00)	(30,000)	$ (30.00)	(30,000)
10	**Total Residential**				**$115,634,942**		**$129,576,704**
11							
12	**Notice Calculation**						
13	Monthly Customer Charges	12	Bills	$13.00	$156	$13.00	$156
14	Distribution Charge	80.3	Mcf	2.7848	224	3.8984	313
15	Gas Supply Acquisition Charge	80.3	Mcf	0.0391	3	0.0459	4
16	Cost of Gas	80.3	Mcf	4.5312	364	4.5312	364
17	**Total Annual Residential Bill**				**$747**		**$837**
18							
19	**Annual Residential Increase**					12.0%	**$89.97**
20	**Monthly Residential Increase**					12.0%	**$7.50**

Schedule F3.1

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Present and Proposed Revenue Detail Including Cost of Gas

Case No.: U-21540
Exhibit No.: A-16
Schedule: F3.1
Page: 2 of 6
Witness: S. L. Burzycki
Date: March 1, 2024

	(a)	(b)		(c)	(d)	(e)	(f)
		Billing Determinants		Present		Proposed	
Line No.	Description	Quantity	Units	Rate	Revenue	Rate	Revenue
1	**General Service - Small* (incl. Comm. Lighting)**						
2	Monthly Customer Charge	149,823	Bills	$35.00	$5,243,805	$40.00	$5,992,920
3	Distribution Charge	5,947,106.2	Mcf	1.8228	10,840,385	1.8498	11,000,957
4	Gas Supply Acquisition Charge	5,947,106.2	Mcf	0.0391	232,532	0.0459	272,972
5	Cost of Gas	5,947,106.2	Mcf	4.5312	26,947,528	4.5312	26,947,528
6	**Total General Service - Small**				**$43,264,250**		**$44,214,377**
7							
8							
9	**General Service - Medium***						
10	Monthly Customer Charge	205	Bills	50.00	$10,250	55.00	$11,275
11	Distribution Charge	30,643.0	Mcf	1.7661	54,119	1.7951	55,007
12	Gas Supply Acquisition Charge	30,643.0	Mcf	0.0391	1,198	0.0459	1,407
13	Cost of Gas	30,643.0	Mcf	4.5312	138,850	4.5312	138,850
14	**Total General Service - Medium**				**$204,417**		**$206,539**
15							
16							
17	**General Service - Large***						
18	Monthly Customer Charge	743	Bills	$425.00	$315,775	$450.00	$334,350
19	Distribution Charge	341,390.0	Mcf	1.1684	398,880	1.2214	416,974
20	Gas Supply Acquisition Charge	341,390.0	Mcf	0.0391	13,348	0.0459	15,670
21	Cost of Gas	341,390.0	Mcf	4.5312	1,546,906	4.5312	1,546,906
22	**Total General Service - Large**				**$2,274,910**		**$2,313,900**

Schedule F3.1

Michigan Public Service Commission	Case No.: U-21540
Michigan Gas Utilities Corporation	Exhibit No.: A-16
Present and Proposed Revenue Detail Including Cost of Gas	Schedule: F3.1
	Page: 3 of 6
	Witness: S. L. Burzycki
	Date: March 1, 2024

	(a)	(b)		(c)	(d)	(e)	(f)
		Billing Determinants		**Present**		**Proposed**	
Line No.	**Description**	**Quantity**	**Units**	**Rate**	**Revenue**	**Rate**	**Revenue**
1	**Special Contract**						
2	Monthly Customer Charge	12	Bills	$8,202	$98,429	$8,202.45	$98,429
3	Distribution Charge	260.2	Mcf	1.2075	314	1.2673	330
4	Gas Supply Acquisition Charge	260.2	Mcf	0.0000	0	0.0000	0
5	Cost of Gas	260.2	Mcf	4.5312	1,179	4.5312	1,179
6	**Total Special Contract**				**$99,923**		**$99,938**

Schedule F3.1

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Present and Proposed Revenue Detail Including Cost of Gas

Case No.: U-21540
Exhibit No.: A-16
Schedule: F3.1
Page: 4 of 6
Witness: S. L. Burzycki
Date: March 1, 2024

	(a)	(b)		(c)	(d)	(e)	(f)
Line		**Billing Determinants**		**Present**		**Proposed**	
No.	**Description**	**Quantity**	**Units**	**Rate**	**Revenue**	**Rate**	**Revenue**
1	**TR-1 Transport**						
2	Customer Charge	1,176	Bills	$925.00	$1,087,800	$1,000.00	$1,176,000
3	Distribution Charge - Peak	1,185,486.7	Mcf	0.8606	1,020,230	0.9133	1,082,705
4	Off Peak	944,217.6	Mcf	0.6937	655,004	0.7739	730,698
5	**Total TR-1 Transport**				**$2,763,034**		**$2,989,403**
1	**TR-2 Transport**						
2	Customer Charge	480	Bills	$ 2,525.00	$1,212,000	$ 2,600.00	$1,248,000
3	Distribution Charge - Peak	3,157,022.6	Mcf	0.5268	1,663,120	0.5779	1,824,443
4	Off Peak	3,558,066.2	Mcf	0.3625	1,289,799	0.4411	1,569,342
5	**Total TR-2 Transport**				**$4,164,919**		**$4,641,786**
1	**TR-3 Transport**						
2	Customer Charge	48	Bills	$ 3,205.00	$153,840	$ 3,300.00	$158,400
3	Distribution Charge - Peak	1,706,689.4	Mcf	0.5135	876,385	0.5641	962,743
4	Off Peak	2,104,410.6	Mcf	0.3476	731,493	0.4258	895,986
5	**Total TR-3 Transport**				**$1,761,718**		**$2,017,129**

Schedule F3.1

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Present and Proposed Revenue Detail Including Cost of Gas

Case No.: U-21540
Exhibit No.: A-16
Schedule: F3.1

Witness: S. L. Burzycki
Date: March 1, 2024

	(a)	(b)		(c)	(d)	(e)	(f)
		Billing Determinants		Present		Proposed	
Line No.	Description	Quantity	Units	Rate	Revenue	Rate	Revenue
1	**Aggregated - Residential to Residential**						
2	Customer Charge	84	Bills	$ 34.50	$2,898	$ 34.50	$2,898
3	Distribution Charge	2,666.3	Mcf	2.7848	7,425	3.8984	10,394
4	Total				**$10,323**		**$13,292**
5							
6	**Aggregated - Small to General Service - Small**						
7	Customer Charge	2,676	Bills	56.50	$151,194	61.50	$ 164,574
8	Distribution Charge	420,112.8	Mcf	1.8228	765,782	1.8498	777,125
9	Total				**$916,976**		**$941,699**
10							
11	**Aggregated - Small to General Service - Medium**						
12	Customer Charge	192	Bills	71.50	$13,728	76.50	$ 14,688
13	Distribution Charge	82,398.2	Mcf	1.7661	145,523	1.7951	147,913
14	Total				**$159,251**		**$162,601**
15							
16	**Aggregated - Large to General Service - Large**						
17	Customer Charge	68	Bills	446.50	$30,362	471.50	$ 32,062
18	Distribution Charge	48,401.4	Mcf	1.1684	56,552	1.2214	59,118
19	Total				**$86,914**		**$91,180**
20							
21	**Total Aggregated**				**$1,014,213**		**$1,046,170**

Schedule F3.1

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Present and Proposed Revenue Detail Including Cost of Gas

Case No.: U-21540
Exhibit No.: A-16
Schedule: F3.1

Witness: S. L. Burzycki
Date: March 1, 2024

	(a)	(b)		(c)	(d)	(e)	(f)
Line		**Billing Determinants**		**Present**		**Proposed**	
No.	**Description**	**Quantity**	**Units**	**Rate**	**Revenue**	**Rate**	**Revenue**
1	**Choice - Residential**						
2	Customer Charge	201,588	Bills	$ 13.00	$2,620,644	$ 13.00	$2,620,644
3	Distribution Charge	1,346,322.3	Mcf	2.7848	3,749,238	3.8984	5,248,466
4	Total				**$6,369,882**		**$7,869,110**
5							
6	**Choice - General Service - Small**						
7	Customer Charge	24,084	Bills	35.00	$842,940	40.00	$963,360
8	Distribution Charge	951,895.6	Mcf	1.8228	1,735,115	1.8498	1,760,816
9	Total				**$2,578,055**		**$2,724,176**
10							
11	**Choice - General Service - Medium**						
12	Customer Charge	12	Bills	50.00	$600	55.00	$660
13	Distribution Charge	1,848.8	Mcf	1.7661	3,265	1.7951	3,319
14	Total				**$3,865**		**$3,979**
15							
16	**Choice - General Service - Large**						
17	Customer Charge	36	Bills	425.00	$15,300	450.00	$16,200
18	Distribution Charge	21,316.3	Mcf	1.1684	24,906	1.2214	26,036
19	Total				**$40,206**		**$42,236**
20							
21	**Total Choice**				**$8,988,143**		**$10,635,522**
22							
23	**MGUC Totals**						
24	Monthly Customer Charge	2,240,781.4	Bills		$35,973,773		$37,008,668
25	Income Assistance Provision Credits	5,200.0	Bills		($65,100)		($65,100)
26	Distribution Charge	34,294,114.1	Mcf		58,671,196.6		75,083,177.1
27	Gas Supply Acquisition Charge	18,732,616.4	Mcf		733,633		861,222
28	Cost of Gas	18,732,616.4	Mcf		85,020,081		85,020,081
29	**Total MGUC**				**$180,333,584**		**$197,908,048**

Schedule F3.2

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Present and Proposed Revenue Detail Excluding Cost of Gas

Case No.: U-21540
Exhibit No.: A-16
Schedule: F3.2

Witness: S. L. Burzycki
Date: March 1, 2024

	(a)	(b)		(c)	(d)	(e)	(f)
		Billing Determinants		**Present**		**Proposed**	
Line No.	**Description**	**Quantity**	**Units**	**Rate**	**Revenue**	**Rate**	**Revenue**
1	**Residential***						
2	Monthly Customer Charge	1,859,554	Bills	$13.00	$24,174,207	$13.00	$24,174,207
3	Distribution Charge	12,443,860	Mcf	2.7848	34,653,661	3.8984	48,510,805
4	Gas Supply Acquisition Charge	12,443,860	Mcf	0.0391	486,555	0.0459	571,173
5	Cost of Gas	12,443,860	Mcf	0.0000	0	0.0000	0
6	**Provisions**						
7	Income Assistance - RIA	1,200	Bills	$ (13.00)	($15,600)	$ (13.00)	($15,600)
8	Income Assistance - SIA	3,000	Bills	$ (6.50)	(19,500)	$ (6.50)	(19,500)
9	Income Assistance - LIAC	1,000	Bills	$ (30.00)	(30,000)	$ (30.00)	(30,000)
10	**Total Residential**				**$59,249,323**		**$73,191,085**
11							
12	**Notice Calculation**						
13	Monthly Customer Charges	12	Bills	$13.00	$156	$13.00	$156
14	Distribution Charge	80.3	Mcf	2.7848	224	3.8984	313
15	Gas Supply Acquisition Charge	80.3	Mcf	0.0391	3	0.0459	4
16	Cost of Gas	80.3	Mcf	0.0000	0	0.0000	0
17	**Total Annual Residential Bill**				**$383**		**$473**
18							
19	**Annual Residential Increase**						**$89.97**
20							
21	**Monthly Residential Increase**						**$7.50**

Schedule F3.2

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Present and Proposed Revenue Detail Excluding Cost of Gas

Case No.: U-21540
Exhibit No.: A-16
Schedule: F3.2
Page: 2 of 6
Witness: S. L. Burzycki
Date: March 1, 2024

	(a)	(b)		(c)	(d)	(e)	(f)
Line		**Billing Determinants**		**Present**		**Proposed**	
No.	**Description**	**Quantity**	**Units**	**Rate**	**Revenue**	**Rate**	**Revenue**
1	**General Service - Small* (incl. Comm. Lighting)**						
2	Monthly Customer Charge	149,823	Bills	$35.00	$5,243,805	$40.00	$5,992,920
3	Distribution Charge	5,947,106.2	Mcf	1.8228	10,840,385	1.8498	11,000,957
4	Gas Supply Acquisition Charge	5,947,106.2	Mcf	0.0391	232,532	0.0459	272,972
5	Cost of Gas	5,947,106.2	Mcf	0.0000	0	0.0000	0
6	**Total General Service - Small**				**$16,316,722**		**$17,266,849**
7							
8							
9	**General Service - Medium***						
10	Monthly Customer Charge	205	Bills	50.00	$10,250	55.00	$11,275
11	Distribution Charge	30,643.0	Mcf	1.7661	54,119	1.7951	55,007
12	Gas Supply Acquisition Charge	30,643.0	Mcf	0.0391	1,198	0.0459	1,407
13	Cost of Gas	30,643.0	Mcf	0.0000	0	0.0000	0
14	**Total General Service - Medium**				**$65,567**		**$67,689**
15							
16							
17	**General Service - Large***						
18	Monthly Customer Charge	743	Bills	$425.00	$315,775	$450.00	$334,350
19	Distribution Charge	341,390.0	Mcf	1.1684	398,880	1.2214	416,974
20	Gas Supply Acquisition Charge	341,390.0	Mcf	0.0391	13,348	0.0459	15,670
21	Cost of Gas	341,390.0	Mcf	0.0000	0	0.0000	0
22	**Total General Service - Large**				**$728,003**		**$766,993**

Schedule F3.2

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Present and Proposed Revenue Detail Excluding Cost of Gas

Case No.: U-21540
Exhibit No.: A-16
Schedule: F3.2
Page: 3 of 6
Witness: S. L. Burzycki
Date: March 1, 2024

	(a)	(b)		(c)	(d)	(e)	(f)
Line		**Billing Determinants**		**Present**		**Proposed**	
No.	**Description**	**Quantity**	**Units**	**Rate**	**Revenue**	**Rate**	**Revenue**
1	**Special Contract**						
2	Monthly Customer Charge	12	Bills	$8,202.45	$98,429	$8,202.45	$98,429
3	Distribution Charge	260.2	Mcf	1.2075	314	1.2673	330
4	Gas Supply Acquisition Charge	260.2	Mcf	0.0000	0	0.0000	0
5	Cost of Gas	260.2	Mcf	0.0000	0	0.0000	0
6	**Total Special Contract**				**$98,744**		**$98,759**

Schedule F3.2

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Present and Proposed Revenue Detail Excluding Cost of Gas

Case No.: U-21540
Exhibit No.: A-16
Schedule: F3.2
Page: 4 of 6
Witness: S. L. Burzycki
Date: March 1, 2024

	(a)	(b)		(c)	(d)	(e)	(f)
Line		**Billing Determinants**		**Present**		**Proposed**	
No.	**Description**	**Quantity**	**Units**	**Rate**	**Revenue**	**Rate**	**Revenue**
1	**TR-1 Transport**						
2	Customer Charge	1,176	Bills	$925.00	$1,087,800	$1,000.00	$1,176,000
3	Distribution Charge - Peak	1,185,486.7	Mcf	0.8606	1,020,230	0.9133	1,082,705
4	Off Peak	944,217.6	Mcf	0.6937	655,004	0.7739	730,698
5	**Total TR-1 Transport**				**$2,763,034**		**$2,989,403**
6							
7							
8	**TR-2 Transport**						
9	Customer Charge	480	Bills	$ 2,525.00	$1,212,000	$ 2,600.00	$1,248,000
10	Distribution Charge - Peak	3,157,022.6	Mcf	0.5268	1,663,120	0.5779	1,824,443
11	Off Peak	3,558,066.2	Mcf	0.3625	1,289,799	0.4411	1,569,342
12	**Total TR-2 Transport**				**$4,164,919**		**$4,641,786**
13							
14							
15	**TR-3 Transport**						
16	Customer Charge	48	Bills	$ 3,205.00	$153,840	$ 3,300.00	$158,400
17	Distribution Charge - Peak	1,706,689.4	Mcf	0.5135	876,385	0.5641	962,743
18	Off Peak	2,104,410.6	Mcf	0.3476	731,493	0.4258	895,986
19	**Total TR-3 Transport**				**$1,761,718**		**$2,017,129**

Schedule F3.2

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Present and Proposed Revenue Detail Excluding Cost of Gas

Case No.: U-21540
Exhibit No.: A-16
Schedule: F3.2

Witness: S. L. Burzycki
Date: March 1, 2024

	(a)	(b)		(c)	(d)	(e)	(f)
Line No.	Description	Billing Determinants Quantity	Units	Present Rate	Present Revenue	Proposed Rate	Proposed Revenue
1	**Aggregated - Residential to Residential**						
2	Customer Charge	84	Bills	$ 34.50	$2,898	$ 34.50	$2,898
3	Distribution Charge	2,666.3	Mcf	2.7848	7,425	3.8984	10,394
4	Total				**$10,323**		**$13,292**
5							
6	**Aggregated - Small to General Service - Small**						
7	Customer Charge	2,676	Bills	56.50	$151,194	61.50	$ 164,574
8	Distribution Charge	420,112.8	Mcf	1.8228	765,782	1.8498	777,125
9	Total				**$916,976**		**$941,699**
10							
11	**Aggregated - Small to General Service - Medium**						
12	Customer Charge	192	Bills	71.50	$13,728	76.50	$ 14,688
13	Distribution Charge	82,398.2	Mcf	1.7661	145,523	1.7951	147,913
14	Total				**$159,251**		**$162,601**
15							
16	**Aggregated - Large to General Service - Large**						
17	Customer Charge	68	Bills	446.50	$30,362	471.50	$ 32,062
18	Distribution Charge	48,401.4	Mcf	1.1684	56,552	1.2214	59,118
19	Total				**$86,914**		**$91,180**
20							
21	**Total Aggregated**				**$1,014,213**		**$1,046,170**

Schedule F3.2

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Present and Proposed Revenue Detail Excluding Cost of Gas

Case No.: U-21540
Exhibit No.: A-16
Schedule: F3.2

Witness: S. L. Burzycki
Date: March 1, 2024

	(a)	(b)		(c)	(d)	(e)	(f)
Line		Billing Determinants		Present		Proposed	
No.	Description	Quantity	Units	Rate	Revenue	Rate	Revenue
1	**Choice - Residential**						
2	Customer Charge	201,588	Bills	$ 13.00	$2,620,644	$ 13.00	$2,620,644
3	Distribution Charge	1,346,322.3	Mcf	2.7848	3,749,238	3.8984	5,248,466
4	Total				**$6,369,882**		**$7,869,110**
5							
6	**Choice - General Service - Small**						
7	Customer Charge	24,084	Bills	35.00	$842,940	40.00	$963,360
8	Distribution Charge	951,895.6	Mcf	1.8228	1,735,115	1.8498	1,760,816
9	Total				**$2,578,055**		**$2,724,176**
10							
11	**Choice - General Service - Medium**						
12	Customer Charge	12	Bills	50.00	$600	55.00	$660
13	Distribution Charge	1,848.8	Mcf	1.7661	3,265	1.7951	3,319
14	Total				**$3,865**		**$3,979**
15							
16	**Choice - General Service - Large**						
17	Customer Charge	36	Bills	425.00	$15,300	450.00	$16,200
18	Distribution Charge	21,316.3	Mcf	1.1684	24,906	1.2214	26,036
19	Total				**$40,206**		**$42,236**
20							
21	**Total Choice**				**$8,988,143**		**$10,635,522**
22							
23	**MGUC Totals**						
24	Monthly Customer Charge	2,240,781	Bills		$35,973,773		$37,008,668
25	Income Assistance Provision Credits	5,200	Bills		($65,100)		($65,100)
26	Distribution Charge	34,294,114.1	Mcf		58,671,197		75,083,177
27	Gas Supply Acquisition Charge	18,732,616.4	Mcf		733,633		861,222
28	Cost of Gas	18,732,616.4	Mcf		0		0
29	**Total MGUC**				**$95,313,503**		**$112,887,966**

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Comparison of Present and Proposed Monthly Bills

RESIDENTIAL Service Rate

Case No.: U-21540
Exhibit No.: A-16
Schedule: F4

Witness: S. L. Burzycki
Date: March 1, 2024

	(a)	(b)	(c)	(d)	(e)	(f)
				Increase		
Line No.	Monthly Usage (Mcf)	Present Net Monthly Bill ($/Month)	Proposed Net Monthly Bill ($/Month)	Amount ($/Month)	Percent (%)	Unit Cost ($/Mcf)
1	0	$13.00	$13.00	$0.00	0.00%	
2	2	27.71	29.95	2.24	8.09%	$14.98
3	5	49.78	55.38	5.60	11.25%	11.08
4	7	64.49	72.33	7.84	12.16%	10.33
5	10	86.55	97.75	11.20	12.94%	9.78
6	15	123.33	140.13	16.81	13.63%	9.34
7	20	160.10	182.51	22.41	14.00%	9.13
8	25	196.88	224.89	28.01	14.23%	9.00
9	30	233.65	267.26	33.61	14.39%	8.91

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Comparison of Present and Proposed Monthly Bills

SMALL GENERAL SERVICE Rate

Case No.: U-21540
Exhibit No.: A-16
Schedule: F4
Page: 2 of 7
Witness: S. L. Burzycki
Date: March 1, 2024

	(a)	(b)	(c)	(d)	(e)	(f)
				Increase		
Line No.	Monthly Usage (Mcf)	Present Net Monthly Bill ($/Month)	Proposed Net Monthly Bill ($/Month)	Amount ($/Month)	Percent (%)	Unit Cost ($/Mcf)
1	0	$35.00	$40.00	$5.00	14.29%	
2	10	98.93	104.27	5.34	5.40%	$10.43
3	25	194.83	200.67	5.84	3.00%	8.03
4	50	354.66	361.35	6.69	1.89%	7.23
5	75	514.48	522.02	7.53	1.46%	6.96
6	100	674.31	682.69	8.38	1.24%	6.83

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Comparison of Present and Proposed Monthly Bills

MEDIUM GENERAL SERVICE Rate

Case No.: U-21540
Exhibit No.: A-16
Schedule: F4
Page: 3 of 7
Witness: S. L. Burzycki
Date: March 1, 2024

