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by Sidney Davy Miller

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March 3, 2023

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

Re: Michigan Gas Utilities Corporation
Case No. U-21366

Dear Ms. Felice:

Enclosed for electronic filing in the above matter are:

(1) Application;
(2) Notice of Hearing;
(3) Certification of Richard F. Stasik;
(4) Index of Exhibits;
(5) Direct Testimony, non-confidential Exhibits of Richard F. Stasik, Anthony Reese (Public), Jared J. Peccarelli, Ann E. Bulkley, Aaron L. Nelson, Shannon L. Burzycki, and Nathan W. Lee.
(6) Public-Non-confidential documentation which complies with Part II of the Rate Case Filing Requirements established by the Commission's Order dated July 31, 2017, issued in Case No. U-18238;
(7) Protective Order;
(8) Appearances of Sherri A. Wellman, Paul M. Collins, and Benjamin J. Holwerda; and
(9) Proof of Service reflecting electronic service on intervenors in Case Nos. U-20718 and U-17880.

Hard-copies containing the non-confidential version of this filing, as well as a USB of the workpapers in native electronic format and documentation addressing Part III of the Rate Case Filing Requirements promulgated in Case No. U-18238 will be directly served on the Commission Staff and all intervening parties in Case No. U-20718 and U-17880, the Company's last general rate case.

If you have any questions, please call me at the number above.

Very truly yours,

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

Sherri Wellman

Digitally signed by: Sherri Wellman
DN: CN = Sherri Wellman email = wellmans@millercanfield.com C = AD O = Miller Canfield
Date: 2023.03.03 13:51:40 -05'00'

By: ______________________________

Sherri A. Wellman

SAW/ehk
Enclosures
cc w/enc: Lori Mayabb, MPSC Staff (MayabbL@michigan.gov)
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-21366
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 rates, (ii) continue its Demand Response Pilot Program, (iii) approve changes to its Main Replacement Program ("MRP") rider and surcharges, (iv) continue the relief granted in Case No. U-21114 by waiving the meter testing requirements of R 460.2351 and authorizing the use of R 460.2351a(3) for sampling and testing, and (iii) make miscellaneous changes to its tariffs. 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 183,400 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.; and 1939 PA 3, as amended, MCL 460.1 et seq. Pursuant to these statutory 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-20718 and concluded by Commission Order Approving Settlement Agreement dated September 9, 2021. The revised rates approved in Case No. U-20718 were based on a 2022 projected test year and an authorized rate of return on common equity of 9.85%.

5. On February 1, 2023, MGUC filed its rate Filing Announcement in Case No. U-21366 pursuant to the rate case filing requirements established by the Commission's July 31, 2017 Order in Case No. U-18238.

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

II. REQUESTED BASE RATE INCREASE

7. Based on 2024 projected costs of providing service to the Company's customers, and due, in large part, to infrastructure investments, inflation and increased operations and maintenance and debt costs the Company's existing 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, 2021, as required by the rate case filing requirements. MGUC proposes that rates be established based upon a projected test year ending December 31, 2024. 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 as well as significant and swift increases in interest rates that have been taking place since early 2022. These inflationary pressures have increased O&M expenses over the past two years and into the 2024 test year and the costs to complete capital projects placed in service in 2022 and later. In addition, non-rate base drivers include day-to-day O&M expenses, bad debt expense, property taxes, the cost of equity, and the cost of debt.

10. The Company will experience a revenue deficiency of $18,474,947 in 2024. This revenue deficiency does not reflect the Company's requested increase in depreciation rates and practices in Case No. U21329. Reflecting the depreciation rates and practices including the plant transfers from Case No. U-21329 increases the annual rate increase by $0.6 million for a total 2024 revenue deficiency of $19,114,362, an aggregate increase of approximately 9.1%. The 2024 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 to a rate of return on common equity of 10.4%.

12. MGUC represents that the proposed revenue increase of not less than $19,114,362 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, 2024, MGUC's proposes rates for each customer class rate schedule as reflected in Exhibit A-16, Schedule F5. These rates are designed to recover the projected revenue deficiency of not less than $19,114,362.

14. The Company is proposing to continue its Demand Response Pilot program and is also proposing that the Commission approve changes to its MRP rider and surcharges. These changes to the MRP rider include (i) an update to the list of projects to reflect those that will be placed in service during 2023 and 2024 and included in base rates as part of the Company's projected test year ending December 31, 2024; (ii) updates to the forecasted capital costs for remaining projects to address inflation; and (iii) an extension to the period of time covered by the MRP rider for two additional years with a new expiration date of 2029.

15. The Company is also seeking a continuation of the relief granted in Case No. U-21114 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.

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

17. MGUC proposes to implement its revised rates no earlier than January 1, 2024, and no later than the day after the Commission issues an order approving MGUC's request, if an order is issued after January 1, 2024.

IV. TESTIMONY AND EXHIBITS

18. 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

19. MGUC's current natural gas rates, based on the projected 2024 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 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 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, 2024, 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 $19,114,362 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, (ii) approval of changes to its MRP rider and surcharges, (iii) continuation of the relief granted in Case No. U-21114 by waiving the meter testing requirements of R 460.2351 and authorizing the use of R 460.2351a(3) for sampling and testing; and

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

Respectfully submitted,

MICHIGAN GAS UTILITIES CORPORATION

Sherri Wellman

Digitally signed by: Sherri Wellman
DN: CN = Sherri Wellman email = wellmans@millercanfield.com C = AD O = Miller Canfield
Date: 2023.03.03 13:52:13 -05'00'

Dated: March 3, 2023 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-21366

- 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) 457-6137 for a free copy of its application. Any person may review the application at the offices of Michigan Gas Utilities Corporation or on the Commission's website at: mpscdockets@michigan.gov.

- The prehearing conference in this matter will be held:

DATE/TIME:	**___________, _________, 2023, 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 3, 2023 application for approval to increase its rates for the sale, distribution, and transportation of natural gas, and for other related relief. Specifically, MGUC seeks Commission approval (i) to increase beginning January 1, 2024 its natural gas base rates to produce an annual revenue increase of up to $19,114,362; (ii) of a Rate of Return of 10.40%; (iii) to continue its Demand Response Pilot Program; (iv) of changes to its Main Replacement Pipeline ("MRP") rider and surcharges; (v) to continue the relief granted in Case No. U-21114 by waiving the meter testing requirements of R 460.2351 and authorizing the use of R 460.2351a(3) for sample and testing; and (vi) of all other changes and requests 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 **____________, 2023**. (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-21366**. 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 mpscdockets@michigan.gov and at the office of MGUC. 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.

__________, 2023

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the application of	)	
MICHIGAN GAS UTILITIES CORPORATION	)	Case No. U-21366
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, states that he has provided the data required pursuant to the Rate Case Filing Requirements established by the Commission's order dated July 31, 2017, issued 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 3, 2023

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-21366

DIRECT TESTIMONY OF
RICHARD F. STASIK

FOR

MICHIGAN GAS UTILITIES CORPORATION

March 3 2023

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-21366

QUALIFICATIONS
OF
RICHARD F. STASIK
PART I

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Richard 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") 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 Michigan Public Service Commission ("MPSC" or the "Commission") in the annual reviews of the State Reliability Mechanism charge for Upper Michigan Energy Resources Corporation ("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.

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 and 6690-UR-126).

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 2024, and (4) MGUC's 2024 projected test year, including a summary of new matters that are starting with the test year and impact MGUC's test year forecast.

I will also provide an update on some of the reporting and other conditions from MGUC's last rate case (Case No. U-20718). 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 $29.6 billion in market cap as of year-end 2022, 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-20718.

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 2023 and 2027, 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. MGUC will continue to focus on its 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. MGUC will also replace the compressor station at Unit 5 at the Partello storage facility to maintain reliability. MGUC will also be pursuing a new interconnection with DTE to provide an alternative supply of natural gas to serve customers.

- Enhancing field operations to maintain and improve customer care. Another key priority for MGUC is 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. MGUC has established 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 its acquisition in 2015. In fact, over the past five 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 over $100,000 of support to community-based organizations in 2022 and sponsors community events such as Everyday Heroes Event hosted by United Way of Monroe County, the annual Ida Festival of Lights and Duck Derby fundraiser to help assist victims of domestic violence in Hillsdale County and surrounding areas.

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, $72,000 in funding was provided for safety grants to first responders in WPS, Minnesota Energy Resources and MGUC service areas in 2022 for purchasing equipment and providing professional development. WEC also provides matching gift programs for contributions made by its employees, both active and retired, that support local nonprofit organizations.

<u>MGUC's 2024 projected test year rate case</u>

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

A. MGUC's rates were last reset in Case No. U-20718; a case that concluded with the Commission's approval on September 9, 2021 of the settlement agreement reached between MGUC, the Michigan Public Service Commission Staff ("Staff"), the Michigan Attorney General ("AG"), and Citizens Utility Board of Michigan.

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 10.4% and a capital structure that includes 51.4% of permanent equity.

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 51.5% to 51.4%.

Q. Are there any other elements that you would like to specifically point out that impact MGUC?

A. Yes. For the first time, in 2023, MGUC will be participating in the Energy Direct Program, which is administered by the Michigan Department of Health and Human Services ("DHHS"). This program provides funding directly to a utility for the reduction of account balances for specifically-identified customers with arrears. As a condition of participating in this program, MGUC is required to provide a contribution equal to 25% of Energy Direct funding it receives. These funds will be segregated such that they will be available for MGUC to implement further arrears reductions.

MGUC has been informed by DHHS that it will receive $500,000 of program funding in 2023, which makes its matching contribution $125,000 – an amount that MGUC has been informed it is able to seek Commission approval for recovery.

Q. How does MGUC's participation in the Energy Direct Program impact its 2024 Test Year?

A. As described in further detail in Company Witness Reese's direct testimony, MGUC is seeking in this rate case Commission authorization to defer the Company's matching contribution in 2023 as well as any other contributions it makes to the Energy Direct program until its next rate case. Simultaneously, , MGUC is proposing in this rate case to amortize the amount expected to be deferred in 2023 and 2024 over two years and include that amortization expense in its base rates.

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

A. Including the increase in depreciation expense and the effect of new depreciation rates as requested in pending Case No. U-21329, MGUC's direct case supports a total revenue increase of $19.1 million in its base rates, which represents an increase of approximately 9.1% when compared to the Company's current base rates.

Q. What are the key drivers of this rate case as compared to MGUC's last base rate case?

A. The drivers related to this rate request are the historically high levels of inflation for materials and labor that MGUC has recently experienced and expects to persist through the test year, as summarized in Table 1 below, and the significant increases in interest rates that have taken place since early 2022, which are shown in Table 2 below.

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

Month	2021 Annual Inflation Rate	2022 Annual Inflation Rate
January	1.4%	7.5%
February	1.7%	7.9%
March	2.6%	8.5%
April	4.2%	8.3%
May	5.0%	8.6%
June	5.4%	9.1%
July	5.4%	8.5%
August	5.3%	8.3%
September	5.4%	8.2%
October	6.2%	7.7%
November	6.8%	7.1%
December	7.0%	6.5%

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

FOMC Meeting Date	Rate Change (bps)	Federal Funds Rate
February 1, 2023	+ 25	4.50% - 4.75%
December 14, 2022	+ 50	4.25% - 4.50%
November 2, 2022	+ 75	3.75% - 4.00%
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%

[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/

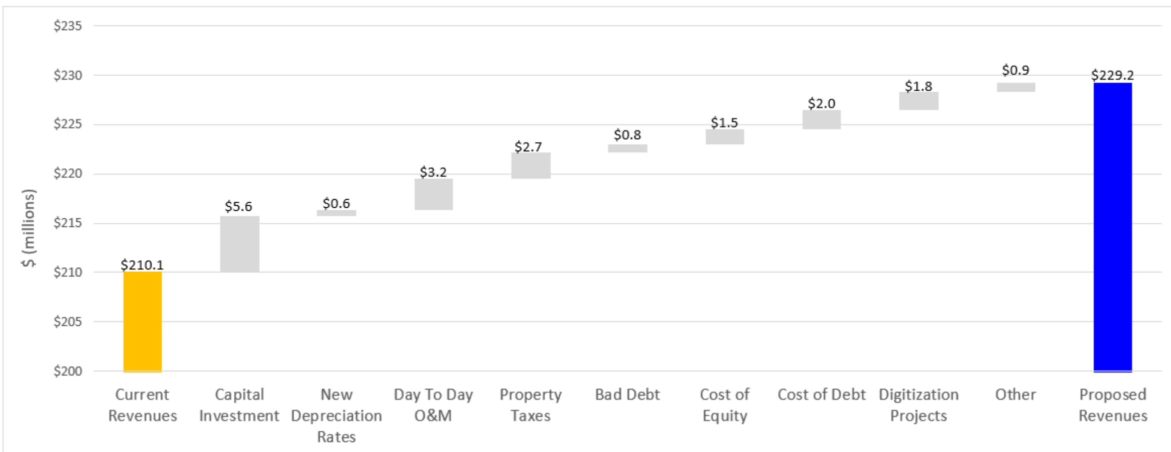
The inflationary pressures have increased not only Operations and Maintenance ("O&M") expenses over the past two years and into the 2024 test year, but also the costs to complete capital projects that have been placed in service in 2022 and later, including those forecasted to be placed in service during the test year.

The most significant upward driver for the total revenue requirement are the costs associated with capital investments made by MGUC since its last rate case. This driver is responsible for $5.6 million of the total revenue requirement increase. 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. Additionally, the Company is proposing to include the updated depreciation rates filed in its pending depreciation case, U-21329. As described in greater detail in the direct testimony of Company Witness Reese, using these updated deprecation rates and making the prescribed plant transfers in the depreciation study results in a further $0.6 million increase in MGUC's test year revenue requirement.

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 $3.2 million higher than they were when MGUC's base rates were last approved in Case No. U-20718. Property Taxes are forecast to increase by $2.7 million, while bad debt expense is forecast to increase $0.8 million as compared to MGUC's most recent rate case. MGUC's forecasted revenue deficiency includes an increase of $3.5 million resulting in proposed changes to MGUC's capital structure, which is comprised of $1.5 million for the cost of equity and $2.0 million for the cost of debt. MGUC also has a $1.8 million revenue requirement increase for a series of MGUC-specific efforts to digitize company records, which do not qualify as a capital project under Generally Accepted Accounting Principles..

Further discussion of these drivers is included in the direct testimony of Company Witness Reese. A summary of the drivers of the requested revenue requirement are shown in Figure 1 below.

Figure 1: Rate Request Drivers Summary



Q. Will MGUC be proposing any changes to the natural gas demand response tariff approved in Case No. U-20718 for approval in this proceeding?

A. No. As of October 2022, MGUC has implemented the tariff as ordered in Case No. U-20718 and the underlying demand response program and to date approximately 20 customers have enrolled.

However, as Company Witness Shannon Burzycki will further discuss in her direct testimony, due to warmer than typical weather this winter (2022-2023), MGUC has not yet been able to obtain sufficient experience with the pilot. Such experience will be necessary to assess what, if any, changes to the pilot would be appropriate. As such, MGUC plans to continue to operate the pilot in its current state to gain more insight and may propose changes based on that insight in a future proceeding.

Q. Will MGUC be introducing any changes to existing service conditions in this proceeding?

A. Yes. MGUC will be introducing some administrative changes that I would characterize as “clean up” to a small number of MGUC’s tariffs. These are discussed in more detail within the direct testimony of Company Witness Burzycki.

Q. Will MGUC be introducing any changes to the Residential Income Allowance (“RIA”) and Senior Bill Assistance program implemented as part of Case No. U-20718?

A. While MGUC will not be proposing any changes to the substantive elements of these programs, it will be proposing two administrative changes.

Subsequent to Case No. U-20718, MGUC had discussions with Staff regarding the number of customers that could be eligible to participate in these programs. During those discussions it was determined that there was a cap on the number of customers that could participate in each – 1,245 customer for the RIA and 600 for the Senior Bill Assistance Program.

As part of this application, MGUC is first proposing to remove the cap on the number of customers that are eligible for these program. Second, MGUC is proposing that it be authorized to defer, for future recovery, the revenue requirement for bill assistance provided to customers to the extent that the actual number of participating customers in these programs exceeds the number of participating customers assumed when final rates are established at the conclusion of this proceeding. These changes are discussed in greater detail in the direct testimony of Company Witness Burzycki.

Q. Will MGUC be introducing any changes to the MRP approved by the Commission in Case No. U-20718?

A. Yes. MGUC is proposing to make three updates to the MRP rider. First, MGUC proposes to update the list of projects that will be included in the MRP to reflect the projects that will be placed in service during 2023 and 2024 and will be included in base rates as part of our projected test year ending December 31, 2024. Second, MGUC is seeking to update the forecasted capital costs of the remaining projects included in the MRP in light of inflation that has been experienced over the past two years. Lastly, MGUC is proposing to extend the period of time covered by the MRP for two additional years such that it will now expire in 2029 rather than the current expiration date of 2027.

Company Witness Nathan Lee addresses the updated capital cost forecast of the remaining MRP projects in his direct testimony and Company Witness Burzycki addresses the updated proposed MRP rider rates reflecting these increased capital cost forecasts and the proposed MRP rider extension in her direct testimony.

<u>Order Conditions from Case No. U-20718</u>

Q. Are there any conditions from the Settlement Agreement approved in Case No. U-20718 that you would like to provide an update?

A. Yes. There are two.

The first is contained in Paragraph 7, subsection L, of the Settlement Agreement that required MGUC to implement a Cross Bore Inspection Program in 2022 and, starting

April 1, 2023, to file an annual report of the previous year's activity. That reporting will contain:

- Annual O&M expenditures related to the Cross Bore Inspection program,
- Number of inspections completed,
- Number of cross bores found, and
- Remediation completed or planned as a result of inspections in the program year.

The annual report will also include an estimate of the current year's Cross Bore Inspection program planned activities, including projected O&M expenditure and the number of inspections to be completed. This report will be filed, as required by April 1, 2023, in Case No. U-20718.

The second condition can be found in Paragraph 7, subsection M, of the Settlement Agreement, which requires MGUC to develop and submit within 24 months of the Commission order approving this Settlement Agreement a multi-year natural gas delivery investment plan ("NGDIP"). Based on the date of the Order in Case U-20718, that NGDIP will be completed and filed with the Commission in that case no later than September 8, 2023.

<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, 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 – Aaron Nelson
5. Sales forecast – Jared Peccarelli
6. Capital investments made by MGUC since its last rate case – 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-21366

DIRECT TESTIMONY AND EXHIBITS OF

ANTHONY REESE

FOR

MICHIGAN GAS UTILITIES CORPORATION

(PUBLIC VERSION)

March 3, 2023

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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).

Summary and Purpose of Testimony

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

A. The purpose of my pre-filed direct testimony is to provide an explanation of the methodology used to develop MGUC's revenue deficiency for the 2024 projected test year, summarize the drivers of MGUC's 2024 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 D5.5,
Exhibit A-11, Schedules A1 and A2,
Exhibit A-12, Schedules B1 through B5,
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-17 K&M Inflation,
Exhibit A-18 forecasted effect of current depreciation study,
Exhibit A-19 (confidential and public versions),
Exhibit A-20 (confidential and public versions),
Exhibit A-21 (confidential and public versions), and

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,
    d. Known and Measurable ("K&M") Items,
    e. Depreciation Rates
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 $19.1 million or 9.1% when the impact of the pending updated deprecation rates proposed in case U-21329 are included, in 2024 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;
- Investing in Partello field structures and equipment;
- Investing in work and asset management software;
- Day-to-day operating and maintenance cost increases to ensure safe and reliable gas service;
- Operating and maintenance costs to digitize company gas distribution system records;

- Property tax increases associated with capital investments and tax rate increases
- Increased bad debt expense;
- Cost associated with the company match to the Energy Direct funding it received to provide customers with energy assistance; and,
- Projecting a higher cost of capital in the 2024 test year.

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

These drivers are being impacted by two Macroeconomic factors (a) historic 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 both 2021 and 2022 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, 2024 indicates a need for an annual rate increase of $18,474,947, approximately $18.5 million or 8.8%, for retail gas operations, which does not ireflect the requested depreciation rate increase in pending Case No. U-21329.

This increase is based on the rates authorized in the Commission's September 9, 2021 Order Approving Settlement Agreement in Case No. U-20718, a proposed return on common equity of 10.4% 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-18488. 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 Nelson.

Q. What impact would those proposed depreciation study rates have on the annual rate increase?

A. Exhibit A-18 shows that updating depreciation rates and practices including the prescribed plant transfers from Case No. U-21329 increases the annual rate increase by $0.6 million. This schedule shows the impacts to rate base as well as to the revenue requirement.

Company Witness Burzycki has also sponsored proposed rates that incorporate this impact into the requested revenue requirement and are based on the cost of service study results sponsored by Company Witness Nelson that also includes the incremental revenue requirement impact of adopting the proposed depreciation study.

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

A. MGUC has used a projected test year ending December 31, 2024.

2021 Historic Test Year Exhibits

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

A. Schedule A1 of Exhibit A-1 calculates MGUC's 2021 historic test year revenue sufficiency based on its rate base, adjusted net operating income, rate of return, and revenue conversion factor. This schedule develops the 2021 Total Company revenue sufficiency of $7.7 million, as shown on Line 16, using the 2021 authorized 9.90% 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 2017 through 2021 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, Permanent Capitalization Balances and Percentages.

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

A. Schedule B1 of Exhibit A-2 calculates MGUC's 2021 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 2021 historic test year utility plant.

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

A. Schedule B3 of Exhibit A-2 depicts MGUC's 2021 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 2021 historic test year working capital.

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

A. Schedule C1 of Exhibit A-3 calculates MGUC's 2021 historic test year adjusted net operating income. Adjusted net operating income includes a $4.9 million adjustment associated with the $5.0 million deferral authorized in Case No. U-20797. The remaining $0.1 million was recorded as a reduction on depreciation expense.

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

A. Schedule C2 of Exhibit A-3 calculates MGUC's 2021 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 2021 historic test year total revenue.