	(a)	(b)	(c)	(d)	(e)	(f)
				Increase		
Line No.	Monthly Usage (Mcf)	Present Net Monthly Bill ($/Month)	Proposed Net Monthly Bill ($/Month)	Amount ($/Month)	Percent (%)	Unit Cost ($/Mcf)
1	0	$50.00	$55.00	$5.00	10.00%	
2	10	$113.36	$118.72	5.36	4.73%	$11.87
3	50	$366.82	$373.61	6.79	1.85%	7.47
4	100	$683.64	$692.22	8.58	1.26%	6.92
5	500	$3,218.20	$3,241.10	22.90	0.71%	6.48
6	1,000	$6,386.40	$6,427.20	40.80	0.64%	6.43

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Comparison of Present and Proposed Monthly Bills

LARGE GENERAL SERVICE Rate

Case No.: U-21540
Exhibit No.: A-16
Schedule: F4
Page: 4 of 7
Witness: S. L. Burzycki
Date: March 1, 2024

	(a)	(b)	(c)	(d)	(e)	(f)
				Increase		
Line No.	**Monthly Usage (Mcf)**	**Present Net Monthly Bill ($/Month)**	**Proposed Net Monthly Bill ($/Month)**	**Amount ($/Month)**	**Percent (%)**	**Unit Cost ($/Mcf)**
1	0	$425.00	$450.00	$25.00	5.88%	
2	10	482.39	507.99	25.60	5.31%	$50.80
3	50	711.94	739.93	27.99	3.93%	14.80
4	100	998.87	1,029.85	30.98	3.10%	10.30
5	250	1,859.68	1,899.63	39.95	2.15%	7.60
6	500	3,294.35	3,349.25	54.90	1.67%	6.70
7	750	4,729.03	4,798.88	69.85	1.48%	6.40
8	1,000	6,163.70	6,248.50	84.80	1.38%	6.25
9	1,250	7,598.38	7,698.13	99.75	1.31%	6.16
10	1,500	9,033.05	9,147.75	114.70	1.27%	6.10

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Comparison of Present and Proposed Monthly Bills

TRANSPORT Service Rate

Case No.: U-21540
Exhibit No.: A-16
Schedule: F4
Page: 5 of 7
Witness: S. L. Burzycki
Date: March 1, 2024

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
					Increase		
Line No.	Meter Class	Monthly Usage (Mcf)	Present Net Monthly Bill ($/Month)	Proposed Net Monthly Bill ($/Month)	Amount ($/Month)	Percent (%)	Unit Cost ($/Mcf)
1	TR-1 Transport	0	925.00	1,000.00	$75.00	8.11%	
2	TR-1 Transport	500	1,318.30	1,425.74	107.44	8.15%	$2.85
3	TR-1 Transport	1,000	1,711.60	1,851.48	139.88	8.17%	1.85
4	TR-1 Transport	2,000	2,498.21	2,702.96	204.75	8.20%	1.35
5	TR-1 Transport	3,000	3,284.81	3,554.44	269.63	8.21%	1.18
6							
7	TR-2 Transport	0	2,525.00	2,600.00	75.00	2.97%	
8	TR-2 Transport	1,000	2,964.74	3,105.40	140.65	4.74%	$3.11
9	TR-2 Transport	2,500	3,624.36	3,863.49	239.13	6.60%	1.55
10	TR-2 Transport	5,000	4,723.72	5,126.99	403.27	8.54%	1.03
11	TR-2 Transport	10,000	6,922.44	7,653.97	731.53	10.57%	0.77
12							
13	TR-3 Transport	0	3,205.00	3,300.00	95.00	2.96%	
14	TR-3 Transport	2,500	4,259.73	4,519.29	259.55	6.09%	$1.81
15	TR-3 Transport	5,000	5,314.47	5,738.57	424.11	7.98%	1.15
16	TR-3 Transport	10,000	7,423.93	8,177.15	753.21	10.15%	0.82
17	TR-3 Transport	25,000	13,752.34	15,492.87	1,740.53	12.66%	0.62
18	TR-3 Transport	50,000	24,299.67	27,685.73	3,386.06	13.93%	0.55
19	TR-3 Transport	75,000	34,847.01	39,878.60	5,031.59	14.44%	0.53

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Comparison of Present and Proposed Monthly Bills

AGGREGATED TRANSPORT Service Rate

Case No.: U-21540
Exhibit No.: A-16
Schedule: F4
Page: 6 of 7
Witness: S. L. Burzycki
Date: March 1, 2024

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Monthly	Present Net	Proposed Net	Increase		Unit
Line No.	Meter Class	Usage (Mcf)	Monthly Bill ($/Month)	Monthly Bill ($/Month)	Amount ($/Month)	Percent (%)	Cost ($/Mcf)
1	Aggregated - Residential to Residential	0	$34.50	$34.50	$0.00	0.00%	
2	Aggregated - Residential to Residential	2	40.07	42.30	2.23	5.56%	$21.15
3	Aggregated - Residential to Residential	5	48.42	53.99	5.57	11.50%	10.80
4	Aggregated - Residential to Residential	7	53.99	61.79	7.80	14.44%	8.83
5	Aggregated - Residential to Residential	10	62.35	73.48	11.14	17.86%	7.35
6	Aggregated - Residential to Residential	15	76.27	92.98	16.70	21.90%	6.20
7	Aggregated - Residential to Residential	20	90.20	112.47	22.27	24.69%	5.62
8	Aggregated - Residential to Residential	25	104.12	131.96	27.84	26.74%	5.28
9	Aggregated - Residential to Residential	30	118.04	151.45	33.41	28.30%	5.05
10							
11	Aggregated - Small to General Service - Small	0	56.50	61.50	5.00	8.85%	
12	Aggregated - Small to General Service - Small	10	74.73	80.00	5.27	7.05%	$8.00
13	Aggregated - Small to General Service - Small	25	102.07	107.75	5.68	5.56%	4.31
14	Aggregated - Small to General Service - Small	50	147.64	153.99	6.35	4.30%	3.08
15	Aggregated - Small to General Service - Small	75	193.21	200.24	7.02	3.64%	2.67
16	Aggregated - Small to General Service - Small	100	238.78	246.48	7.70	3.22%	2.46
17							
18	Aggregated - Small to General Service - Medium	0	71.50	76.50	5.00	6.99%	
19	Aggregated - Small to General Service - Medium	10	89.16	94.45	5.29	5.93%	$9.45
20	Aggregated - Small to General Service - Medium	50	159.81	166.26	6.45	4.04%	3.33
21	Aggregated - Small to General Service - Medium	100	248.11	256.01	7.90	3.18%	2.56
22	Aggregated - Small to General Service - Medium	500	954.55	974.05	19.50	2.04%	1.95
23	Aggregated - Small to General Service - Medium	1,000	1,837.60	1,871.60	34.00	1.85%	1.87
24							
25	Aggregated - Large to General Service - Large	0	446.50	471.50	25.00	5.60%	
26	Aggregated - Large to General Service - Large	10	458.18	483.71	25.53	5.57%	$48.37
27	Aggregated - Large to General Service - Large	50	504.92	532.57	27.65	5.48%	10.65
28	Aggregated - Large to General Service - Large	100	563.34	593.64	30.30	5.38%	5.94
29	Aggregated - Large to General Service - Large	250	738.60	776.85	38.25	5.18%	3.11
30	Aggregated - Large to General Service - Large	500	1,030.70	1,082.20	51.50	5.00%	2.16
31	Aggregated - Large to General Service - Large	750	1,322.80	1,387.55	64.75	4.89%	1.85
32	Aggregated - Large to General Service - Large	1,000	1,614.90	1,692.90	78.00	4.83%	1.69
33	Aggregated - Large to General Service - Large	1,250	1,907.00	1,998.25	91.25	4.79%	1.60
34	Aggregated - Large to General Service - Large	1,500	2,199.10	2,303.60	104.50	4.75%	1.54

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Comparison of Present and Proposed Monthly Bills

CHOICE Service Rates

Case No.: U-21540
Exhibit No.: A-16
Schedule: F4
Page: 7 of 7
Witness: S. L. Burzycki
Date: March 1, 2024

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
					Increase		
Line No.	Meter Class	Monthly Usage (Mcf)	Present Net Monthly Bill ($/Month)	Proposed Net Monthly Bill ($/Month)	Amount ($/Month)	Percent (%)	Unit Cost ($/Mcf)
1	Choice - Residential	0	$13.00	$13.00	$0.00	0.00%	
2	Choice - Residential	2	18.57	20.80	2.23	11.99%	$10.40
3	Choice - Residential	5	26.92	32.49	5.57	20.68%	6.50
4	Choice - Residential	7	32.49	40.29	7.80	23.99%	5.76
5	Choice - Residential	10	40.85	51.98	11.14	27.26%	5.20
6	Choice - Residential	15	54.77	71.48	16.70	30.50%	4.77
7	Choice - Residential	20	68.70	90.97	22.27	32.42%	4.55
8	Choice - Residential	25	82.62	110.46	27.84	33.70%	4.42
9	Choice - Residential	30	96.54	129.95	33.41	34.60%	4.33
10							
11	Choice - General Service - Small	0	35.00	40.00	5.00	14.29%	
12	Choice - General Service - Small	10	53.23	58.50	5.27	9.90%	$5.85
13	Choice - General Service - Small	25	80.57	86.25	5.68	7.04%	3.45
14	Choice - General Service - Small	50	126.14	132.49	6.35	5.03%	2.65
15	Choice - General Service - Small	75	171.71	178.74	7.02	4.09%	2.38
16	Choice - General Service - Small	100	217.28	224.98	7.70	3.54%	2.25
17							
18	Choice - General Service - Medium	0	50.00	55.00	5.00	10.00%	
19	Choice - General Service - Medium	10	67.66	72.95	5.29	7.82%	$7.30
20	Choice - General Service - Medium	50	138.31	144.76	6.45	4.66%	2.90
21	Choice - General Service - Medium	100	226.61	234.51	7.90	3.49%	2.35
22	Choice - General Service - Medium	500	933.05	952.55	19.50	2.09%	1.91
23	Choice - General Service - Medium	1,000	1,816.10	1,850.10	34.00	1.87%	1.85
24							
25	Choice - General Service - Large	0	425.00	450.00	25.00	5.88%	
26	Choice - General Service - Large	10	436.68	462.21	25.53	5.85%	$46.22
27	Choice - General Service - Large	50	483.42	511.07	27.65	5.72%	10.22
28	Choice - General Service - Large	100	541.84	572.14	30.30	5.59%	5.72
29	Choice - General Service - Large	250	717.10	755.35	38.25	5.33%	3.02
30	Choice - General Service - Large	500	1,009.20	1,060.70	51.50	5.10%	2.12
31	Choice - General Service - Large	750	1,301.30	1,366.05	64.75	4.98%	1.82
32	Choice - General Service - Large	1,000	1,593.40	1,671.40	78.00	4.90%	1.67
33	Choice - General Service - Large	1,250	1,885.50	1,976.75	91.25	4.84%	1.58
34	Choice - General Service - Large	1,500	2,177.60	2,282.10	104.50	4.80%	1.52

Case No.: U-21540
Exhibit No: A-16
Schedule: F5
Witness: Shannon L. Burzycki

MICHIGAN GAS UTILITIES CORPORATION
SUMMARY OF TARIFF CHANGES

Tariff Sheet No.	**Rule No.**	**Paragraph**	**Description of Changes**
A-6.00 - A-11.00		Table of Contents	Administrative updates
B-2.00			Continuation of R 460.2351 Waiver
C-36.00	C11	Carry Cost Rate	Updated rate
C-37.00	C11	Discount Rate	Updated rate
C-38.00 - C-45.00	C11	Customer Attachment Program	Updated CAPs
D-1.01	D2	Supplemental Charges	Updated rates
D-1.04 - D-1.07	D2	Supplemental Charges	MRP Surcharge updates
D-4.00	D3.2	Special Credits	Remove rates and reseve for future use
D-6.00	D4	Residential Rate Schedules	Updated rates
D-9.00 - D-13.00	D5 - D7	General Service Rate Schedules	Updated rates
D-15.00	D8	Gas Lighting Schedule	Updates rates and clarifying language added
E-1.00	E1.1	General Provisions and Definitions	Update language
E-7.00	E4	Quantities	Update language
E-13.00	E5.4	Rates and Charges	Updated Customer Charge and rates

Continued From Sheet No. A-5.00

INDEX

SECTION D
RATE SCHEDULES

SECTION E
GAS TRANSPORTATION SERVICE

Continued on Sheet No. A-7.00

TABLE OF CONTENTS - CHECKLIST

Continued on Sheet No. A-9.00

Continued From Sheet No. A-8.00

TABLE OF CONTENTS - CHECKLIST (Contd.)

Continued on Sheet No. A-10.00

Issued: ~~**December 12, 2023**~~
By: Theodore Eidukas
VP - Regulatory Affairs
Milwaukee, Wisconsin

Continued From Sheet No. A-9.00

TABLE OF CONTENTS - CHECKLIST (Contd.)

Continued on Sheet No. A-11.00

Issued: **~~December 12, 2023~~**
By: Theodore Eidukas
VP - Regulatory Affairs
Milwaukee, Wisconsin

Continued From Sheet No. A-10.00

TABLE OF CONTENTS - CHECKLIST (Contd.)

Continued From Sheet No. B-1.00

B1. TECHNICAL STANDARDS FOR GAS SERVICE (R 460.2301 – R 460.2384) (Contd.)
https://ars.apps.lara.state.mi.us/AdminCode/DownloadAdminCodeFile?FileName=R%20460.2301%20to%20R%20460.2384.pdf

PART 5 METERS METERING EQUIPMENT INSPECTIONS AND TESTS

R 460.2351	Meters and associated metering devices; inspections; tests; and records. **(WAIVED)**
R 460.2351a	Statistical quality sampling program for diaphragm-type meters.
R 460.2352	Rescinded.
R 460.2353	Retirement of meters.
R 460.2354	Accuracy of metering equipment; tests; standards.
R 460.2355	Meter shop; design; meter testing system; standards; handling; calibration cards; calibrated orifices.
R 460.2356	Pressure measurement standards.
R 460.2357	Records; meter tests.
R 460.2358	Records; meter and associated metering device data.

PART 6 BILL ADJUSTMENT; METER ACCURACY

R 460.2361	Rescinded.
R 460.2362	Determination of adjustment.
R 460.2363	Refunds.
R 460.2364	Rescinded.
R 460.2365	Consumption data records.

PART 7 SHUTOFF OF SERVICE

R 460.2371	Conditions for establishing gas service; liability; notice and record of Inability to establish service; refusal of service to customer using other gaseous fuel; exception; service quality.
R 460.2372	Gas facilities hazard.
R 460.2373	Shutoff of service.
R 460.2374	Rescinded.

Refer to the Company's approved Rule C5.1, Access to Premises.

R 460.101 et seq. are the rules pertaining to CONSUMER STANDARDS AND BILLING PRACTICES FOR ELECTRIC AND NATURAL GAS SERVICE. See Administrative Rule B2, PART 8, PROCEDURES FOR SHUTOFF AND RESTORATION OF SERVICE R 460.136, R 460.137, R 460.138, R 460.139, R 460.140, R 460.141, R 460.142 and R 460.143.

PART 8 GAS QUALITY

R 460.2381	Gas purity.
R 460.2382	Heating value; authorized variations.
R 460.2383	Heating value records; location and accuracy of measuring equipment; frequency of heating value determination.
R 460.2384	Rescinded.

Continued on Sheet No. B-3.00

Continued from Sheet No. C-35.00

C11. Customer Attachment Program (Contd.)

(7) Customer Attachment Project

A Project may consist of a single customer, requiring only the installation of a service line and meter, or may consist of numerous customers requiring the installation of mains, service lines and meters. A Project will generally be defined as a customer or group of customers that may be served from the contiguous expansion of new distribution facilities.

(8) Revenue Deficiency

A discounted Cost of Service Model (Model) will be used to calculate the Net Present Value (NPV) Revenue Deficiency anticipated from a Project. The Model will use the expected incremental revenues and incremental costs associated with the Project for each year of a twenty year period. From this information an annual net revenue excess or deficiency will be calculated. The annual net revenue excess or deficiency will be discounted and summed to determine the NPV revenue deficiency of the Project. If the NPV revenue deficiency is negative, the discounted revenues exceed the discounted costs, then a NPV revenue deficiency of zero will be used.

(9) Model Assumptions:

Incremental Revenues:

The Incremental Revenues will be calculated based on current rates and a forecast of the timing and number of customer attachments as well as the customers' annual consumption levels.

Incremental Costs:

(i) Carrying Cost Rate

The Carrying Cost Rate will be based on the weighted rate of debt, equity and associated taxes. The cost will be equal to and weighted in proportion to those authorized in the Company's most recent rate order. The Carrying Cost Rate is equal to **~~8.45~~9.10%.**

Continued on Sheet No. C-37.00

Continued from Sheet No. C-36.00

C11. Customer Attachment Program (Contd.)

(ii) Plant in Service

Plant in Service shall reflect the Company's estimated cost to construct distribution mains, customer service lines, meters and pressure regulators or regulating facilities for the Project. The timing of the facility investment, primarily service lines, will correspond with the projected timing of the customer attachments.

The facility investment for an individual customer service line will be limited to the greater of 400 feet or 150% of the average length of all service lines within the Project.

(iii) Carrying Costs

The Carrying Costs will be the product of the average of beginning and end-of-year net plant, Plant in Service minus accumulated depreciation minus deferred taxes, multiplied by the Carrying Cost Rate, noted in paragraph 1 above.

(iv) Depreciation

Depreciation expense will be the product of Plant in Service multiplied by the appropriate prescribed depreciation rates approved for the Company.

(v) Property Taxes and Other Operating Expenses

Property taxes will be the product of Plant in Service multiplied by the Company's average property tax rate. All other incremental operating expenses will be included as identified. Incremental O&M will at a minimum include a proportional cost for monthly meter reading, billing and mailing.

(vi) Discount Rate

The Discount Rate will be a weighted rate of long-term debt and common equity. The cost will be equal to and weighted in proportion to those authorized in the Company's most recent rate order. Based on the Company's rate order in Case No. **U-~~21366~~ 21540** dated ~~**August 30, 2023**~~, the Discount Rate is equal to ~~**6.83**~~**7.41%.**

Continued on Sheet No. C-38.00

Continued from Sheet No. C-37.00

C11. Customer Attachment Program (Contd.)

(10) Customer Attachment Project Areas

All gas sold in any area specifically listed below is subject to the following Customer Attachment Project (CAP) charges. CAP areas and charges shall be added to or removed from the list from time to time by the Company.

CAP No.	CAP Name	CAP Charge Per Month	Last Billing Month For Surcharge
~~X368~~	~~Cheyenne Tr & 120th~~	~~$37.03~~	~~June 2024~~
~~X371~~	~~Strasburg S Otter & Hubbard~~	~~$34.48~~	~~March 2024~~
~~X372~~	~~M140~~	~~$12.66~~	~~May 2024~~
~~X373~~	~~Plum~~	~~$18.26~~	~~January 2024~~
~~X374~~	~~Airport Road~~	~~$14.82~~	~~January 2024~~
~~X375~~	~~Scottdale~~	~~$16.59~~	~~July 2024~~
~~X376~~	~~72nd s of 16~~	~~$29.59~~	~~May 2024~~
~~X377~~	~~2nd Ave~~	~~$32.39~~	~~June 2024~~
~~X378~~	~~California~~	~~$26.26~~	~~July 2024~~
~~X382~~	~~114th Ave.~~	~~$30.00~~	~~September 2024~~
~~X383~~	~~Date Rd~~	~~$22.89~~	~~July 2024~~
~~X386~~	~~102nd from 13th to 15th~~	~~$25.88~~	~~July 2024~~
~~X387~~	~~108th - Allegan~~	~~$30.00~~	~~August 2024~~
~~X388~~	~~Kendra Rd~~	~~$31.02~~	~~July 2024~~
~~X389~~	~~Ferris St.~~	~~$43.12~~	~~June 2024~~
~~X390~~	~~Territorial Rd~~	~~$20.08~~	~~September 2024~~
~~X392~~	~~Hagar Shore II~~	~~$33.43~~	~~October 2024~~
X393	Lake Allegan North	$26.64	June 2025
~~X395~~	~~Kelly~~	~~$33.90~~	~~July 2024~~
~~X396~~	~~34th North of 138th~~	~~$32.03~~	~~October 2024~~
~~X397~~	~~56th Street~~	~~$22.02~~	~~September 2024~~
~~X398~~	~~Echo Rd~~	~~$12.00~~	~~August 2024~~
X399	112th & Brielle	$32.75	March 2025
~~X400~~	~~Reading Rd~~	~~$37.91~~	~~November 2024~~
~~X401~~	~~Tawas Drive~~	~~$14.98~~	~~September 2024~~
~~X402~~	~~Finzel Road~~	~~$45.25~~	~~August 2024~~
~~X403~~	~~E Randall~~	~~$31.50~~	~~December 2024~~

Continued on Sheet No. C-39.00

Continued from Sheet No. C-38.00

C11. Customer Attachment Program (Contd.)

CAP No.	CAP Name	CAP Charge Per Month	Last Billing Month For Surcharge
~~X404~~	~~Carleton West Project~~	~~$58.83~~	~~November 2024~~
~~X405~~	~~Big Hill Rd.~~	~~$23.56~~	~~December 2024~~
~~X406~~	~~Wolcott St.~~	~~$8.84~~	~~October 2024~~
~~X408~~	~~Ferndale Road~~	~~$18.30~~	~~December 2024~~
~~X409~~	~~119th~~	~~$28.27~~	~~October 2024~~
X410	Benton Center	$19.60	November 2025
X413	Coloma Road II	$24.15	January 2026
X414	Kay Drive	$14.15	December 2025
~~X415~~	~~Division Drive~~	~~$260.22~~	~~August 2024~~
X416	Chabot/Off Riverside	$18.11	March 2025
~~X417~~	~~13865 Carleton West Rd~~	~~$52.12~~	~~November 2024~~
~~X418~~	~~Miller Drive~~	~~$14.64~~	~~December 2024~~
~~X419~~	~~Suder & Substation~~	~~$37.57~~	~~November 2024~~
~~X420~~	~~Wells & Central~~	~~$25.41~~	~~November 2024~~
~~X421~~	~~Laplaisance~~	~~$26.32~~	~~December 2024~~
~~X422~~	~~36th - Dorr~~	~~$45.16~~	~~December 2024~~
~~X423~~	~~Country Lane Main~~	~~$32.27~~	~~December 2024~~
~~X424~~	~~Washington~~	~~$15.63~~	~~December 2024~~
X425	Lake Chapin	$25.01	January 2025
X426	Hull Rd.	$35.65	May 2025
X427	War, Buhl, Mentel	$46.15	October 2025
X428	Stanley Dr	$21.51	June 2025
X429	68th St	$19.55	July 2025
X430	58th St	$18.94	July 2025
X431	Taylor Street	$15.68	August 2025
X432	Pershing Drive	$25.39	July 2025
X433	Black River Rd	$22.27	August 2025
X434	Waldron	$15.99	December 2025
X435	CR380/69th	$24.76	August 2025
X436	Territorial #2	$16.57	December 2025

Continued on Sheet No. C-40.00

Continued from Sheet No. C-39.00

C11. Customer Attachment Program (Contd.)

CAP No.	CAP Name	CAP Charge Per Month	Last Billing Month For Surcharge
X437	Tudor Rd	$24.45	September 2025
~~X438~~	~~Bankers/Cambria~~	~~$42.69~~	~~December 2024~~
X440	S Fremont Rd	$14.72	May 2025
X441	Onway Dr (E of Whiteford Rd.)	$20.10	May 2025
X442	Chabot/Off Broderick	$29.38	August 2025
X443	E. Beach	$20.73	December 2025
X444	Walnut	$21.23	August 2025
X446	Ida Center (W of Lewis Ave)	$41.88	June 2025
X447	106th Ave & 6th St	$5.85	September 2025
X448	Ida West W of Summerfield	$38.70	June 2025
X449	Ida West E of Gloff	$12.81	July 2025
X450	E Substation Rd	$49.48	June 2025
X451	Brewer Rd	$9.01	June 2025
X453	Long Lake Road	$51.28	January 2026
X455	Consear Rd	$35.39	April 2026
X456	Lincoln St Pvt Drive	$38.51	November 2025
X457	Tudor Rd. #2	$37.22	November 2025
X459	73rd 1/2 Street	$18.85	March 2026
X460	Erie	$21.10	September 2026
X461	Lime Lake	$18.53	October 2026
X462	Edgewood Rd-W of M125	$35.80	April 2026
X463	Handy Dr -W of Spaulding	$18.30	July 2026
X465	Samaria Rd-W of Whiteford	$40.09	April 2026
X466	Secor and Todd-S of Ida Cntr	$45.12	August 2026
X467	Summerfield Rd-N of Cortz	$39.51	May 2026
X468	Whiteford-W of Temperance	$48.42	June 2026
X470	Lincoln at Carolyn	$26.74	April 2026
X471	Hillandale	$22.26	May 2026
X473	Rich St & 128th Ave	$30.25	June 2026
X474	Grand Mere	$41.74	July 2026

Continued on Sheet No. C-41.00

Continued from Sheet No. C-40.00

C11. Customer Attachment Program (Contd.)

CAP No.	CAP Name	CAP Charge Per Month	Last Billing Month For Surcharge
X475	TULIP	$22.29	September 2027
X477	Fox Hollow Dr	$12.21	June 2026
X478	Tantre Drive	$25.32	August 2026
X479	Garfield Rd	$19.39	September 2026
X480	Stumpmier Road	$24.10	November 2026
X481	Blue Star @ Private Dr	$19.02	June 2027
X482	Briar Hill Road	$19.88	May 2027
X483	1167 102nd	$5.94	October 2026
X484	11360 168th	$95.62	November 2026
X485	13th & 130th	$20.00	March 2027
X486	129th Ave	$20.00	March 2027
X487	Maxwell Rd.	$97.23	November 2026
X488	Jakes Alley	$60.09	November 2026
X489	136th Ave and 14th Ave	$30.00	March 2027
X490	Kruse Rd	$26.49	July 2027
X492	Suder Rd, Lotus Dr.	$49.99	September 2027
X493	Victory Road	$39.22	August 2027
X494	Hallett Rd	$28.20	October 2027
X495	Melvin & 44th	$40.35	October 2027
X496	N Hillsdale Rd. at Moore	$19.05	October 2027
X497	Laplaisance & Lavigne Rd	$49.45	August 2027
X498	Lake Forest Path	$24.91	November 2027
X499	Whisper Ln & CT	$29.53	October 2027
X500	Dale Ct.	$20.93	October 2027
X501	Niebles Landing	$9.07	October 2027
X502	Ida West Road	$48.38	December 2027
X503	Burr Oak Rd. Bronson	$21.42	January 2028
X504	26th Street - Monterey Twp.	$20.00	May 2028
X505	Morocco Rd	$32.12	May 2028
X506	Baseline at 71 1/2 St.	$19.52	July 2028

Continued on Sheet No. C-42.00

Continued from Sheet No. C-41.00

C11. Customer Attachment Program (Contd.)

CAP No.	CAP Name	CAP Charge Per Month	Last Billing Month For Surcharge
X507	Whiteford Center Rd.	$31.52	July 2028
X508	Swartz Rd	$36.98	July 2028
X509	Donnell & Bennett	$11.58	July 2028
X510	7th Street	$32.76	August 2028
X511	13th St off 102nd	$19.41	July 2028
X512	Pierce @ Carolyn	$29.38	August 2028
X513	Farr Rd. W	$57.52	August 2028
X514	Carter/Anabell Roads	$64.39	September 2028
X515	137th E of 30th	$51.74	September 2028
X516	Holden Rd	$24.94	September 2028
X517	Browntown Rd	$27.46	October 2028
X518	Euclid Street	$13.70	October 2028
X520	E. Creek	$47.83	November 2028
X521	Rich St W of M231	$39.24	November 2028
X522	N Telegraph - Newport/I275	$58.81	December 2028
X523	Bercaw - 8 Mile	$19.95	November 2028
X524	Post Rd	$20.00	February 2029
X525	Stutzman Farms	$20.85	April 2029
X526	Olnhausen	$18.26	April 2029
X527	Meanwell Rd	$38.21	May 2029
X528	Edgewood Rd	$21.28	May 2029
~~X529~~	~~Beach Drive~~	~~$10.49~~	~~June 2024~~
X530	Lost Peninsula Phase 2	$31.82	July 2029
X531	Wood Rd/Minx Rd	$30.37	July 2029
X532	Blatchford & Paw Paw Rd.	$35.00	August 2029
X533	8th st n of 146th	$59.51	July 2029
X534	Stadler & Doty Rd.	$35.22	August 2029
X535	Johnson Rd	$36.43	September 2029
X536	Pier Rd	$35.33	August 2029

Continued on Sheet No. C-43.00

Continued from Sheet No. C-42.00

C11. Customer Attachment Program (Contd.)

CAP No.	CAP Name	CAP Charge Per Month	Last Billing Month For Surcharge
X537	South Stoney Creek Rd.	$40.75	September 2029
X538	California @ Ott	$35.01	September 2029
X539	S. Telegraph Rd.	$34.58	September 2029
X540	E. Stein Rd.	$50.76	October 2029
X541	Carter Rd	$40.86	October 2029
X542	Orchard Trail	$44.47	December 2029
X543	Rockey Weed @ Ann Ct	$35.40	January 2030
X544	Browntown Phase 2	$36.16	January 2030
X545	Niles Rd	$35.00	March 2030
X546	Dunks Rd	$35.22	March 2030
X547	50TH ST CAP	$65.44	June 2030
X548	Kelly Rd	$45.05	April 2030
X549	EGGERT RD	$50.55	May 2030
X550	Rosehill Rd	$31.90	June 2030
X551	Reinhardt Rd	$36.30	June 2030
X552	Maxwell Rd	$48.85	June 2030
X553	463 & 467 6TH STREET	$31.70	July 2030
X555	M86 Main	$32.21	July 2030
X556	Meanwell/Ida West Rd	$27.72	July 2030
X557	Tulip Street	$18.02	August 2030
X558	Lavign/S Otter Creek	$35.00	September 2030
X559	CR 384	$25.11	September 2030
X560	Port Creek	$57.83	September 2030
X561	120th/27th/Haas Dr	$36.76	October 2030
X562	1934 Lincoln Rd	$106.15	August 2030
X563	LULU/Wells/Ida Center	$41.15	October 2030
X564	Cherry @ Plum	$18.51	November 2030
X565	810 N 16th St Main Ext	$56.92	September 2030
X566	Carter Rd	$43.17	November 2030

Continued on Sheet No. C-44.00

Continued from Sheet No. C-43.00

C11. Customer Attachment Program (Contd.)

CAP No.	CAP Name	CAP Charge Per Month	Last Billing Month For Surcharge
X567	Ruggles Rd	$20.31	November 2030
X568	2760 Half Moon Lake Rd	$33.66	November 2030
X569	Woods of Lochaven Condos	$34.50	December 2030
X570	Mckinley	$17.22	December 2030
X571	PAW PAW LAKE @ HAGAR SHORE	$27.88	December 2030
X572	MARRS @ 2170	$34.09	December 2030
X573	HOLDEN @ LEMON CREEK	$50.14	February 2031
X574	LEMON CREEK @ JERICHO	$29.28	March 2031
X575	Gast @ Browntown	$28.76	March 2031
X576	Wildlife Rd	$29.94	August 2030
X577	Brockelbank	$30.00	September 2030
X578	Homer Rd	$31.32	September 2030
X579	Blue Star S of 20th	$22.01	March 2031
X580	Scottdale #2	$45.00	May 2031
X581	Rocky Weed-Linco Grain Dryers	$35.00	May 2031
X582	Morocco Rd	$72.32	May 2031
X583	East Gateway Dr	$34.87	March 2031
X584	Kline St.	$33.47	June 2031
X585	Secor Rd	$97.37	July 2031
X586	Marrs Rd GD	$35.25	September 2031
X587	AMY @ BOYER	$30.42	October 2031
X588	8TH ST NORTH	$70.81	October 2031
X589	37TH ST S OF 140TH	$84.72	November 2031
X590	Telegraph Rd	$40.83	August 2031
X591	Telegraph (N of Labo)	$39.96	November 2031
X592	Long Lake Rd	$42.40	August 2031
X593	Niles @ John Beers	$35.00	November 2031
X594	Maple St @ 11910	$24.93	July 2031
X595	Driftboat Ln	$68.55	January 2032
X596	Atlantic Ave @ Blue Star	$32.36	February 2032

Continued on Sheet No. C-45.00

Continued from Sheet No. C-44.00

C11. Customer Attachment Program (Contd.)

CAP No.	CAP Name	CAP Charge Per Month	Last Billing Month For Surcharge
X597	442 Riverview Dr Main Ext	$48.42	August 2032
X598	CHERRY @ TULIP	$22.44	August 2032
X599	Ready Rd	$24.28	August 2032
X600	Sylvania-Petersburg Rd	$68.73	July 2032
X601	GEIGER RD	$53.91	September 2032
X602	909 Burr Oak Rd Main Ext.	$32.78	September 2032
X603	Maxwell Rd	$59.86	September 2032
X604	S Angola & E Pearl	$35.00	October 2032
X605	Riverside @ Dogwood	$9.81	October 2032
X606	N. Stoney Creek	$88.88	July 2032
X607	LAKE FOREST PATH	$34.57	December 2032
X608	Stevensville Baroda-Hinchman BH	$47.60	December 2032
X609	Lost Peninsula Phase 3A	$43.62	December 2032
X610	12th & 102nd	$35.04	October 2032
X611	10271 Buchanan Main Ext	$81.99	January 2033
X612	142nd	$35.00	January 2033
X613	Russell Rd	$23.55	June 2033
X614	Suder Road	$48.49	May 2033
X615	5th St Main Ext	$15.86	March 2033
X616	PINE CT	$22.20	August 2033
X617	132nd West of 47th	$182.87	August 2032
X618	W ERIE	$78.81	July 2033
X619	M40 EASMENT, SOUTH OF 134TH	$128.84	November 2032
X620	DIXON	$67.03	September 2033
X621	**ROBINSON TWP**	**$55.40**	**July 2032**
X622	**GRAND HAVEN**	**$50.93**	**May 2032**
X623	**GRAND HAVEN TWP**	**$35.63**	**September 2032**
X624	**FRUITPORT**	**$94.59**	**September 2032**
X625	**ROBINSON TWP**	**$35.00**	**June 2032**
X626	**IDA TWP**	**$86.95**	**November 2033**
X627	**Whiteford TWP**	**$65.99**	**December 2033**
X628	**Fennville**	**$33.46**	**November 2033**
X629	**ERIE TWP**	**$43.26**	**January 2034**

Continued from Sheet No. D-1.00

SECTION D
RATE SCHEDULES

D2. SUPPLEMENTAL CHARGES (contd.)

Customer Class	EWR Surcharge (per Mcf)		Distribution Charge + Gas Supply Acquisition Charge (per Mcf)*		Total Distribution Charge (per Mcf)	
RESIDENTIAL SERVICE	$0.1512	+	**$~~2.8239~~3.9443**	=	**$~~2.9751~~4.0955**	per Mcf
CHOICE RESIDENTIAL GEN SERVICE	$0.1512	+	**$~~2.7848~~3.8984**	=	**$~~2.9360~~4.0496**	per Mcf
TR - Res	$0.1512	+	**$~~2.7848~~3.8984**	=	**$~~2.9360~~4.0496**	per Mcf

Customer Class	EWR Surcharge (per meter, daily)		Fixed Customer Charge (daily)		Total Customer Charge (daily)	
SMALL GENERAL SERVICE	$0.1200	+	$~~1.1507~~**1.3151**	=	$~~1.2707~~**1.4351**	per customer
MEDIUM GENERAL SERVICE	$1.0054	+	$~~1.6438~~**1.8082**	=	$~~2.6492~~**2.8136**	per customer
LARGE GENERAL SERVICE	$4.8470	+	$~~13.9726~~**14.7945**	=	$~~18.8196~~**19.6415**	per customer
STREET LIGHTS	$0.1253	+	$~~1.1507~~**1.3151**	=	$~~1.2760~~**1.4404**	per contract

Customer Class	EWR Surcharge (per month)		Fixed Customer Charge (monthly)		Total Customer Charge (monthly)	
TRANSPORTATION						
TR-1	$38.91	+	**$~~925~~1,000**	**=**	**$~~963.91~~1,038.91**	per meter
TR-2	$211.34	+	**$~~2,525~~2,600**	**=**	**$~~2,736.34~~2,811.34**	per meter
TR-3	$918.93	+	**$~~3,205~~3,300**	**=**	**$~~4,123.93~~4,218.93**	per meter
TR - GS	$3.65	+	$~~35~~**40**	=	$~~38.65~~**43.65**	per meter
TR - GM	$30.58	+	$~~50~~**55**	=	$~~80.58~~**85.58**	per meter
TR - GL	147.43	+	$~~425~~**450**	=	$~~572.43~~**597.43**	per meter
SPECIAL CONTRACTS	$136.39					per meter

*Gas Supply Acquisition Charge is not applicable to Gas Choice customers or Aggregated Transportation accounts.

Continued on Sheet No. D-1.02

Issued: ~~**December 12, 2023**~~
By: Theodore Eidukas
VP - Regulatory Affairs
Milwaukee, Wisconsin

Effective for service rendered
On and After: **January 1, ~~2024~~2025**
Issued Under Authority of the
Michigan Public Service Commission
Order Dated: ~~**August 30, 2023**~~ **In Case No. U-~~21366~~21540,** February 10, 2022, in Case No. U-20882, December 17, 2020, in Case No. U-20922

Continued from Sheet No. D-1.03

SECTION D
RATE SCHEDULES

D2. SUPPLEMENTAL CHARGES (contd.)

MRP RIDER
MAIN REPLACEMENT PROGRAM RIDER

1. The MRP Rider is limited to the recovery of the removal and/or replacement of transmission facilities only, specifically those impacted by 49 CFR Part 192 Subpart O or the 2019 Mega Rule.

2. The revenue distribution and the accounting provisions produced from this MRP Rider shall have no precedential value in the company's next rate case.

3. The Company will set up special accounts for the removal and replacement transmission mains affected by 49 CFR Part 192 Subpart O or the 2019 Mega Rule.

4. The Company's proposed recovery is based upon an annual revenue requirement calculation by rate schedule with the main allocation factor of average and peak and the corresponding number of customers as approved by the Commission in the Company's most recent rate case.

5. The Company's calculation is based upon the following:

   a. Original Cost and Accumulated Reserve for Post 12/31/~~2024~~2025

      1. Used and useful after 1/1/~~2025~~2026
      2. Capital expenditures is limited to new plant under this rider
      3. Adjustments for the retirement of existing assets

   b. Calculation of post in - service carrying charges on net plant additions and related deferred taxes

      1. Calculated from the date that the applicable assets are used and useful, January 1 of the year following installation.
      2. Based on the Company's embedded interest cost and recorded at the gross rate for recovery on deferred taxes that lessens amount for recovery.

   c. Calculation of deferred taxes on depreciation

Continued on Sheet No. D-1.05

Continued from Sheet No. D-1.05

SECTION D
RATE SCHEDULES

D2. SUPPLEMENTAL CHARGES (contd.)

MRP RIDER

MAIN REPLACEMENT PROGRAM RIDER

APPLICABILITY

Applicable to all customers receiving service under the Company's sales and transportation rate schedules and Special Contract Customers.

MAIN REPLACEMENT PROGRAM (MRP)

This MRP Rider as approved by the MPSC recovers the cost of the MRP not included in MGUC's base rates. These projects included pipeline replacements and related costs. By having this surcharge in place, MCUC recovers over time the costs associated with these replacement projects, which should reduce the frequency of expensive general rate cases in the future.

All customers receiving service under Rate Schedules Residential, Small General Service, Medium General Service, Large General Service, TR-1, TR-2, TR-3 and Special Contract shall be assessed a monthly charge in addition to the Customer Charge component of their applicable rate which will enable the Company to begin and complete the replacement initiative.

The company can bill this surcharge to all of its customers monthly.

This Rider surcharge will become effective with the first billing cycle of January ~~2025~~2026, and reflects the allocation of the required annual revenue increase needed based upon the main allocation factor of average and the number of customers per rate group as defined and approved in the Company's last rate proceeding.

Continued on Sheet No. D-1.07

Continued from Sheet No. D-1.06

SECTION D
RATE SCHEDULES

D2. SUPPLEMENTAL CHARGES (contd.)

MRP RIDER

MAIN REPLACEMENT PROGRAM RIDER

The Rider MRP charge will be implemented on a **bill** rendered basis beginning in January ~~2025~~2026 and will continue as approved in **U-**~~21366~~21540 **or** until the earlier of either: (i) base rates are established in a future contested case addressing the MRP, or (ii) December 31, **2027**. Per Customer Meter charges may change annually. The charge for the specific Rate Schedule by year is:

Line	Customer Class	~~2025~~	2026	2027
		Per Customer Meter Per Month		
1	Residential	~~$0.19~~	~~$0.64~~ $0.23	~~$0.90~~$0.56
2	Small General Service	~~$0.46~~	~~$1.55~~$0.59	~~$2.17~~$1.41
3	Medium General Service	~~$0.15~~	~~$0.50~~$0.32	~~$0.70~~$0.78
4	Large General Service	~~$10.06~~	~~$34.00~~$4.39	~~$47.77~~$10.59
5	Transportation:			
6	TR-1	~~$12.44~~	~~$42.06~~$87.29	~~$59.11~~$210.63
7	TR-2	~~$75.83~~	~~$256.41~~$92.47	~~$360.31~~$223.12
8	TR-3	~~$632.01~~	~~$2,137.04~~$494.62	~~$3,003.04~~$1,193.53
9	Aggregated - Residential	~~$0.47~~	~~$1.58~~$0.49	~~$2.22~~$1.17
10	Aggregated - Small General Service	~~$1.77~~	~~$5.97~~$1.88	~~$8.39~~$4.53
11	Aggregated - Medium General Service	~~$6.81~~	~~$23.00~~$4.27	~~$32.32~~$10.30
12	Aggregated - Large General Service	~~$7.43~~	~~$25.12~~$9.22	~~$35.30~~$22.24
13	Choice - Residential	~~$0.19~~	~~$0.64~~$0.23	~~$0.90~~$0.56
14	Choice - Small General Service	~~$0.46~~	~~$1.53~~$0.58	~~$2.15~~$1.40
15	Choice - Medium General Service	~~$0.15~~	~~$0.50~~$2.07	~~$0.70~~$4.99
16	Choice - Large General Service	~~$8.33~~	~~$28.17~~$10.76	~~$39.58~~$25.96
17	Special Contract	~~$1.28~~	~~$4.32~~$1.56	~~$6.07~~$3.75

Continued on Sheet No. D-2.00

~~D3.2 Special Credits~~

~~PIPELINE REFUND CREDIT~~

~~This credit allows the Company to refund customers the FERC ordered PEPL refund addressed in Opinion No. 885-A dated September 25, 2023 in Docket No. RP19-78-000, et al.~~

~~GCR Residential, Small General Service, Medium & Large General Service, and Gas Choice Customers paying the Reservation Charge shall receive "Pipeline Refund" credits beginning with the Company's January 2024 billing month and ending with the March 2024 billing month.~~

~~Rate Schedule~~	~~Credit per Mcf~~		~~Credit per Meter~~
~~Residential~~	~~($0.3223)~~		
~~Small General Service~~	~~($0.3168)~~		
~~Medium General Service~~	~~($0.1462)~~	~~+~~	~~($16.37)~~
~~Large General Service~~	~~($0.2272)~~	~~+~~	~~($344.62)~~
~~Choice - Residential~~	~~($0.3223)~~		
~~Choice - Small General Service~~	~~($0.3168)~~		
~~Choice - Medium General Service~~	~~($0.1462)~~	~~+~~	~~($16.37)~~
~~Choice - Large General Service~~	~~($0.2272)~~	~~+~~	~~($344.62)~~

~~*Sales and Choice Medium General Service and Large General Service credits will be delivered 50% at a per Mcf rate and 50% as a per meter rate to balance the heating and non-heat load impacts.~~

This sheet has been cancelled and is reserved for future use.

Issued: ~~**January 2, 2024**~~
By: Theodore Eidukas
VP Regulatory Affairs
Milwaukee, Wisconsin

Effective for ~~bills rendered for the **January 2024** through March **2024** billing months.~~
Issued Under Authority of the Michigan
Public Service Commission order dated
~~**December 21, 2023**~~ in Case No: ~~**U-21517**~~

Continued From Sheet No. D-5.00

D4. RESIDENTIAL RATE - (General and Heating) (Contd.)