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

A. Schedule C4 of Exhibit A-3 calculates MGUC's 2021 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 2021 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 2021 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 2021 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 2021 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 2021 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 2021 historic test year local taxes.

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

A. Schedule C11 of Exhibit A-3 depicts MGUC's 2021 historic test year AFUDC.

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

A. Schedule D1 of Exhibit A-4 develops MGUC's 2021 historic test year overall rate of return of 6.50% (shown on Line 20) based on MGUC's 13-month average capital structure, and a 9.90% ROE.

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

A. Schedule D2 of Exhibit A-4 develops MGUC's 2021 historic test year embedded cost of long-term debt of 3.30%, 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 2021 historic test year cost of short-term debt of 1.45%, 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 $149.9 million for the 2021 historic test year, as shown on Line 16.

2024 Projected Test Year Exhibits

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

A. Schedule A1 of Exhibit A-11 calculates MGUC's 2024 projected test year revenue deficiency based on its rate base, adjusted net operating income, rate of return on equity ("ROE") of 10.4%, and revenue conversion factor. This schedule indicates that the 2024 Total Company revenue deficiency is $18.5 million, or 8.8%, not including the effects of the requested depreciation rate changein Case U-21329. 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 2024 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.

<u>Rate Base</u>

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

A. Schedule B1 of Exhibit A-12 calculates MGUC's 2024 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 2024 projected test year utility plant. To arrive at the 2024 projected test year utility plant, the September 30, 2022 actual balance of utility plant was projected forward using MGUC's 2022, 2023, and 2024 construction projections.

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

A. Schedule B3 of Exhibit A-12 depicts MGUC's 2024 projected test year accumulated provision for depreciation. To arrive at the 2024 projected test year accumulated provision for depreciation, the September 30, 2022 actual balance of accumulated provision for depreciation was projected forward using MGUC's existing plant and 2022, 2023, and 2024 construction projections.

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

A. Schedule B4 of Exhibit A-12 calculates MGUC's 2024 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 2021 historical year, projected bridge period and 2024 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 2024 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 2024 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 2024 projected test year total revenue.

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

A. Schedule C4 of Exhibit A-13 calculates MGUC's 2024 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 2024 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 2024 projected test year total depreciation and amortization expense based on rates and practices approved in Case No. U-18488.

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

A. Schedule C7 of Exhibit A-13 calculates MGUC's 2024 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 2024 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 2024 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 2024 projected test year local taxes.

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

A. Schedule C11 of Exhibit A-13 depicts MGUC's 2024 projected test year AFUDC.

Capital Structure

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

A. Schedule D1 of Exhibit A-14 develops MGUC's 2024 projected test year overall rate of return of 5.97%, shown on Line 22, Column G based on MGUC's 13-month average permanent common equity ratio set at 51.4% with a 10.4% 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 2021 historic test year and the 2024 projected test year. For both the 2021 historic test year and the 2024 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 $29.8 million in 2021, and $29.5 million in 2024, which reduces the revenue requirement.

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

A. Schedule D2 of Exhibit A-14 develops MGUC's 2024 projected test year embedded cost of long term debt of 3.85%, based on a 13-month average, as shown on Line 20. There is one new debt issue for the 2023 bridge year, a $35 million 30-year issue in October 2023, with an expected interest rate of 6.15%.

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

A. Schedule D3 of Exhibit A-14 develops MGUC's 2024 projected test year cost of short-term debt of 6.12%, based on a 13-month average, as shown on Line 26. The forecasted borrowing rate includes $152 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 one forecasted new issue. The rate for the October 2023 forecasted issue is 6.15%. It includes the 30 year forecasted benchmark Treasury at 4.10% plus a 205 basis point spread. The 205 basis point spread can be split into multiple components – 110 basis points for the historical credit spread between Treasuries and A rated utilities when the markets are in good order, 10 basis points for private placement, 5 basis points for infrequency of issuance, 5 basis points for small size and 75 basis point spread risk for market volatility. MGUC estimated a test year incremental short term debt rate of 5.50% using the existing Q3 2022 1 month Commercial Paper rate of 3.50% plus projected Federal Reserve Bank Federal Funds rate increases in Q4 2022 of 125 basis points, followed by 50 basis points in Q1 2023 and 25 basis points in Q2 2023.

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 $194.7 million for the 2024 projected test year, as shown on Line 16. MGUC requests a 10.4% ROE for the 2024 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 industry models.

<u>Inflation Rates</u>

Q. Please explain Schedule C20 of Exhibit A-17.

A. Schedule C20 calculates the non-labor inflation rates for 2023 and 2024 using a methodology similar to that used by MGUC in Case No. U-20718. The non-labor inflation rates calculated are 3.6% for 2023 and 2.4% for 2024.

<u>O&M Expenses</u>

Q. Please describe how MGUC developed 2024 O&M expenses.

A. MGUC started with 2022 actual O&M expenses and inflated them to 2024 using the rates developed on Schedule C20 in Exhibit A-17 for non-labor. The labor inflation factors used were 5.25% for 2023 and 4.55% in 2024, 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 December 2022 MGUC headcount. MGUC then adjusted this 2024 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. Yes, Local 12295 in January 2023 ratified a new contract.

Q. Please explain the wage increases negotiated and the rates for both 2023 and 2024 in the new contract.

A. Local 12295 negotiated a general wage increase (GWI) as well as a market adjustment. The GWI was [redacted] and [redacted] in 2023 and 2024 respectively. The market adjustment was [redacted] and [redacted] in 2023 and 2024 respectively.

Q. Please explain Schedule C1 of Exhibit A-17.

A. Schedule C1 develops the O&M costs for MGUC's 2024 projected test year. This exhibit begins with 2022 actual O&M amounts. The 2022 expenses were first inflated at the estimated inflation factors as calculated on Exhibit A-17 Schedule C20. 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 2024 projected test year O&M expenses, as detailed on Schedule C1 of Exhibit A-17 compared to actual O&M expenses from 2022.

A. There are 18 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 Schedule C20 of Exhibit A-17.

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

Q. Please explain Schedule C2 of Exhibit A-17.

A. Schedule C2 of Exhibit A-17 calculates the K&M increase 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 C2 of Exhibit A-17, MGUC calculated the 2024 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 2024 projected test year, MGUC has calculated a K&M increase of $171,070 in Account 735, as shown on Line 8 of page 1 of 2 of Schedule C2 of Exhibit A-17.

Q. Please explain Schedule C3 of Exhibit A-17.

A. Schedule C3 of Exhibit A-17 calculates a K&M item related to account 824 Other Expenses. This relates to process & instrumentation drawings which are required to document valves, sensors, and other devices on each section of pipe. These drawings increase the safety of all future work. The Company hires contractors for this work due to the specific skillset needed. The Company projects a K&M increase of $40,960 for the 2024 test year.

Q. Please explain Schedule C4 of Exhibit A-17.

A. Schedule C4 of Exhibit A-17 calculates a K&M item 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 Pipeline and Hazardous Materials Administration (PHMSA) requirement for each well to be logged every seven years. One well is planned to be logged in 2024 while there were no such wells in the 2022 test year rate case. The increase of K&M for well logging is estimated to be $30,000 in test year 2024.

Q. Please explain Schedule C5 of Exhibit A-17.

A. Schedule C5 of Exhibit A-17 calculates the K&M adjustment for account 856 Mains Expense associated with Casing Vent Replacements. Casing are required to have vents. The Company hires contractors to install the vents because of the depth of the casings - MGUC crews do not have the necessary equipment or resources to install them. The Company projects a K&M increase of $25,000 for the 2024 test year.

Q. Please explain Schedule C6 of Exhibit A-17.

A. Schedule C6 of Exhibit A-17 calculates the $2,050,000 K&M adjustment for account 874 Mains and Services Expenses associated with multiple items. First, increased overtime for Locators. The increase in overtime for locating is driven by enhanced damaged prevention, MISS DIG and reporting of damages to the Commission. Our locators are being urged by the MPSC to report more information and document more of the locate communications with the excavation contractors. Additionally, the scale of locates continue to expand which requires to locate during off hours more frequently and the expansion of normal work days to 10 hour days during peak construction months. This is primarily driven by the high speed communications network buildouts across MGUC's service territory. The Company projects a K&M increase of $100,000 for the 2024 test year.

Next, in account 874 is the K&M associated with Damage Prevention. These incremental costs come from several aspects of our Damage Prevention Program. Increased time for employees to report damaging parties to the MPSC as a part of their real time reporting initiative and our need to reduce third party damages from repeat offenders. We have also incurred additional costs for our presence in the communities sharing the Damage Prevention message which increases the number of locate requests and the expanded scope of the tickets. The Company projects a K&M increase of $50,000 for the 2024 test year.

Third, in account 874 is the K&M associated with 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. The Company plans to hire a full time employee to implement and administer this program as well as perform data analysis on integrity management programs. In addition, current MGUC employees in the Engineering and Compliance departments will be involved in this program. The internal labor for these employees that historically has been charged to capital related work, will be decreased, resulting in an increase in O&M. The Company projects a K&M increase of $150,000 for the 2024 test year.

Fourth, in account 874 is the K&M adjustment associated with the Scanning of As-Built records Project. The as-built construction records of MGUC's gas mains are currently on paper stored in file cabinets in local operations offices. This project includes scanning those records into an electronic picture file format which can then be stored on the Company's secure servers. Completion of this project allows access to the records for all Company employees that work on the distribution systems, and protects the records from loss. MGUC estimates this project will provide lasting benefits up to the full life of the gas main. The Company projects a K&M increase of $500,000 for the 2024 test year.

Lastly, in account 874 is the K&M adjustment associated with the Service Card Digitization project. The Service Card Digitization Project is an effort to enter service line attributes into a database and map service lines in the Company's Geographic Information System (GIS). The service line records are currently held on scanned paper documents. Attributes such as pipe material, vintage, size, length, presence of excess flow valve and other data available on the scanned record will be entered into an electronic database. The service lines will be mapped in GIS based on known meter and main locations which will then be linked to the database of attributes. Completion of this project is necessary to allow ongoing updates for new and altered service lines on MGUC's system to allow the Company to identify, track, report, rank, and mitigate risks in accordance with the PHMSA and MPSC requirements, and to help prevent third-party damage from excavation activities. In addition, this project is expected to enable MGUC to maximize risk reduction efforts by identifying areas to focus field resources. MGUC estimates this project will provide lasting benefits up to the full life of the service pipe. The Company projects a K&M increase of $1,250,000 for the 2024 test year.

Q. Please explain Schedule C7 of Exhibit A-17.

A. Schedule C7 of Exhibit A-17 calculates the $746,902 K&M adjustment for account 880 Other Expenses associated with Maintenance of Facilities. At certain MGUC facilities maintenance work associated with parking lots, building painting, tuck pointing, etc. has been identified. The Company projects a K&M increase of $80,000 for the 2024 test year.

Next, in account 880 Other Expenses 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 2024 of $662,550 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 2024. Relative to outsourcing in 2024, doing the work internally is approximately $50,000 lower.

Lastly, in account 880 Other Expenses is a K&M associated with physical security increases. The cost increase for physical security exceeds the inflation assumption related to contracted guard services which is a necessity of protecting our company assets. The Company projects a net K&M increase of $4,352 for the 2024 test year.

Q. Please explain Schedule C8 of Exhibit A-17.

A. Schedule C8 of Exhibit A-17 calculates the $50,000 decrease K&M adjustment for account 887 Maintenance of Mains associated with Maintenance of Exposed Main under Bridges. MGUC has embarked on a project to replace main located under exposed 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 personnel. The Company projects a K&M increase of $100,000 for the 2024 test year.

Additionally, in account 887 is the K&M adjustment associated with Right of Way (ROW) clearing expense. In 2022, MGUC spent approximately $584,000 for ROW clearing. MGUC will continue to perform ROW clearing in the 2024 test year, however, the scope of the work is expected to decrease. The Company projects a K&M decrease of $150,000 for the 2024 test year.

Q. Please explain Schedule C9 of Exhibit A-17.

A. Schedule C9 of Exhibit A-17 calculates the K&M adjustment for account 893 Maintenance of Meters and House Regulators associated with Painting of Large Meter sets. MGUC maintains the painting of these meters by brush painting on an as needed basis. After years of maintaining the meter sets in this manner, many of these meter sets are in need of sandblasting and painting by a professional contractor. The Company projects a K&M increase of $50,000 for the 2024 test year.

Q. Please explain Schedule C10 of Exhibit A-17.

A. Schedule C10 of Exhibit A-17 calculates the K&M adjustment for account 902 Meter Reading associated with meter reading expense. With the full implementation of AMI, the Company will have eliminated all meter reader positions delivering significant O&M savings. In 2022, there was $117,885 of contracted meter reading expense. In the 2024 test year there will no longer be the need for any contracted meter reading. Any manual reads that may need to be performed will be done by MGUC employees. The Company projects a K&M decrease of $120,714 for the 2024 test year.

Q. Please explain Schedule C11 of Exhibit A-17.

A. Schedule C11 of Exhibit A-17 calculates the $152,576 decrease K&M adjustment for account 903 Customer Records and Collection. 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 2024 of $662,550 in account 880. As discribed above in relation to Schedule C7 of Exhibit A-17, insourcing this function is the least cost alternative in 2024. Next, in Account 903 is the K&M adjustment associated with one-time credits received in 2022 from an IT vendor we utilize for contracted services. The Company projects a K&M increase of $47,424 for the 2024 test year.

Q. Please explain Schedule C12 of Exhibit A-17.

A. Schedule C12 of Exhibit A-17, page 1 of 3 calculates the K&M adjustment associated with uncollectible expense. To be consistent with past practice, MGUC has forecasted its 2024 projected test year uncollectible expense equal to its 5-year historic average of net write-offs, which is $2.75 million. This results in a total K&M increase of $2.35 million in Account 904.

Schedule C12 of Exhibit A-17, page 2 of 3, calculates the 2024 projected test year uncollectible expense of $2.75 million. As shown on this exhibit, for the 5-year period 2018-2022, MGUC's average net uncollectibles have equaled 1.31% of MGUC's tariff revenues. This percent was multiplied by MGUC's 2024 projected test year revenues of $210.44 million to arrive at a 2024 projected test year uncollectible expense of $2.75 million.

Schedule C12 of Exhibit A-17, page 3 of 3, calculates the Account 904 K&M expenses for MGUC participation in the Energy Direct Program, which is administered by the Michigan Department of Health and Human Services ("DHHS"). The program requires MGUC to provide a contribution equal to 25 percent of Energy Direct funding it receives. Company Witness Stasik identifies the assistance MGUC will receive from the program in 2023 of $500,000. The company projects a K&M increase of $125,000.

Q. How does the company request to recover the company match portion of the Energy Direct Program cost?

A. As described in the answer to the previous question MGUC is proposing an accounting treatment that would allow deferral of the Company's matching contribution of $125,000 into a regulatory asset account starting in 2023. The company estimates incurring costs in 2023 and 2024. The cumulative cost impact of $250,000 is requested to be recovered over a 2 year period beginning in 2024. Further, MGUC proposes to defer any other contributions it makes to the Energy Direct program and continue to amortize $125,000 annually until its next rate case.

Q. Please explain Schedule C13 of Exhibit A-17.

A. Schedule C13 of Exhibit A-17 calculates the K&M adjustment for Account 920 Administrative and General Salaries. There are two items driving the increase in this account. The first is the need to fill open positions in IT Security and Physical Security which are driven by an increase in baseline work and an increasing threat environment. The second is removing a onetime adjustment related to a 2022 vacation acrrual true-up. The Company projects a K&M increase of $156,074 for the 2024 test year.

Q. Please explain Schedule C14 of Exhibit A-17.

A. Schedule C14 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 IT Security due to an increase in baseline work and an increasing threat environment, and IT Software Maintenance contract cost inflated at a software vendor industry standard of 5 percent. Additionally, we have removed a one-time adjustment related to 2022 supply chain vendor credits received. The Company projects a K&M increase of $44,051 for the 2024 test year.

Q. Please explain Schedule C15 of Exhibit A-17.

A. Schedule C15 of Exhibit A-17 calculates the K&M adjustment for Account 923 Outside Services Employed which relates to external legal counsel. The use of external legal services in 2022 was lower than usual. We expect these matters in 2024 to be back to a normal level, if not higher. In addition, the external counsel rates that we use to support and supplement our internal legal and regulatory team are rising. The Company projects a K&M increase of $180,032 for the 2024 test year.

Q. Please explain Schedule C16 of Exhibit A-17.

A. Schedule C16 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 from historically bad weather events as well as general inflationary pressures on the insurable values of existing property. The Company projects a K&M increase of $16,496 for the 2024 test year.

Q. Please explain Schedule C17 of Exhibit A-17.

A. Schedule C17 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 $121,169 for the 2024 test year.

Q. Please explain Schedule C18 of Exhibit A-17.

A. Schedule C18 of Exhibit A-17 calculates the Benefits K&M expenses for MGUC. MGUC is forecasting a K&M increase of $2.3 million in Account 926, as shown on Line 23.

The 2024 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 1-4 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 2022 FTE was then applied to the number of FTE's in the test year and inflated as follows:

- Medical costs – 7.3% for 2023 and 2024, provided by Fidelity
- Dental costs – 2.6% for 2023 and 3.8% for 2024, provided by Delta Dental
- 401(k) benefit costs - general wage inflation factors of 5.25% for 2023 and 4.55% for 2024 were applied

Deferred Compensation was estimated using the July 31, 2022 balance and applying an asset return using assumptions that differ by investment type.

Actual costs from 2022 were inflated by the factors developed in Exhibit A-17 for the sub-accounts on lines 6 through 12.The 2024 employee benefit costs for the sub-accounts on lines 14 through 17 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 19 on page 1.

Q. Please explain Schedule C19 of Exhibit A-17.

A. Schedule C19 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 $776,937. That is a K&M increase of $43,688 from the 2022 costs inflated to 2024. 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 2024 Service Company (WBS) Return On/Of is $496,520 as shown on line 14 of page 2. The 2022 actual amount was $426,025. The K&M increase largely represents the difference between the 2022 amount inflated using the inflation factors shown in Schedule C20 of Exhibit A-17 and the forecasted 2024 Service Company (WBS) Return On/Of amount. Schedule C19 of Exhibit A-17, page 2 calculates the 2024 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-18488.

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

A. Yes, case No. U-21329 was filed in December of 2022.

Q. What impact would those proposed depreciation study rates have on the annual rate increase?

A. As described above, MGUC estimates in Exhibit A-18 that updating rates and practices including the prescribed plant transfers from case No. U-21329 would increase the annual revenue requirement by $0.6 million.

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 $10.25 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 did MGUC previously estimate personal property tax expense in a forecasted test year?

A. MGUC previously estimated the amount of personal property tax expense by increasing the prior year's taxes paid by an inflation factor. This previously method materially understated the actually incurred expenses.

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 $9.1 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?

A. Table 1 below shows historic (2016-2022) and forecasted (2023-2024) reported personal property for MGUC.

Table 1:

Year	Michigan Reported Personal Property	Year over Year increase
2024	$679 Million	9.4%
2023	$621 Million	11.3%
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 2017-2022 were underestimated by over $9 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
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 2024 test year and will continue until MGUC's next rate case.

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 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 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 2022-2023 Salary Budget Survey (Exhibit A-19, both confidential and public) report found that 85% of organizations offer some sort of variable pay (WAW SBS2022, page 48). Additionally, a 2020 study by Aon Human Capital Solutions (Exhibit A-20, both confidential and public) reported 100% of front-line employees and their managers are eligible for annual incentives. 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.

WEC's 2024 Incentive Compensation Plans

Q. What incentive compensation plans will apply to MGUC in the 2024 test year?

A. While the incentive compensation plans for the year 2024 have not been finalized and approved, it is expected that compensation plans essentially identical to MGUC's current plans will remain in place through 2024. 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 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 2024 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 2024 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 2024 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 2024.

This 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 OSIP 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.

<u>Non-Executive Incentive Plan</u>

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%
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 2024 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 2023 Non-Executive Incentive Plan is the plan that governs incentive pay for performance that occurs during calendar year 2023. The payouts under this plan will occur no later than March 15, 2024. See Exhibit A-21, page 1, for MGUC and Page 2 for WBS (confidential and public versions). The 2024 plan will be formally adopted in early 2024 and is expected to remain unchanged from 2023. MGUC expects that its non-executive incentive compensation for performance during calendar year 2024 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 a 2020 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 a 2020 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 a 2020 net 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.

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 2024 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 2024 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-21366
and for other relief	)	
	)	

DIRECT TESTIMONY AND EXHIBITS OF

ANN E. BULKLEY

ON BEHALF OF

MICHIGAN GAS UTILITIES CORPORATION

March 3, 2023

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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-21366

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.

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. Please describe 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. I estimated the Company's 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"). My recommendation also takes into consideration the following factors: (1) the Company's capital expenditure requirements; (2) the regulatory environment in which the Company operates; (3) the Company's rate adjustment mechanisms; and (4) the Company's proposed capital structure as compared to the capital structures 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 the Company's requested ROE falls within the range of the analytical results.

Q. How is the remainder of your direct testimony organized?

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

- Section III provides a summary of my analyses and conclusions.
- Section IV reviews the regulatory guidelines pertinent to the development of the cost of capital.
- Section V discusses current and projected capital market conditions and the effect of those conditions on MGUC's cost of equity.
- Section VI explains my selection of a proxy group of natural gas utilities.
- Section VII describes my analyses and the analytical basis for my recommendation of the appropriate ROE for MGUC.
- Section VIII 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 IX assesses the proposed capital structure, cost of debt and overall rate of return of MGUC.
- Section X presents my conclusions and recommendations.

III. 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:

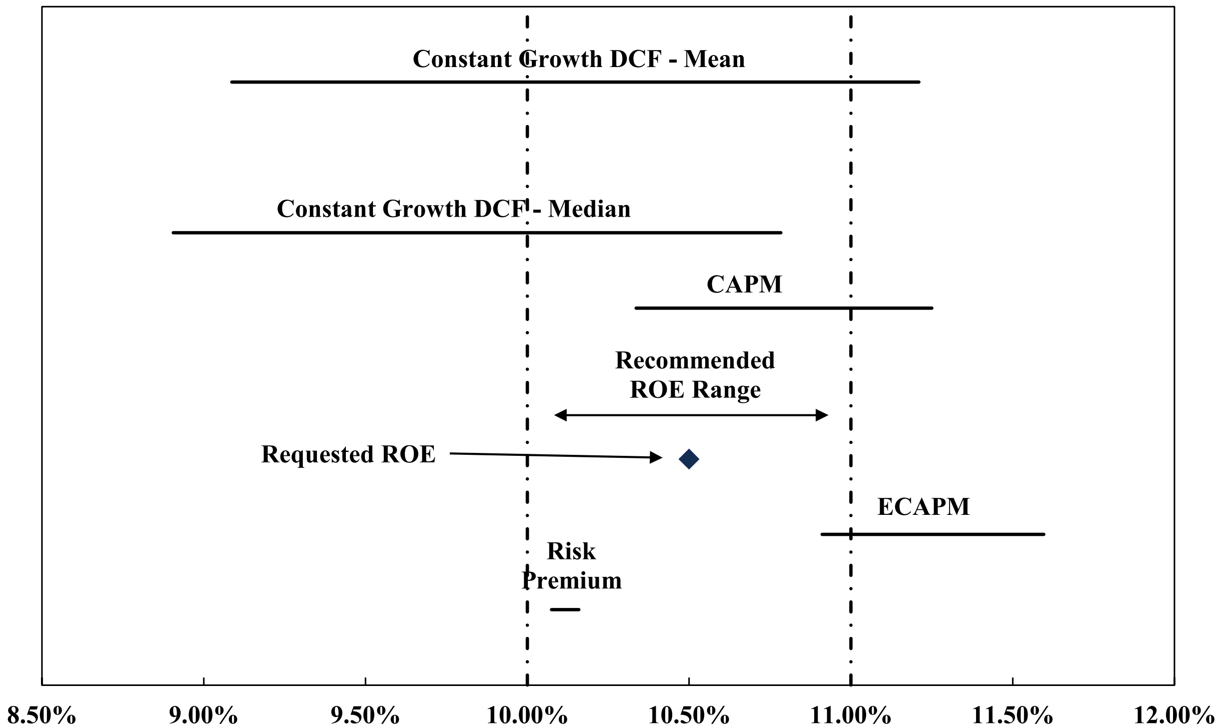
- The United States Supreme Court's *Hope* and *Bluefield* decisions[1] established the standards for determining a fair and reasonable authorized ROE for public utilities, including consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to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

A. Figure 1 summarizes the range of results produced by the Constant Growth DCF, CAPM, ECAPM, and Risk Premium analyses based on data through the end of January 2023.

[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*").

Figure 1: Summary of Cost of Equity Analytical Results



As shown in Figure 1 (and in Schedule D6), the range of results produced by the models used to estimate the cost of equity 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 MGUC 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:

- Inflation is expected to persist over the near-term, which increases the operating risk of the utility during the period in which rates will be in effect.

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

- Since utility dividend yields are now less attractive than the risk-free rates of government bonds, and interest rates are expected to remain near current levels over the next year, and since utility stock prices are inversely related to changes in interest rates, it is likely that utility share prices will decline.

- Utility stocks, which have historically been viewed as safe-haven investments in turbulent markets, have experienced volatility that is similar to the overall market in the past nine months, indicating an increase in the risk of equity investment in the utility sector.

- Rating agencies have responded to the risks of the utility sector, with Moody's Investors Service ("Moody's") most recently indicating its outlook for the industry in 2023 is "negative," citing increasing interest rates, inflation and high natural gas prices, all of which create pressure for customer affordability and prompt rate recovery.

- Similarly, equity analysts have noted the increased risk for the utility sector as a result of rising interest rates and expect the sector to underperform over the near-term.

- Consequently, the results of the DCF model, which relies on current utility share prices, is likely to 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 MGUC.

Q. What is your conclusion regarding the appropriate authorized ROE for MGUC in this proceeding?

A. Considering the analytical results presented in Figure 1, current and prospective capital market conditions, as well as the level of regulatory, business, and financial risk faced by MGUC's natural gas operations in Michigan relative to the proxy group, I believe a range from 10.00 to 11.00 percent is reasonable for the Company's ROE. The Company's requested ROE of 10.40 percent is consistent with, albeit lower than the midpoint of, this range.

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

A. Yes. Comparing the Company's proposed equity ratio of 51.40 percent to the proxy group demonstrates that the Company's requested equity ratio is well within the range of equity ratios for the proxy group, and below the average equity ratio. Further, the Company's proposed equity ratio is reasonable considering that credit rating agencies have identified the outlook for the utility sector as "negative" due to the negative effect on the cash flows and credit metrics associated with increasing interest rates, inflation and commodity costs, and the pressure that those factors place on customer affordability and utilities' prompt rate recovery.

IV. REGULATORY PRINCIPLES

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 leads to just and reasonable rates.[2]

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

A. Yes, in its decision in Case No. U-20697, the Commission stated that:

> The criteria for establishing a fair rate of return for public utilities is rooted in the language of the landmark United States Supreme Court cases 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 rate of return, 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?

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

3 MPSC Case No. U-20697, 12/17/2020 Order, p 156.

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]

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. A return that is adequate to attract capital at reasonable terms enables the utility to continue to provide safe, reliable electric service while maintaining its financial integrity. That return should be commensurate with returns required by investors elsewhere in the market for investments of comparable 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

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

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

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. Does the fact that the Company is 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 ("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 debt and equity investors' assessments of risk. Specifically regarding debt investors, credit rating agencies consider the authorized ROE and equity ratio for regulated utilities to be very important for two reasons: (1) they help determine the cash flows and credit metrics of the regulated utility; and (2) they provide an indication of the degree of regulatory support for credit quality in the jurisdiction. To the extent that the authorized returns in a jurisdiction are lower than the returns that have been authorized more broadly, credit rating agencies will consider this in the overall risk assessment of the regulatory jurisdiction in which the company operates. Not only do credit ratings affect the overall cost of borrowing, they also act as a signal to equity investors about the risk of investing in the equity of a company.

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.

V. 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 that are specific either to the proxy group, in the case of the DCF model, or to the expectations of market risk, in the case of the CAPM. The results of the cost of equity estimation 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 analyst uses current and projected market data, specifically 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.

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 recommended ROE 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) changes in monetary policy; (2) currently high inflation that has continued well into 2022; and (3) increased 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.

Q. What effect do current and prospective market conditions have on the cost of equity for MGUC?

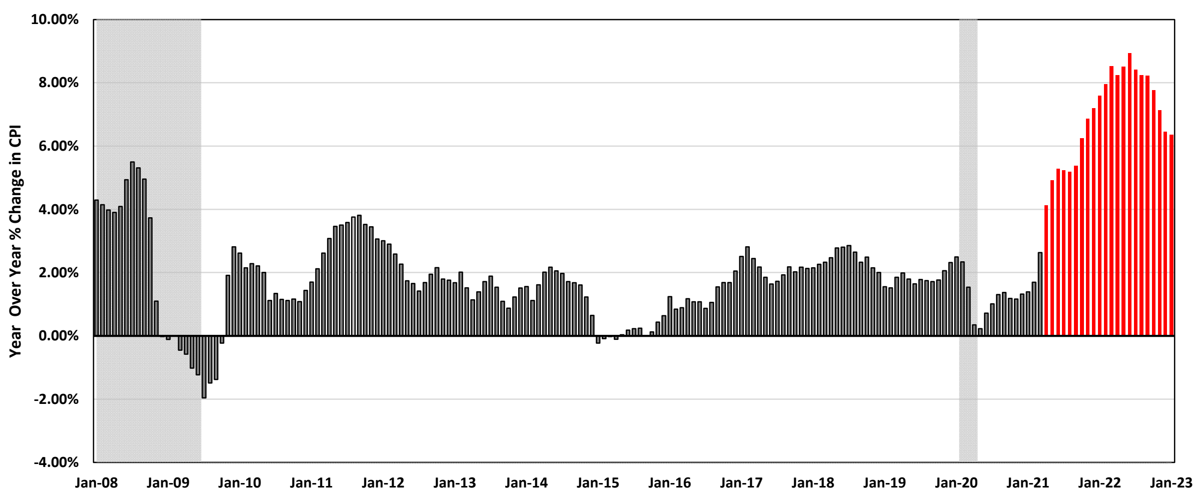
A. As is discussed in more detail in the remainder of this section, the combination of persistently high inflation, and the Federal Reserve's changes in monetary policy, contribute to an expectation of increased market risk and an increase in the cost of the investor-required return. It is essential that these factors be considered in setting a forward-looking ROE. Inflation has recently been at some of the highest levels seen in approximately 40 years. Interest rates, which have increased from the pandemic lows seen in 2020 are expected to continue to increase in direct response to the Federal Reserve's monetary policy. Since there is a strong historical inverse correlation between interest rates and the share prices of utility stocks (share prices of utility stocks typically fall when interest rates rise), it is reasonable to expect that investors' required return for utility companies will also increase. Therefore, cost of equity estimates based solely on current market conditions will understate the cost of equity required by investors during the future period that the Company's rates determined in this proceeding will be in effect.

A. Inflationary Expectations in Current and Projected Capital Market Conditions

Q. Has inflation increased significantly over the past year?

A. Yes. As shown in Figure 2, the year-over-year ("YOY") change in the Consumer Price Index ("CPI") published by the Bureau of Labor Statistics has increased steadily since the beginning of 2021, rising from 1.37 percent in January 2021 to a high of 9.0 percent in June 2022, which was the largest 12-month increase since 1981 and significantly greater than any level seen since January 2008. As shown in Figure 2, since that time, while inflation has declined in response to the Federal Reserve's monetary policy, inflation continues to remain elevated.

Figure 2: YOY Percent Change in the Consumer Price Index, January 2008 – January 2023[6]



6 Bureau of Labor Statistics, shaded area indicates a recession.

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 over at least the next year and that it will continue to increase short-term interest rates to reduce inflation. For example, Federal Reserve Chair Powell at the Federal Open Market Committee ("FOMC") meeting in February 2023 anticipated further increases in the federal funds rate, and observed that while inflation is off of its recent highs, it remains significantly above the Federal Reserve's long-term target:

> We continue to anticipate that ongoing increases will be appropriate in order to attain a stance of monetary policy that is sufficiently restrictive to return inflation to 2 percent over time.
>
> …..
>
> Inflation remains well above our longer-run goal of 2 percent. Over the 12 months ending in December, total PCE prices rose 5.0 percent; excluding the volatile food and energy categories, core PCE prices rose 4.4 percent. The inflation data received over the past three months show a welcome reduction in the monthly pace of increases. And while recent developments are encouraging, we will need substantially more evidence to be confident that inflation is on a sustained downward path.
>
> …..
>
> With today's action, we have raised interest rates by 4-1/2 percentage points over the past year. We continue to anticipate that ongoing increases in the target range for the federal funds rate will be appropriate in order to attain a stance of monetary policy that is sufficiently restrictive to return inflation to 2 percent over time.
>
> …..
>
> At the December meeting, we all wrote down our best estimates of what we thought the ultimate level would be [of the federal funds rate], and that's obviously back in December. And the median for that was between five and five and a quarter percent. At the March meeting, we're going to update those assessments. We did not update them today. We did, however, continue to say that we believe ongoing rate hikes will be appropriate to attain a sufficiently restrictive stance of policy to bring inflation back down to 2 percent. We think we've covered a lot of ground, and financial conditions have certainly tightened. I would say we still think there's work to do there. We haven't made a decision on exactly where that will be. I think, you know, we're going to be looking carefully at the incoming data between now and the March meeting and then the May meeting. I don't feel

> a lot of certainty about where that will be. It could certainly be higher than we're writing down right now. If we come to the view that we need to write down to -- you know, to move rates up beyond what we said in December we would certainly do that. At the same time, if the data come in, in the other direction then we'll -- you know, we'll make data-dependent decisions at coming meetings, of course.[7]

B. The 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. As of the FOMC meeting on December 14, 2022, the Federal Reserve has taken the following actions:

- Completed its taper of Treasury bond and mortgage-backed securities purchases;[8]
- Increased the target federal funds rate beginning in March 2022 through a series of increases from a target range of 0.00 to 0.25 percent to a target range of 4.50 percent to 4.75 percent;[9]
- Anticipates ongoing increases in the target range will be appropriate to achieve its goals of maximum employment at the inflation rate of 2.00 percent over the long-run;[10]
- Began reducing its holdings of Treasury and mortgage-backed securities on June 1, 2022.[11] The Federal Reserve is reducing the size of its balance sheet by only reinvesting principal payments on owned securities after the total amount of

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7 Transcript. Chair Powell Press Conference, February 1, 2023; clarification added.

8 Federal Reserve Bank of New York, https://www.newyorkfed.org/markets/domestic-market-operations/monetary-policy-implementation/treasury-securities/treasury-securities-operational-details#monthly-details.

9 Federal Reserve. Press Releases, March 16, 2022; Transcript. Chair Powell Press Conference, February 1, 2023.

10 Transcript. Chair Powell Press Conference, February 1, 2023.

11 Federal Reserve. Press Release, May 4, 2022.

payments received exceeds a defined cap. For Treasury securities, the cap is set at $30 billion per month for the first three months and $60 billion per month after the first three months. The cap for mortgage-backed securities is set at $17.5 billion per month for the first three months and $35 billion per month thereafter.[12]

C. The Effect of Inflation and Monetary Policy on Interest Rates and the Investor-Required Return

Q. What effect will inflation and the Federal Reserve's normalization of monetary policy have on long-term interest rates?

A. Inflation and the Federal Reserve's normalization of monetary policy are expected to result in long-term interest rates remaining relatively high over at least the next year. Specifically, inflation reduces the purchasing power of the future interest payments an investor expects to receive over the duration of the bond. This risk increases the longer the duration of the bond. As a result, if investors expect inflation to remain relatively high, they will require higher yields to compensate for the increased risk of inflation, which means interest rates will also remain relatively high.

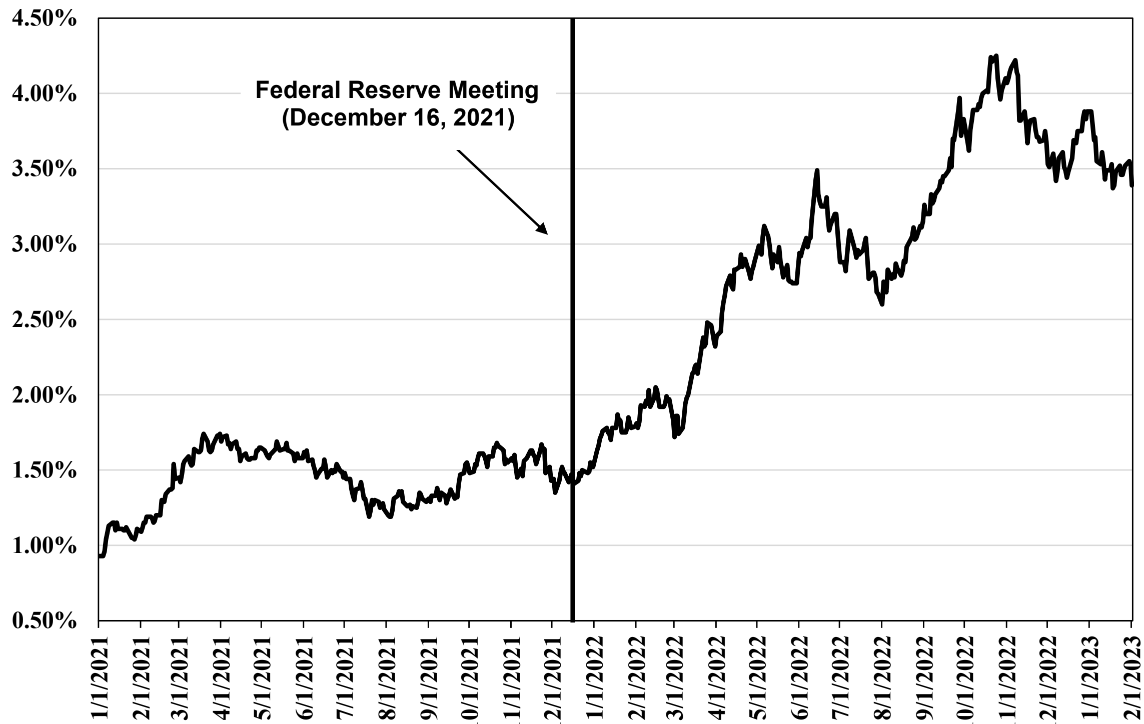
Q. Have the yields on long-term government bonds increased in response to inflation and the Federal Reserve's normalization of monetary policy?

A. Yes. At the FOMC meetings throughout 2022 and thus far into 2023, the Federal Reserve has continued to note its concerns over the sustained increased levels of inflation and has continued to accelerate the process of normalizing monetary policy to combat inflation. As shown in Figure 3, since the Federal Reserve's December 2021 meeting, the yield on

[12] Federal Reserve. "Plans for Reducing the Size of the Federal Reserve's Balance Sheet." Press Release, May 4, 2022.

10-year Treasury bonds has more than doubled, increasing from 1.47 percent on December 15, 2021 to 3.52 percent on January 31, 2023. The increase is due to the Federal Reserve's announcements at each of the meetings since December 2021 and the continued elevated levels of inflation.

Figure 3: 10-Year Treasury Bond Yield, January 2021– January 2023[13]



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 through at least the end of 2023. According to the most recent *Blue Chip Financial Forecasts* report, the consensus estimate of the average yield on the 10-year Treasury bond is approximately 3.60 percent through the first quarter of 2024.[14]

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[13] S&P Capital IQ Pro.

[14] *Blue Chip Financial Forecasts*, Vol. 42, No. 2, February 1, 2023.

Q. Do recent changes in the Gross Domestic Product ("GDP") affect the current outlook for inflation and interest rates?

A. No. While FOMC participants have recently reduced their projections for economic activity for real GDP growth to 0.5 percent in 2023,[15] which is well below the median estimate for the longer-run normal GDP growth rate, the Federal Reserve has highlighted that the labor market continues to be extremely tight, and in fact, the unemployment rate reached 3.4 percent in January 2023, the lowest it has been in over 50 years.[16] Therefore, with a tight labor market and persistently high inflation, the Federal Reserve has indicated its need to continue a restrictive monetary policy to moderate demand to better align it with supply.[17]

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

A. As shown in Figure 4, when the Commission authorized an ROE of 9.85 percent in the Company's 2021 rate proceeding, interest rates (as measured by the 30-year Treasury bond yield) were 1.92 percent and inflation was 5.39 percent. However, since the Company's last rate proceeding, long-term interest rates have nearly doubled, and, as discussed, inflation is also higher.

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15 FOMC. Summary of Economic Projections. December 14, 2022.

16 Mutikani, Lucia. "U.S. reports blowout job growth; unemployment lowest since 1969." Reuters, February, 3, 2023.

17 Transcript. Chair Powell. Press Conference, February 1, 2023.

Figure 4: Change in Market Conditions Since MGUC's Last Rate Case[18]

Docket	Date	Federal Funds Rate	30-Day Avg of 30-Year Treasury Bond Yield	Inflation Rate	Auth'd ROE
U-20718	9/9/2021	0.08%	1.92%	5.39%	9.85%
Current	1/31/2023	4.33%	3.71%	6.35%	

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 the past five years. 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).[19]

18 St. Louis Federal Reserve Bank; Bureau of Labor Statistics.

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

Q. How do equity analysts expect the utilities sector to perform in an increasing interest rate environment?

A. Equity analysts project that utilities will underperform the broader market given high inflation and the recent increases in interest rates. Fidelity classifies the utility sector as underweight,[20] and *Morningstar* recently noted that many of the market conditions that supported the premium valuation of utilities over the last decade mainly low inflation, interest rates and energy prices are currently reversing:

> Utilities' relative outperformance in 2022 while the market frets about the economy suggests that utilities remain a defensive haven. Utilities also outperformed ahead of the 2001 and the 2007-09 recessions. However, we think utilities' weak total returns in 2022 should concern investors. For the first time in a decade, the tailwinds supporting utilities' earnings growth and premium valuations (low inflation, low interest rates, and low energy price) are reversing
>
> Utilities' growth prospects are our biggest concern going into 2023. Utilities no longer offer a yield premium as bond yields climbed to their highest level in 15 years. Without that yield premium, the only advantage utilities offer investors is earnings growth. This is why high inflation and rising interest rates loom large for utilities in 2023. Inflation, including higher energy prices, will raise customer bills and could force utilities to re-evaluate their growth plans. Higher interest costs will sap cash flow and make infrastructure investments more expensive.[21]

Additionally, *The Wall Street Journal* recently attributed the 14 percent decline in the S&P Utilities Index between September and October 2022 to the recent increase in long-term treasury yields:

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[20] Fidelity. "First Quarter 2023 Investment Research Update." February 8, 2023.

[21] Miller, Travis. "Can Utilities Maintain Growth Against Macroeconomic Headwinds?" *Morningstar*, January 3, 2023.

> A big draw of utility stocks has become less attractive as interest rates have climbed. Utility stocks are known for their sizable dividends, offering investors a regular stream of income. Companies in the S&P 500 utilities sector offer a dividend yield of 3.3%, among the highest payout percentages in the index, according to FactSet.
>
> But the outsize dividends of utility stocks are no match for climbing bond yields. The yield on the benchmark 10-year Treasury note finished above 4% on Monday for a second consecutive session. Friday marked the 10-year yield's first close above the 4% level since 2008 and 11 straight weeks of gains. Treasurys are viewed as essentially risk-free if held to maturity.
>
> "The 10-year is repricing everything. I've got something that's even safer and yields even more," said Kevin Barry, chief investment officer at Summit Financial, comparing Treasurys and utility stocks. [22]

Similarly, Barron's recently noted that the decline in share prices can be attributed to the relatively high valuations and low dividend yields of utilities as compared to other asset classes such as Treasuries. [23] According to Barron's, even after the recent decline in share prices, the Utilities Select ETF was yielding 2.85 percent, which is a yield that will not "lure in buyers when the ultrasafe 10-year Treasury note yields close to 4%."[24] Therefore, Barron's currently recommends not buying utility stocks.