RATE

Customer Charge:	Daily	Monthly
	$ 0.4274 per customer, or	$ 13.00 per customer, plus

Distribution Charge
$ ~~2.7848~~3.8984 per Mcf, plus

Gas Supply Acquisition Charge
$ ~~0.0391~~ 0.0459per Mcf (This charge is not applicable to Gas Choice customers or Aggregated Transportation accounts.)

Residential Income Assistance (RIA) Service Provision:

When service is supplied to a residential customer for primary residence, where the total household income does not exceed 150% of the Federal Poverty Level, a credit shall be applied during all billing months. *The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:*

1. *A Home Heating Credit energy draft*
2. *State Emergency Relief*
3. *Assistance from a Michigan Energy Assistance Program (MEAP)*
4. *SNAP*
5. *Medicaid*

If the customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the Income Assistance Service Provision (RIA) shall be applied as follows:
Income Assistance Credit: $(13.00) per customer per month

Low Income Assistance Credit (LIAC):

Company selected residential customers may receive the LIAC. This credit is available for up to **83** qualifying residential customers where the total household income does not exceed 150% of the Federal Poverty Level, a credit shall be applied during all billing months. *The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:*

1. *A Home Heating Credit energy draft*
2. *State Emergency Relief*
3. *Assistance from a Michigan Energy Assistance Program (MEAP)*
4. *SNAP*
5. *Medicaid*

The monthly credit for the LIAC shall be applied as follows:
Low Income Assistance Credit: $(30.00) per customer per month

If a credit balance occurs, the credit shall apply to the customer's future utility charges.

Continued on Sheet No. D-7.00

Continued From Sheet No. D-8.00

D5. SMALL GENERAL SERVICE RATE - (General and Heating)

AVAILABILITY

Subject to limitations and restrictions contained in orders of the Michigan Public Service Commission in effect from time to time and in the Rules and Regulations of the Company, service is available under this rate schedule to any non-residential customer for any purpose.

RATE

Customer Charge:

Daily	Monthly
$ ~~1.1507~~**1.3151** per customer, or	$ ~~35~~**40**.00 per customer, plus

Distribution Charge
$ ~~1.8228~~ 1.8498 per Mcf, plus

Gas Supply Acquisition Charge
$ ~~0.0391~~0.0459 per Mcf (This charge is not applicable to Gas Choice customers or Aggregated Transportation accounts.)

Gas Cost Recovery Charge
The monthly gas cost recovery charge as set forth on Sheet No. D-2.00.

Supplemental Charges
This rate is subject to the Supplemental Charges set forth on Sheet Nos. D-1.00 and D-1.01.

Main Replacement Program Rider
This rate is subject to the Main Replacement Program Rider charges set forth on Sheet Nos. D-1.04, D-1.05, D-1.06 and D-1.07.

Seasonal Service Charge
A charge of $50.00, payable in either a flat amount or three equal installments, will be made to partially cover the cost of restoring service when it has been temporarily discontinued at the customer's request.

Delayed Payment Charge and Due Date
A delayed payment charge of 2%, shall be applied to the unpaid balance outstanding not compounded, net of sales tax, of any bill which is not paid on or before the due date shown thereon. The due date shall be 21 days following the date of mailing.

Continued on Sheet No. D-10.00

Continued from Sheet No. D-10.00

D6. MEDIUM GENERAL SERVICE RATE - (General and Heating)

AVAILABILITY

Subject to limitations and restrictions contained in orders of the Michigan Public Service Commission in effect from time to time and in the Rules and Regulations of the Company, service is available under this rate schedule to any non-residential customer for any purpose.

RATE

Customer Charge:

Daily	Monthly
$ ~~1.6438~~**1.8082** per customer, or	$ ~~50~~**55**~~.00~~ per customer, plus

Distribution Charge
$ ~~1.7661~~1.7951 per Mcf, plus

Gas Supply Acquisition Charge
$ ~~0.0391~~0.0459 per Mcf (This charge is not applicable to Gas Choice customers or Aggregated Transportation accounts.)

Gas Cost Recovery Charge
The monthly gas cost recovery charge as set forth on Sheet No. D-2.00.

Supplemental Charges
This rate is subject to the Supplemental Charges set forth on Sheet Nos. D-1.00 and D-1.01.

Seasonal Service Charge
A charge of $50.00, payable in either a flat amount or three equal installments, will be made to partially cover the cost of restoring service when it has been temporarily discontinued at the customer's request.

Main Replacement Program Rider
This rate is subject to the Main Replacement Program Rider charges set forth on Sheet Nos. D-1.04, D-1.05, D-1.06 and D-1.07.

Delayed Payment Charge and Due Date
A delayed payment charge of 2%, shall be applied to the unpaid balance outstanding not compounded, net of sales tax, of any bill which is not paid on or before the due date shown thereon. The due date shall be 21 days following the date of mailing.

Continued on Sheet No. D-12.00

Continued from Sheet No. D-12.00

D7. LARGE GENERAL SERVICE RATE - (General and Heating)

AVAILABILITY

Subject to limitations and restrictions contained in orders of the Michigan Public Service Commission in effect from time to time and in the Rules and Regulations of the Company, service is available under this rate schedule to any non-residential customer for any purpose.

RATE

Customer Charge:

Daily: $ ~~13.9726~~**14.7945** per customer, or
Monthly: $ ~~425~~**450**.00 per customer,
plus

Distribution Charge
$ ~~1.1684~~1.2214 per Mcf, plus

Gas Supply Acquisition Charge
$ ~~0.0391~~0.0459 per Mcf (This charge is not applicable to Gas Choice customers or Aggregated Transportation accounts.)

Gas Cost Recovery Charge
The monthly gas cost recovery charge as set forth on Sheet No. D-2.00.

Supplemental Charges:
This rate is subject to the Supplemental Charges set forth on Sheet Nos. D-1.00 and D-1.01.

Main Replacement Program Rider
This rate is subject to the Main Replacement Program Rider charges set forth on Sheet Nos. D-1.04, D-1.05, D-1.06 and D-1.07.

Seasonal Service Charge
A charge of $50.00, payable in either a flat amount or three equal installments, will be made to partially cover the cost of restoring service when it has been temporarily discontinued at the customer's request.

Delayed Payment Charge and Due Date
A delayed payment charge of 2% shall be applied to the unpaid balance outstanding not compounded, net of sales tax, of any bill which is not paid on or before the due date shown thereon. The due date shall be 21 days following the date of mailing.

Continued on Sheet No. D-14.00

Continued from Sheet No. D-14.00

D8. GAS LIGHTING RATE

AVAILABILITY

Subject to limitations and restrictions contained in orders of the Michigan Public Service Commission in effect from time to time and in the Rules and Regulations of the Company.

Rate Schedule	Distribution Charge
Commercial -	**$ ~~1.8228~~1.8498** per Mcf (In accordance with the terms of the service agreement)

Street Lights - (In accordance with the terms of the service agreement)

Gas Supply Acquisition Charge
$ ~~0.0391~~0.0459 per Mcf

Gas Cost Recovery Charge
The monthly gas cost recovery charge as set forth on Sheet No. D-2.00.

Supplemental Charges
This rate is subject to the Supplemental Charges set forth on Sheet Nos. D-1.00 and D-1.01.

Main Replacement Program Rider
This rate is subject to the Main Replacement Program Rider charges set forth on Sheet Nos. D-1.04, D-1.05, D-1.06 and D-1.07.

RULES AND REGULATIONS

Service under this rate schedule shall be subject to the Standard Rules and Regulations of the Company plus the following condition:

No additional gas burning devices may be attached to the service connection for light(s) served under this rate.

SPECIAL TAXES

(1) In municipalities which levy special taxes, license fees, or street rentals against the Company, and which levy has been successfully maintained, the standard of rates shall be increased within the limits of such municipalities so as to offset such special charges and thereby prevent the customers in other localities from being compelled to share any portion of such local increase.

(2) Bills shall be increased to offset any new or increased special tax or excise imposed by any governmental authority upon the Company's production, transmission or sale of gas.

Continued on Sheet No. D-16.00

SECTION E
GAS TRANSPORTATION

E1. GAS TRANSPORTATION SERVICE RULES

E1.1 General provisions and definitions.

(a) "Gas" means natural gas, manufactured gas, or a combination of the two.

(b) "Alternate-fuel capability" means the ability to actually utilize a fuel other than gas, in place of gas.

(c) "Nominations" means the process by which the customer notifies the Company of expected transportation quantities.

(d) "Day" means a period of 24 consecutive hours (23 hours when changing from standard to daylight time and 25 hours when changing back to standard time) beginning at **9:00** a.m. **Central clock** time, **as defined by the North American Energy Standards Board (NAESB)**, or at such other time as may be mutually agreed.

(e) "Annual Contract Quantity" (ACQ) means a quantity of gas, as specified in the transportation contract between the customer and the Company, that is based on the customer's maximum historical 12-month usage (determined from the customer's 36-month base period) plus adjustments for known or expected changes.

(f) "Maximum Daily Quantity" (MDQ) means a quantity of gas, as specified in the transportation contract between the customer and the Company, that is based on the customer's historical peak-month usage (determined from the customer's 36-month base period) plus adjustments for known or expected changes. The MDQ will be available, subject to updates, on the Company's secured internet-enabled portal. The MDQ is the greatest quantity of gas that the Company agrees to accept for transportation on the customer's behalf on any day.

(g) "Average Daily Quantity" (ADQ) means a quantity of gas equal to the customer's contractual ACQ divided by 365.

(h) "Month" means a period beginning at **9:00** a.m. **Central clock** time on the first day of a calendar month and ending at **9:00** a.m. **Central clock** time on the first day of the following calendar month.

(i) "Broker" means an intermediary that arranges the purchase of gas from the producer and the sale of that gas to a Buyer.

Continued on Sheet No. E-2.00

Continued From Sheet No. E-6.00

E3. Gas quality. (Contd)

(vii) Gas shall not contain a nitrogen content in excess of three percent by volume.

(b) Gas delivered to the Company shall have a total heating value per cubic foot of not less than 950 British thermal unit (BTUs) nor more than 1,100 BTUs.

E4. SERVICE REQUIREMENTS

(a) Quantities

(i) The customer may deliver or cause to be delivered and the Company will accept quantities of gas up to the MDQ ~~agreed to in the contract with the customer.~~ as calculated annually and made available on a secured internet-enabled portal. Such deliveries shall be made to the Company at a location(s) agreed to by the Company and the customer where the Company's pipeline facilities are connected with: (a) the facilities where the gas is being produced; or (b) with other facilities through which the gas is being transported. Deliveries to the Company in excess of the agreed upon quantities shall be grounds for termination of the contract by the Company.

Iii) Gas delivered to the Company shall be thermally evaluated at the point of receipt into the Company's system, and the Company will deliver to the customer gas with an equivalent British thermal unit (BTU) content based on: (a) the Company's calculated average BTU content; or (b) test results from a BTU sampler located at the point of redelivery to the customer.

(b) Pressure.

The Company shall not be required to alter its prevailing line pressure at the delivery point or at the redelivery point.

(c) Measurement.

(i) When delivered to the customer, all gas shall be measured by the Company. The accuracy of meters used for that purpose shall be evaluated and maintained in accordance with the Michigan Public Service Commission Technical Standards For Gas Service (Technical Standards R460.2301).

Continued on Sheet No. E-8.00

Continued From Sheet No. E-12.00

E5. TRANSPORTATION SERVICE AND RATES (Contd.)

E5.3 AGGREGATION OF ACCOUNTS OPTION

(b) Only the subsidiary accounts will be eligible for aggregation with the master account. To qualify as a subsidiary account a facility must be served under any of the Sales Service Rates or Transportation Service Rates. The customer, or the customer's agent, must specify which of the other facilities will be designated as a subsidiary account. The customer may designate some or all of its other facilities as subsidiary accounts.

(c) The facility designated as the master account shall be subject to and billed under the provisions of its transportation tariff. Facilities designated as subsidiary accounts shall be subject to all the terms and conditions of the master account tariff, except that each subsidiary account will pay the customer charge, distribution charge and all applicable Supplemental charges as set forth on Sheet Nos. D-1.00 and D-1.01 in effect for its designated sales or transportation rate, rather than the customer charge and transportation charge in effect for the master account.

(d) Each subsidiary account will be required to have remote metering installed and will be subject to the Daily Balancing provisions contained in Section 5.8 below. Each subsidiary account will be subject to a monthly telemetering charge of $21.50, which is in addition to the charges specified in Section E5.3 (c) above.

E5.4 RATES AND CHARGES

	Transportation Service Rate		
Monthly Charges:	TR-1	TR-2	TR-3
Customer Charge -			
Each Meter	$ ~~925.00~~1,000 / meter	$ ~~2,525.00~~2,600 / meter	$ ~~3,205.00~~3,300 / meter
Each Subsidiary Account	$ 21.50 / meter	$ 21.50 / meter	$ 21.50 / meter
Transportation Rates:			
Peak (November to March)	$ ~~0.8606~~0.9133 per Mcf	$ ~~0.5268~~0.5779 per Mcf	$ ~~0.5135~~0.5641 per Mcf
Off-Peak (April to October)	$ ~~0.6937~~0.7739 per Mcf	$ ~~0.3625~~0.4411 per Mcf	$ ~~0.3476~~0.4258 per Mcf

Service Category
- TR-1 Usage between 0 and 57,500 Mcf annually
- TR-2 Usage between 57,500 and 572,400 Mcf annually
- TR-3 Usage greater than 572,400 Mcf annually

Optional Discount Rates - The Company, at its discretion, may negotiate lower rates for individual customers, down to a minimum of $0.20 per Mcf.

DAILY BALANCING SERVICE % Difference From Nomination	Effective Rate Per Mcf
>0.0% up to 8.0%	$0.2291
>8.0%	$0.4041

Applicable Daily Balancing Charges for Undertake Imbalances during High Flow Constraint Periods and Overtake Imbalances during Low Flow Constraint Periods

% Difference From Nomination	Effective Rate Per Mcf
>0.0% up to 10.0%	$0.0000
>10.0%	$0.6300

Continued on Sheet No. E-14.00

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility
Historical and Forecasted

Line No.		2023 Historical Total O&M	2025 Forecasted Total O&M Not Including K&M	K&M	2025 Forecasted Total O&M Including K&M	K&M Reason
1	(1) PRODUCTION EXPENSES					
2	A. Gas Steam Production					
3	Operation:					
4	(700) Operation Supervision & Engineering	-	-	-	-	
5	(701) Operation Labor	-	-	-	-	
6	(702) Boiler Fuel	-	-	-	-	
7	(703) Miscellaneous Steam Expenses	-	-	-	-	
8	(704) Transferred-Credit	-	-	-	-	
9						
10	TOTAL Operation	-	-	-	-	
11						
12	Maintenance:					
13	(705) Maintenance Supervision & Engineering	-	-	-	-	
14	(706) Maintenance of Structures & Improvements	-	-	-	-	
15	(707) Maintenance of Boiler Plant Equipment	-	-	-	-	
16	(708) Maint of Oth Stm ProdPlt	-	-	-	-	
17						
18	TOTAL Maintenance	-	-	-	-	
19	TOTAL Production Expenses-Gas Steam	-	-	-	-	
20						
21	B. Liquified Gas Production					
22	Operation:					
23	(710) Operation Supervision & Engineering	-	-	-	-	
24	(711) Steam Expenses	-	-	-	-	
25	(712) Other Power Expenses	-	-	-	-	
26	(717) Petroleum Gas Expenses	-	-	-	-	
27	(728) Petroleum Gas	-	-	-	-	
28	(732) Purification Expenses	-	-	-	-	
29	(735) Miscellaneous Production Expenses	969	1,016	(335)	681	MGP Amortization
30	(736) Rents	-	-	-	-	
31						
32	TOTAL Operation	969	1,016	(335)	681	
33						
34	Maintenance:					
35	(740) Maintenance Supervision & Engineering	-	-	-	-	
36	(741) Maintenance of Structures & Improvements	-	-	-	-	
37	(742) Maintenance of Production Equipment	-	-	-	-	
38						
39	TOTAL Maintenance	-	-	-	-	
40	TOTAL Production Expenses-Liquified Gas	969	1,016	(335)	681	

May not cross-check due to rounding.

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility
Historical and Forecasted

Line No.		2023 Historical Total O&M	2025 Forecasted Total O&M Not Including K&M	K&M	2025 Forecasted Total O&M Including K&M	K&M Reason
41						
42	C. Natural Gas Production					
43	Operation:					
44	(754) Field Compressor Station	-	-	-	-	
45	(756) Field Measuring & Regulating Station	-	-	-	-	
46						
47	TOTAL Operation	-	-	-	-	
48						
49	Maintenance:		-	-	-	
50		-	-	-	-	
51						
52	TOTAL Maintenance	-	-	-	-	
53	TOTAL Production Expenses-Natural Gas	-	-	-	-	
54						
55	D. Other Gas Supply Expenses					
56	Operation:					
57	(800) Natural Gas Well Head Purchases	-	-	-	-	
58	(804) Natural Gas City Gas Purchases	273	297	-	297	
59	(804.1) Liquified Natural Gas Purchases	-	-	-	-	
60	(807) Purchase Gas Expense	-	-	-	-	
61	(808.1) Gas Withdrawn From Storage-Debit	-	-	-	-	
62	(808.2) Gas Delivered to Storage-Credit	-	-	-	-	
63	(810) Gas Used for Compress Station Fuel	-	-	-	-	
64	(812) Gas Used for Other Operations-Credit	-	-	-	-	
65	(813) Other Gas Supply Expenses	8	9	-	9	
66						
67	TOTAL Operation	282	306	-	306	
68						
69	Maintenance:					
70		-	-	-	-	
71						
72	TOTAL Maintenance	-	-	-	-	
73	TOTAL Production Expenses-Other Gas Supply	282	306	-	306	
74						
75	TOTAL PRODUCTION EXPENSES	1,250	1,322	(335)	987	

May not cross-check due to rounding.

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility
Historical and Forecasted

Line No.		2023 Historical Total O&M	2025 Forecasted Total O&M Not Including K&M	K&M	2025 Forecasted Total O&M Including K&M	K&M Reason
76	(2) NATURAL GAS STORAGE					
77	Operation:					
78	(814) Operation Supervision & Engineering	153	166	-	166	
79	(815) Maps & Records	1	1	-	1	
80	(816) Wells	74	79	-	79	
81	(817) Lines Expense	30	32	-	32	
82	(818) Compressor Station	33	35	-	35	
83	(819) Compress Station F&Pwr	-	-	-	-	
84	(820) Measuring & Regulating Station	4	4	-	4	
85	(821) Purification Expenses	10	10	-	10	
86	(824) Other Expenses	149	159		159	
87						
88	TOTAL Operation	454	487	-	487	
89						
90	Maintenance:					
91	(830) Maintenance Supervision & Engineering	-	-	-	-	
92	(831) Maintenance of Structures & Improvements	34	36	-	36	
93	(832) Maintenance Reservoirs & Wells	36	37	60	97	Partello Well Logging
94	(833) Maintenance of Lines	1	1	-	1	
95	(834) Maintenance Compressor Station Equipment	26	28	-	28	
96	(835) Maintenance Measuring & Regulating Equipment	-	-	-	-	
97	(836) Maintenance Purification Equipment	5	5	-	5	
98	(837) Maintenance Other Equipment	4	4	-	4	
99	(840) Supervision & Engineering	-	-	25	25	Leak Detection & Repair
100	(843.7) Compressor Equipment			50	50	Leak Detection & Repair
101						
102	TOTAL Maintenance	106	112	135	247	
103	TOTAL Natural Gas Storage Expenses	561	599	135	734	
104						
105	(3) TRANSMISSION EXPENSES					
106	Operation:					
107	(850) Operation Supervision & Engineering	10	11		11	
108	(851) Sys Cont & Load Disp	-	-	-	-	
109	(854) Gas For Compressor Station Fuel	43	46	-	46	
110	(856) Mains Exp	4	5	385	390	Casing Vent Replacements, Leak Detection & Repair
111	(857) Measuring & Regulating Station	106	111	-	111	
112	(859) Other Expenses	26	27	-	27	
113						
114	TOTAL Operation	189	199	730	584	
115						
116	Maintenance:					
117	(863) Maintenance of Mains	1	1	300	301	Leak Detection & Repair
118	(865) Maintenance Measuring & Regulating Equipment	112	119	125	244	Maintenance & Measuring of Regulator Station,Leak Detection & Repair
119	(867) Maintenance Other Equipment	-	-	-	-	
120						
121	TOTAL Maintenance	113	120	425	545	
122	TOTAL Transmission Expenses	302	320	1,155	1,130	

May not cross-check due to rounding.

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility
Historical and Forecasted

Line No.		2023 Historical Total O&M	2025 Forecasted Total O&M Not Including K&M	K&M	2025 Forecasted Total O&M Including K&M	K&M Reason
123						
124	(4) DISTRIBUTION EXPENSES					
125	Operation:					
126	(870) Operation Supervision & Engineering	764	824	225	1,049	Leak Detection & Repair
127	(871) Distribution Load Dispatching	189	205	-	205	
128	(874) Mains and Services Expenses	2,299	2,480	1,377	3,857	Locators, Pipeline Safety Management System, Leak Detection & Repair
129	(875) Measuring & Regulating Station Equipment	25	27	25	52	Leak Detection & Repair
130	(877) Measuring & Regulating Station Equipment-City Gate Check Stati	195	210	150	360	Measuring and Regulating Station Expenses - City Gate
131	(878) Meter & House Regulator Expense	684	740	200	940	Leak Detection & Repair
132	(879) Customer Installations Expense	823	890	-	890	
133	(880) Other Expenses	2,720	2,926	1,019	3,944	In House Dispatch, Deferred Maintenance of Facilities, Gas Code Compliance, Air Testing
134	(881) Rents	7	7	-	7	
135						
136	TOTAL Operation	7,704	8,309	2,996	11,305	
137						
138	Maintenance:					
139	(885) Maintenance Supervision & Engineering	-	-	5	5	
140	(887) Maintenance of Mains	738	793	1,025	1,818	Exposed Main Under Bridges, ROW Clearing, Tools, General Maintenance
141	(889) Maintenance of Measuring & Regulating Station	69	75	-	75	
142	(891) Maintenance of Measuring & Regulating Gate Station Equipment	111	120	150	270	Maintenance Of Meas & Reg Stat Equip-City Gate
143	(892) Maintenance of Services	774	818	275	1,093	Cross Bore Program Camera Maintenance, Other Maintenance Work
144	(893) Maintenance of Meters & House Regulators	452	489		489	
145	(894) Maintenance of Other Equipment	296	317	-	317	
146						
147	TOTAL Maintenance	2,440	2,612	1,455	4,067	
148	TOTAL Distribution Expenses	10,144	10,921	4,451	15,372	
149						

May not cross-check due to rounding.