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

A. While interest rate have increased substantially over the past year, the valuations of utilities have remained elevated and have not fully reflected the effect of the recent increase in interest rates. To illustrate this point, I examined the difference between the dividend yields of utility stocks and the yields on long-term government bonds (*i.e.*, the "yield spread"). I selected the dividend yield on the S&P Utilities Index as the measure of the

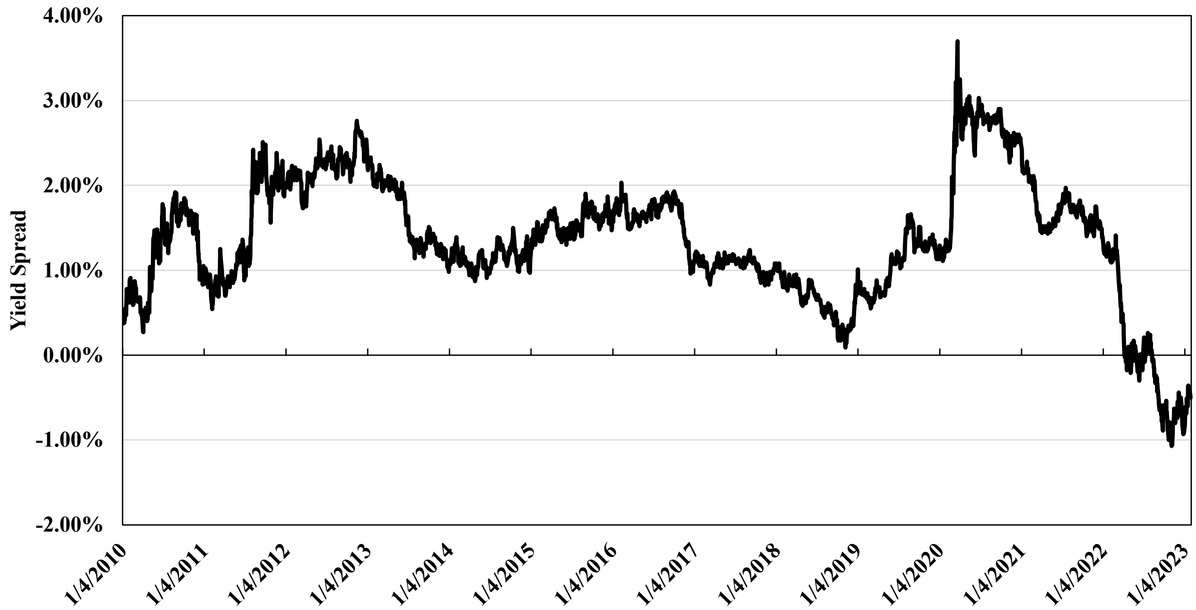
[22] Miao, Hannah. "Utility Stock stumble as treasury yields climb." *The Wall Street Journal*, October 18, 2022.

[23] Sonenshine, Jacob. "Utilities Stocks Have Fallen off a Cliff. They Just Got Downgraded, Too." Barron's, October 17, 2022.

[24] *Id*.

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. As shown in Figure 5, the yield spread as of January 31, 2023 was negative 0.49 percent, meaning that the yield on the 10-year Treasury bond exceeds the dividend yield for the S&P Utilities Index. Furthermore, the current negative yield spread is well below the long-term average yield spread since 2010 of 1.37 percent. Given that the yield spread is currently well below the long-term average, as well as the expectation that interest rates will remain relatively high through at least through 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 5: Spread between the S&P Utilities Index Dividend Yield and the 10-year Treasury Bond Yield, January 2010 – January 2023[25]



Q. Do you have any further context as to how unlikely it is to have a negative yield spread of this magnitude?

A. Yes. For further context as to how unlikely it is to have a yield spread of -0.49 percent, I calculated the z-score for the current yield spread, which measures the number of standard deviations from the mean. The current yield spread of -0.49 percent has a z-score of -2.51, indicating that a yield spread of -0.49 percent is over 2 standard deviations from the mean of 1.36 percent. In other words, 95 percent of the daily yield spread observations from 2010 to 2023 fall between -0.11 percent and 2.83 percent, with the current yield spread of -0.49 percent being outside of that range. Thus, the current yield spread is an outlier, which is why equity analysts do not expect this current level to hold.

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

Q. What is the significance of the inverse relationship between interest rates and utility share prices in the current market?

A. If interest rates remain relatively high as expected, then the share prices of utilities, which have been strong in 2022 relative to the market, would be expected to decline. If the prices of utility stocks decline, then the current DCF model, which relies on historical averages of share prices to calculate the dividend yield, is likely to understate the dividend yield and thus the cost of equity.

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

A. Yes. 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 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.*[26]

[26] MPSC Case No. U-20697, 12/17/2020 Order, pp 165-166 (emphasis added).

E. Conclusion

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

A. Through 2023, investors expect long-term interest rates to remain relatively high in response to continued elevated levels of inflation and the Federal Reserve's normalization of monetary policy. Because the share prices of utilities are inversely correlated to interest rates, and long-term government bond yields are already substantially greater than utility stock dividend yields and are expected to remain elevated through at least 2023. These factors will likely result in a decline in utility share prices, which is the reason a number of equity analysts expect the utility sector to underperform over the near-term. The expected underperformance of utilities means that current DCF models using recent historical data likely underestimate investors' required return over the period that rates will be in effect. Therefore, this expected change in market conditions supports consideration of the higher end of the range of cost of equity results produced by the DCF models. Moreover, prospective market conditions warrant consideration of forward-looking cost of equity estimation models such as the CAPM and ECAPM, which may better reflect expected market conditions.

VI. 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 Integrys Holding, Inc. ("Integrys"), which is a wholly-owned subsidiary of WEC Energy Group.

MGUC distributes natural gas to approximately 183,000 customers in southern and western Michigan.[27] As of December 31, 2021, MGUC's net utility natural gas plant in Michigan was approximately $338 million.[28] In 2021, MGUC transported approximately 16.6 million Mcf to its sales customers and approximately 15.7 million Mcf for its customer choice and transportation customers.[29]

MGUC is not directly rated by either Moody's or S&P. MGUC's direct parent, Integrys, has a long-term rating of A- (Outlook: Stable) from S&P and Baa1 (Outlook: Stable) from Moody's.[30]

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

A. One of the purposes of this proceeding is to estimate the cost of equity for a natural gas utility company that is not itself publicly traded. Because the cost of equity is a market-based concept and because MGUC's operations do not make up the entirety of a publicly traded entity, it is necessary to establish a group of companies that are both publicly traded and comparable to MGUC in certain fundamental business and financial respects to serve as its "proxy" in the cost of equity estimation process.

Even if MGUC were a publicly traded entity, it is possible that transitory events could bias its market value over a given period. A significant benefit of using a proxy

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[27] MGUC website.

[28] Michigan Gas Utilities Corporation, 2021 Annual LDC filing to the Michigan Public Service Commission, April 29, 2022, at 110.

[29] *Id*., at 305C, 306C, and 313.

[30] S&P Global Market Intelligence and Moody's.

group is that it moderates the effects of unusual events that may be associated with any one company. The companies included in the proxy group all possess a set of operating and risk characteristics that are substantially comparable to the Company's, and thus provide a reasonable basis to derive and estimate the appropriate cost of equity for MGUC.

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

A. The overall purpose of developing a set of screening criteria is to select a proxy group of companies that align with the financial and operational characteristics of MGUC and that investors would view as comparable to the Company. 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 at least two utility industry analysts;
- have positive long-term earnings growth forecasts from at least two utility industry equity analysts;
- derive more than 60.00 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 parties to a merger or transformative transaction during the analytical periods relied on.

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 against establishing a proxy group of companies that are comparable in business and financial risk to 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 6. This group is generally comparable to MGUC.

Figure 6: Proxy Group

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

VII. COST OF EQUITY ESTIMATION

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

A. The overall rate of return for a regulated utility is the weighted average cost of capital, in which the cost rates of the individual sources of capital are weighted by their respective book values. The ROE is the cost of common equity capital in the utility's capital structure for ratemaking purposes. 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. The required cost of equity is estimated by using analytical techniques that rely on market-based data to quantify investor expectations regarding equity returns, adjusted for certain incremental costs and risks. Informed judgment is then applied to determine where the Company's cost of equity falls within the range of results produced by multiple analytical techniques. The key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, as well as the subject company in the context of the proxy group, in particular.

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

A. I considered the results of the constant growth DCF model, the CAPM, the ECAPM, and a Bond Yield Plus Risk Premium analysis.[31] As discussed in more detail below, a reasonable cost of equity estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results.

A. Importance of Multiple Analytical Approaches

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

A. The cost of equity is not directly observable. Therefore, 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

[31] In the Company's last rate proceeding, Docket No. U-20718, I also reviewed the results of a multi-stage DCF model to address certain outlier growth rates. I did not find that circumstance present in the current data set and therefore did not rely on a multi-stage DCF model in my Direct Testimony.

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 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[32] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[33] recommend the CAPM, DCF, and Bond Yield Plus Risk Premium approaches.

Q. Do current market conditions support your reliance on more than one analytical approach?

A. Yes. As discussed previously, interest rates have increased substantially over the past year and are expected to remain elevated over at least the next year from the lows seen during the COVID-19 pandemic. The benefit of using multiple models is that each model relies on different assumptions, certain of which may better reflect current and projected market conditions at different times. As discussed previously, the CAPM, ECAPM, and Bond Yield Plus Risk Premium analysis offer some balance through the use of projected interest rates since the effect of changes in interest rates, particularly the recent increase in interest rates, may not be captured as well in the DCF model at this time. Therefore, it is important

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

33 Brigham, Eugene and Louis Gapenski. Financial Management: Theory and Practice. Orlando, Dryden Press, 1994, at 341.

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. 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. [34]

B. 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:

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

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:

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

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

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.

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, 2023.

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

A. I use an average of recent trading days to calculate the term P_0 in the DCF model to reflect current market data while also ensuring that the result of the model is not skewed by anomalous events that may affect stock prices on any given trading day.

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

A. Yes. Because 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, dividends per share and book value per share all grow at the same constant rate. Over the long run, however, dividend growth can only be sustained by earnings growth. Therefore, it is important to consider a variety of sources in arriving at a single projected long-term earnings growth rate for 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. Why are EPS growth rates the appropriate growth rates to be relied on in the DCF model?

A. 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 reflect accurately investor perceptions of a company's growth prospects.

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

A. I calculated a low end result for my DCF model using the minimum growth rate of the three sources (*i.e.*, the lowest of the Zacks, Yahoo Finance, and Value Line projected earnings growth rates) for each of the proxy group companies. I used a similar approach to calculate a high-end result, using the maximum growth rate of the three sources for each proxy group company. The mean results were calculated using the average growth rate from all three sources for each proxy group company.

Q. What are the results of your DCF analyses?

A. Figure 7 summarizes the results of my DCF analyses. As shown in Figure 7, the mean and median DCF results using the average growth rates range from 9.85 percent to 10.11 percent, and the mean and median results using the maximum growth rates range from 10.77 percent to 11.28 percent. While I also summarize the DCF results using the minimum growth rates, given the expected underperformance of utility stocks going forward and thus the likelihood that the DCF model is understating the cost of equity, I do not believe it is appropriate to consider these DCF results at this time.

Figure 7: DCF Results

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.03%	9.99%	11.15%
90-Day Avg. Stock Price	9.15%	10.11%	11.28%
180-Day Avg. Stock Price	9.07%	10.03%	11.19%
Average	9.08%	10.04%	11.21%
Median Results:			
30-Day Avg. Stock Price	8.81%	9.79%	10.76%
90-Day Avg. Stock Price	8.94%	9.90%	10.87%
180-Day Avg. Stock Price	8.88%	9.85%	10.77%
Average	8.88%	9.85%	10.80%

Q. Have regulatory commissions acknowledged that the DCF model might understate the cost of equity given the current capital market conditions of high inflation and increased interest rates?

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 the current capital market conditions of high inflation and increased interest rates has resulted in the DCF model understating the utility cost of equity, and that weight should be placed on risk premium models, such as the CAPM, 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.[35]
>
> …..
>
> 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.[36]

Q. What are your conclusions about the results of the DCF models?

A. As discussed previously, one primary assumption of the DCF models is a constant price-to-earnings ratio, and that assumption is heavily influenced by the market price of utility stocks. Since utility stocks are expected to underperform the broader market over the near-term as interest rates remain elevated and yields on long-term government bonds exceed

[35] Penn. Pub. Util. Comm'n et.al. v, Aqua Penn. Wastewater Inc., Pennsylvania Public Utility Commission, Docket Nos. R-2021-3027385 and R-2021-3027386, Opinion and Order, May 12, 2022, pp. 154–155.

[36] Id., Opinion and Order, May 12, 2022, pp. 177–178.

utility dividend yields, it is important to consider the results of the DCF models with caution. Therefore, while I have given weight to the results of the constant growth DCF model, my recommendation also gives weight to the results of other cost of equity estimation models.

C. CAPM Analysis

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. 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.

The CAPM is defined by four components:

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

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. Non-diversifiable risk is measured by beta, which is defined as:

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

The variance of the market return (*i.e.*, Variance (r_m)) is a measure of the uncertainty of the general market, and the Covariance between the return on a specific security and the general market (*i.e.*, Covariance (r_e, r_m)) 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, which is 3.71 percent;[37] (2) the average projected 30-year Treasury bond yield for the second quarter of 2023 through the second quarter of 2024, which is 3.82 percent;[38] and (3) the average projected 30-year Treasury bond yield for 2024 through 2028, which is 3.90 percent.[39]

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 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 using five years of weekly returns relative to the NYSE Composite Index. Additionally, as shown on Schedules D9 and D10,

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[37] Bloomberg Professional as of January 31, 2023.

[38] *Blue Chip Financial Forecasts*, Vol. 42, No. 2, February 1, 2023, at 2.

[39] *Blue Chip Financial Forecasts*, Vol. 41, No. 12, December 2, 2022, at 14.

I considered another CAPM analysis that relies on the long-term average beta coefficient for the companies in my proxy group, which is calculated as an average of the *Value Line* beta coefficients for the companies in my proxy group from 2013 through 2022.

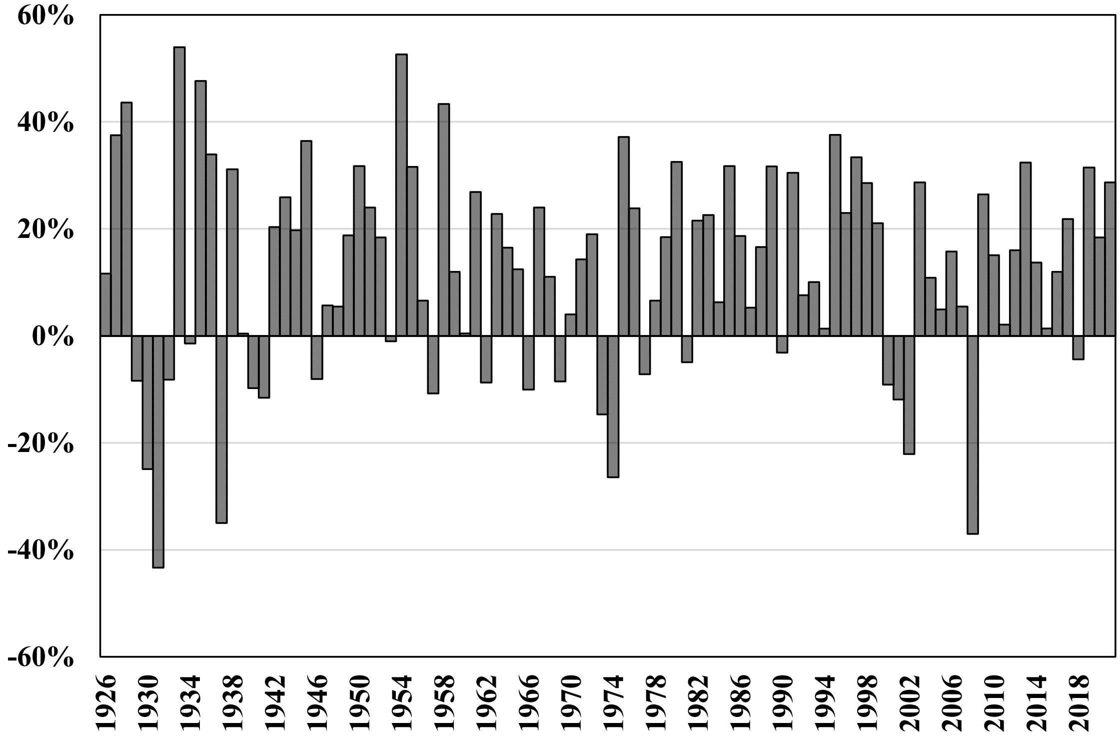
Q. How do you estimate the market risk premium in the CAPM?

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 1.75 percent and a weighted long-term growth rate of 10.65 percent, the estimated required market return for the S&P 500 Index as of January 31, 2023 is 12.50 percent. Based on the three risk-free rates considered, the market risk premium ranges from 8.60 percent to 8.79 percent.

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

A. As shown in Figure 8, given the range of annual equity returns that have been observed over the past century, a current expected market return of 12.50 percent is not unreasonable. As shown, in 50 out of the past 96 years (or roughly 52 percent of observations), the realized equity market return was 12.50 percent or greater.

Figure 8: Realized U.S. Equity Market Returns (1926-2021)[40]



Q. Did you 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.[41] 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:

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

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

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

In essence, 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.[42]

As with the CAPM, my application of the ECAPM uses the forward-looking market risk premium estimates, the three yields on 30-year Treasury securities noted earlier as the risk-free rate, and the current Bloomberg, current *Value Line*, and long-term *Value Line* beta coefficients.

Q. What are the results of your CAPM analyses?

A. As shown in Figure 9 (*see* also Schedule D10), my traditional CAPM analysis produces a range of returns from 10.24 percent to 11.14 percent. The ECAPM analysis results range from 10.80 percent to 11.48 percent.

[42] *Id*., at 191.

Figure 9: CAPM Results

	Current 30-Day Avg 30-Year Treasury Yield	Near-Term Projected 30-Year Treasury Yield	Longer-Term Projected 30-Year Treasury Yield
CAPM:			
Current *Value Line* Beta	11.10%	11.12%	11.14%
Current Bloomberg Beta	10.48%	10.51%	10.53%
Long-term Avg. *Value Line* Beta	10.24%	10.26%	10.28%
ECAPM:			
Current *Value Line* Beta	11.45%	11.47%	11.48%
Current Bloomberg Beta	10.99%	11.00%	11.02%
Long-term Avg. *Value Line* Beta	10.80%	10.82%	10.84%

D. Bond Yield Plus Risk Premium Analysis

Q. Please describe the Bond Yield Plus Risk Premium approach.

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 investors must be compensated to bear that 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 companies as the historical measure of the cost of equity to determine the risk premium.

Q. Are there other considerations that should be addressed in conducting this analysis?

A. Yes. 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.[43]

Q. Is the Bond Yield Plus Risk Premium analysis relevant to investors?

A. Yes. Investors are aware of authorized ROEs in other jurisdictions, and they consider those authorizations as a benchmark for a reasonable level of equity returns for utilities of comparable risk operating in other jurisdictions. Because my Bond Yield Plus Risk Premium 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.

[43] *See e.g.*, Berry, S. Keith. "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* Harris, Robert S. "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return." *Financial Management*, Spring 1986, at 66.

Q. What did the regression analysis used in your Bond Yield Plus Risk Premium analysis reveal?

A. As shown in Figure 10, from 1992 through January 2023, 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:

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

Where:

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

a = intercept term

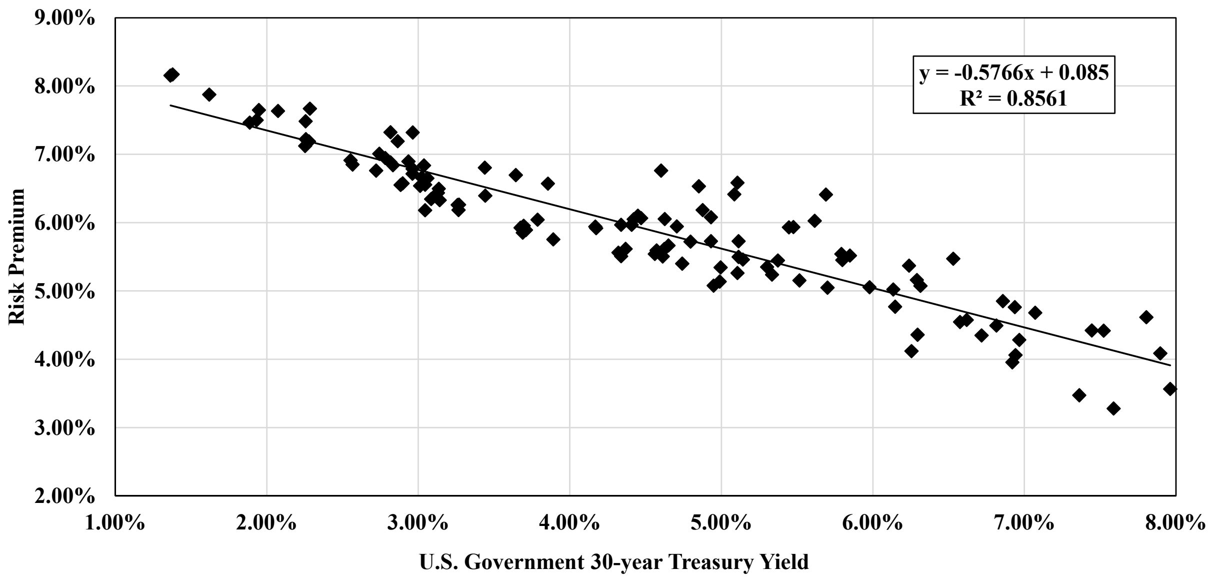
b = slope term

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

Data regarding authorized ROEs were derived from all natural gas distribution rate cases from 1992 through January 2023 as reported by Regulatory Research Associates ("RRA").[44] This equation's coefficients were statistically significant at the 99.00 percent level.

[44] This analysis began with a total of 1,200 cases and was screened to eliminate limited issue rider cases, transmission-only cases, and cases that were silent with respect to the authorized ROE. After applying those screening criteria, the analysis was based on data for over 750 cases.

Figure 10: Risk Premium Regression Analysis



Q. What are the cost of equity estimates that result from this equation?

Q. As shown in Schedule D12, based on the current 30-day average of the 30-year U.S. Treasury bond yield, the risk premium would be 6.36 percent, resulting in an estimated cost of equity of 10.07 percent. Based on the consensus estimate of the near-term (*i.e.*, Q2/2023 – Q2/2024) projected 30-year U.S. Treasury bond yield (*i.e.*, 3.82 percent), the risk premium would be 6.30 percent, resulting in an estimated cost of equity of 10.12 percent. Based on a consensus estimate of the longer-term (*i.e.*, 2024 – 2028) projection of the 30-year U.S. Treasury bond yield (*i.e.*, 3.90 percent), the risk premium would be 6.25 percent, resulting in an estimated cost of equity of 10.15 percent.

Q. How did the results of the Bond Yield Plus Risk Premium analysis inform your recommended ROE for MGUC?

A. I have considered the results of the Bond Yield Risk Premium analysis in setting my recommended ROE range for MGUC. As noted, investors consider the authorized ROE of a company when assessing the risk of that company as compared to utilities of comparable risk operating in other jurisdictions.

VIII. REGULATORY AND BUSINESS RISKS

Q. Taken alone, do the results from the cost of equity estimation models for the proxy group provide an appropriate estimate of the cost of equity for the Company?

A. No. These results provide only a range for the appropriate estimate of the Company's cost of equity. There are several additional factors that must be taken into consideration when determining where the Company's cost of equity falls within the range of results. These factors, which are discussed below, should be considered with respect to their overall effect on the Company's risk profile.

A. Capital Expenditures

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

A. As of December 31, 2022, the Company had net utility plant of approximately $369 million, and the Company currently projects capital expenditures for 2023 through 2027 of approximately $257 million.[45] Therefore, the Company's projected capital expenditures represent approximately 70 percent of its net utility plant as of December 31, 2022.

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, they do. 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 large 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

[45] Data provided by the Company.

> 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.[46]

While MGUC is not currently rated by the credit rating agencies, the Company's business risk is also increased as a result of 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. How do MGUC's capital expenditure requirements compare to those of the proxy group companies?

A. As shown on Schedule D13, I 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 2023-2027 by its total net utility plant as of December 31, 2022. As shown therein, MGUC's ratio of capital expenditures as a percentage of net utility plant is consistent with the median for the proxy group.

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

A. As part of the settlement of its last rate case, 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 the majority of the costs included in MGUC's capital expenditures plan do not qualify for cost recovery through the MRP. In

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

fact, the MRP represents only approximately 19.2 percent of the Company's projected capital expenditures over the 2023-2027 period. As a result, MGUC still depends on rate case filings for the majority of its capital cost recovery.

Q. Are capital investment recovery mechanisms common among natural gas distribution utilities?

A. Yes. As shown on Schedule D14, approximately 72 percent of the proxy group utilities recover costs through capital tracking mechanisms.

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 are significant and will continue over the next few years. Although MGUC has an MRP to recover a portion of these expenditures, the vast majority of operating subsidiaries held by the proxy group companies also have some form of capital tracking mechanism, meaning that this risk mitigation is already reflected in the proxy group companies. Further, given that a large portion of MGUC's capital expenditures do not qualify for recovery through the MRP, the Company depends on rate case filings to recover the majority of its capital expenditures. Accordingly, I conclude that, all else equal, the Company's risk profile regarding capital expenditures is consistent somewhat greater than that of the proxy group.

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 authorities recognize that because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms, and doing so balances the long-term interests of investors and customers. To achieve this balance, the Company must be able to finance its operations assuming a reasonable opportunity to earn an appropriate return on invested capital to maintain an acceptable financial profile. In that respect, 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, the 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.

In addition, 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 (which is to say that 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. How do credit rating agencies consider regulatory risk in establishing a company's credit rating?

A. 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.[47]

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."[48] 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;

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

[48] 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.

(2) tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.[49]

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, "[f]or rate regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations."[50] Moody's has further highlighted the relevance of a stable and predictable regulatory 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."[51]

Q. Have you conducted any analysis of the regulatory framework in Michigan relative to the jurisdictions in which the companies in your proxy group operate?

A. Yes. I have evaluated the regulatory framework in Michigan on three factors that are important in terms of providing a regulated utility an opportunity to earn its authorized ROE. These are: (1) test year convention (*i.e.*, forecast vs. historical); (2) method for

[49] *Id.*, at 1.

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

[51] *Id.*

determining rate base (*i.e.*, average vs. year-end); and (3) prevalence of capital cost recovery between rate cases. The results of this regulatory risk assessment are shown in Schedule D14 and are summarized as follows:

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

Capital Cost Recovery: As discussed previously, MGUC has an MRP surcharge to recover capital costs for main replacement; however, MGUC does not have a mechanism related to the recovery for the majority of their capital expenditures. Approximately 72 percent of the utility operating subsidiaries of the proxy group companies have some form of capital cost recovery mechanism in place.

Volumetric Risk: MGUC does not have protection against volumetric risk through a decoupling or other revenue stabilization mechanism; however, approximately 88 percent of the utility operating subsidiaries of the proxy group companies have some protection against volumetric risk.

Q. How are credit rating agencies currently viewing the utility sector?

A. Credit rating agencies have (i) indicated that the industry overall has increased risk; (ii) responded with close scrutiny of the financial coverage ratios of the sector; and (iii) maintain a negative outlook on the industry overall for 2023. Therefore, it is critically important to consider these factors and to recognize that the investor-required ROE would be higher today than at the time of Commission decisions in the recent past. As discussed in more detail in Section V, current market conditions demonstrate greater risk than at the time the Commission authorized returns in the recent past.

Q. Are you aware of any utilities that have been affected by negative rate case developments?

A. Yes. In Arizona Public Service's ("APS") most recently completed rate case, the Arizona Corporation Commission ("AZCC") reduced the authorized ROE for APS from 10.00 percent to 8.70 percent, even though the Administrative Law Judge had recommended an ROE of 9.16 percent.[52] As a result of this rate case decision, credit ratings agencies instituted negative ratings actions, the stock price of APS's parent Pinnacle West Capital Corporation fell significantly, and APS's projected earnings growth rate estimates were reduced to zero or nearly zero. For example, after the decision, APS's projected EPS growth rates reported by IBES were reduced to nearly zero. In addition, the five-year projected EPS growth rates published by *Value Line* for APS fell from 5.0 percent in July 2021 prior to the deliberations in the rate proceeding to "Nil" in October 2021, and most recently are at just 0.5 percent as of January 2023. *Value Line* noted the following in its July 2022 report on PNW:

> Pinnacle West stock is still reeling from the regulatory thrashing the company suffered late last year. The issue has lost over 30% of its value from mid-2021, when it started to become apparent that things would not go the company's way in its general rate case. When the decision arrived in November, Pinnacle West saw its allowed return on equity (ROE) reduced from 10% to 8.7% (the lowest level in the U.S.), and its annual earning power cut by $0.90 per share. There were some strong relief rallies based on the hope for restitution, but that sentiment has faded, as its utility subsidiary (APS) has been unsuccessful in its bid for a judiciary appeal. In

[52] Arizona Corporation Commission, ALJ Recommended Opinion and Order, August 2, 2021, at 322.

> December, it filed a petition for special action with the Arizona Supreme Court, but was turned down. APS also put in a request to argue its case before the state Court of Appeals, but has received no response.[53]

In January 2023, *Value Line* reiterated PNW's difficulties in 2022, and stated that 2023 "probably won't be significantly better," noting that APS's ROE issues has been quite volatile over the past 18 months and that investors have been trying to gauge if the setback would be permanent or not.[54]

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

A. As discussed, many of the operating subsidiaries of the proxy group companies have relatively more timely cost recovery as compared to MGUC. Both Moody's and S&P have identified the supportiveness of the regulatory environment as an important consideration in developing their overall credit ratings for regulated utilities. 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

53 *Value Line*, Pinnacle West, October 21, 2022.

54 *Value Line*, Pinnacle West, January 20, 2023.

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. [55]

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 does 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, I have estimated the implied market capitalization for the Company (*i.e.*, the market capitalization if the

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

Company were a stand-alone publicly-traded entity) relative to the actual market capitalization for the proxy group companies.

Specifically, to estimate the size of the Company's implied market capitalization relative to the proxy group, I first calculated the implied equity balance of MGUC's capital structure by multiplying the Company's 2022 net utility plant in service by the Company's proposed common equity ratio of 51.40 percent. I then applied the median market-to-book ratio for the proxy group of 1.72 to the Company's implied common equity balance to estimate an implied market capitalization, which is approximately $326 million, or approximately 7.2 percent of the median market capitalization for the proxy group

Q. How did 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.[56] As shown in Schedule D15, the median market capitalization of the proxy group is approximately $4.50 billion, which corresponds to the fourth decile of *Kroll's* market capitalization data.[57] Based on *Kroll's* analysis, that decile corresponds to a size premium of 0.58 percent (*i.e.*, 58 basis points). In comparison, MGUC's implied market capitalization of approximately $326 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

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[56] *Kroll* Cost of Capital Navigator – Size Premium; annual data as of January 31, 2023.

[57] *Id.*

and the size premium for the proxy group is 157 basis points (*i.e.*, 2.15 percent minus 0.58 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.[58]

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 smaller water utilities had greater risk and required higher returns on equity than larger water utilities.[59] 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

58 *Kroll*. Valuation Handbook: Guide to Cost of Capital. 2019, Exhibit 7.2.

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

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.[60]

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.[61] 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. utility group was positive and statistically significant indicating that small size risk was relevant for regulated utilities.[62]

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. 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

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[60] *Id*.

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

[62] *Id.*

adjustment, would adequately compensate AEL&P for its greater risk."[63] 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.[64] 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.[65] 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.[66]

Additionally, the Minnesota Public Utilities Commission ("Minnesota PUC") authorized an ROE for Otter Tail Power Company ("Otter Tail") above the mean DCF 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.[67]

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

64 *Id.*, at 32 and 37.

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

66 *Id*.

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

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."[68]

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 believe it is important to consider the small size of the Company's natural gas distribution operations in the determination of where, within the range of analytical results, MGUC's required cost of equity falls. All else equal, the additional risk associated with the Company's small size supports an ROE toward the upper end of the range of results from the cost of equity estimation models.

[68] *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).

D. Flotation Cost

Q. What are flotation costs?

A. Flotation costs are the costs associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other issuance costs.

Q. Why is it important to consider flotation costs in the allowed ROE?

A. A regulated utility must have the opportunity to earn an ROE that is both competitive and compensatory to attract and retain new investors. To the extent that a company is denied the opportunity to recover prudently incurred flotation costs, actual returns will fall short of expected (or required) returns, thereby diluting equity share value.

Q. Are flotation costs part of the utility's invested costs or part of the utility's expenses?

A. Flotation costs are part of the invested costs of the utility, which are properly reflected on the balance sheet under "paid in capital." They are not current expenses, and, therefore, are not reflected on the income statement. Rather, like investments in rate base or the issuance costs of long-term debt, flotation costs are incurred over time. As a result, the great majority of a utility's flotation cost is incurred prior to the test year but remains part of the cost structure that exists during the test year and beyond, and as such, should be recognized for ratemaking purposes. Therefore, it is irrelevant whether an issuance occurs during the test year or is planned for the test year because failure to allow recovery of past flotation costs may deny MGUC the opportunity to earn its required rate of return in the future.

Q. Please provide an example of why a flotation cost adjustment is necessary to compensate investors for the capital they have invested.

A. Suppose WEC Energy issues stock with a value of $100, and an equity investor invests $100 in WEC Energy in exchange for that stock. Further, suppose that, after paying the flotation costs associated with the equity issuance, which include fees paid to underwriters and attorneys, among others, WEC Energy ends up with only $97 of net issuance proceeds, rather than the $100 the investor contributed. WEC Energy invests that $97 in plant used to serve its customers, which becomes part of rate base. Absent a flotation cost adjustment, the investor will thereafter earn a return on only the $97 invested in rate base, even though she contributed $100. Making a small flotation cost adjustment gives the investor a reasonable opportunity to earn the authorized return, rather than the lower return that results when the authorized return is applied to an amount less than what the investor contributed.

Q. Is the date of WEC Energy's last issuance of common equity important in the determination of flotation costs?

A. No, the vintage of the issuance is not particularly important because an investor should have a reasonable opportunity to earn a return on the full amount of capital that he or she has contributed, but without the recognition of flotation costs, the investor suffers a shortfall in every year after which the capital has been invested. For example, prior to its acquisition by WEC, Integrys had two equity issuances. As shown in Schedule D16, Integrys closed on equity issuances of approximately $173 million and $102 million (for a total of 5.9 million shares of common stock) in November 2003 and November 2005, respectively. Returning to my earlier example, the investor who contributed $100 is entitled to a reasonable opportunity to earn a return on $100 not only in the first year after the investment, but in every subsequent year in which he or she has the $100 invested. Leaving aside depreciation, which is dealt with separately, there is no basis to conclude that the investor is entitled to earn a return on $100 in the first year after issuance, but thereafter is entitled to earn a return on only $97. As long as the $100 is invested, the investor should have a reasonable opportunity to earn a return on the entire amount.

Q. Is the need to consider flotation costs eliminated because MGUC is a wholly-owned subsidiary of Integrys, which is a wholly-owned subsidiary of WEC Energy?

A. No, it is not. Although MGUC is a wholly-owned subsidiary of Integrys, and in turn, of WEC Energy, it is appropriate to consider flotation costs. Wholly-owned subsidiaries receive equity capital from their parent and provide returns on the capital that roll up to the parent, which is designated to attract and raise capital based upon the returns of those subsidiaries. To deny recovery of issuance costs associated with the capital that is invested in the subsidiaries ultimately penalizes the investors that fund utility operations and inhibits the utility's ability to obtain new equity capital at a reasonable cost. This is particularly important for MGUC because, as I discussed previously, it is planning significant capital expenditures in the near term.

Q. Is the need to consider flotation costs recognized by the academic and financial communities?

A. Yes, it is. The need to reimburse shareholders for the lost returns associated with equity issuance costs is recognized by the academic and financial communities in the same spirit that investors are reimbursed for the costs of issuing debt. This treatment is consistent with the philosophy of a fair ROR. According to Dr. Shannon Pratt:

> Flotation costs occur when new issues of stock or debt are sold to the public. The firm usually incurs several kinds of flotation or transaction costs, which reduce the actual proceeds received by the firm. Some of these are direct out-of-pocket outlays, such as fees paid to underwriters, legal expenses, and prospectus preparation costs. Because of this reduction in proceeds, the firm's required returns on these proceeds equate to a higher return to compensate for the additional costs. Flotation costs can be accounted for either by amortizing the cost, thus reducing the cash flow to discount, or by incorporating the cost into the cost of capital. Because flotation costs are not typically applied to operating cash flow, one must incorporate them into the cost of capital. [69]

Q. What is the effect of flotation costs on MGUC's cost of equity?

A. My flotation cost is estimated on the costs of issuing equity that were incurred by Integrys in two prior common equity issuances. As shown in Schedule D15, based on the costs of those two issuances, the impact on the proxy group's cost of equity amounts to approximately13 basis points (*i.e.*, 0.13 percent).

Q. Do your final results include an adjustment for flotation cost recovery?

A. No, they do not. I did not make an explicit adjustment for flotation costs to any of my quantitative results. Rather, I discuss flotation costs and provide the estimate as additional context and support for the range of results produced by my cost of equity estimation models and the Company's requested ROE of 10.40 percent.

[69] Pratt, Shannon P. Cost of Capital Estimation and Applications. Second Edition, at 220-21.

IX. CAPITAL STRUCTURE

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

A. Yes, it is. The equity ratio is the primary indicator of financial risk for a regulated utility such as MGUC. Assuming other factors equal, a higher debt ratio increases the risk to equity 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 the claim of debt holders. Therefore, the greater the debt service requirement, the less cash flow available for common equity holders. To the extent the equity ratio is reduced, it is necessary to increase the authorized ROE to compensate investors for the greater financial risk associated with a lower equity ratio.

Q. What is MGUC's proposed capital structure?

A. MGUC is proposing a ratemaking capital structure based on 51.40 percent permanent common equity and 48.60 percent long-term debt.

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. Since the ROE is set based on the return that is derived from the risk-comparable proxy group, it is reasonable to look to the average capital structure for the proxy group to benchmark the equity ratios for the Company.

Q. Please discuss your analysis of the capital structures of the proxy group companies.

A. I calculated the average proportion of common equity, long-term debt and preferred stock for the most recent three years for each of the utility operating subsidiaries in the proxy group.[70] As shown in Schedule D17, the average common equity ratio for operating subsidiaries of the proxy group companies over the past three years was 56.41 percent (representing a range from 48.73 percent to 61.47 percent). Given that MGUC's proposed equity ratio of is well within the range of equity ratios for the utility operating subsidiaries of the proxy group companies, I consider it to be reasonable.

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 outlook for utilities in 2023.

For example, Moody's recently revised its 2023 outlook for the regulated gas and electric utilities sector to "negative" based on ongoing challenges of inflation, increasing interest rates and higher natural gas prices. Moody's noted that these challenges increase the pressure on customer affordability, and thus face heightened public scrutiny and the ability of utilities to promptly recover their costs. Moody's concluded that regulated utilities' financial metrics are already under pressure with little cushion, and that sustained

[70] Long-term debt includes the current portion of long-term debt, assuming that the current portion would be refinanced with debt at maturity.

capital spending is likely as utilities continue progress towards emissions reductions and net-zero goals. Moody's noted that the outlook could return to stable if regulatory support remains intact, natural gas prices are at a level where utilities are able to recover their fuel and purchased power costs without delay beyond 12 months, overall inflation moderates, interest rates stabilize and/or utilities' aggregate funds from operations-to-debt ratio remains between 14% and 15%.[71]

Fitch Ratings ("Fitch") also highlights similar factors identified by Moody's as challenging utilities' outlook for 2023, stating that the sector faces mounting cost pressures due to "elevated commodity prices, inflationary headwinds and rising interest costs," and that some offset in managing these headwinds include "higher authorized ROEs and the use of tools such as securitization of under-recovered fuel balances."[72]

Likewise, S&P also continues to maintain a negative outlook for the utility industry,[73] noting that since downgrades outpaced upgrades for a second consecutive year in 2021, the median investor-owned utility credit rating fell to the "BBB" category for the first time ever.[74] Further, S&P expects continued pressure on cash flows over the near-term as utilities continue to increase leverage to fund capital expenditure plans necessary to reduce greenhouse gas emissions and improve safety and reliability. Finally, S&P also highlights inflation, higher interest rates and rising commodity prices as additional risks

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71 Moody's Investors Service, Outlook. "2023 outlook negative due to higher natural gas prices, inflation and rising interest rates." November 10, 2022; Moody's Investors Service. Outlook, Sector In-Depth. "Inflation, high natural gas prices complicate prospects for supportive rate increases." November 11, 2022.

72 Fitch Ratings. "North American Utilities, Power & Gas Outlook 2023." December 7, 2022, at 1-2.

73 S&P Global Ratings. "Regulated Utilities: Credit quality has weakened and credit risks are rising." July 14, 2022.

74 S&P Global Ratings. "For the First Time Ever, the Median Investor-Owned Utility Ratings Falls to the 'BBB' Category." January 20, 2022.

that could further constrain the credit metrics for utilities over the near-term. Specifically regarding inflation, S&P notes:

> Inflation recently spiked to its highest level in decades after rising for several consecutive months in 2021. Given the sustained increase to the U.S. consumer price index in 2021, inflation no longer appears to be just transitory and may have financial implications for the investor-owned North American regulated utility industry. Because of the regulatory lag within the industry, inflation, which causes prices to rise, typically leads to a weakening of financial performance. The regulatory lag is the timing difference between when costs are incurred and when regulators allow those costs to be fully recovered from ratepayers.[75]

The credit ratings agencies' continued concerns over the negative effects of inflation 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.

X. CONCLUSION AND RECOMMENDATION

Q. What is your conclusion regarding a fair ROE for MGUC?

A.

A. Figure 11 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 10.40 percent reasonable.

[75] *Id*.

Figure 11: Summary of Analytical Results

Constant Growth DCF	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.03%	9.99%	11.15%
90-Day Avg. Stock Price	9.15%	10.11%	11.28%
180-Day Avg. Stock Price	9.07%	10.03%	11.19%
Average	9.08%	10.04%	11.21%
Median Results:			
30-Day Avg. Stock Price	8.81%	9.79%	10.76%
90-Day Avg. Stock Price	8.94%	9.90%	10.87%
180-Day Avg. Stock Price	8.88%	9.85%	10.77%
Average	8.88%	9.85%	10.80%

CAPM / ECAPM / Bond Yield Risk Premium	Current 30-Day Avg 30-Year Treasury Yield	Near-Term Projected 30-Year Treasury Yield	Longer-Term Projected 30-Year Treasury Yield
CAPM:			
Current *Value Line* Beta	11.10%	11.12%	11.14%
Current Bloomberg Beta	10.48%	10.51%	10.53%
Long-term Avg. *Value Line* Beta	10.24%	10.26%	10.28%
ECAPM:			
Current *Value Line* Beta	11.45%	11.47%	11.48%
Current Bloomberg Beta	10.99%	11.00%	11.02%
Long-term Avg. *Value Line* Beta	10.80%	10.82%	10.84%
Bond Yield Risk Premium:	10.07%	10.12%	10.15%

Q. What is your conclusion with respect to MGUC's proposed capital structure?

A. MGUC's proposal to establish a capital structure based on 51.40 percent permanent common equity and 48.60 percent long-term debt is within the range of actual capital structures of the proxy group companies. 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, it does.