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility
Historical and Forecasted

Line No.		2023 Historical Total O&M	2025 Forecasted Total O&M Not Including K&M	K&M	2025 Forecasted Total O&M Including K&M	K&M Reason
150	(5) CUSTOMER ACCOUNTS EXPENSES					
151	Operation:					
152	(901) Supervision	81	88	-	88	
153	(902) Meter Reading Expenses	392	421	463	885	AMI
154	(903) Customer Records and Collection Expenses	4,744	5,033	347	5,380	Care Center, Dispatch In-House, IT Credits
155	(904) Uncollectible Accounts	2,273	2,385	(497)	1,887	Uncollectible Accounts
156	(905) Miscellaneous Customer Accounts Expenses	96	102	-	102	
157	TOTAL Customer Accounts Expenses	7,587	8,029	313	8,342	
158						
159	(6) CUSTOMER SERVICE AND INFORMATIONAL EXPENSES					
160	Operation:					
161	(907) Supervision	19	20	-	20	
162	(908) Customer Assistance Expenses	317	341	-	341	
163	(909) Informational and Instructional Expenses	152	159	-	159	
164	(910) Miscellaneous Customer Service and Informational Expenses	-	-	-	-	
165	TOTAL Cust. Service and Informational Expenses	487	520	-	520	
166						
167	(7) SALES EXPENSES					
168	Operation:					
169	(911) Supervision	-	-	-	-	
170	(912) Demonstrating and Selling Expenses	-	-	-	-	
171	(913) Advertising Expenses	-	-	-	-	
172	(916) Miscellaneous Sales Expenses	-	-	-	-	
173	TOTAL Sales Expenses	-	-	-	-	
174						

May not cross-check due to rounding.

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility
Historical and Forecasted

Line No.		2023 Historical Total O&M	2025 Forecasted Total O&M Not Including K&M	K&M	2025 Forecasted Total O&M Including K&M	K&M Reason
175	(8) ADMINISTRATIVE AND GENERAL EXPENSES					
176	Operation:					
177	(920) Administrative and General Salaries	2,972	3,230	189	3,419	Executive, Audit Backfills, HR Backfills, Physical & IT Security, Vacation Accrual Adjustment
178	(921) Office Supplies and Expenses	381	400	1,116	1,516	Admin Serivce Contractor, COO, Consulting, Deloitte, Supply Chain Credits, Pipeline Penalties Reserve Adjustment
179	(922) Administrative Expenses Transferred-Credit	(187)	(196)	-	(196)	
180	(923) Outside Services Employed	500	525	493	1,018	Legal & Regulatory Services
181	(924) Property Insurance	88	93	6	99	Property Insurance
182	(925) Injuries and Damages	1,034	1,086	125	1,211	Injuries & Damages
183	(926) Employee Pensions and Benefits	189	2,779	2,491	5,271	Pension & Benefits
184	(927) Franchise Requirements	1,116	-	-	-	
185	(928) Regulatory Commission Expenses	663	703	51	754	Rate Case, Michicagn Clean Air Act
186	(929) Duplicate Charges-Cr.	-	-	-	-	
187	(930) Advertising Expenses	-	-	-	-	
188	(930.1) General Advertising Expenses	-	-	-	-	
189	(930.2) Miscellaneous General Expenses	576	605	67	673	Return On/Of
190	(931) Rents	402	422	-	422	
191	TOTAL Operation	7,735	9,646	4,539	14,186	
192						
193	Maintenance:					
194	(935) Maintenance of General Plant	-	-	-	-	
195	TOTAL Maintenance	-	-	-	-	
196	TOTAL Administrative and General Expenses	7,735	9,646	4,539	14,186	
197						
198	**Total Operations and Maintenance Expense**	**28,066**	**31,357**	**10,258**	**41,270**	

May not cross-check due to rounding.

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility - Labor
Historical and Forecasted

Line No.		2023 Historical Total O&M	2024 CPI	2025 CPI	2025 Forecaste Total O&M Not Including K&M
1	(1) PRODUCTION EXPENSES				
2	A. Gas Steam Production				
3	Operation:				
4	(700) Operation Supervision & Engineering	-	4.528%	3.986%	-
5	(701) Operation Labor	-	4.528%	3.986%	-
6	(702) Boiler Fuel	-	4.528%	3.986%	-
7	(703) Miscellaneous Steam Expenses	-	4.528%	3.986%	-
8	(704) Transferred-Credit	-	4.528%	3.986%	-
9					
10	TOTAL Operation	-			-
11					
12	Maintenance:				
13	(705) Maintenance Supervision & Engineering	-	4.528%	3.986%	-
14	(706) Maintenance of Structures & Improveme	-	4.528%	3.986%	-
15	(707) Maintenance of Boiler Plant Equipment	-	4.528%	3.986%	-
16	(708) Maint of Oth Stm ProdPlt	-	4.528%	3.986%	-
17					
18	TOTAL Maintenance	-			-
19	TOTAL Production Expenses-Gas Steam	-			-
20					
21	B. Liquified Gas Production				
22	Operation:				
23	(710) Operation Supervision & Engineering	-	4.528%	3.986%	-
24	(711) Steam Expenses	-	4.528%	3.986%	-
25	(712) Other Power Expenses	-	4.528%	3.986%	-
26	(717) Petroleum Gas Expenses	-	4.528%	3.986%	-
27	(728) Petroleum Gas	-	4.528%	3.986%	-
28	(732) Purification Expenses	-	4.528%	3.986%	-
29	(735) Miscellaneous Production Expenses	-	4.528%	3.986%	-
30	(736) Rents	-	4.528%	3.986%	-
31					
32	TOTAL Operation	-			-
33					
34	Maintenance:				
35	(740) Maintenance Supervision & Engineering	-	4.528%	3.986%	-
36	(741) Maintenance of Structures & Improveme	-	4.528%	3.986%	-
37	(742) Maintenance of Production Equipment	-	4.528%	3.986%	-
38					
39	TOTAL Maintenance	-			-
40	TOTAL Production Expenses-Liquified Gas	-			-

May not cross-check due to rounding.

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility - Labor
Historical and Forecasted

Line No.		2023 Historical Total O&M	2024 CPI	2025 CPI	2025 Forecaste Total O&M Not Including K&M
41					
42	C. Natural Gas Production				
43	Operation:				
44	(754) Field Compressor Station	-	4.528%	3.986%	-
45	(756) Field Measuring & Regulating Station	-	4.528%	3.986%	-
46					
47	TOTAL Operation	-			-
48					
49	Maintenance:				-
50		-	4.528%	3.986%	-
51					
52	TOTAL Maintenance	-			-
53	TOTAL Production Expenses-Natural Gas	-			-
54					
55	D. Other Gas Supply Expenses				
56	Operation:				
57	(800) Natural Gas Well Head Purchases	-	4.528%	3.986%	-
58	(804) Natural Gas City Gas Purchases	257	4.528%	3.986%	279
59	(804.1) Liquified Natural Gas Purchases	-	4.528%	3.986%	-
60	(807) Purchase Gas Expense	-	4.528%	3.986%	-
61	(808.1) Gas Withdrawn From Storage-Debit	-	4.528%	3.986%	-
62	(808.2) Gas Delivered to Storage-Credit	-	4.528%	3.986%	-
63	(810) Gas Used for Compress Station Fuel	-	4.528%	3.986%	-
64	(812) Gas Used for Other Operations-Credit	-	4.528%	3.986%	-
65	(813) Other Gas Supply Expenses	8	4.528%	3.986%	9
66					
67	TOTAL Operation	265			288
68					
69	Maintenance:				
70		-	4.528%	3.986%	-
71					
72	TOTAL Maintenance	-			-
73	TOTAL Production Expenses-Other Gas Sup	265			288
74					
75	TOTAL PRODUCTION EXPENSES	265			288

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility - Labor
Historical and Forecasted

Line No.		2023 Historical Total O&M	2024 CPI	2025 CPI	2025 Forecaste Total O&M Not Including K&M
76	(2) NATURAL GAS STORAGE				
77	Operation:				
78	(814) Operation Supervision & Engineering	153	4.528%	3.986%	167
79	(815) Maps & Records	1	4.528%	3.986%	1
80	(816) Wells	20	4.528%	3.986%	22
81	(817) Lines Expense	19	4.528%	3.986%	21
82	(818) Compressor Station	7	4.528%	3.986%	8
83	(819) Compress Station F&Pwr	-	4.528%	3.986%	-
84	(820) Measuring & Regulating Station	2	4.528%	3.986%	2
85	(821) Purification Expenses	8	4.528%	3.986%	8
86	(824) Other Expenses	72	4.528%	3.986%	79
87					
88	TOTAL Operation	283			307
89					
90	Maintenance:				
91	(830) Maintenance Supervision & Engineering	-	4.528%	3.986%	-
92	(831) Maintenance of Structures & Improveme	-	4.528%	3.986%	-
93	(832) Maintenance Reservoirs & Wells	2	4.528%	3.986%	2
94	(833) Maintenance of Lines	1	4.528%	3.986%	1
95	(834) Maintenance Compressor Station Equipı	4	4.528%	3.986%	4
96	(835) Maintenance Measuring & Regulating Eı	-	4.528%	3.986%	-
97	(836) Maintenance Purification Equipment	3	4.528%	3.986%	3
98	(837) Maintenance Other Equipment	-	4.528%	3.986%	-
99	(840) Supervision & Engineering	-	4.528%	3.986%	-
100	(843.7) Compressor Equipment				
101					
102	TOTAL Maintenance	9			10
103	TOTAL Natural Gas Storage Expenses	292			317
104					
105	(3) TRANSMISSION EXPENSES				
106	Operation:				
107	(850) Operation Supervision & Engineering	7	4.528%	3.986%	7
108	(851) Sys Cont & Load Disp	-	4.528%	3.986%	-
109	(854) Gas For Compressor Station Fuel	-	4.528%	3.986%	-
110	(856) Mains Exp	4	4.528%	3.986%	4
111	(857) Measuring & Regulating Station	5	4.528%	3.986%	6
112	(859) Other Expenses	2	4.528%	3.986%	3
113		-			
114	TOTAL Operation	18			20
115					
116	Maintenance:				
117	(863) Maintenance of Mains	0	4.528%	3.986%	1
118	(865) Maintenance Measuring & Regulating Eı	54	4.528%	3.986%	59
119	(867) Maintenance Other Equipment	-	4.528%	3.986%	-
120					
121	TOTAL Maintenance	55			59
122	TOTAL Transmission Expenses	73			79

May not cross-check due to rounding.

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility - Labor
Historical and Forecasted

Line No.		2023 Historical Total O&M	2024 CPI	2025 CPI	2025 Forecaste Total O&M Not Including K&M
123					
124	(4) DISTRIBUTION EXPENSES				
125	Operation:				
126	(870) Operation Supervision & Engineering	619	4.528%	3.986%	673
127	(871) Distribution Load Dispatching	188	4.528%	3.986%	205
128	(874) Mains and Services Expenses	1,819	4.528%	3.986%	1,977
129	(875) Measuring & Regulating Station Equipm	21	4.528%	3.986%	23
130	(877) Measuring & Regulating Station Equipm	142	4.528%	3.986%	154
131	(878) Meter & House Regulator Expense	598	4.528%	3.986%	650
132	(879) Customer Installations Expense	699	4.528%	3.986%	760
133	(880) Other Expenses	1,908	4.528%	3.986%	2,074
134	(881) Rents	-	4.528%	3.986%	-
135		-			
136	TOTAL Operation	5,994			6,515
137					
138	Maintenance:				
139	(885) Maintenance Supervision & Engineering	-	4.528%	3.986%	-
140	(887) Maintenance of Mains	497	4.528%	3.986%	540
141	(889) Maintenance of Measuring & Regulating	59	4.528%	3.986%	65
142	(891) Maintenance of Measuring & Regulating	84	4.528%	3.986%	91
143	(892) Maintenance of Services	141	4.528%	3.986%	153
144	(893) Maintenance of Meters & House Regulat	397	4.528%	3.986%	431
145	(894) Maintenance of Other Equipment	192	4.528%	3.986%	209
146					
147	TOTAL Maintenance	1,370			1,489
148	TOTAL Distribution Expenses	7,364			8,005
149					

May not cross-check due to rounding.

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility - Labor
Historical and Forecasted

Line No.		2023 Historical Total O&M	2024 CPI	2025 CPI	2025 Forecaste Total O&M Not Including K&M
150	(5) CUSTOMER ACCOUNTS EXPENSES				
151	Operation:				
152	(901) Supervision	80	4.528%	3.986%	87
153	(902) Meter Reading Expenses	254	4.528%	3.986%	276
154	(903) Customer Records and Collection Exper	1,477	4.528%	3.986%	1,605
155	(904) Uncollectible Accounts	-	4.528%	3.986%	-
156	(905) Miscellaneous Customer Accounts Expe	35	4.528%	3.986%	38
157	TOTAL Customer Accounts Expenses	1,846			2,006
158					
159	(6) CUSTOMER SERVICE AND INFORMATIONAL EXPENSES				
160	Operation:				
161	(907) Supervision	18	4.528%	3.986%	20
162	(908) Customer Assistance Expenses	224	4.528%	3.986%	243
163	(909) Informational and Instructional Expenses	-	4.528%	3.986%	-
164	(910) Miscellaneous Customer Service and Inf	-	4.528%	3.986%	-
165	TOTAL Cust. Service and Informational Expe	242			263
166					
167	(7) SALES EXPENSES				
168	Operation:				
169	(911) Supervision	-	4.528%	3.986%	-
170	(912) Demonstrating and Selling Expenses	-	4.528%	3.986%	-
171	(913) Advertising Expenses	-	4.528%	3.986%	-
172	(916) Miscellaneous Sales Expenses	-	4.528%	3.986%	-
173	TOTAL Sales Expenses	-			-
174					

May not cross-check due to rounding.

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility - Labor
Historical and Forecasted

Line No.		2023 Historical Total O&M	2024 CPI	2025 CPI	2025 Forecaste Total O&M Not Including K&M
175	(8) ADMINISTRATIVE AND GENERAL EXPENSES				
176	Operation:				
177	(920) Administrative and General Salaries	2,960	4.528%	3.986%	3,217
178	(921) Office Supplies and Expenses	-	4.528%	3.986%	-
179	(922) Administrative Expenses Transferred-Cr	-	4.528%	3.986%	-
180	(923) Outside Services Employed	-	4.528%	3.986%	-
181	(924) Property Insurance	-	4.528%	3.986%	-
182	(925) Injuries and Damages	49	4.528%	3.986%	53
183	(926) Employee Pensions and Benefits	-	4.528%	3.986%	-
184	(927) Franchise Requirements	-	4.528%	3.986%	-
185	(928) Regulatory Commission Expenses	188	4.528%	3.986%	204
186	(929) Duplicate Charges-Cr.	-	4.528%	3.986%	-
187	(930) Advertising Expenses	-	4.528%	3.986%	-
188	(930.1) General Advertising Expenses	-	4.528%	3.986%	-
189	(930.2) Miscellaneous General Expenses	29	4.528%	3.986%	32
190	(931) Rents	2	4.528%	3.986%	2
191	TOTAL Operation	3,228			3,509
192					
193	Maintenance:				
194	(935) Maintenance of General Plant	-	4.528%	3.986%	-
195	TOTAL Maintenance	-			-
196	TOTAL Administrative and General Expenses	3,228			3,509
197					
198	TOTAL Operation and Maintenance Expense	13,310			14,468

May not cross-check due to rounding.

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility - Non-Labor
Historical and Forecasted

Line No.		2,023 Historical Total O&M	2024 CPI	2025 CPI	2025 Forecasted Total O&M Not Including K&M
1	(1) PRODUCTION EXPENSES				
2	A. Gas Steam Production				
3	Operation:				
4	(700) Operation Supervision & Engineering	-	2.500%	2.350%	-
5	(701) Operation Labor	-	2.500%	2.350%	-
6	(702) Boiler Fuel	-	2.500%	2.350%	-
7	(703) Miscellaneous Steam Expenses	-	2.500%	2.350%	-
8	(704) Transferred-Credit	-	2.500%	2.350%	-
9					
10	TOTAL Operation	-			-
11					
12	Maintenance:				
13	(705) Maintenance Supervision & Engineering	-	2.500%	2.350%	-
14	(706) Maintenance of Structures & Improvements	-	2.500%	2.350%	-
15	(707) Maintenance of Boiler Plant Equipment	-	2.500%	2.350%	-
16	(708) Maint of Oth Stm ProdPlt	-	2.500%	2.350%	-
17					
18	TOTAL Maintenance	-			-
19	TOTAL Production Expenses-Gas Steam	-			-
20					
21	B. Liquified Gas Production				
22	Operation:				
23	(710) Operation Supervision & Engineering	-	2.500%	2.350%	-
24	(711) Steam Expenses	-	2.500%	2.350%	-
25	(712) Other Power Expenses	-	2.500%	2.350%	-
26	(717) Petroleum Gas Expenses	-	2.500%	2.350%	-
27	(728) Petroleum Gas	-	2.500%	2.350%	-
28	(732) Purification Expenses	-	2.500%	2.350%	-
29	(735) Miscellaneous Production Expenses	969	2.500%	2.350%	1,016
30	(736) Rents	-	2.500%	2.350%	-
31					
32	TOTAL Operation	969			1,016
33					
34	Maintenance:				
35	(740) Maintenance Supervision & Engineering	-	2.500%	2.350%	-
36	(741) Maintenance of Structures & Improvements	-	2.500%	2.350%	-
37	(742) Maintenance of Production Equipment	-	2.500%	2.350%	-
38					
39	TOTAL Maintenance	-			-
40	TOTAL Production Expenses-Liquified Gas	969			1,016

May not cross-check due to rounding.

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility - Non-Labor
Historical and Forecasted

Line No.		2,023 Historical Total O&M	2024 CPI	2025 CPI	2025 Forecasted Total O&M Not Including K&M
41					
42	C. Natural Gas Production				
43	Operation:				
44	(754) Field Compressor Station	-	2.500%	2.350%	-
45	(756) Field Measuring & Regulating Station	-	2.500%	2.350%	-
46					
47	TOTAL Operation	-			-
48					
49	Maintenance:				-
50		-	2.500%	2.350%	-
51					
52	TOTAL Maintenance	-			-
53	TOTAL Production Expenses-Natural Gas	-			-
54					
55	D. Other Gas Supply Expenses				
56	Operation:				
57	(800) Natural Gas Well Head Purchases	-	2.500%	2.350%	-
58	(804) Natural Gas City Gas Purchases	16	2.500%	2.350%	17
59	(804.1) Liquified Natural Gas Purchases	-	2.500%	2.350%	-
60	(807) Purchase Gas Expense	-	2.500%	2.350%	-
61	(808.1) Gas Withdrawn From Storage-Debit	-	2.500%	2.350%	-
62	(808.2) Gas Delivered to Storage-Credit	-	2.500%	2.350%	-
63	(810) Gas Used for Compress Station Fuel	-	2.500%	2.350%	-
64	(812) Gas Used for Other Operations-Credit	-	2.500%	2.350%	-
65	(813) Other Gas Supply Expenses	0	2.500%	2.350%	0
66					
67	TOTAL Operation	16			17
68					
69	Maintenance:				
70		-	2.500%	2.350%	-
71					
72	TOTAL Maintenance	-			-
73	TOTAL Production Expenses-Other Gas Supply	16			17
74					
75	TOTAL PRODUCTION EXPENSES	985			1,033

May not cross-check due to rounding.

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility - Non-Labor
Historical and Forecasted

Line No.		2,023 Historical Total O&M	2024 CPI	2025 CPI	2025 Forecasted Total O&M Not Including K&M
76	(2) NATURAL GAS STORAGE				
77	Operation:				
78	(814) Operation Supervision & Engineering	(1)	2.500%	2.350%	(1)
79	(815) Maps & Records	-	2.500%	2.350%	-
80	(816) Wells	54	2.500%	2.350%	57
81	(817) Lines Expense	11	2.500%	2.350%	12
82	(818) Compressor Station	26	2.500%	2.350%	27
83	(819) Compress Station F&Pwr	-	2.500%	2.350%	-
84	(820) Measuring & Regulating Station	2	2.500%	2.350%	2
85	(821) Purification Expenses	2	2.500%	2.350%	2
86	(824) Other Expenses	77	2.500%	2.350%	81
87					
88	TOTAL Operation	172			180
89					
90	Maintenance:				
91	(830) Maintenance Supervision & Engineering	-	2.500%	2.350%	-
92	(831) Maintenance of Structures & Improvements	34	2.500%	2.350%	36
93	(832) Maintenance Reservoirs & Wells	33	2.500%	2.350%	35
94	(833) Maintenance of Lines	1	2.500%	2.350%	1
95	(834) Maintenance Compressor Station Equipment	22	2.500%	2.350%	24
96	(835) Maintenance Measuring & Regulating Equipment	-	2.500%	2.350%	-
97	(836) Maintenance Purification Equipment	2	2.500%	2.350%	2
98	(837) Maintenance Other Equipment	4	2.500%	2.350%	4
99	(840) Supervision & Engineering	-	2.500%	2.350%	-
100	(843.7) Compressor Equipment				
101					
102	TOTAL Maintenance	97			102
103	TOTAL Natural Gas Storage Expenses	269			282
104					
105	(3) TRANSMISSION EXPENSES				
106	Operation:				
107	(850) Operation Supervision & Engineering	3	2.500%	2.350%	4
108	(851) Sys Cont & Load Disp	-	2.500%	2.350%	-
109	(854) Gas For Compressor Station Fuel	43	2.500%	2.350%	46
110	(856) Mains Exp	1	2.500%	2.350%	1
111	(857) Measuring & Regulating Station	101	2.500%	2.350%	105
112	(859) Other Expenses	23	2.500%	2.350%	24
113					
114	TOTAL Operation	171			180
115					
116	Maintenance:				
117	(863) Maintenance of Mains	1	2.500%	2.350%	1
118	(865) Maintenance Measuring & Regulating Equipment	57	2.500%	2.350%	60
119	(867) Maintenance Other Equipment	-	2.500%	2.350%	-
120					
121	TOTAL Maintenance	58			61
122	TOTAL Transmission Expenses	229			241

May not cross-check due to rounding.