Brattle

Ann E. Bulkley

PRINCIPAL

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With more than 25 years of experience in the energy industry, Ms. Bulkley specializes in regulatory economics for the electric and natural gas sectors, including rate of return, cost of equity, and capital structure issues.

Ms. Bulkley has extensive state and federal regulatory experience, and she has provided expert testimony on the cost of capital in nearly 100 regulatory proceedings before 32 state regulatory commissions and the Federal Energy Regulatory Commission (FERC).

In addition to her regulatory experience, Ms. Bulkley has provided valuation and appraisal services for a variety of purposes, including the sale or acquisition of utility assets, regulated ratemaking, ad valorem tax disputes, and other litigation purposes. In addition, she has experience in the areas of contract and business unit valuation, strategic alliances, market restructuring, and regulatory and litigation support.

Ms. Bulkley is a Certified General Appraiser licensed in the Commonwealth of Massachusetts and the State of New Hampshire.

Prior to joining Brattle, Ms. Bulkley was a Senior Vice President at an economic consultancy and held senior positions at several other consulting firms.

AREAS OF EXPERTISE

- Regulatory Economics, Finance & Rates
- Regulatory Investigations & Enforcement
- Tax Controversy & Transfer Pricing
- Electricity Litigation & Regulatory Disputes
- M&A Litigation

EDUCATION

- **Boston University**
  MA in Economics
- **Simmons College**
  BA in Economics and Finance

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2022–Present)**
  Principal
- **Concentric Energy Advisors, Inc. (2002–2021)**
  Senior Vice President
  Vice President
  Assistant Vice President
  Project Manager
- **Navigant Consulting, Inc. (1997–2002)**
  Project Manager
- **Reed Consulting Group (1995-1997)**
  Consultant- Project Manager
- **Cahners Publishing Company (1995)**
  Economist

SELECTED CONSULTING EXPERIENCE & EXPERT TESTIMONY

REGULATORY ANALYSIS AND RATEMAKING

Have provided a range of advisory services relating to regulatory policy analysis and many aspects of utility ratemaking, with specific services including:

- Cost of capital and return on equity testimony, cost of service and rate design analysis and testimony, development of ratemaking strategies
- Development of merchant function exit strategies

- Analysis and program development to address residual energy supply and/or provider of last resort obligations
- Stranded costs assessment and recovery
  Performance-based ratemaking analysis and design
- Many aspects of traditional utility ratemaking (e.g., rate design, rate base valuation)

COST OF CAPITAL

Have provided expert testimony on the cost of capital and capital structure in nearly 100 regulatory proceedings before state and federal regulatory commissions in the United States.

RATEMAKING

Have assisted several clients with analysis to support investor-owned and municipal utility clients in the preparation of rate cases. Sample engagements include:

- Assisted several investor-owned and municipal clients on cost allocation and rate design issues including the development of expert testimony supporting recommended rate alternatives.
- Worked with Canadian regulatory staff to establish filing requirements for a rate review of a newly regulated electric utility. Along with analyzing and evaluating rate application, attended hearings and conducted investigation of rate application for regulatory staff. And prepared, supported, and defended recommendations for revenue requirements and rates for the company. Additionally, developed rates for gas utility for transportation program and ancillary services.

VALUATION

Have provided valuation services to utility clients, unregulated generators, and private equity clients for a variety of purposes, including ratemaking, fair value, ad valorem tax, litigation and damages, and acquisition. Appraisal practices are consistent with the national standards established by the Uniform Standards of Professional Appraisal Practice.

Representative projects/clients have included:

- Prepared appraisals of electric utility transmission and distribution assets for ad valorem tax purposes.
- Prepared appraisals of several hydroelectric generating facilities for ad valorem tax purposes.
- Conducted appraisals of fossil fuel generating facilities for ad valorem tax purposes.
- Conducted appraisals of generating assets for the purposes of unwinding sale-leaseback agreements.
- For a confidential utility client, prepared valuation of fossil and nuclear generation assets for financing purposes for regulated utility client.

- Prepared a valuation of a portfolio of generation assets for a large energy utility to be used for strategic planning purposes. Valuation approach included an income approach, a real options analysis, and a risk analysis.
- Assisted clients in the restructuring of NUG contracts through the valuation of the underlying assets. Performed analysis to determine the option value of a plant in a competitively priced electricity market following the settlement of the NUG contract.
- Prepared market valuations of several purchase power contracts for large electric utilities in the sale of purchase power contracts. Assignment included an assessment of the regional power market, analysis of the underlying purchase power contracts, and a traditional discounted cash flow valuation approach, as well as a risk analysis. Analyzed bids from potential acquirers using income and risk analysis approached. Prepared an assessment of the credit issues and value at risk for the selling utility.
- Prepared appraisal of a portfolio of generating facilities for a large electric utility to be used for financing purposes.
- Prepared fair value rate base analyses for Northern Indiana Public Service Company for several electric rate proceedings. Valuation approaches used in this project included income, cost, and comparable sales approaches.
- Prepared an appraisal of a fleet of fossil generating assets for a large electric utility to establish the value of assets transferred from utility property.
- Conducted due diligence on an electric transmission and distribution system as part of a buy-side due diligence team.
- Provided analytical support for and prepared appraisal reports of generation assets to be used in ad valorem tax disputes.
- Provided analytical support and prepared testimony regarding the valuation of electric distribution system assets in five communities in a condemnation proceeding.
- Prepared feasibility reports analyzing the expected net benefits resulting from municipal ownership of investor-owned utility operations.
- Prepared independent analyses of proposal for the proposed government condemnation of the investor-owned utilities in Maine and the formation of a public power district.
- Valued purchase power agreements in the transfer of assets to a deregulated electric market.

STRATEGIC AND FINANCIAL ADVISORY SERVICES

Have assisted several clients across North America with analytically-based strategic planning, due diligence, and financial advisory services.

Representative projects include:

- Preparation of feasibility studies for bond issuances for municipal and district steam clients.
- Assisted in the development of a generation strategy for an electric utility. Analyzed various NERC regions to identify potential market entry points. Evaluated potential competitors and alliance partners. Assisted in the development of gas and electric price forecasts. Developed a framework for the implementation of a risk management program.
- Assisted clients in identifying potential joint venture opportunities and alliance partners. Contacted interviewed and evaluated potential alliance candidates based on company-established criteria for several LDCs and marketing companies. Worked with several LDCs and unregulated marketing companies to establish alliances to enter into the retail energy market. Prepared testimony in support of several merger cases and participated in the regulatory process to obtain approval for these mergers.
- Assisted clients in several buy-side due diligence efforts, providing regulatory insight and developing valuation recommendations for acquisitions of both electric and gas properties.

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arizona Corporation Commission				
UNS Electric	11/22	UNS Electric	Docket No. E-04204A-15-0251	Return on Equity
Tucson Electric Power Company	6/22	Tucson Electric Power Company	Docket No. G-01933A-22-0107	Return on Equity
Southwest Gas Corporation	12/21	Southwest Gas Corporation	Docket No. G-01551A-21-0368	Return on Equity
Arizona Public Service Company	10/19	Arizona Public Service Company	Docket No. E-01345A-19-0236	Return on Equity
Tucson Electric Power Company	04/19	Tucson Electric Power Company	Docket No. E-01933A-19-0028	Return on Equity
Tucson Electric Power Company	11/15	Tucson Electric Power Company	Docket No. E-01933A-15-0322	Return on Equity
UNS Electric	05/15	UNS Electric	Docket No. E-04204A-15-0142	Return on Equity
UNS Electric	12/12	UNS Electric	Docket No. E-04204A-12-0504	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arkansas Public Service Commission				
Oklahoma Gas and Electric Co	10/21	Oklahoma Gas and Electric Co	Docket No. D-18-046-FR	Return on Equity
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity
California Public Utilities Commission				
PacifiCorp, d/b/a Pacific Power	5/22	PacifiCorp, d/b/a Pacific Power	Docket No. A-22-05-006	Return on Equity
San Jose Water Company	05/21	San Jose Water Company	A2105004	Return on Equity
Colorado Public Utilities Commission				
Public Service Company of Colorado	11/22	Public Service Company of Colorado	Docket No. 22AL-0530E	Return on Equity
Public Service Company of Colorado	01/22	Public Service Company of Colorado	Docket No. 22AL-0046G	Return on Equity
Public Service Company of Colorado	07/21	Public Service Company of Colorado	21AL-0317E	Return on Equity
Public Service Company of Colorado	02/20	Public Service Company of Colorado	20AL-0049G	Return on Equity
Public Service Company of Colorado	05/19	Public Service Company of Colorado	19AL-0268E	Return on Equity
Public Service Company of Colorado	01/19	Public Service Company of Colorado	19AL-0063ST	Return on Equity
Atmos Energy Corporation	05/15	Atmos Energy Corporation	Docket No. 15AL-0299G	Return on Equity
Atmos Energy Corporation	04/14	Atmos Energy Corporation	Docket No. 14AL-0300G	Return on Equity
Atmos Energy Corporation	05/13	Atmos Energy Corporation	Docket No. 13AL-0496G	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Connecticut Public Utilities Regulatory Authority				
United Illuminating	09/22	United Illuminating	Docket No. 22-08-08	Return on Equity
United Illuminating	05/21	United Illuminating	Docket No. 17-12-03RE11	Return on Equity
Connecticut Water Company	01/21	Connecticut Water Company	Docket No. 20-12-30	Return on Equity
Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16	Return on Equity
Yankee Gas Services Co. d/b/a Eversource Energy	06/18	Yankee Gas Services Co. d/b/a Eversource Energy	Docket No. 18-05-10	Return on Equity
The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42	Return on Equity
The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04	Return on Equity
Federal Energy Regulatory Commission				
Sea Robin Pipeline	12/22	Sea Robin Pipeline	Docket No. RP22-___	Return on Equity
Northern Natural Gas Company	07/22	Northern Natural Gas Company	Docket No. RP22-___	Return on Equity
Transwestern Pipeline Company, LLC	07/22	Transwestern Pipeline Company, LLC	Docket No. RP22-___	Return on Equity
Florida Gas Transmission	02/21	Florida Gas Transmission	Docket No. RP21-441	Return on Equity
TransCanyon	01/21	TransCanyon	Docket No. ER21-1065	Return on Equity
Duke Energy	12/20	Duke Energy	Docket No. EL21-9-000	Return on Equity
Wisconsin Electric Power Company	08/20	Wisconsin Electric Power Company	Docket No. EL20-57-000	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Panhandle Eastern Pipe Line Company, LP	10/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-78-000 RP19-78-001	Return on Equity
Panhandle Eastern Pipe Line Company, LP	08/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-1523	Return on Equity
Sea Robin Pipeline Company LLC	11/18	Sea Robin Pipeline Company LLC	Docket# RP19-352-000	Return on Equity
Tallgrass Interstate Gas Transmission	10/15	Tallgrass Interstate Gas Transmission	RP16-137	Return on Equity
Idaho Public Utilities Commission				
Intermountain Gas Co	12/22	Intermountain Gas Co	C-INT-G-22-07	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	05/21	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-21-07	Return on Equity
Illinois Commerce Commission				
Peoples Gas Light & Coke Company	01/23	Peoples Gas Light & Coke Company	D-23-0069	Return on Equity
North Shore Gas Company	01/23	North Shore Gas Company	D-23-0068	Return on Equity
Illinois American Water	02/22	Illinois American Water	Docket No. 22-0210	Return on Equity
North Shore Gas Company	02/21	North Shore Gas Company	No. 20-0810	Return on Equity
Indiana Utility Regulatory Commission				
Indiana Michigan Power Co.	07/21	Indiana Michigan Power Co.	IURC Cause No. 45576	Return on Equity
Indiana Gas Company Inc.	12/20	Indiana Gas Company Inc.	IURC Cause No. 45468	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Southern Indiana Gas and Electric Company	10/20	Southern Indiana Gas and Electric Company	IURC Cause No. 45447	Return on Equity
Indiana and Michigan American Water Company	09/18	Indiana and Michigan American Water Company	IURC Cause No. 45142	Return on Equity
Indianapolis Power and Light Company	12/17	Indianapolis Power and Light Company	Cause No. 45029	Fair Value
Northern Indiana Public Service Company	09/17	Northern Indiana Public Service Company	Cause No. 44988	Fair Value
Indianapolis Power and Light Company	12/16	Indianapolis Power and Light Company	Cause No.44893	Fair Value
Northern Indiana Public Service Company	10/15	Northern Indiana Public Service Company	Cause No. 44688	Fair Value
Indianapolis Power and Light Company	09/15	Indianapolis Power and Light Company	Cause No. 44576 Cause No. 44602	Fair Value
Kokomo Gas and Fuel Company	09/10	Kokomo Gas and Fuel Company	Cause No. 43942	Fair Value
Northern Indiana Fuel and Light Company, Inc.	09/10	Northern Indiana Fuel and Light Company, Inc.	Cause No. 43943	Fair Value
Iowa Department of Commerce Utilities Board				
MidAmerican Energy Company	01/22	MidAmerican Energy Company	Docket No. RPU-2022-0001	Return on Equity
Iowa-American Water Company	08/20	Iowa-American Water Company	Docket No. RPU-2020-0001	Return on Equity
Kansas Corporation Commission				
Atmos Energy Corporation	08/15	Atmos Energy Corporation	Docket No. 16-ATMG-079-RTS	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Kentucky Public Service Commission				
Kentucky American Water Company	11/18	Kentucky American Water Company	Docket No. 2018-00358	Return on Equity
Maine Public Utilities Commission				
Central Maine Power	08/22	Central Maine Power	Docket No. 2022-00152	Return on Equity
Central Maine Power	10/18	Central Maine Power	Docket No. 2018-194	Return on Equity
Maryland Public Service Commission				
Maryland American Water Company	06/18	Maryland American Water Company	Case No. 9487	Return on Equity
Massachusetts Appellate Tax Board				
Hopkinton LNG Corporation	03/20	Hopkinton LNG Corporation	Docket No.	Valuation of LNG Facility
FirstLight Hydro Generating Company	06/17	FirstLight Hydro Generating Company	Docket No. F-325471 Docket No. F-325472 Docket No. F-325473 Docket No. F-325474	Valuation of Electric Generation Assets
Massachusetts Department of Public Utilities				
National Grid USA	11/20	Boston Gas Company	DPU 20-120	Return on Equity
Berkshire Gas Company	05/18	Berkshire Gas Company	DPU 18-40	Return on Equity
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Michigan Public Service Commission				
Michigan Gas Utilities Corporation	03/21	Michigan Gas Utilities Corporation	Case No. U-20718	Return on Equity
Wisconsin Electric Power Company	12/11	Wisconsin Electric Power Company	Case No. U-16830	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Michigan Tax Tribunal				
New Covert Generating Co., LLC.	03/18	The Township of New Covert Michigan	MTT Docket No. 000248TT and 16-001888-TT	Valuation of Electric Generation Assets
Covert Township	07/14	New Covert Generating Co., LLC.	Docket No. 399578	Valuation of Electric Generation Assets
Minnesota Public Utilities Commission				
Minnesota Energy Resources Corporation	11/22	Minnesota Energy Resources Corporation	Docket No. G011/GR-22-504	Return on Equity
CenterPoint Energy Resources	11/21	CenterPoint Energy Resources	D-G-008/GR-21-435	Return on Equity
Allete, Inc. d/b/a Minnesota Power	11/21	Allete, Inc. d/b/a Minnesota Power	D-E-015/GR-21-630	Return on Equity
Otter Tail Power Company	11/20	Otter Tail Power Company	E017/GR-20-719	Return on Equity
Allete, Inc. d/b/a Minnesota Power	11/19	Allete, Inc. d/b/a Minnesota Power	E015/GR-19-442	Return on Equity
CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	10/19	CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	G-008/GR-19-524	Return on Equity
Great Plains Natural Gas Co.	09/19	Great Plains Natural Gas Co.	Docket No. G004/GR-19-511	Return on Equity
Minnesota Energy Resources Corporation	10/17	Minnesota Energy Resources Corporation	Docket No. G011/GR-17-563	Return on Equity
Missouri Public Service Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Ameren Missouri	08/22	Ameren Missouri	File No. ER-2022-0337	Return on Equity
Missouri American Water Company	07/22	Missouri American Water Company	Case No. WR-2022-0303 Case No. SR-2022-0304	Return on Equity
Evergy Missouri West	1/22	Evergy Missouri West	File No. ER-2022-0130	Return on Equity
Evergy Missouri Metro	1/22	Evergy Missouri Metro	File No. ER-2022-0129	Return on Equity
Ameren Missouri	03/21	Ameren Missouri	Docket No. ER-2021-0240 Docket No. GR-2021-0241	Return on Equity
Missouri American Water Company	06/20	Missouri American Water Company	Case No. WR-2020-0344 Case No. SR-2020-0345	Return on Equity
Missouri American Water Company	06/17	Missouri American Water Company	Case No. WR-17-0285 Case No. SR-17-0286	Return on Equity
Montana Public Service Commission				
Montana-Dakota Utilities Co.	06/20	Montana-Dakota Utilities Co.	D2022.11.099	Return on Equity
Montana-Dakota Utilities Co.	06/20	Montana-Dakota Utilities Co.	D2020.06.076	Return on Equity
Montana-Dakota Utilities Co.	09/18	Montana-Dakota Utilities Co.	D2018.9.60	Return on Equity
New Hampshire - Board of Tax and Land Appeals				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Public Service Company of New Hampshire d/b/a Eversource Energy	11/19 12/19	Public Service Company of New Hampshire d/b/a Eversource Energy	Master Docket No. 28873-14-15-16-17PT	Valuation of Utility Property and Generating Assets
New Hampshire Public Utilities Commission				
Public Service Company of New Hampshire	05/19	Public Service Company of New Hampshire	DE-19-057	Return on Equity
New Hampshire-Merrimack County Superior Court				
Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	04/18	Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	220-2012-CV-1100	Valuation of Utility Property
New Hampshire-Rockingham Superior Court				
Eversource Energy	05/18	Public Service Commission of New Hampshire	218-2016-CV-00899 218-2017-CV-00917	Valuation of Utility Property
New Jersey Board of Public Utilities				
New Jersey American Water Company, Inc.	01/22	New Jersey American Water Company, Inc.	WR22010019	Return on Equity
Public Service Electric and Gas Company	10/20	Public Service Electric and Gas Company	EO18101115	Return on Equity
New Jersey American Water Company, Inc.	12/19	New Jersey American Water Company, Inc.	WR19121516	Return on Equity
Public Service Electric and Gas Company	04/19	Public Service Electric and Gas Company	EO18060629 GO18060630	Return on Equity
Public Service Electric and Gas Company	02/18	Public Service Electric and Gas Company	GR17070776	Return on Equity
Public Service Electric and Gas Company	01/18	Public Service Electric and Gas Company	ER18010029 GR18010030	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
New Mexico Public Regulation Commission				
Southwestern Public Service Company	07/19	Southwestern Public Service Company	19-00170-UT	Return on Equity
Southwestern Public Service Company	10/17	Southwestern Public Service Company	Case No. 17-00255-UT	Return on Equity
Southwestern Public Service Company	12/16	Southwestern Public Service Company	Case No. 16-00269-UT	Return on Equity
Southwestern Public Service Company	10/15	Southwestern Public Service Company	Case No. 15-00296-UT	Return on Equity
Southwestern Public Service Company	06/15	Southwestern Public Service Company	Case No. 15-00139-UT	Return on Equity
New York State Department of Public Service				
New York State Electric and Gas Company Rochester Gas and Electric	05/22	New York State Electric and Gas Company Rochester Gas and Electric	22-E-0317 22-G-0318 22-E-0319 22-G-0320	Return on Equity
Corning Natural Gas Corporation	07/21	Corning Natural Gas Corporation	Case No. 21-G-0394	Return on Equity
Central Hudson Gas and Electric Corporation	08/20	Central Hudson Gas and Electric Corporation	Electric 20-E-0428 Gas 20-G-0429	Return on Equity
Niagara Mohawk Power Corporation	07/20	National Grid USA	Case No. 20-E-0380 20-G-0381	Return on Equity
Corning Natural Gas Corporation	02/20	Corning Natural Gas Corporation	Case No. 20-G-0101	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/19	New York State Electric and Gas Company Rochester Gas and Electric	19-E-0378 19-G-0379 19-E-0380 19-G-0381	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	04/19	Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	19-G-0309 19-G-0310	Return on Equity
Central Hudson Gas and Electric Corporation	07/17	Central Hudson Gas and Electric Corporation	Electric 17-E-0459 Gas 17-G-0460	Return on Equity
Niagara Mohawk Power Corporation	04/17	National Grid USA	Case No. 17-E-0238 17-G-0239	Return on Equity
Corning Natural Gas Corporation	06/16	Corning Natural Gas Corporation	Case No. 16-G-0369	Return on Equity
National Fuel Gas Company	04/16	National Fuel Gas Company	Case No. 16-G-0257	Return on Equity
KeySpan Energy Delivery	01/16	KeySpan Energy Delivery	Case No. 15-G-0058 Case No. 15-G-0059	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/15	New York State Electric and Gas Company Rochester Gas and Electric	Case No. 15-E-0283 Case No. 15-G-0284 Case No. 15-E-0285 Case No. 15-G-0286	Return on Equity
North Dakota Public Service Commission				
Montana-Dakota Utilities Co.	05/22	Montana-Dakota Utilities Co.	C-PU-22-194	Return on Equity
Montana-Dakota Utilities Co.	08/20	Montana-Dakota Utilities Co.	C-PU-20-379	Return on Equity
Northern States Power Company	12/12	Northern States Power Company	C-PU-12-813	Return on Equity
Northern States Power Company	12/10	Northern States Power Company	C-PU-10-657	Return on Equity
Oklahoma Corporation Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Oklahoma Gas & Electric	12/21	Oklahoma Gas & Electric	Cause No. PUD 202100164	Return on Equity
Arkansas Oklahoma Gas Corporation	01/13	Arkansas Oklahoma Gas Corporation	Cause No. PUD 201200236	Return on Equity
Oregon Public Service Commission				
PacifiCorp d/b/a Pacific Power & Light	03/22	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-399	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	02/20	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-374	Return on Equity
Pennsylvania Public Utility Commission				
American Water Works Company Inc.	04/22	Pennsylvania-American Water Company	Docket No. R-2020-3031672 (water) Docket No. R-2020-3031673 (wastewater)	Return on Equity
American Water Works Company Inc.	04/20	Pennsylvania-American Water Company	Docket No. R-2020-3019369 (water) Docket No. R-2020-3019371 (wastewater)	Return on Equity
American Water Works Company Inc.	04/17	Pennsylvania-American Water Company	Docket No. R-2017-2595853	Return on Equity
South Dakota Public Utilities Commission				
MidAmerican Energy Company	05/22	MidAmerican Energy Company	D-NG22-005	Return on Equity
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity
Texas Public Utility Commission				
Entergy Texas, Inc.	07/22	Entergy Texas, Inc.	D-53719	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Southwestern Public Service Commission	08/19	Southwestern Public Service Commission	Docket No. D-49831	Return on Equity
Southwestern Public Service Company	01/14	Southwestern Public Service Company	Docket No. 42004	Return on Equity
Utah Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	05/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20-035-04	Return on Equity
Virginia State Corporation Commission				
Virginia American Water Company, Inc.	11/21	Virginia American Water Company, Inc.	Docket No. PUR-2021-00255	Return on Equity
Virginia American Water Company, Inc.	11/18	Virginia American Water Company, Inc.	Docket No. PUR-2018-00175	Return on Equity
Washington Utilities Transportation Commission				
Cascade Natural Gas Corporation	06/20	Cascade Natural Gas Corporation	Docket No. UG-200568	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	12/19	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-191024	Return on Equity
Cascade Natural Gas Corporation	04/19	Cascade Natural Gas Corporation	Docket No. UG-190210	Return on Equity
West Virginia Public Service Commission				
West Virginia American Water Company	04/21	West Virginia American Water Company	Case No. 21-02369-W-42T	Return on Equity
West Virginia American Water Company	04/18	West Virginia American Water Company	Case No. 18-0573-W-42T Case No. 18-0576-S-42T	Return on Equity
Wisconsin Public Service Commission				
Wisconsin Electric Power Company and Wisconsin Gas LLC	04/22	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-110	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Wisconsin Public Service Corp.	04/22	Wisconsin Public Service Corp.	6690-UR-127	Return on Equity
Alliant Energy		Alliant Energy		Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	03/19	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-109	Return on Equity
Wisconsin Public Service Corp.	03/19	Wisconsin Public Service Corp.	6690-UR-126	Return on Equity
Wyoming Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	03/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-578-ER-20	Return on Equity
Montana-Dakota Utilities Co.	05/19	Montana-Dakota Utilities Co.	30013-351-GR-19	Return on Equity