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility - Non-Labor
Historical and Forecasted

Line No.		2,023 Historical Total O&M	2024 CPI	2025 CPI	2025 Forecasted Total O&M Not Including K&M
123					
124	(4) DISTRIBUTION EXPENSES				
125	Operation:				
126	(870) Operation Supervision & Engineering	145	2.500%	2.350%	152
127	(871) Distribution Load Dispatching	0	2.500%	2.350%	1
128	(874) Mains and Services Expenses	480	2.500%	2.350%	504
129	(875) Measuring & Regulating Station Equipment	3	2.500%	2.350%	4
130	(877) Measuring & Regulating Station Equipment-City Gate Check Station	53	2.500%	2.350%	56
131	(878) Meter & House Regulator Expense	86	2.500%	2.350%	90
132	(879) Customer Installations Expense	124	2.500%	2.350%	130
133	(880) Other Expenses	812	2.500%	2.350%	852
134	(881) Rents	7	2.500%	2.350%	7
135					
136	TOTAL Operation	1,710			1,794
137					
138	Maintenance:				
139	(885) Maintenance Supervision & Engineering	-	2.500%	2.350%	-
140	(887) Maintenance of Mains	241	2.500%	2.350%	253
141	(889) Maintenance of Measuring & Regulating Station	10	2.500%	2.350%	10
142	(891) Maintenance of Measuring & Regulating Gate Station Equipment	28	2.500%	2.350%	29
143	(892) Maintenance of Services	633	2.500%	2.350%	664
144	(893) Maintenance of Meters & House Regulators	56	2.500%	2.350%	58
145	(894) Maintenance of Other Equipment	103	2.500%	2.350%	108
146					
147	TOTAL Maintenance	1,070			1,123
148	TOTAL Distribution Expenses	2,780			2,917
149					

May not cross-check due to rounding.

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility - Non-Labor
Historical and Forecasted

Line No.		2,023 Historical Total O&M	2024 CPI	2025 CPI	2025 Forecasted Total O&M Not Including K&M
150	(5) CUSTOMER ACCOUNTS EXPENSES				
151	Operation:				
152	(901) Supervision	2	2.500%	2.350%	2
153	(902) Meter Reading Expenses	138	2.500%	2.350%	145
154	(903) Customer Records and Collection Expenses	3,268	2.500%	2.350%	3,428
155	(904) Uncollectible Accounts	2,273	2.500%	2.350%	2,385
156	(905) Miscellaneous Customer Accounts Expenses	60	2.500%	2.350%	63
157	TOTAL Customer Accounts Expenses	5,741			6,023
158					
159	(6) CUSTOMER SERVICE AND INFORMATIONAL EXPENSES				
160	Operation:				
161	(907) Supervision	0	2.500%	2.350%	0
162	(908) Customer Assistance Expenses	93	2.500%	2.350%	98
163	(909) Informational and Instructional Expenses	152	2.500%	2.350%	159
164	(910) Miscellaneous Customer Service and Informational Expenses	-	2.500%	2.350%	-
165	TOTAL Cust. Service and Informational Expenses	245			257
166					
167	(7) SALES EXPENSES				
168	Operation:				
169	(911) Supervision	-	2.500%	2.350%	-
170	(912) Demonstrating and Selling Expenses	-	2.500%	2.350%	-
171	(913) Advertising Expenses	-	2.500%	2.350%	-
172	(916) Miscellaneous Sales Expenses	-	2.500%	2.350%	-
173	TOTAL Sales Expenses	-			-
174					

May not cross-check due to rounding.

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility - Non-Labor
Historical and Forecasted

Line No.		2,023 Historical Total O&M	2024 CPI	2025 CPI	2025 Forecasted Total O&M Not Including K&M
175	(8) ADMINISTRATIVE AND GENERAL EXPENSES				
176	Operation:				
177	(920) Administrative and General Salaries	12	2.500%	2.350%	12
178	(921) Office Supplies and Expenses	381	2.500%	2.350%	400
179	(922) Administrative Expenses Transferred-Credit	(187)	2.500%	2.350%	(196)
180	(923) Outside Services Employed	500	2.500%	2.350%	525
181	(924) Property Insurance	88	2.500%	2.350%	93
182	(925) Injuries and Damages	985	2.500%	2.350%	1,033
183	(926) Employee Pensions and Benefits	2,649	2.500%	2.350%	2,779
184	(927) Franchise Requirements	-	2.500%	2.350%	-
185	(928) Regulatory Commission Expenses	475	2.500%	2.350%	498
186	(929) Duplicate Charges-Cr.	-	2.500%	2.350%	-
187	(930) Advertising Expenses	-	2.500%	2.350%	-
188	(930.1) General Advertising Expenses	-	2.500%	2.350%	-
189	(930.2) Miscellaneous General Expenses	547	2.500%	2.350%	573
190	(931) Rents	400	2.500%	2.350%	420
191	TOTAL Operation	5,850			6,137
192					
193	Maintenance:				
194	(935) Maintenance of General Plant	-	2.500%	2.350%	-
195	TOTAL Maintenance	-			-
196	TOTAL Administrative and General Expenses	5,850			6,137
197					
198	TOTAL Operation and Maintenance Expenses	16,099			16,890

May not cross-check due to rounding.

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 735
Manufactured Gas Plant Remediation

Case No.: U-21540
Exhibit No.: A-17
Schedule: G2

Witness: Anthony Reese

Line			Non Labor	
1	2025 Manufactured Gas Plant Remediation Amortization			$ 681,190
2	2023 Manufactured Gas Plant Remediation Amortization		$ 968,589	
3	2024 Inflation	2.500%		
4	2025 Inflation	2.350%		
5	Composite Inflation	4.909%		
6	Inflation on 2023 Manufactured Gas Plant Remediation Amortization		$ 47,546	
7	2023 Manufactured Gas Plant Remediation Amortization Inflated to 2025			$ 1,016,134
8	Known and Measurable Increase (Decrease) in 2025			$ (334,944)
				Account 735

Michigan Gas Utilities Corporation
Calculation of Manufactured Gas Plant Costs
For the Period Ending December 31, 2025

Case No.: U-21540
Exhibit No.: A-17
Schedule: G2
Page: 2 of 2
Witness: Anthony Reese

	Year Expenditure Incurred	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Vintage Year Costs	3,887,126	1,037,171	778,741	332,126	520,348	622,499	437,697	425,922	1,644,256	343,545
2	Amortization of Costs - Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
3	January	66,545	74,786	81,276	74,883	73,975	75,736	76,094	70,562	80,716	83,579
4	February	66,545	74,786	81,276	74,883	73,975	75,736	76,094	70,562	80,716	83,579
5	March	66,545	74,786	81,276	52,680	73,975	75,736	76,094	70,562	80,716	83,579
6	April	66,545	74,786	81,276	74,883	73,975	75,736	76,094	70,562	80,716	83,579
7	May	66,545	74,786	81,276	74,883	73,975	75,736	76,094	70,562	80,716	83,579
8	June	66,545	74,786	81,276	74,883	73,975	75,736	76,094	70,562	80,716	83,579
9	July	66,545	74,786	81,276	74,883	73,975	75,736	76,094	70,562	80,716	83,579
10	August	66,545	74,786	81,276	74,883	73,975	75,736	76,094	70,562	80,716	83,579
11	September	66,545	74,786	81,276	74,883	73,975	75,736	76,094	70,562	80,716	83,579
12	October	66,545	74,786	81,276	74,883	73,975	75,736	76,094	70,562	80,716	83,579
13	November	66,545	74,786	81,276	74,883	73,975	75,736	76,094	70,562	80,716	83,579
14	December	66,545	74,786	81,276	74,883	73,975	75,736	76,094	70,562	80,716	83,579
15	Annual Amortization	798,534	897,434	975,308	876,389	887,703	908,830	913,131	846,742	968,589	1,002,943
16	End of Year Env Study Accrual			22,067,000	21,176,000	19,313,000	17,388,000	17,997,000	14,547,000	14,201,000	14,201,000
17	Net Unamortized Balance	26,116,308	26,914,842	27,563,114	26,293,870	24,165,665	21,769,532	21,891,323	19,238,837	18,267,794	17,934,451

18 **Total Amortization for the Twelve Months Ending, December 31, 2025**

19 Historical Period Amount - Twelve Months Ended, December 31, 2023

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 832
Underground Storage Expenses - Maintenance of reservoirs and wells

Case No.: U-21540
Exhibit No.: A-17
Schedule: G3
Page: 1 of 1
Witness: Anthony Reese

Line			Labor		Non Labor	
1	2025 FERC (832) maintenance					$ 97,416
2	2023 FERC (832) maintenance		$ 2,281		$ 33,302	
3	2024 Inflation	4.528%		2.500%		
4	2025 Inflation	3.986%		2.350%		
5	Composite Inflation	8.694%		4.909%		
6	Inflation on 2023 FERC (832) maintenance		$ 198		$ 1,635	
7	2023 FERC (832) maintenance Inflated to 2025					$ 37,416
8	Known and Measurable Increase (Decrease) in 2025					$ 60,000
						Account 832

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 840
Underground Storage Expenses - Operation Supervision and Engineering

Case No.: U-21540
Exhibit No.: A-17
Schedule: G4
Page: 1 of 1
Witness: Anthony Reese

Line			Labor		Non Labor	
1	2025 FERC (840) maintenance					$ 25,000
2	2023 FERC (840) maintenance		$ -		$ -	
3	2024 Inflation	4.528%		2.500%		
4	2025 Inflation	3.986%		2.350%		
5	Composite Inflation	8.694%		4.909%		
6	Inflation on 2023 FERC (840) maintenance		$ -		$ -	
7	2023 FERC (840) maintenance Inflated to 2025					$ -
8	Known and Measurable Increase (Decrease) in 2025					$ 25,000
						Account 840

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 843.7
Underground Storage Expenses - Maintenance of Compressor Equipment

Case No.: U-21540
Exhibit No.: A-17
Schedule: G5

Witness: Anthony Reese

Line			Labor		Non Labor	
1	2025 FERC (843.7) maintenance					$ 50,000
2	2023 FERC (843.7) maintenance		$ -		$ -	
3	2024 Inflation	4.528%		2.500%		
4	2025 Inflation	3.986%		2.350%		
5	Composite Inflation	8.694%		4.909%		
6	Inflation on 2023 FERC (843.7) maintenance		$ -		$ -	
7	2023 FERC (843.7) maintenance Inflated to 2025					$ -
8	Known and Measurable Increase (Decrease) in 2025					$ 50,000
						Account 843.7

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 856
Transmission Operations Mains Expense

Case No.: U-21540
Exhibit No.: A-17
Schedule: G6
Page: 1 of 1
Witness: Anthony Reese

Line			Labor		Non Labor	
1	2025 FERC (856) Mains Exp					$ 389,840
2	2023 FERC (856) Mains Exp		$ 4,470			
3	2024 Inflation	4.528%		2.500%		
4	2025 Inflation	3.986%		2.350%		
5	Composite Inflation	8.694%		4.909%		
6	Inflation on 2023 (856) Mains Exp		$ 389		$ -	
7	2023 (856) Mains Exp Inflated to 2025					$ 4,859
8	Known and Measurable Increase (Decrease) in 2025					$ 384,981
						Account 856

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 863
Maintenance of Mains

Case No.: U-21540
Exhibit No.: A-17
Schedule: G7

Witness: Anthony Reese

Line			Labor		Non Labor	
1	2025 FERC (863) Mains Exp					$ 301,339
2	2023 FERC (863) Mains Exp		$ -		$ 1,259	
3	2024 Inflation	4.528%		2.500%		
4	2025 Inflation	3.986%		2.350%		
5	Composite Inflation	8.694%		4.909%		
6	Inflation on 2023 (863) Mains Exp		$ -		$ 62	
7	2023 (863) Mains Exp Inflated to 2025					$ 1,321
8	Known and Measurable Increase (Decrease) in 2025					$ 300,018
						Account 863

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 865
Maintenance of of Measuring and Regulating Station Equipment

Case No.: U-21540
Exhibit No.: A-17
Schedule: G8
Page: 1 of 1
Witness: Anthony Reese

Line			Labor		Non Labor	
1	2025 FERC (865) Mains Exp					$ 244,075
2	2023 FERC (865) Mains Exp		$ 54,243		$ 57,303	
3	2024 Inflation	4.528%		2.500%		
4	2025 Inflation	3.986%		2.350%		
5	Composite Inflation	8.694%		4.909%		
6	Inflation on 2023 (865) Mains Exp		$ 4,716		$ 2,813	
7	2023 (865) Mains Exp Inflated to 2025					$ 119,075
8	Known and Measurable Increase (Decrease) in 2025					$ 125,000
						Account 865

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 870
Distribution Operations Operation Supervision and Engineering

Case No.: U-21540
Exhibit No.: A-17
Schedule: G9
Page: 1 of 1
Witness: Anthony Reese

Line			Labor		Non Labor	
1	2025 FERC (870) Mains and Services Expenses					$ 1,049,448
2	2023 FERC (870) Mains and Services Expenses		$ 618,773		$ 144,769	
3	2024 Inflation	4.528%		2.500%		
4	2025 Inflation	3.986%		2.350%		
5	Composite Inflation	8.694%		4.909%		
6	Inflation on 2023 (870) Mains and Services Expenses		$ 53,794		$ 7,106	
7	2023 (870) Mains and Services Expenses Inflated to 2025					$ 824,443
8	Known and Measurable Increase (Decrease) in 2025					$ 225,005
						Account 870

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 874
Distribution Operations Mains and Services Expenses

Case No.: U-21540
Exhibit No.: A-17
Schedule: G10
Page: 1 of 1
Witness: Anthony Reese

Line			Labor		Non Labor	
1	2025 FERC (874) Mains and Services Expenses					$ 3,857,160
2	2023 FERC (874) Mains and Services Expenses		$ 1,818,778		$ 480,019	
3	2024 Inflation	4.528%		2.500%		
4	2025 Inflation	3.986%		2.350%		
5	Composite Inflation	8.694%		4.909%		
6	Inflation on 2023 (874) Mains and Services Expenses		$ 158,119		$ 23,563	
7	2023 (874) Mains and Services Expenses Inflated to 2025					$ 2,480,479
8	Known and Measurable Increase (Decrease) in 2025					$ 1,376,681

Account 874

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 875
Distribution Operations Measuring and Regulating Station Expenses - General

Case No.: U-21540
Exhibit No.: A-17
Schedule: G11
Page: 1 of 1
Witness: Anthony Reese

Line			Labor		Non Labor	
1	2025 FERC (875) Mains and Services Expenses					$ 51,991
2	2023 FERC (875) Mains and Services Expenses		$ 21,492		$ 3,461	
3	2024 Inflation	4.528%		2.500%		
4	2025 Inflation	3.986%		2.350%		
5	Composite Inflation	8.694%		4.909%		
6	Inflation on 2023 (875) Mains and Services Expenses		$ 1,868		$ 170	
7	2023 (875) Mains and Services Expenses Inflated to 2025					$ 26,991
8	Known and Measurable Increase (Decrease) in 2025					$ 25,000
						Account 875

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 877
Distribution Operations Measuring and Regulating Station Expenses - City Gate Check Stations

Case No.: U-21540
Exhibit No.: A-17
Schedule: G12
Page: 1 of 1
Witness: Anthony Reese

Line			Labor		Non Labor	
1	2025 FERC (877) Mains and Services Expenses					$ 359,603
2	2023 FERC (877) Mains and Services Expenses		$ 141,700		$ 52,982	
3	2024 Inflation	4.528%		2.500%		
4	2025 Inflation	3.986%		2.350%		
5	Composite Inflation	8.694%		4.909%		
6	Inflation on 2023 (877) Mains and Services Expenses		$ 12,319		$ 2,601	
7	2023 (877) Mains and Services Expenses Inflated to 2025					$ 209,602
8	Known and Measurable Increase (Decrease) in 2025					$ 150,001
						Account 877

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 878
Distribution Operations Meter and House Regulator Expenses

Case No.:	U-21540
Exhibit No.:	A-17
Schedule:	G13
Page:	1 of 1
Witness:	Anthony Reese

Line			Labor		Non Labor	
1	2025 FERC (878) Mains and Services Expenses					$ 940,144
2	2023 FERC (878) Mains and Services Expenses		$ 598,075		$ 85,855	
3	2024 Inflation	4.528%		2.500%		
4	2025 Inflation	3.986%		2.350%		
5	Composite Inflation	8.694%		4.909%		
6	Inflation on 2023 (878) Mains and Services Expenses		$ 51,995		$ 4,214	
7	2023 (878) Mains and Services Expenses Inflated to 2025					$ 740,139
8	Known and Measurable Increase (Decrease) in 2025					$ 200,005
						Account 878

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 880
Distribution Operations Other Expenses

Case No.: U-21540
Exhibit No.: A-17
Schedule: G14
Page: 1 of 1
Witness: Anthony Reese

Line			Labor		Non Labor	
1	2025 FERC (880) Other Expenses					$ 3,944,340
2	2023 FERC (880) Other Expenses		$ 1,907,831		$ 811,939	
3	2024 Inflation	4.528%		2.500%		
4	2025 Inflation	3.986%		2.350%		
6	Composite Inflation	8.694%		4.909%		
7	Inflation on 2023 (880) Other Expenses		$ 165,861		$ 39,856	
8	2023 (880) Other Expenses Inflated to 2025					$ 2,925,487
9	Known and Measurable Increase (Decrease) in 2025					$ 1,018,854
						Account 880

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 885
Distribution Maintenance Supervision and Engineering

Case No.: U-21540
Exhibit No.: A-17
Schedule: G15

Witness: Anthony Reese

Line			Labor		Non Labor	
1	2025 FERC (885) Maintenance of Mains					$ 5,000
2	2023 FERC (885) Maintenance of Mains		$ -		$ -	
3	2024 Inflation	4.528%		2.500%		
4	2025 Inflation	3.986%		2.350%		
6	Composite Inflation	8.694%		4.909%		
7	Inflation on 2023 (885) Maintenance of Mains		$ -		$ -	
8	2023 (885) Maintenance of Mains Inflated to 2025					$ -
9	Known and Measurable Increase (Decrease) in 2025					$ 5,000
						Account 885

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 887
Distribution Maintenance of Mains

Case No.: U-21540
Exhibit No.: A-17
Schedule: G16
Page: 1 of 1
Witness: Anthony Reese

Line						
1	2025 FERC (887) Maintenance of Mains					$ 1,818,147
			Labor		Non Labor	
2	2023 FERC (887) Maintenance of Mains		$ 496,907		$ 241,196	
3	2024 Inflation	4.528%		2.500%		
4	2025 Inflation	3.986%		2.350%		
6	Composite Inflation	8.694%		4.909%		
7	Inflation on 2023 (887) Maintenance of Mains		$ 43,200		$ 11,840	
8	2023 (887) Maintenance of Mains Inflated to 2025					$ 793,143
9	Known and Measurable Increase (Decrease) in 2025					$ 1,025,004
						Account 887

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 891
Distribution Maintenance of Measuring and Regulating Gate Station Equipment- City Gate Check Stations

Case No.: U-21540
Exhibit No.: A-17
Schedule: G17
Page: 1 of 1
Witness: Anthony Reese

Line								
1	2025 FERC (891) Maintenance of Meters & House Regulators						$	270,011
				Labor		Non Labor		
2	2023 FERC (891) Maintenance of Meters & House Regulators		$	83,756	$	27,617		
3	2024 Inflation	4.528%			2.500%			
4	2025 Inflation	3.986%			2.350%			
6	Composite Inflation	8.694%			4.909%			
7	Inflation on 2023 (891) Maintenance of Meters & House Regulators		$	7,281	$	1,356		
8	2023 (891) Maintenance of Meters & House Regulators Inflated to 2025						$	120,011
9	Known and Measurable Increase (Decrease) in 2025						$	150,001

Account 891

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 892
Distribution Maintenance of Services

Case No.: U-21540
Exhibit No.: A-17
Schedule: G18

Witness: Anthony Reese

Line			Labor		Non Labor	
1	2025 FERC (892) Maintenance of Meters & House Regulators					$ 1,092,659
2	2023 FERC (892) Maintenance of Meters & House Regulators		$ 141,174		$ 633,131	
3	2024 Inflation	4.528%		2.500%		
4	2025 Inflation	3.986%		2.350%		
6	Composite Inflation	8.694%		4.909%		
7	Inflation on 2023 (892) Maintenance of Meters & House Regulators		$ 12,273		$ 31,079	
8	2023 (892) Maintenance of Meters & House Regulators Inflated to 2025					$ 817,658
9	Known and Measurable Increase (Decrease) in 2025					$ 275,001
						Account 892

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 902
Customer Accounts Expense - Meter Reading

Case No.: U-21540
Exhibit No.: A-17
Schedule: G19

Witness: Anthony Reese

Line						
1	2025 FERC (902) Meter Reading Expenses					$ 884,647
			Labor		Non Labor	
2	2023 FERC (902) Meter Reading Expenses		$ 254,296		$ 138,181	
3	2024 Inflation	4.528%		2.500%		
4	2025 Inflation	3.986%		2.350%		
6	Composite Inflation	8.694%		4.909%		
7	Inflation on 2023 (902) Meter Reading Expenses		$ 22,108		$ 6,783	
8	2023 (902) Meter Reading Expenses Inflated to 2025					$ 421,368
9	Known and Measurable Increase (Decrease) in 2025					$ 463,279
						Account 902

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 903
Customer Accounts Expenses - Customer Records and Collection

Case No.: U-21540
Exhibit No.: A-17
Schedule: G20
Page: 1 of 1
Witness: Anthony Reese

Line			Labor		Non Labor	
1	2025 FERC (903) Customer Records and Collection Expenses					$ 5,379,615
2	2023 FERC (903) Customer Records and Collection Expenses		$ 1,476,524		$ 3,267,506	
3	2024 Inflation	4.528%		2.500%		
4	2025 Inflation	3.986%		2.350%		
6	Composite Inflation	8.694%		4.909%		
7	Inflation on 2023 (903) Customer Records and Collection Expenses		$ 128,364		$ 160,394	
8	2023 (903) Customer Records and Collection Expenses Inflated to 2025					$ 5,032,788
9	Known and Measurable Increase (Decrease) in 2025					$ 346,827