CERTIFICATIONS/ACCREDITATIONS

Certified General Appraiser, licensed in the Commonwealth of Massachusetts and the State of New Hampshire

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-21366
and for other relief.	)	
____	)	

DIRECT TESTIMONY AND EXHIBITS

OF SHANNON L. BURZYCKI

FOR

MICHIGAN GAS UTILITIES CORPORATION

March 3, 2023

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 and U-21273). I also sponsored testimony in MGUC's EWR plan and reconciliation proceedings (Case Nos. U-20430, U-20709. U-20782, U-20882 and U-21211), as well as in MGUC's certificate of public convenience and necessity proceedings (Case Nos. U-20853 and U-21292) and rate case proceeding, Case No. U-20718.

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 revisions to MGUC's Main Replacement Program ("MRP") Rider approved in Case No. U-20718, to revise the Low Income Assistance Program and Senior Credits to remove participation caps and include deferral accounting, to request the continued waiver of Mich Admin. Rule 51, R 460.2351, and to summarize miscellaneous, administrative tariff revisions. My testimony will include the calculation of the revised MRP revenue requirement and proposed MRP surcharges.

Q. DOES YOUR DIRECT TESTIMONY INCLUDE MORE THAN ONE RATE DESIGN MODEL?

A. Yes, my direct testimony and rate design exhibits reflect two models that are nearly identical but for changes to the Company's 2024 future test year driven solely by the depreciation rates, as discussed in Company Witness Nelson's testimony, utilized to derive the two rate designs. Exhibits and Schedules labeled as "Alternate" were developed using the depreciation rates proposed in Case No. U-21329. Exhibits and Schedules labeled as "Base" were developed using the current depreciation rates.

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 (Alternate);
2. Schedule F2.2, Summary of Present and Proposed Revenue by Rate Schedule Excluding Cost of Gas (Alternate);

3. Schedule F3.1, Present and Proposed Revenue Detail Including Cost of Gas (Alternate);
4. Schedule F3.2, Present and Proposed Revenue Detail Excluding Cost of Gas (Alternate);
5. Schedule F4, Comparison of Present and Proposed Monthly Bills (Alternate); and
6. Schedule F5, Summary of Tariff Changes and Proposed Revised Tariff Sheets;
7. Schedule F6.1, Summary of Present and Proposed Revenue by Rate Schedule Including Cost of Gas (Base);
8. Schedule F6.2, Summary of Present and Proposed Revenue by Rate Schedule Excluding Cost of Gas (Base);
9. Schedule F7.1, Present and Proposed Revenue Detail Including Cost of Gas (Base);
10. Schedule F7.2, Present and Proposed Revenue Detail Excluding Cost of Gas (Base); and
11. Schedule F8, Comparison of Present and Proposed Monthly Bills (Base).

I am also sponsoring the following exhibits that relate to the MRP Rider:

- Exhibit A-23 Proposed MRP Revenue Requirement; and
- Exhibit A-24 Proposed MRP Customer Surcharges.

Q. DID YOU PREPARE OR CAUSE THESE EXHIBITS TO BE PREPARED?

A. Yes, I did.

Q. PLEASE DESCRIBE SCHEDULE F2.1 AND F6.1 OF EXHIBIT A-16.

A. Schedule F2.1 (Alternate) and F6.1 (Base) 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 AND F6.2 OF EXHIBIT A-16.

A. Schedule F2.2 (Alternate) and F6.2 (Base) 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 AND F7.1 OF EXHIBIT A-16.

A. Schedule F3.1 (Alternate) and F7.1 (Base) 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 AND F7.2 OF EXHIBIT A-16.

A. Schedule F3.2 (Alternate) and F7.2 (Base) 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-20718) to the test year billing determinants to calculate revenues. The cost of gas component of $6.2280 per Mcf was derived from Company Witness Aaron Nelson's Cost of Service Study ("COSS") (total gas costs of $123,147,987 divided by sales of 19,773,359 Mcf).

Q. PLEASE DESCRIBE SCHEDULE F4 AND F8 OF EXHIBIT A-16.

A. Schedule F4 (Alternate) and F8 (Base) 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.

MGUC Rate Schedule	Revenue Increase $	Revenue Increase %
Residential	$11,153,175	8.2%
General Service	2,839,013	4.9%
Special Contract	29	0%
Transport	3,270,804	43.0%
Aggregated - Residential	2,124	23.2%
Aggregated - General Service	219,545	19.8%
Choice – Residential	1,274,647	21.4%
Choice - General Service	457,994	19.1%
TOTAL MGUC	$19,114,361	9.1%

The detail underlying these proposed rates can be found in Schedule F3.1 of Exhibit A-16. The values in this table were derived using the depreciation rates proposed in Case No. U-21329.

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 COSS sponsored by Company Witness Nelson, specifically Exhibit A-16, Schedule F1.8;
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 Nelson and shown in Exhibit A-16, Schedule F1.8. To that end, MGUC is proposing to change its monthly customer and volumetric charges to better match the monthly fixed costs incurred by MGUC in providing services to these customers.

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 Nelson’s Exhibit A-16, Schedules F1.6 thru F1.10.

Q. ARE THE ASSUMPTIONS LISTED ABOVE REASONABLE?

A. Yes, because they lead to a reasonable match between cost causation and cost recovery.

Monthly Customer Charges

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 not proposing any changes to the Administrative Charge.

Q. ARE YOU PROPOSING CHANGES TO THE MONTHLY CUSTOMER CHARGES?

A. Yes. The following table summarizes those changes.

MGUC Customer Class	Monthly Fixed Charge Current	Monthly Fixed Charge Proposed	Increase/Decrease $	Increase/Decrease %
Residential	$ 13.00	$ 14.00	$ 1.00	7.7%
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	$ 430.00	$ 5.00	1.2%
Special Contract	$ 8,082.97	$ 8,082.97	N/A	N/A
TR-1 Transport	$ 850.00	$ 950.00	$ 100.00	11.8%
TR-2 Transport	$ 2,250.00	$ 2,450.00	$ 200.00	8.9%
TR-3 Transport	$ 3,050.00	$ 3,250.00	$ 200.00	6.6%
Aggregated - Residential to Residential	$ 13.00	$ 14.00	$ 1.00	7.7%
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	$ 430.00	$ 5.00	1.2%
Choice - Residential	$ 13.00	$ 14.00	$ 1.00	7.7%
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	$ 430.00	$ 5.00	1.2%

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 Nelson (specifically Schedule F1.10 of Exhibit A-16), however, supports a Monthly Customer Charge of $28.55 for a residential customer. In an effort to moderate the amount of the increase, MGUC is proposing that the Residential Monthly Customer Charge only be increased by a dollar to $14.00. While this is approximately half the $28.55 supported by the COSS, it does represent a 7.7% increase over the current Monthly Fixed Charge.

Q. WHY IS MGUC PROPOSING AN INCREASE TO THE RESIDENTIAL CUSTOMER CHARGE?

A. Even under current rates there a significant amount of revenue collection that varies with variation in customer consumption – the volumetric distribution rate under MGUC’s current rate design. Due to this misalignment of cost occurrence and cost recovery, MGUC collects more revenue to cover fixed costs when customers use more gas and less revenue to cover fixed costs when customers use less gas. MGUC believes it is appropriate to recover fixed costs through the Monthly Fixed Charge, also referred to as the Customer Charge, consistent with the fixed nature of the costs that are incurred. Under MGUC's proposal, not only would the proposed Customer Charge be more aligned with cost causation, but it would also reduce the volatility in customer bills since a larger portion of the total bill will be fixed each month and will fluctuate based on changes in weather or other customer usage patterns. Customers will continue to receive appropriate price signals based on their consumption of natural gas, and this proposal will serve to reduce the cost-shifting from low load factor customers to higher load factor customers.

Q. HOW DOES MGUC'S PROPOSED RESIDENTIAL CUSTOMER CHARGE COMPARE WITH OTHER GAS UTILITIES IN MICHIGAN?

A. With regards to other gas utilities in Michigan, the current residential fixed charge rates range from a low of $5.00 per month for UMERC[1] customers to $13.60 per month for Consumers Energy customers and $13.50 per month for DTE's customers.

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.

[1] $5.00 per month Customer Charge set in Case No. U-7501, Order Approving Settlement Agreement dated March 31, 1983.

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 $794,132 for the 2024 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 $0.0402 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 $353, only $156 is collected by the monthly Customer Charge, or approximately 44%, while 55% 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 a seasonal, weather-dependent business. Under MGUC's proposal, the $12 annual increase to the Customer Charge would limit the expansion of the gap and strive to maintain a small portion of the split of the customer charge of 39% and the volumetric component of 61%. Therefore, these proposed increases are reasonable and appropriate because absent these increases, customer rates will actually be less aligned with cost causation than they would be without proposed increases in the Monthly Fixed Charges.

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 $2.2478/ Mcf. A typical residential customer uses 85.3 Mcf for a calendar year with "normal" weather. Under these rates a typical residential customer pays $156 a year in Customer Charges, $192 for Distribution Charges, and $5 for Gas Acquisition Charges, which totals $353 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 $6.2280/Mcf, a customer using 85.3 Mcf would have an annual gas charge of $531. Adding the $353 for distribution service, and the $531 for the cost of gas, a typical Residential sales customer has an annual bill of $884.

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 during the year versus having higher costs during the winter months when their consumption is the highest.

Q. CAN YOU QUANTIFY THE IMPACT OF A HIGHER MONTHLY CUSTOMER CHARGE FOR A RESIDENTIAL CUSTOMER DURING A COLDER THAN NORMAL WINTER?

A. While a typical Residential customer uses 85.3 Mcf annually under normal weather, the same customer may use 103 Mcf annually during a colder than normal winter (the average residential customer used 103 Mcf in the year that included the 2013-2014 colder-than-normal winter). With MGUC's proposed Customer Charge of $14.00 per month, a Distribution Charge of $2.9792 per Mcf, a typical Residential customer using 103 Mcf would pay $479 in annual distribution charges or $3 less than a Residential Customer Charge of $13.00 per month, a Distribution Charge of $3.1199 per Mcf.

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 for various consumption levels.

Q. WILL INCREASING THE MONTHLY RESIDENTIAL CUSTOMER CHARGE PROVIDE A DISINCENTIVE TO CONSERVE NATURAL GAS?

A. No. Customers will continue to have an incentive to conserve natural gas as 61% of their bill will continue to be based on the volumetric charge. The most significant portion of the typical Residential customer bill is related to gas costs, which are also recovered volumetrically through the GCR portion of the bill. In MGUC's proposed rate design, the volumetric Distribution Charge is $3.0194 per Mcf,[2] while the gas commodity cost is significantly higher at $6.2280 per Mcf.

The largest portion of these costs for a Residential customer over a typical year is incurred during the heating season and can be significantly reduced through any conservation efforts undertaken by the customer.

Q. CAN YOU PROVIDE SOME EXAMPLES OF LOW USE RESIDENTIAL HEATING CUSTOMERS?

A. Yes. These can include customers with second homes or cottages, customers that are retired and spend the winters away from home, and customers with a separately metered heated detached garage. Other customers using less than the average 85.3 Mcf per year would likely include those using natural gas only for water heating or cooking.

[2] $0.0402 per Mcf for the Gas Acquisition Charge and $2.9792 per Mcf for the Distribution Charge.

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 Nelson’s Schedule F1.7 of Exhibit A-16, MGUC's 2023 Projected COSS-Detailed Summary indicates that the Residential classes (General Service, Customer Choice, and Aggregated) plus 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.[3]

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 this rate design MGUC is not proposing any changes.

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;

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[3] James C. Bonbright, Albert Danielson, and David Kamerschen, Principles of Public Utility Rates (Arlington, VA: Public Utilities Reports, Inc., 1988).

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.

Gas Demand Response Pilot Program Update

Q. PLEASE PROVIDE THE BACKGROUND OF THE PILOT GAS DEMAND RESPONSE PROGRAM.

A. The Commission in Case No. U-20464 ordered all Michigan utilities to include demand response offerings in their next filing of a rate case. MGUC proposed the pilot Gas Demand Response Program in its last rate case, U-20718. The pilot Gas Demand Response Program was approved 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. HOW DID MGUC NOTIFY CUSTOMERS OF THE PILOT GAS DEMAND RESPONSE PROGRAM?

A. The Company notified customers of the new pilot program in the October 2022 Customer Connection bill insert and on the new Gas Demand Response webpage that went live in September 2022 on the Company's website.

Q. DID MGUC ENROLL CUSTOMERS IN THE GAS DEMAND RESPONSE PILOT AFTER IT WAS APPROVED?

A. Yes, the Company received interest from customers in late September and began to enroll eligible customers in October 2022, prior to the 2022-2023 heating season. Eligibility is determined by the customer's account being in good standing and a customer must be on Company supply year-round with an active AMI device.

Q. HOW MANY CUSTOMERS APPLIED AND HOW MANY WERE ELIGIBLE TO PARTICIPATE?

A. As of February 16, 2023, the Company received 24 Residential applications. The Company determined that 16 Residential customers were eligible and enrolled at the start of the heating season and a few more applications that have been recently received are currently being processed.

Q. HAS MGUC CALLED A GAS DEMAND RESPONSE EVENT IN THE 2022-2023 HEATING SEASON?

A. Yes, the Company called a Gas Demand Response ("GDR") event on Friday, February 3, 2023 starting at 10:00 AM ET for a duration of two hours. Customers were given:

- An Advisory Notice: 24-hour advance notification of the upcoming GDR event;
- A Start Notice: notification one hour prior to the event; and,
- An End Notice: notification that the event ended and that they may return to their preferred thermostat setting.

Q. WHAT WAS THE OUTCOME OF THE GAS DEMAND RESPONSE EVENT?

A. The Company is still evaluating the results of the event and can provide upon request all GDR event data for the 2022-2023 heating season when data has been gathered and analyzed.

Q. WILL MGUC CALL ANOTHER EVENT IN THE 2022-2023 HEATING SEASON?

A MGUC is uncertain if another event will be called because due to the warmer-than-normal heating season the Company is being selective in choosing potential event days in an effort to obtain useful data.

Q. DID MGUC INCENTIVIZE CUSTOMERS PER THE APPROVED TARIFF?

A. Yes, the Company issued two $50 Visa Gift Cards on November 30, 2022 that were awarded based on a random drawing. The two winning customers were also notified utilizing CNS that they were randomly selected and to expect the gift card through the Unites States Postal System. In addition, any customers enrolled at the end of the heating season will be entered into another one-in-ten chance drawing to win a $25 gift card.

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. Due to the program just beginning in November 2022, the Company would like to remain with the current approved program.

Modifications to Tariff Sheets

Q. IS MGU PROPOSING ANY MODIFICATIONS TO TARIFFS?

A. Yes. These modifications are discussed in pages 26-30 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 three 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 2023 and 2024. Because these projects will be included in base rates as part of our projected test year ending December 31, 2024, it would not be appropriate to continue to include these projects in the Rider. Second, MGUC is seeking to update the forecasted capital costs of the remaining projects included in the MRP in light of inflation that has been experienced over the past two years. Company Witness Nathan Lee addresses the updated capital cost forecast of the remaining MRP projects in his direct testimony.

Lastly, MGUC is proposing to extend the period of time covered by the MRP for two additional years such that it will now expire in 2029 rather than the current expiration date of 2027. Below, in my direct testimony, I provide testimony supporting the proposed MRP Rider surcharges for the period of 2025 – 2029 using the forecasted capital costs provided in Company Witness Lee's testimony.

Q. PLEASE PROVIDE AN OVERVIEW OF MRP RIDER.

A. The MRP Rider, as approved in Case No. 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, 2024. The following section of my testimony describes the exhibits I am sponsoring that support the MRP surcharge for 2025 through 2029.

Q. PLEASE DESCRIBE PAGE 1 OF EXHIBIT A-23.

A. Exhibit A-23 calculates the 2025 through 2029 annual revenue requirement for each year that was used to develop the annual customer surcharges, including the proposed surcharge for 2025. 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 8.90% 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 based to derive the total annual revenue requirements illustrated on line 11 for each year.

Q. WHAT IS THE BASIS FOR THE 8.90% CAPITAL CHARGE RATE?

A. The 8.90% 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 2029.

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 11 of Exhibit A-23, page 1. All allocation factors on the exhibit are based on the 2024 Cost of Service Study supported by Company Witness Nelson. 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, 2029.

Q. IS THE COMPANY PROPOSING A REPORTING REQUIREMENT?

A. MGUC also proposes filing in this docket an annual MRP report by April 1st of the year following the program year, detailing the annual capital spend for the projects for which recovery through the MRP Rider occurs.

Q. IS MGUC PROPOSING THAT THE MRP RIDER SURCHARGE BE UPDATED EACH YEAR?

A. Yes. As reflected in Exhibit A-24, the new MRP Rider surcharges will begin in 2025 and update each year through 2029 on a service rendered basis beginning in January. This approach is consistent with the approvals granted in Case No. U-20718.

Q. ARE YOU SPONSORING TARIFF SHEETS REFLECTIVE OF THE PROPOSED MRP RIDER?

A. Yes, see pages 23-27 of Exhibit A-16, Schedule F5 which reflect the MRP Rider and surcharges proposed for 2025 through 2029.

<u>Low Income Assistance Provisions and Senior Credit Assistance</u>

Q. PLEASE PROVIDE MGUC'S BACKGROUND WITH THE LOW INCOME ASSISTANCE PROGRAM.

A. MGUC implemented the Low Income and Senior Bill Assistance Program in January 2022 per the Settlement Agreement Order for Case No. U-20718, dated September 9, 2021. In that Order, the maximum number of customers to be on each program established were:

- Residential Income Allowance (RIA): 1,245 customers;
- Low Income Allowance (LIA): 255 customers; and
- Senior Assistance Program: 800 customers.

Since implementing these programs starting on January 1, 2022, MGUC has participated in Low-Income workgroups including the Energy Assistance Affordability, Alignment and Assistance ("AAA") Subcommittee and has learned additional information that has led to MGUC identifying changes to the RIA and Senior Assistance program that it is proposing in this rate case. Additionally, MGUC is proposing a change in how customers are enrolled in the RIA.

Q. DESCRIBE WHAT CHANGES MGUC IS REQUESTING TO THE RIA AND THE SENIOR ASSISTANCE PROGRAM?

A. In order to align MGUC's tariffs with other utilities, and at the suggestion of Commission Staff, MGUC is proposing to remove the current customer participation limit on the RIA and the Senior Assistance Program and requesting Commission authorization for deferred accounting treatment for the revenue impact if enrollment in the program exceeds the projected customer participation level assumed when final rates are established in this proceeding.

Q. WHAT RIA ENROLLMENT PROCESS IS MGUC PROPOSING?

A. MGUC is proposing to make RIA credits available to all qualifying customers similar to the uncapped RIA credit provisions that are Commission-approved for Consumers Energy and DTE Energy. Customers will be automatically enrolled in the credit for 12 months upon the receipt of a

Home Heating Credit ("HHC") energy draft or State Emergency Relief ("SER") payment. Customers who seek the credit who have not been automatically enrolled in the credit will be required to verify total household income with customer provided proof that they have received or are currently participating in, one or more of the following within the past 12 months:

- Home Heating Credit (HHC), State Emergency
- Relief (SER), Michigan Energy Assistance Program, Medicaid, or
- Supplementary Nutrition Assistance Program.