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 904
Customer Accounts Expenses - Uncollectible Accounts

Case No.: U-21540
Exhibit No.: A-17
Schedule: G21
Page: 1 of 2
Witness: Anthony Reese

Line			Non Labor	
1	2025 Uncollectible Accounts			$ 1,887,441
2	2023 Uncollectible Accounts		$ 2,273,289	
3	2024 Inflation	2.500%		
4	2025 Inflation	2.350%		
6	Composite Inflation	4.909%		
7	Inflation on 2023 Uncollectible Accounts		$ 111,590	
8	2023 Uncollectible Accounts Inflated to 2025			$ 2,384,879
9	Known and Measurable Increase (Decrease) in 2025			$ (497,437)
				Account 904

Michigan Gas Utilities Corporation
Allowance for Uncollectibles Expense for 2024

Case No.: U-21540
Exhibit No.: A-17
Schedule: G21
Page: 2 of 2
Witness: Anthony Reese

Line	Year	Write-Offs	Collections	Net Uncollectibles	Total Gas Service Revenues	Net Uncollectibles as a Percent of Revenue
		[P-522, Page 228A]			[P-522, Page 300 less EWR]	
1	2018	$2,411,978	$0	$2,411,978	$145,314,914	1.6598%
2	2019	$1,715,822	$0	$1,715,822	$137,937,019	1.2439%
3	2020	$904,695	$0	$904,695	$124,639,233	0.7259%
4	2021	$729,764	$0	$729,764	$136,597,813	0.5342%
5	2022	$2,266,703	$0	$2,266,703	$212,347,848	1.0674%
6					Average	1.0463%
7						
8						
9	Allowance for Uncollectible Expense for 2024					
10						
11		2024 Forecasted Total Revenue without rate increase			$180,399,335	
12		5-Year Average Net Uncollectibles as a Percent of Revenue			1.046%	
13		Net Uncollectibles Allowance for 2024			$1,887,441	
14						

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 920
Administrative and General - Administrative and General Salaries

Case No.: U-21540
Exhibit No.: A-17
Schedule: G22
Page: 1 of 1
Witness: Anthony Reese

Line			Labor		Non Labor	
1	2025 FERC (920) Administrative and General Salaries					$ 3,419,076
2	2023 FERC (920) Administrative and General Salaries		$ 2,960,112		$ 11,566	
3	2024 Inflation	4.528%		2.500%		
4	2025 Inflation	3.986%		2.350%		
6	Composite Inflation	8.694%		4.909%		
7	Inflation on 2023 (920) Administrative and General Salaries		$ 257,343		$ 568	
8	2023 (920) Administrative and General Salaries Inflated to 2025					$ 3,229,589
9	Known and Measurable Increase (Decrease) in 2025					$ 189,487
						Account 920

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 921
Administrative and General - Office Supplies and Expense

Case No.: U-21540
Exhibit No.: A-17
Schedule: G23
Page: 1 of 1
Witness: Anthony Reese

Line							
1	2025 FERC (921) Office Supplies and Expenses						$ 1,516,335
			Labor		Non Labor		
2	2023 FERC (921) Office Supplies and Expenses		$ -		$ 380,937		
3	2024 Inflation	4.528%		2.500%			
4	2025 Inflation	3.986%		2.350%			
6	Composite Inflation	8.694%		4.909%			
7	Inflation on 2023 (921) Office Supplies and Expenses		-		$ 18,699		
8	2023 (921) Office Supplies and Expenses Inflated to 2025						$ 399,637
9	Known and Measurable Increase (Decrease) in 2025						$ 1,116,698
							Account 921

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 923
Administrative and General - Outside Services Employed

Case No.: U-21540
Exhibit No.: A-17
Schedule: G24

Witness: Anthony Reese

Line			Labor		Non Labor	
1	2025 FERC (923) Outside Services Employed					$ 1,017,537
2	2023 FERC (923) Outside Services Employed		$ -		$ 500,462	
3	2024 Inflation	4.528%		2.500%		
4	2025 Inflation	3.986%		2.350%		
6	Composite Inflation	8.694%		4.909%		
7	Inflation on 2023 (923) Outside Services Employed		$ -		$ 24,566	
8	2023 (923) Outside Services Employed Inflated to 2025					$ 525,028
9	Known and Measurable Increase (Decrease) in 2025					$ 492,509
						Account 923

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 924
Administrative and General - Property Insurance

Case No.: U-21540
Exhibit No.: A-17
Schedule: G25
Page: 1 of 1
Witness: Anthony Reese

Line			Labor		Non Labor	
1	2025 FERC (924) Property Insurance					$ 99,056
2	2023 FERC (924) Property Insurance		$ -		$ 88,286	
3	2024 Inflation	4.528%		2.500%		
4	2025 Inflation	3.986%		2.350%		
5	Composite Inflation	8.694%		4.909%		
6	Inflation on 2023 (924) Property Insurance		$ -		$ 4,334	
7	2023 (924) Property Insurance Inflated to 2025					$ 92,619
8	Known and Measurable Increase (Decrease) in 2025					$ 6,436
						Account 924

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 925
Administrative and General - Injuries and Damages Expenses

Case No.: U-21540
Exhibit No.: A-17
Schedule: G26
Page: 1 of 1
Witness: Anthony Reese

Line			Labor		Non Labor	
1	2025 Injuries & Damages					$ 1,210,819
2	2023 Injuries & Damages		$ 48,850		$ 984,665	
3	2024 Inflation	4.528%		2.500%		
4	2025 Inflation	3.986%		2.350%		
5	Composite Inflation	8.694%		4.909%		
6	Inflation on 2023 Costs		$ 4,247		$ 48,335	
7	2023 Costs Inflated to 2025					$ 1,086,096
9	Known and Measurable Increase (Decrease) in 2025					$ 124,723
						Account 925

MICHIGAN GAS UTILITY COMPANY
Known and Measurable Adjustment, account 926
Administrative and General - Employee Pensions and Benefits Expenses
Summary of Employee Benefit Costs
Test Year Ended December 31, 2025

Case No.: U-21540
Exhibit No.: A-17
Schedule: G27

Witness: Anthony Reese

Line No.	Description	2023 Actual $	2025 Forecast $	Increase $	Increase %	Forecast Method
1	Medical Benefits	$ 1,714,217	$ 2,061,833	$ 347,616	20.3%	MGUC Estimate
2	Dental Benefits	$ 83,074	$ 92,416	$ 9,342	11.2%	MGUC Estimate
3	401(k)	$ 1,138,672	$ 1,237,674	$ 99,002	8.7%	MGUC Estimate
4	Deferred comp	$ (2,033)	$ 9,321	$ 11,354	558.5%	MGUC Estimate
5	Performance Units	$ 93	$ 111,900	$ 111,807	120222.6%	MGUC Estimate
6	**Subtotal - MGUC Estimate**	$ 2,934,023	$ 3,513,144	$ 579,121	19.7%	
7						
8	Long Term Disability	$ 63,245	$ 66,350	$ 3,105	4.9%	Inflationary
9	Life Insurance	$ 32,155	$ 33,733	$ 1,578	4.9%	Inflationary
10	Tuition Reimbursement and Other	$ 15,668	$ 16,437	$ 769	4.9%	Inflationary
11	Executive Benefits	$ 47,262	$ 49,582	$ 2,320	4.9%	Inflationary
12	Benefit Administration	$ 38,887	$ 40,796	$ 1,909	4.9%	Inflationary
13	Benefits Billed to/from Affiliates	$ 109,300	$ 114,665	$ 5,365	4.9%	Inflationary
14	Capitalized Benefits	$ (1,310,333)	$ (1,374,654)	$ (64,321)	4.9%	Inflationary
15	**Subtotal - Inflationary Items**	$ (1,003,816)	$ (1,053,091)	$ (49,275)	4.9%	
16						
17	Qualified Pension	$ 92,305	$ 1,159,822	$ 1,067,517	-1156.5%	Actuarial Analysis
18	NonQualified Pension	$ 24,482	$ 22,396	$ (2,086)	-8.5%	Actuarial Analysis
19	OPEB	$ 99,092	$ 165,449	$ 66,357	-67.0%	Actuarial Analysis
20	Postemployment	$ (104,542)	$ -	$ 104,542	-100.0%	Actuarial Analysis
21	**Subtotal - Actuarial Analysis**	$ 111,337	$ 1,347,667	$ 1,236,330	-1110.4%	
22						
23	**Benefits Billed from WBS**	$ 607,702	$ 1,434,891	$ 827,189	136.1%	See Page 2
24						
25	**TOTAL EMPLOYEE BENEFIT COSTS**	$ 2,649,246	$ 5,242,611	$ 2,593,365	97.9%	
26						
27	Composite non-labor inflation rate	4.909%				
28						
29	2023 Costs inflated to 2025	$ 2,779,291				
30						
31	Known and Measurable Increase (Decrease) in 2025		$ 2,463,321			

MICHIGAN GAS UTILITY COMPANY
Known and Measurable Adjustment, account 926
Summary of Employee Benefit Costs

Test Year Ended December 31, 2025

Case No.: U-21540
Exhibit No.: A-17
Schedule: G27
Page: 2 of 2
Witness: Anthony Reese

Line No.	Description	2023 Actual $	2025 Forecast $	Increase $	Increase %	Forecast Method
1	Medical Benefits	$ 15,309,929	$ 18,689,166	$ 3,379,237	22.1%	MGUC Estimate
2	Dental Benefits	$ 741,922	$ 837,667	$ 95,745	12.9%	MGUC Estimate
3	401(k)	$ 13,150,774	$ 14,294,166	$ 1,143,392	8.7%	MGUC Estimate
4	Deferred comp	$ 8,761,339	$ 7,472,476	$ (1,288,863)	14.7%	MGUC Estimate
5	Performance Units	$ (1,730,775)	$ 17,514,300	$ 19,245,075	1111.9%	MGUC Estimate
6	**Subtotal - MGUC Estimate**	$ 36,233,189	$ 58,807,775	$ 22,574,586	62.3%	
7						
8	Long Term Disability	$ 530,748	$ 556,801	$ 26,053	4.9%	Inflationary
9	Life Insurance	$ 372,883	$ 391,187	$ 18,304	4.9%	Inflationary
10	Tuition Reimbursement and Other	$ 168,779	$ 177,064	$ 8,285	4.9%	Inflationary
11	Executive Benefits	$ 9,146,936	$ 9,595,936	$ 449,000	4.9%	Inflationary
12	Benefit Administration	$ 346,884	$ 363,912	$ 17,028	4.9%	Inflationary
13	Benefits Billed to/from Affiliates	$ -	$ -	$ -	0.0%	Inflationary
14	**Subtotal - Inflationary Items**	$ 10,566,230	$ 11,084,900	$ 518,670	4.9%	
15						
16	Qualified Pension	$ (5,326,946)	$ (3,322,462)	$ 2,004,484	37.6%	Actuarial Analysis
17	NonQualified Pension	$ (10,133,136)	$ 3,545,879	$ 13,679,015	-135.0%	Actuarial Analysis
18	OPEB	$ (1,654,113)	$ (472,187)	$ 1,181,926	71.5%	Actuarial Analysis
19	Postemployment	$ (180,596)	$ 21,164	$ 201,760	111.7%	Actuarial Analysis
20	**Subtotal - Actuarial Analysis**	$ (17,294,791)	$ (227,606)	$ 17,067,185	-98.7%	
21						
22	**TOTAL EMPLOYEE BENEFIT COSTS**	$ 29,504,628	$ 69,665,069	$ 40,160,441	136.1%	
23						
24	Allocation Percentage from WBS to MGU	2.1%	2.1%			
25						
26	Allocation Dollars from WBS to MGUC	$ 607,702	$ 1,434,891	$ 827,189	136.1%	

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 928
Administrative and General - Regulatory Commission Expense

Case No.: U-21540
Exhibit No.: A-17
Schedule: G28

Witness: Anthony Reese

Line			Labor		Non Labor	
1	2025 FERC (928) Regulatory Commission Expense					$ 753,891
2	2023 FERC (928) Regulatory Commission Expense		$ 187,920		$ 475,134	
3	2024 Inflation	4.528%		2.500%		
4	2025 Inflation	3.986%		2.350%		
6	Composite Inflation	8.694%		4.909%		
7	Inflation on 2023 (928) Regulatory Commission Expense		$ 16,337		$ 23,323	
8	2023 (928) Outside Services Employed Inflated to 2025					$ 702,715
9	Known and Measurable Increase (Decrease) in 2025					$ 51,176
						Account 928

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 930.2
Administrative and General - Miscellaneous General Expenses

Case No.: U-21540
Exhibit No.: A-17
Schedule: G29
Page: 1 of 2
Witness: Anthony Reese

Line			Labor		Non Labor*		Service Company (WBS) Return on/of	
1	2025 FERC (930.2) Miscellaneous General Expenses							$ 672,634
2	2023 FERC (930.2) Miscellaneous General Expenses		$ 29,406		$ 199,541		$ 346,965	
3	2024 Inflation	4.528%		2.500%		2.500%		
4	2025 Inflation	3.986%		2.350%		2.350%		
6	Composite Inflation	8.694%		4.909%		4.909%		
7	Inflation on 2023 (930.2) Miscellaneous General Expenses		$ 2,556		$ 9,795		$ 17,032	
8	2023 (930.2) Miscellaneous General Expenses Inflated to 2025							$ 605,295
9	Known and Measurable Increase (Decrease) in 2025							$ 67,339
10	*Service Company Return on/off is in Non Labor but separated here for clarity							Account 930.2

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 930.2
Service Company Return On/Of

Case No.: U-21540
Exhibit No.: A-17
Schedule: G29
Page: 2 of 2
Witness: Anthony Reese

Line		Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Total
1	Service Company Assets earning a Return	-1,250,247	-1,240,048	-1,242,582	-1,298,885	-1,365,931	-1,428,620	-1,515,704	-1,558,562	-1,624,806	-1,675,007	-1,755,931	-1,844,739	
2	MGU PreTax Weighted Cost of Capital	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	
3	Return on Assets	-95,394	-94,616	-94,809	-99,105	-104,221	-109,004	-115,648	-118,918	-123,973	-127,803	-133,977	-140,754	
4														
5	Revenue Req on Service Company AFUDC	-4,049	-3,717	-3,488	-3,347	-3,167	-2,976	-2,733	-2,611	-2,464	-2,377	-2,342	-2,312	
6	Revenue Req AFUDC Debt - 12 Mos Total	-1,116	-1,025	-962	-923	-873	-821	-754	-720	-680	-655	-646	-638	
7														
8	Total ROA	-100,559	-99,358	-99,258	-103,375	-108,260	-112,800	-119,134	-122,249	-127,117	-130,835	-136,965	-143,703	
9														
10	Monthly Average	-8,380	-8,280	-8,272	-8,615	-9,022	-9,400	-9,928	-10,187	-10,593	-10,903	-11,414	-11,975	
11														
12	Service Company Depreciation	47,130	46,763	46,767	46,968	47,355	47,520	48,252	48,426	48,358	48,523	49,328	49,556	
13														
14	Total Service Company Return On/Of*	35,154	34,787	34,792	34,993	35,380	35,545	36,277	36,451	36,382	36,548	37,353	37,581	**431,242**
15														
16	*Uses Year End Average for Asset Portion													

Michigan Gas Utilities Corporation
Estimate of Inflation for 2024 and 2025

Case No.: U-21540
Exhibit No.: A-18
Page: 1 of 1
Witness: Anthony Reese

Line	Source	Date	2024	2025
1	Philly Fed	August, 2023	2.50%	2.40%
2	Blue Chip	August, 2023	2.50%	2.30%
3	**MGUC Estimate (Simple Average)**		**2.50%**	**2.35%**
4	**Cumulative Impact from 2023 to 2025**			**4.91%**

Exhibit No. A-19 is FULLY CONFIDENTIAL –

a PUBLIC REDACTED version will not be provided

Exhibit No. A-20 is FULLY CONFIDENTIAL –

a PUBLIC REDACTED version will not be provided

Exhibit No. A-21 is FULLY CONFIDENTIAL –

a PUBLIC REDACTED version will not be provided

2024 Annual Incentive Plan Overview

REDACTED

WEC Energy Group

WEC Business Services (WBS)

Weighting by measurement			Funding	Goals	Example
Cost control [redacted]	[redacted] controllable O&M across WEC Energy Group		**Thresh**[redacted] **Interm**[redacted] **Target**[redacted] **Maxim**[redacted]	[redacted]	**Fund**[redacted]**t threshold:** [redacted] **Fund**[redacted]**t intermediat**[redacted] **Fund**[redacted]**t target:** [redacted] **Fund**[redacted]**t maximum:** [redacted]
Customer satisfaction [redacted]	[redacted] total company aggregated transaction satisfaction	Weighted based on average customer population: [redacted]	**Thresh**[redacted] **Target**[redacted] **Maxim**[redacted]	[redacted]	**Fund**[redacted]**t threshold:** [redacted] **Fund**[redacted]**t target:** [redacted] **Fund**[redacted]**t maximum:** [redacted]
	[redacted] total company aggregated satisfaction		**Thresh**[redacted] **Target**[redacted] **Maxim**[redacted]	[redacted]	**Fund**[redacted]**t threshold:** [redacted] **Fund**[redacted]**t target:** [redacted] **Fund**[redacted]**t maximum:** [redacted]
Safety [redacted]	[redacted] WBS DART incidents		**Thresh**[redacted] **Target**[redacted] **Maxim**[redacted]	[redacted]	**Fund**[redacted]**t threshold:** [redacted] **Fund**[redacted]**t maximum:** [redacted]
	[redacted] WBS lost-time injuries		**Thresh**[redacted] **Target**[redacted] **Maxim**[redacted]	[redacted]	**Fund**[redacted]**t threshold:** [redacted] **Fund**[redacted]**t target:** [redacted] **Fund**[redacted]**t maximum:** [redacted]
Diversity [redacted]	[redacted] total company supplier diversity		Total combined company goals **Thres**[redacted] **Targe**[redacted] **Maxi**[redacted]	[redacted]	**Fund**[redacted]**t threshold:** [redacted] **Fund**[redacted]**t target:** [redacted] **Fund**[redacted]**t maximum:** [redacted]
	[redacted] total company workforce diversity		WEC Energy Group workforce diversity goals, as determined by chief executive officer.		**Funds**[redacted]**t threshold:** [redacted] **Funds**[redacted]**t target:** [redacted] **Funds**[redacted]**t maximum:** [redacted]

WBS Incentive Plan calculation example

[redacted]

Actual individual target incentive awards may vary, depending on position. Performance below threshold levels will yield no funding.

O&M: Operations and maintenance **DART:** Days away, restricted or transferred

2024 Annual Incentive Plan Overview

REDACTED

Michigan Gas Utilities (MGU)

Weighting by measurement		Funding	Goals	Example	
Cost control [redacted]	[redacted] MGU net income	**Thres**[redacted] **Interm**[redacted] **Target**[redacted] **Maxim**[redacted]	[redacted]	**MGU Incentive Plan calculation example** [redacted] Actual individual target incentive awards may vary, depending on position. Performance below threshold levels will yield no funding.	**Fund**[redacted]**hreshold:** [redacted] **Fund**[redacted]**ntermediate** [redacted] **Fund**[redacted]**target:** [redacted] **Fund**[redacted]**maximum:** [redacted]
Customer satisfaction [redacted]	[redacted] MGU transaction satisfaction	**Thres**[redacted] **Target**[redacted] **Maxim**[redacted]	[redacted]		**Fund**[redacted]**hreshold:** [redacted] **Fund**[redacted]**target:** [redacted] **Fund**[redacted]**maximum:** [redacted]
	[redacted] MGU (company) satisfaction	**Thres**[redacted] **Target**[redacted] **Maxim**[redacted]	[redacted]		**Fund**[redacted]**hreshold:** [redacted] **Fund**[redacted]**target:** [redacted] **Fund**[redacted]**maximum:** [redacted]
Safety [redacted]	[redacted] MGU DART incidents	**Thres**[redacted] **Target**[redacted] **Maxim**[redacted]	[redacted]		**Fund**[redacted]**hreshold:** [redacted] **Fund**[redacted]**maximum:** [redacted]
	[redacted] MGU lost-time injuries	**Thres**[redacted] **Target**[redacted] **Maxim**[redacted]	[redacted]		**Fund**[redacted]**hreshold:** [redacted] **Fund**[redacted]**target:** [redacted] **Fund**[redacted]**maximum:** [redacted]
Diversity [redacted]	[redacted] Michigan supplier diversity	**Thres**[redacted] **Target**[redacted] **Maxin**[redacted]	[redacted]		**Funds**[redacted]**t threshold:** [redacted] **Funds**[redacted]**at target:** [redacted] **Funds**[redacted]**at maximum:** [redacted]
	[redacted] total company workforce diversity	WEC Energy Group workforce diversity goals, as determined by chief executive officer.			**Funds**[redacted]**t threshold:** [redacted] **Funds**[redacted]**at target:** [redacted] **Funds**[redacted]**at maximum:** [redacted]

O&M: Operations and maintenance **DART:** Days away, restricted or transferred

Michigan Gas Utilities Company
MRP Revenue Requirement

Case No.: U-21540
Exhibit No.: A-23

Witness: Shannon L. Burzycki

Line No	Description	Source	2026	2027
			(a)	(b)
	Capital Investment			
1	Annual MRP Investment	Witness Lee Testimony	11,431,000	625,000
	Net Rate Base			
2	Cumulative Capital Investment	Prior Year Plus Line 1	11,431,000	12,056,000
3	Accumulated Depreciation	Prior Year - Line 8	(169,179)	(516,786)
4	Accumulated Deferred Taxes	Page 2; Line 5	(259,484)	(501,034)
5	Ending Net Rate Base	Sum Line 2 - Line 4	11,002,338	11,038,180
6	Average Net Rate Base	Line 5 (PY + CY)/2	5,501,169	11,020,259
	Total Cost			
7	Return on Rate Base	9.10%	500,606	1,002,844
8	Depreciation (1/2 year convention)	2.96%	169,179	347,608
9	Property Taxes	Page 2	-	265,771
10	Total Revenue Requirement	Line 7 Thru Line 10	669,785	1,616,222

Michigan Gas Utilities Company
MRP Revenue Requirement

Case No.: U-21540
Exhibit No.: A-23

Witness: Shannon L. Burzycki

Line No	Description	Source	2026	2027
			(a)	(b)
	Deferred Tax Expense			
1	Tax Depreciation	Line 7	428,663	848,641
2	Book Depreciation	Page 1 Line 8	169,179	347,608
3	Time Difference	Line 2 - Line 1	259,484	501,034
4	Deferred Tax Expense	25.7%	66,791	128,966
5	Accumulated Deferred Tax Expense	Prior Year Plus Line 4	66,791	195,757
	Tax Depreciation		Year 1	Year 2
6	MACRS Tax Depreciation Rate (20 Years)		3.750%	7.219%
7	Year 1 Additions	Cost & MACRS Rate	428,663	825,204
8	Year 2 Additions	Cost & MACRS Rate		23,438
9	Year 3 Additions	Cost & MACRS Rate		
10	Year 4 Additions	Cost & MACRS Rate		
11	Year 5 Additions	Cost & MACRS Rate		
12	Total Tax Depreciation	Sum of Lines 7 thru 11	428,663	848,641
	Property Tax			
13	Factor		0.93	0.87
14	Year 1 Investment Taxable Value	Cost X Factor X 50%	5,315,415	4,972,485
15	Year 2 Investment Taxable Value	Cost X Factor X 50%		290,625
16	Year 3 Investment Taxable Value	Cost X Factor X 50%		
17	Year 4 Investment Taxable Value	Cost X Factor X 50%		
18	Year 5 Investment Taxable Value	Cost X Factor X 50%		
19	Total Taxable Value	Sum of Lines 13 thru 17	5,315,415	5,263,110
20	Millage	$ 50	$ 50	$ 50
21	Property Tax Assessed	(Line 19 X Line 20) / 1000	265,771	263,156
22	Property Tax Expense			265,771

Michigan Gas Utilities Corporation
Proposed MRP Customer Surcharges 2026
Test Year Ending December 31, 2025

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(L)	(I)	(K)	(J)	(M)	(N)	(O)	(P)	(Q)	(R)
			Residential			Small			Medium				Large				Super Large	Other
Line No.	Line Description	Total MGU Natural Gas	General Service-Residential	Customer Choice-Residential	Agg Transport-Residential	General Service-Small	Customer Choice-GS-Small	Agg Transport-GS-Small	General Service-Medium	Transport-TR-1	Customer Choice-GS-Medium	Agg Transport-GS-Medium	General Service-Large	Transport-TR-2	Customer Choice-GS-Large	Agg Transport-GS-Large	Transport-TR-3	Special Contract
1	2025 dist. main plant in service (Workpaper REO-2, Sched 13, Line 33)	276,715,089	176,430,251	19,123,778	16,742	35,951,242	5,752,934	2,071,766	155,353	6,923,920	10,252	361,415	1,346,207	18,335,979	159,990	259,044	9,808,527	7,690
2	2025 dist. main class allocation	1.000000	0.637588	0.069110	0.000061	0.129922	0.020790	0.007487	0.000561	0.025022	0.000037	0.001306	0.004865	0.066263	0.000578	0.000936	0.035446	0.000028
3	MRP Revenue Requirement (Exhibit A-23)	$669,785	$427,047	$46,289	$41	$87,019	$13,925	$5,015	$376	$16,759	$25	$875	$3,258	$44,382	$387	$627	$23,741	$19
4	2025 daily average customers (Exhibit A-16, Schedule F1.3)	186,733	154,964	16,799	7	12,485	2,008	223	98	16	1	17	62	40	3	6	4	1
5	Throughput (MCF) (Exhibit A-16, Schedule F1.3)	34,294,114	12,443,860	1,346,322	2,666	5,947,106	951,896	420,113	2,129,704	82,398	1,849	30,643	341,390	6,715,089	21,316	48,401	3,811,100	260
6	Average use per customer		80.3	80.1	380.9	476.4	474.1	1,883.9	21,731.7	5,149.9	1,848.8	1,792.7	5,513.6	167,877.2	7,105.4	8,534.6	952,775.0	260.2
7	Annual cost per customer		$2.76	$2.76	$5.79	$6.97	$6.93	$22.49	$3.84	$1,047.45	$24.82	$51.18	$52.63	$1,109.55	$129.08	$110.56	$5,935.35	$18.61
8	Monthly cost per customer		$0.23	$0.23	$0.49	$0.59	$0.58	$1.88	$0.32	$87.29	$2.07	$4.27	$4.39	$92.47	$10.76	$9.22	$494.62	$1.56

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(L)	(I)	(K)	(J)	(M)	(N)	(O)	(P)	(Q)	(R)
			Residential			Small			Medium				Large				Super Large	Other
Line No.	Line Description	Total MGU Natural Gas	General Service-Residential	Customer Choice-Residential	Agg Transport-Residential	General Service-Small	Customer Choice-GS-Small	Agg Transport-GS-Small	General Service-Medium	Transport-TR-1	Customer Choice-GS-Medium	Agg Transport-GS-Medium	General Service-Large	Transport-TR-2	Customer Choice-GS-Large	Agg Transport-GS-Large	Transport-TR-3	Special Contract
1	2025 dist. main plant in service (Workpaper REO-3, Sched 13, Line 33)	276,715,089	176,430,251	19,123,778	16,742	35,951,242	5,752,934	2,071,766	155,353	6,923,920	10,252	361,415	1,346,207	18,335,979	159,990	259,044	9,808,527	7,690
2	2025 dist. main class allocation	1.000000	0.637588	0.069110	0.000061	0.129922	0.020790	0.007487	0.000561	0.025022	0.000037	0.001306	0.004865	0.066263	0.000578	0.000936	0.035446	0.000028
3	MRP Revenue Requirement (Exhibit A-23)	$1,616,222	$1,030,484	$111,697	$98	$209,982	$33,601	$12,101	$907	$40,441	$60	$2,111	$7,863	$107,096	$934	$1,513	$57,289	$45
4	2025 daily average customers (Exhibit A-16, Schedule F1.3)	186,733	154,964	16,799	7	12,485	2,008	223	98	16	1	17	62	40	3	6	4	1
5	Throughput (MCF) (Exhibit A-16, Schedule F1.3)	34,294,114	12,443,860	1,346,322	2,666	5,947,106	951,896	420,113	2,129,704	82,398	1,849	30,643	341,390	6,715,089	21,316	48,401	3,811,100	260
6	Average use per customer		80.3	80.1	380.9	476.4	474.1	1,883.9	21,731.7	5,149.9	1,848.8	1,792.7	5,513.6	167,877.2	7,105.4	8,534.6	952,775.0	260.2
7	Annual cost per customer		$6.65	$6.65	$13.97	$16.82	$16.73	$54.26	$9.26	$2,527.55	$59.88	$123.50	$126.99	$2,677.39	$311.49	$266.79	$14,322.28	$44.91
8	Monthly cost per customer		$0.56	$0.56	$1.17	$1.41	$1.40	$4.53	$0.78	$210.63	$4.99	$10.30	$10.59	$223.12	$25.96	$22.24	$1,193.53	$3.75

Michigan Gas Utilities Corporation
Necessity of Continuation of Waiver for Meter Testing Requirements Rule 51
Evaluation

Case No.: U-21540
Exhibit No.: A-25
Witness: Shannon L. Burzycki

	ACTUAL METERS REMOVED							ADDITIONAL METERS TO BE REMOVED						
District	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**	**Average Per Year**	**2024**	**2025**	**2026**	**2027**	**2028**	**Total**	**Estimated Complete by December 31, 2028?**
Monroe	1,712	1,557	1,956	1,040	1,366	7,631	**1,526**	3,700	3,700	3,700	3,700	3,700	18,500	NO
Coldwater	779	1,583	1,730	1,728	1,066	6,886	**1,377**	1,483	1,483	1,483	1,483	1,483	7,415	YES
Benton Harbor	2,265	1,142	1,690	1,368	1,094	7,559	**1,512**	3,316	3,316	3,316	3,316	3,316	16,580	NO
Grand Haven	1,005	710	826	648	438	3,627	**725**	1,875	1,875	1,875	1,875	1,875	9,375	NO
Allegan	1,089	881	732	772	419	3,893	**779**	822	822	822	822	822	4,110	YES
TOTAL	6,850	5,873	6,934	5,556	4,383	29,596	**5,919**	11,196	11,196	11,196	11,196	11,196	55,980	

($000)

Rule Section	Proposed Rule (As Amended)	Impact	Forecasted Cost Development Strategy	Capital / O&M	Annual Cost Forecast	Labor / Non-Labor	Compliance Requirement Date	Department	FERC Account(s)
191.19 Large volume gas release report	Each operator of a gas pipeline facility must report a large-volume gas release on DOT Form PHMSA-F7100.5. Each report must be submitted within 30 days after detection of a large-volume gas release. A large-volume gas release report is not required if an incident report has already been submitted under part 191 for the same event and the release volume identified in the incident report is within 10 percent of the total release volume on cessation of the release.	New section, requires reporting of releases > 1 MMCF within 30 days after detection, unless the event is reported under the Incident definition.	Assume one occurence per year	O&M	$ 5.0	Labor	2025: Ongoing	Engineering	856 - Mains Expenses (transmission) 874 - Mains and Services Expenses (distribution)
191.23 Safety related conditions	(a)(9) Any safety-related condition that could lead to an imminent hazard to public safety and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20% or more reduction in operating pressure or shutdown of operation of a pipeline, UNGSF, or an LNG facility that contains or processes gas or LNG.	Adds "to public safety".	Assume one occurence per year	O&M	$ 5.0	Labor	2025: Ongoing	Engineering	874 - Mains and services expenses
192.12 Underground natural gas storage facilities.	(c) Procedural manuals. Each operator of an UNGSF must prepare and follow for each facility one or more manuals of written procedures for conducting operations, maintenance, and emergency preparedness and response activities under paragraphs (a) and (b) of this section. Such manuals must include procedures for eliminating leaks and minimizing releases of gas. Each operator must keep records necessary to administer such procedures and review and update these manuals at intervals not exceeding 15 months, but at least once each calendar year. Each operator must keep the appropriate parts of these manuals accessible at locations where UNGSF work is being performed. Each operator must have written procedures in place before commencing operations or beginning an activity not yet implemented.	Added a requirement for procedures to eliminate leaks and minimize releases of gas for storage fields.	Assumes a partial FTE to adminster requirements	O&M	$ 25.0	Labor	2025: Ongoing	Engineering	840 - Operation supervision and engineering (storage)
192.18 How to notify PHMSA	(c) Unless otherwise specified, if an operator submits, pursuant to § 192.8, 192.9, 192.13, 192.179, 192.319, 192.461, 192.506(b), 192.607(e)(4), 192.607(e)(5), 192.619, 192.624(c)(2)(iii), 192.624(c)(6),192.632(b)(3), 192.634, 192.636, 192.703(d)(4), 192.706(a)(2), 192.710(c)(7), 192.712(d)(3)(iv), 192.712(e)(2)(i)(E), 192.714, 192.745, 192.760(h), 192.763(c), 192.917, 192.921(a)(7), 192.927, 192.933, or 192.937(c)(7) a notification for use of a different integrity assessment method, analytical method, compliance period, sampling approach, pipeline material, or technique (e.g., "other technology" or "alternative equivalent technology") than otherwise prescribed in those sections, that notification must be submitted to PHMSA for review at least 90 days in advance of using the other method, approach, compliance timeline, or technique. An operator may proceed to use the other method, approach, compliance timeline, or technique 91 days after submitting the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing the operator that PHMSA objects to the proposal or that PHMSA requires additional time and/or more information to conduct its review.	PHMSA adding more specific references to notification requirements. 192 part 13, 319, 461, 703, 706, 714, 760, 763, 917, 927, and 933 references are new. 319 and 461 is for the testing of pipeline coating integrity added in RIN-2; 714 covers immediate repair criteria for on-shore transmission lines, 927 covers internal corrosion and I think it's a notification about alternative internal corrosion assessment although I can't find the exact language; 933 covers a notificaiton to PHMSA for a long term pressure reduction responding to a detected anomaly; and 703, 706, 760, and 763 are for requirements added in this rule.	Assume one occurence per year	O&M	$ 5.0	Labor	2025: Ongoing	Engineering	885 - maintenance supervision and engineering
192.167 Compressor stations: emergency shutdown	(a)(2) It must discharge gas from the blowdown piping at a location where the gas will not create a hazard to public safety;	Added "to public safety"	Assume one-time externally-contracted evaluation to validate compliance in 2025	O&M	$ 50.0	Non-Labor	2025: One Time	Engineering	843.7 - Maintenance of compressor equipment
192.179 Transmission line valves	(c) Each section of a transmission line, other than offshore segments, between main line valves must have a blowdown valve with enough capacity to allow the transmission line to be blown down as rapidly as practicable. Each blowdown discharge must be located so the gas can be blown to the atmosphere without hazard to public safety and, if the transmission line is adjacent to an overhead electric line, so that the gas is directed away from the electrical conductors.	Added "to public safety"	Ongoing evaluations to validate compliance for public safety with adders for discharge facilities	O&M	$ 25.0	Labor	2025: Ongoing	Engineering	865 Maintenance of measuring and regulating station equipmen
192.199 Requirements for design and configuration of pressure relief and limiting devices	(i) All new, replaced, relocated, or otherwise changed pressure relief and limiting devices must be designed and configured, as demonstrated by a documented engineering analysis, to minimize unnecessary releases of gas by ensuring each of the following: (1) The set and reset actuation pressure of the pressure relief device and where pressures are taken must minimize release volumes beyond what is necessary to provide adequate overpressure protection; (2) The design (including sizing and material) and configuration of the pressure relief device and its associated piping must be appropriate for its set and reset actuation pressure to minimize pressure choking, compatible with the composition of transported gas, and suitable for reliable operation in expected operating and environmental conditions; and (3) Installation of the pressure relief device must include upstream and downstream isolation valves to facilitate testing and maintenance.	New requirement. Design standards for new, replaced, relocated, or otherwise changed relief and limiting devices to minimize unnecessary emissions.	Assume annual evaluations to validate compliance	O&M	$ 25.0	Labor	2025: Ongoing	Engineering	875 Measuring and regulating station expenses—General
192.617 Investigation of failures	(e) Failure defined. For the purposes of this section, the term failure means when any portion of a pipeline becomes inoperable, is incapable of safely performing its intended function, or has become unreliable or unsafe for continued use.	New requirement. Defines the term "failure" for "investigation of failures"	Assumes one FTE to administer additional failure analysis	O&M	$ 100.0	Labor	2025: Ongoing	Compliance	870 - Operation supervision and engineering
192.705 Transmission lines: Patrolling	(b) Operators must conduct patrols at least 12 times each calendar year at intervals not exceeding 45 days.	Instead of intervals ranging from quarterly to annual, all transmission lines must now be patrolled monthly.	Assumes total increase are four times current costs	O&M	$ 80.0	Non-Labor	2025: Ongoing	Field Operations	856 - Mains expenses
192.723 Distribution systems: Leakage surveys	(a) General. Each operator of a gas distribution pipeline must conduct periodic leakage surveys with leak detection equipment in accordance with this section. All leakage surveys performed pursuant to this section must use leak detection equipment that meets the requirements of § 192.763.		Assumes total increase are two times current costs	O&M	$ 600.0	Non-Labor	2025: Ongoing	Field Operations	856 - Mains Expenses 874 - Mains and Services Expenses 878 - Meter and house regulator expenses
192.760 Leak grading and repair	(a) General. Each operator must have and follow written procedures for grading and repairing leaks that meet or exceed the requirements of this section. (1) These requirements are applicable to leaks on all portions of a gas pipeline including, but not limited to, line pipe, valves, flanges, meters, regulators, tie-ins, launchers, and receivers. (2) The leak grading and repair procedure must prioritize leaks by the hazard to public safety and the environment. (3) Each leak must be investigated immediately and continuously until a leak grade determination has been made.	New code section. Includes 192.760(a)-(i)	Capital Portion of cost estimate based on: Assumption that the number of leaks identified will double. Of leaks found, 80% estimated to be above ground and cost $300 each. While 20 % would be below grade, and cost $5000. Additional rechecks, emergency response, and prospecting costs are included in estimate.	Capital	$ 1,500.0	Non-Labor	2025: Ongoing	Field Operations	382 - Meter Assemblies 367 - Transmission Mains 380 - Distribution Services 376 - Distribution Mains

Michigan Public Service Commission
Michigan Gas Utilities
Forecasted Operations and Maintenance Costs and Capital Expenditures Summary from Proposed LDAR Rules
for the year ending December 2025
($000)

Rule Section	Proposed Rule (As Amended)	Impact	Forecasted Cost Development Strategy	Capital / O&M	Annual Cost Forecast	Labor / Non-Labor	Compliance Requirement Date	Department	FERC Account(s)
192.760 Leak grading and repair		Inserted duplicate line for Capital and O&M split	O&M portion of cost estimate based on: Assumption that the number of leaks identified will double. Of leaks found, 80% estimated to be above ground and cost $300 each. While 20 % would be below grade, and cost $5000. Additional rechecks, emergency response, and prospecting costs are included in estimate.	O&M	$ 500.0	Non-Labor	2025: Ongoing	Field Operations	863 - Maintenance of mains (transmission) 887 - maintenance of mains (distribution) 892 - maintenance of services 893 - Maintenance of meters and house regulators
192.763 Advanced Leak Detection Program	(b) Advanced Leak Detection Performance Standard. Each operator's ALDP described in paragraph (a) must be capable of detecting all leaks that have a sufficient release rate to produce a reading of 5 parts per million or more of gas when measured from a distance of 5 feet or less from the pipeline, or within a wall-to-wall paved area. (1) The performance of the ALDP must be validated and documented with engineering tests and analyses. (2) Records validating that the ALDP meets the performance standard must be maintained for at least 5 years after the date that ALDP is no longer used by the operator.	Performance standards.	Estimated cost associated with the new equipment and support needed for ALD Equipment and software $510,000; comprised of: - Equipment $300,000, - Internal Labor: Analyst $10,000 - Internal Labor: Leak investigation $200,000	Capital	$ 500.0	Non-Labor	2025: Ongoing	Field Operations	394 - Tools Shop and Garage Equipment
192.769 Qualification of leakage survey, investigation, grading, and repair personnel	Only individuals qualified under subpart N of this part may conduct leakage survey, investigation, grading, and repair. Individuals qualified under subpart N must also possess training, experience, and knowledge in the field of leakage survey, leak investigation, and leak grading, including documented work history or training associated with those activities.	New code requirement. Makes leakage survey, investigation, and repair subject to OQ.	Additional FTE to train and qualify new requirements	O&M	$ 100.0	Labor	2025: Ongoing	Operator Qualificatio	870 - Operation supervision and engineering
192.770 Minimizing emissions from gas transmission pipeline blowdowns	(a) Except as provided in paragraph (b) of this section, when an operator performs any intentional release of gas (including blowdowns or venting for scheduled repairs, construction, operations, or maintenance) from a gas transmission pipeline, the operator must prevent or minimize the release of gas to the environment through one or more of the following methods: (1) Isolating the smallest section of the pipeline necessary to complete the task by use of valves or the installation of control fittings; (2) Routing gas released from the pipeline from the nearest isolation valves or control fittings to a flare or to other equipment as fuel gas; (3) Reducing pressure by use of in-line compression; (4) Reducing pressure by use of mobile compression to a segment or storage vessel adjacent to the nearest isolation valves; (5) Transferring the gas to a segment of a lower pressure pipeline system adjacent to the nearest isolation valves; or (6) Employing an alternative method demonstrated to result in a release volume reduction of at least 50% compared to venting gas directly to the atmosphere without mitigative action. (b) An operator is not required to comply with the provisions of paragraph (a) during an event that activates its emergency plan under § 192.615(a)(3) when such minimization would delay emergency response or result in a safety risk during pipeline assessments or maintenance. Each emergency release conducted without mitigation must be documented, including the justification for release without mitigation. (c) Operators must document the methodologies used in paragraph (a) and describe how the methodologies minimize the release of gas to the environment.	New code section, requiring actions to minimize gas loss during pipeline blowdowns including minimizing the affected section, flaring, use of an in-line or mobile compressor to reduce line pressure, or transferring gas to a segment of lower pressure. Exceptions for emergency operations.	Additional FTE to administer and document new requirements: $100,000 Equiptment lease/rentals: $200,000	O&M	$ 300.0	Labor	2025: Ongoing	Engineering	863 Maintenance of mains
192.773 Pressure relief device maintenance and adjustment of configuration	(a) Each operator must develop, maintain, and follow written operations and maintenance procedures to assess the proper function of pressure limiting or relief device and to repair or replace each failed pressure limiting or relief device. When a pressure limiting or relief device fails to operate or allows gas to release to the atmosphere at an operating pressure above or below the set actuation pressure range defined for the device in the operator's operations and maintenance procedure, the operator must: (1) Assess the pilot, springs, seats, pressure gauges, and other components to ensure proper functioning, sensing, and set/reset actuation pressures are within actuation pressure tolerances; (2) Assess the inlet and outlet piping for piping that restricts the inlet or outlet gas flow, piping that restricts the sensing pressure, debris, and other restrictions that could impede the operation or restrict the capacity to relieve overpressure conditions; (3) Repair or replace the device to eliminate the malfunction as follows: (i) If a pressure relief device activates above its set pressure and above the pressure limits in § 192.201(a) or § 192.739 as applicable, fails to operate, or otherwise fails to provide overpressure protection, the operator must repair or replace the device or pressure sensing equipment immediately. (ii) If a pressure relief device allows gas to release to the atmosphere at an operating pressure below the set actuation pressure range, the operator must take immediate and continuous action with on-site personnel to stop the release until the device is repaired or replaced. The relief device or pressure sensing equipment must be repaired or replaced as soon as practicable but within 30 days. (b) Each operator must develop, maintain, and follow written operations and maintenance procedures to ensure that a pressure relief device configuration, as demonstrated by a documented engineering analysis, employs set and reset actuation pressures ensuring minimization of release volumes while providing adequate overpressure protection.	New code section. Requirement have written procedures to assess and repair any pressure limiting or relief device that fails to operate or vents gas when it isn't supposed to. Operators also must have procedures to ensure pressure limiting or relief devices have set and reset actuation pressures designed to reduce emissions while still providing adequate overpressure protection.	Partial FTE to evaluate and correct relief issues	O&M	$ 25.0	Labor	2025: Ongoing	Engineering	870 - Operation supervision and engineering