Q. EXPLAIN THE DEFERRED ACCOUNTING TREATMENT MGUC IS REQUESTING FOR THE RIA AND THE SENIOR ASSISTANCE PROGRAM.

A. MGUC is requesting deferred accounting treatment for the revenue impact if enrollment in the program exceeds the projected customer participation level assumed when final rates are established in this proceeding, which MGUC is proposing to remain unchanged at 1,245 customers for the RIA and the 800 Senior customers. If authorized, this deferral would remain in effect until base rates are next established in a future MGUC rate case.

Meter Testing Requirement Waiver

Q. IN THE COMMISSION'S NOVEMBER 18, 2021 ORDER IN CASE NO. U-21114, 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 THE COMPANY'S

NEXT GENERAL RATE CASE DECISION. IS THE COMPANY REQUESTING IN THIS CASE A CONTINUATION OF THE APPROVALS GRANTED IN CASE NO. U-21114?

A. Yes. As required per the Commission's Order in Case No. U-21114, the Company in its next rate case is either request for continuation of relief granted in Case No. U-21114 or seek recovery of increased expenses associated with the additional inspections and testing requirements of Rule 51. 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 No. U-21114. The Company represents that the currently used testing procedures have proven effective. As such, I am sponsoring a revised Tariff Sheet No. B-2.00 which reflects the continued waiver of Rule 51, R 460.2351.

Tariff Revisions

Q. PLEASE EXPLAIN SCHEDULE F5 OF EXHIBIT A-16.

A. Schedule F5, pages 1-2 summarize the changes being proposed for MGUC's natural gas tariff. Pages 3-41 are redlined versions of the proposed tariff sheets.

Q. WHAT REVISION IS MGUC PROPOSING ON TARIFF SHEET NO. A-4.00?

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. A-16.00?

A. MGUC is adding the definition of Utility stemming from Staff workgroup discussions.

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-7.00 THROUGH C-9.00?

A. MGUC is proposing to add the definition for Electric Power Generation stemming from Staff workgroup discussions and to reletter the remaining definitions.

Q. WHAT REVISIONS ARE MGUC PROPOSING ON TARIFF SHEET NO. C-20.01?

A. Remove C4.6 Choice of Rates as this is duplicative of C5.3(c) Selection of Rate.

Q. WHAT REVISION IS MGUC PROPOSING ON TARIFF SHEET NO. C-22.00?

A. MGUC is updating the references to the Administrative Rules in Customer Responsibilities C5.2 and updating the reconnect fee to $50 as approved in Case No. U-17880, dated December 11, 2015.

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 project areas.

Q. WHAT REVISION IS MGUC PROPOSING ON TARIFF SHEET NO. D-1.01?

A. The Company is updating the 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 2025 through 2029.

Q. WHAT REVISIONS ARE MGUC PROPOSING ON TARIFF SHEET NO. D-6.00 THROUGH D-8.00?

A. The Company has updated its Customer and Distribution charges per its proposed rate design. The Company is proposing to increase the Residential Customer Charge to $14.00 per month, and the Distribution charge to $2.9792 per Mcf and related adjustments to the Low Income Assistance Credit and updated Senior Assistance Credit.

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 $1.9700 per Mcf, Medium General Service, the Company is proposing a Customer Charge of $55.00 per month, a Distribution charge of $1.9155 per Mcf, Large General Service, the Company is proposing a Customer Charge of $430.00 per month, a Distribution charge of $1.3749 per Mcf. In addition, for Small, Medium and Large General Service the Company is proposing a $0.0402 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. The new rate is $1.9700 per Mcf and $0.0402 for Gas Supply Acquisition per Mcf.

Q. WHAT REVISIONS IS MGUC PROPOSING ON TARIFF SHEET NO. E-1.00?

A. MGUC is revising the time requirement related to nomination deadlines.

Q. WHAT REVISIONS IS MGUC PROPOSING ON TARIFF SHEET NO. E-6.00?

A. MGUC is adding the word utilities for clarification.

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 $950, TR-2 $2,450, TR- 3 $3,250. MGUC is also proposing changes to the Peak and Off-Peak rates for each class.

Q. WHAT REVISION IS MGUC PROPOSING ON TARIFF SHEET NO. F-2.00?

A. MGUC is removing the Pricing Pool limit and adding a revision regarding inactive Pools.

Q. WHAT REVISIONS ARE MGUC PROPOSING ON TARIFF SHEET NOS. F-3.00 THROUGH F-5.00?

A. MGUC has added language regarding the Choice Marketer Annual Reconciliation.

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-21366

DIRECT TESTIMONY AND EXHIBITS OF

AARON L. NELSON

FOR

MICHIGAN GAS UTILITIES CORPORATION

March 3, 2023

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-21366
and for other relief.	)	
	)	

QUALIFICATIONS
OF
AARON L. NELSON
PART I

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

A. My name is Aaron L. Nelson. My business address is 231 West Michigan Street, Milwaukee, WI 53203. My position is Senior Project Specialist–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. In 2011, I received a Bachelor of Business Administration degree, with specializations in management and information systems, from the University of Wisconsin–Eau Claire. In 2016, I received a Master's of Science in Management degree, with specialization in financial analysis, from the University of Wisconsin-Milwaukee.

In 2011, I was hired by Wisconsin Electric d/b/a We Energies and worked in several areas prior to my current role. In 2016, I became a Project Specialist in State Regulatory Affairs with WBS and in 2019 I was promoted to Senior Project Specialist in the State Regulatory Affairs Department. My responsibilities include preparation of cost of service studies for all WEC utilities, including MGUC. In addition, I am responsible for electric rate development and service and tariff administration for WEC's electric and steam utilities.

Q. Have you previously testified before any regulatory agency?

A. Yes. I have provided testimony in proceedings concerning natural gas class cost of service before the Michigan Public Service Commission ("MPSC"), the Illinois Commerce Commission, the Minnesota Public Utilities Commission, and the Public Service Commission of Wisconsin ("PSCW"). I have also provided testimony to the PSCW and MPSC relating to electric rate designs and tariff administration.

AARON L. NELSON
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 2024 projected test year. Company Witness Shannon Burzycki's direct testimony relies in part on the results of the class COSS for the 2024 projected test year to develop MGUC's proposed rate design intended to recover the Company's base rate revenue requirement.

Q. Does your direct testimony include more than one COSS model?

A. Yes, my direct testimony and exhibits reflect two COSS models that are nearly identical but for changes to the Company's 2024 future test year driven solely by the depreciation rates utilized to derive the two revenue requirements.

Q. Which data is utilized in the Company's Base Case COSS model?

A. The Company's Base Case COSS model reflects the revenue requirement as calculated using MGUC's currently authorized depreciation rates.

Q. Please explain the Company's Alternative COSS model.

A. The only difference between MGUC's Base Case class COSS and Alternate COSS is that the Alternate COSS utilizes the revenue requirement derived from the updated depreciation rates and accounting practices, including the prescribed plant transfers, for which the Company is currently seeking approval in Case No. U-21329. This results in an approximate increase in the annual revenue requirement of $0.6 million, as noted by Company witness Anthony Reese.

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 (Base Case)
A-16	F1.2	Cost of service summary by customer class at present rates (Base Case)
A-16	F1.3	Unbundled revenue requirement by customer class (Base Case)
A-16	F1.4	Unbundled rate base by customer class (Base Case)
A-16	F1.5	Unbundled unit cost by customer class (Base Case)
A-16	F1.6	Cost of service summary by rate class at present rates (Alternate)
A-16	F1.7	Cost of service summary by customer class at present rates (Alternate)
A-16	F1.8	Unbundled revenue requirement by customer class (Alternate)
A-16	F1.9	Unbundled rate base by customer class (Alternate)
A-16	F1.10	Unbundled unit cost by customer class (Alternate)

These exhibits present the 2024 projected class COSS prepared for MGUC. The accompanying work paper (Work paper ALN-1) includes associated allocation methodologies, supplemental analyses, and data. MGUC is also providing a working

Excel class COSS model with live formulae, consistent with the terms of the Settlement Agreement and Order in Case No. U-20718. Work paper ALN-2 is MGUC's Base Case COSS and work paper ALN-3 is MGUC's Alternate 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, 2024 indicates a need for an annual revenue increase of $18.5 million, or 8.8%[1]; however, this increase does not include the effects of the requested depreciation rate change, which is currently pending in Case No. U-21329, as filed on December 20, 2022. MGUC's Base Case class COSS for the 2024 projected test year is based on and uses the components from this analysis;

2. As explained by Company Witness Reese in his direct testimony, MGUC's analysis of the test year ending December 31, 2024 indicates a need for an additional annual increase of $0.6 million in revenues from retail gas operations, including effects of the requested depreciation rate change, which is currently pending in Case No. U-21329. MGUC's Alternate class COSS for the 2024

[1] Including the additional revenue requirement related to proposed depreciation rates, MGUC's requested increase is $19.1 million or 9.1%.

projected test year is the same as the Base Case COSS model except for the additional noted effects from the deprecation rate change; and

3. The customer class revenue requirements as determined by Exhibit A-16, Schedules F1.2 and F1.7, reasonably apportion 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 Base Case 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-20718, ("2022 Rate Case"). Table 2 summarizes the results of MGUC's Alternate class COSS with respect to the revenue deficiency at present rates by customer class, including the effects of the requested depreciation rate change, which is currently pending in Case No. U-21329.

Table 1
Michigan Gas Utilities Corporation
Base Case COSS Class Revenue Deficiency at Present Rates

Line No.	Line Description	Present Revenue $	Revenue Deficiency $	Revenue Deficiency %	Revenue Requirement $
1	Retail Sales and Transportation				
2	General Service-Residential	135,895,835	14,993,334	11.0%	150,889,169
3	Customer Choice-Residential	5,965,300	1,697,787	28.5%	7,663,087
4	Agg Transport-Residential	9,169	11,824	128.9%	20,993
5	General Service-Small	51,034,504	(728,139)	-1.4%	50,306,365
6	Customer Choice-GS-Small	2,357,385	(884)	0.0%	2,356,501
7	Agg Transport-GS-Small	886,544	261,140	29.5%	1,147,683
8	Transport-TR-1	2,554,487	(182,841)	-7.2%	2,371,646
9	Agg Transport-GS-Medium	169,230	(31,913)	-18.9%	137,317
10	Customer Choice-GS-Medium	0		0.0%	0
11	General Service-Medium	12,053	(1,893)	-15.7%	10,160
12	General Service-Large	6,624,094	(72,641)	-1.1%	6,551,453
13	Transport-TR-2	3,503,546	1,686,905	48.1%	5,190,452
14	Customer Choice-GS-Large	45,770	3,317	7.2%	49,086
15	Agg Transport-GS-Large	54,682	(1,878)	-3.4%	52,803
16	Transport-TR-3	1,229,050	911,656	74.2%	2,140,706
17	Special Contract	99,088	(70,826)	-71.5%	28,263
18	Total Jurisdiction	**210,440,736**	**18,474,947**	**8.8%**	**228,915,683**

Table 2
Michigan Gas Utilities Corporation
Alternate COSS Class Revenue Deficiency at Present Rates

Line No.	Line Description	Present Revenue $	Revenue Deficiency $	Revenue Deficiency %	Revenue Requirement $
1	Retail Sales and Transportation				
2	General Service-Residential	135,895,835	15,980,178	11.8%	151,876,014
3	Customer Choice-Residential	5,965,300	1,806,617	30.3%	7,771,917
4	Agg Transport-Residential	9,169	11,964	130.5%	21,133
5	General Service-Small	51,034,504	(698,484)	-1.4%	50,336,020
6	Customer Choice-GS-Small	2,357,385	5,669	0.2%	2,363,054
7	Agg Transport-GS-Small	886,544	261,367	29.5%	1,147,910
8	Transport-TR-1	2,554,487	(249,878)	-9.8%	2,304,609
9	Agg Transport-GS-Medium	169,230	(33,822)	-20.0%	135,408
10	Customer Choice-GS-Medium	0		0.0%	0
11	General Service-Medium	12,053	(1,802)	-14.9%	10,251
12	General Service-Large	6,624,094	(73,068)	-1.1%	6,551,025
13	Transport-TR-2	3,503,546	1,415,174	40.4%	4,918,721
14	Customer Choice-GS-Large	45,770	3,302	7.2%	49,072
15	Agg Transport-GS-Large	54,682	(1,994)	-3.6%	52,687
16	Transport-TR-3	1,229,050	762,982	62.1%	1,992,032
17	Special Contract	99,088	(73,844)	-74.5%	25,245
18	Total Jurisdiction	**210,440,736**	**19,114,361**	**9.1%**	**229,555,097**

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 2024 natural gas class COSS. Second, I will describe the new 2024 test year class COSS allocation methodology changes from those used in Case No. U-20718. Third, I will provide an overview of the allocation methods used in MGUC's 2024 test year class COSS. Finally, I will describe and summarize the results of MGUC's 2024 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 most important theoretical principle underlying a class COSS is that cost incurrence should follow historical embedded cost causation. The costs that customers become responsible to pay should be those costs that the particular customers caused 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 by 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. In 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[2] and rate base contained in the instant filing as shown in Company Witness Reese's Exhibits A-11 through A-14 for the 2024 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 work paper ALN-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 2022 Rate Case?

A. Yes, the General Service-Medium, Customer Choice-Medium General Service, and Aggregated Transportation-Medium General Service customer classes have been included in the COSS model prepared for the 2024 test year consistent with the terms of the Settlement Agreement and Order in Case No. U-20718.

[2] The only difference between the Company's Base Case COSS and Alternate COSS is the effects of the requested depreciation rate change, which is currently pending in Case No. U-21329. This adds approximately $0.6 million to the revenue requirement for the projected test year, as noted by Company witness Mr. Reese.

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 (New Class Established in Case U-20718)
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 (New Class Established in Case U-20718)
11. Customer Choice–Large General Service,
12. Aggregated Transportation–Residential,
13. Aggregated Transportation–Small General Service,
14. Aggregated Transportation–Medium General Service (New Class Established in Case U-20718),
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 two versions of MGUC's natural gas class COSS. Schedules F1.1 through F1.5 present MGUC's Base Case class COSS with the allocation methods used in the 2022 Rate Case. Support for these schedules is provided in work paper ALN-1. Work paper ALN-2 contains the working Excel model for MGUC's Base Case COSS. Schedules F1.6 through F1.10 present MGUC's Alternate class COSS[3] with the allocation methods used in the 2022 Rate Case. Work paper ALN-3 contains the working Excel model for MGUC's Alternate COSS.

Q. Has the Company made any changes to the class COSS model that was used in the 2022 Rate Case?

A. Generally, no. The model we use for performing class cost of service studies is the same as the model used in MGUC's 2022 Rate Case. The Excel model that was used in MGUC's 2016 Rate Case was integrated onto the software platform, Utilities International Planner ("UIPlanner"). As I noted earlier in my direct testimony, I am providing a working Excel model which mirrors the COSS model compiled in UIPlanner consistent with the settlement provisions approved by the Commission in Case No. U-20718 – MGUC's 2022 Rate Case.

Q. Is the Company proposing any changes to the class allocation methodologies from those used for cost of service in the 2022 Rate Case?

A. Generally, no, but class COSS allocation methodologies are periodically reviewed and updated for reasons discussed previously. It is worth noting that the existing

[3] The only difference between the Company's Base COSS and Alternate COSS is the effects of the requested depreciation rate change, which is currently pending in Case No. U-21329. This adds approximately $0.6 million to the revenue requirement for the projected test yeas, as noted by Company witness Mr. Reese.

class allocation methodologies in MGUC's COSS model provided in this case have been modified to account for the three new Medium classes as agreed to in the Company's 2022 Rate Case, as previously discussed in my direct testimony.

Q. Please summarize the primary cost of service class allocation methodology changes that you are proposing in this case.

A. The primary cost of service class allocation methodology change that I am proposing, and that is included in Exhibit A-16, Schedules F1.1 to F1.10, is the allocation of transmission costs as 100% demand related then allocating those balances to customer classes using average and peak demand, rather than using the zero-intercept regression analysis that was created for MGUC's 2016 test year and subsequently carried forward to the 2022 Rate Case. This revised method of allocating transmission costs is consistent with cost causation principals and is consistent with how other large Michigan jurisdictional natural gas utilities allocate transmission costs. This proposed change is being made to further align cost allocation with cost causation.

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 2022 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 2022 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. MGUC's historical practice was to allocate the transmission investment in Plant Account 367 and related operation and maintenance expenses in Accounts 856 and 863 between the customer- and demand-related classification using a regression analysis of the cost and size of transmission main in service at MGUC. In this 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 to allocate Plant Account 367. Transmission costs were then allocated to customer classes based upon average and peak demand. The results of this updated analysis are generally consistent with the results of the regression analysis derived from Case No. U-17880, which resulted in an allocation between the customer- and demand-related classification of 60.4% and 39.6%, respectively. This method was utilized in Case No. U-20718, as well.

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 were 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 results of the zero-intercept regression analysis are similar to that last completed in Case No. U-17880 and subsequently carried forward and used in Case No. U-20718. 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 51.5% of distribution main costs as customer related and 48.5% as demand related. By comparison, the results of the minimum size study indicate approximately 62.4% of distribution main costs should be assigned as customer related and 37.6% as demand related, which supports that MGUC's zero-intercept results are reasonable. Furthermore, the result of the zero-intercept regression is consistent with the results of the regression analysis from Case No. U-17880, MGUC's 2016 test year rate case. That zero-intercept regression model assigned 54.3% of distribution main costs as customer related and 45.7% as demand related.

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 more gas demanded by a customer or group of customers, the larger and more costly the service lateral will be. 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'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 Rate Case?

A. Yes, as explained in that case, 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. Our metering department supplied estimates of the unit costs for industrial-sized meters. We 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. We 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 2022 Rate Case, 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) is classified as 100% demand-related and is allocated to customer classes based upon group peak demand, which was the allocation factor employed in the 2022 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 the 2022 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 the 2022 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 2022 Rate Case.

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 2022 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 2022 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 2022 Rate Case.

Q. How are accumulated deferred income taxes allocated to customer classes?

A. Our tax department functionalizes these items as production, storage, transmission, distribution, or general costs. Each of the functionalized components were allocated to customer classes based upon the allocated results of their respective gross plant value.

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. The 2023 revenue requirement deferral resulting from capital investments made by MGUC include 2021 interest and depreciation expense associated with capital investments made in 2021 and previous years as noted by Company Witness Reese. The amortization of this balance was allocated to customer classes based upon the allocated results of rate base.

<u>Natural Gas Class COSS for the 2024 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 2024 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 2024 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 2024 projected test year Base Case class COSS. Each of the class revenue requirements are 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 2024 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 2024 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. Please describe Exhibits A-16, Schedules F1.6 to F1.10.

A. Schedules F1.6 to F1.10 present the same information as schedules F1.1 to F1.5 but utilizing the Company's Alternate COSS. The only difference between the Company's Base Case COSS and Alternate COSS is that the Alternate COSS includes the effects of the requested depreciation rate change, which is currently pending in Case No. U-21329, which increases the annual revenue requirement for the 2024 projected test year by approximately $0.6 million, as noted by Company Witness Reese.

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-21366

DIRECT TESTIMONY AND EXHIBITS OF

JARED J. PECCARELLI

FOR

MICHIGAN GAS UTILITIES CORPORATION

March 3, 2023

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-21366

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 before the Michigan Public Service Commission ("MPSC" or the "Commission") in Case No. U-20818. 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 2024 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 2024 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 five 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 July 2022. 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 2, 2022, with an average price of $4.61/dth for 2024.

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

[1] The historical time period of January 2014 through July 2022 was used for the Residential customer count model and the SGS use per customer and customer count models. The Residential use per customer model used monthly data from January 2016 through July 2022. The starting month for the Residential use per customer model was changed to remove 2014 and 2015 from the time series due to the extreme weather in both years (e.g., the year 2014 was more than 15% colder than normal and December 2015 was more than 20% warmer than normal). The elimination of these 2 years resulted in more reasonable model estimates.

from the number of customers model to forecast total sales volumes for each class. 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 MGS Class. At the time of forecast, MGUC did not have a full year of history, so April through October use per customer was annualized to create a yearly use per customer. The MGS customer forecast assumed a growth of 5 customers per year, resulting in the Test Year forecasted to have 15 customers. The yearly estimates for the average use per customer were then multiplied by the yearly estimates for customer counts to forecast total yearly sales volumes. These annual totals were then multiplied by a monthly usage curve to give the model its shape.

The third method was used for the LGS class. The LGS customers were forecasted individually based on a rolling 12-month sum of billed sales through October 2022.

The fourth and fifth methods were used for the Commercial Transportation and Transportation Aggregation customers, respectively. The Commercial Transportation customers were forecasted individually based on a rolling 12-month sum of billed sales through October 2022. The Transportation Aggregation customers were individually forecasted based on customer-specific information provided by each customer's assigned account manager.

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 2024 projected Test Year, the annual total of 6,201 heating degree days was based on the 16-year period of 2006 through 2021 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 2024 Test Year forecast of retail and transportation deliveries?

A. The 2024 Test Year forecast of retail and transportation deliveries, excluding company use and losses, is 34,688 MMcf as presented in Exhibit A-15, Schedule E1. System Output in the Test Year is projected to be 34,751 MMcf.

Q. How does the 2024 Test Year forecast compare to 2022 weather-normalized deliveries?

A. The 2024 Test Year forecast of total deliveries is 1.2% lower than 2022 weather-normalized deliveries. The 2024 Test Year forecast of Residential deliveries is 0.7% lower than 2022 weather-normalized deliveries. Residential deliveries include GCR and GCC customers. The 2024 Test Year forecast of Commercial deliveries is 1.1% lower than 2022 weather-normalized deliveries. Commercial deliveries include SGS GCR, SGS GCC, MGS GCR, MGS GCC and Commercial Lighting customers. The 2024 Test Year forecast of Industrial deliveries is 1.8% lower than 2022 weather-normalized deliveries. Industrial deliveries include LGS GCR, LGS GCC, Special Contract, and End-Use Transportation customers.

Q. Why are the 2024 Test Year forecasts of Residential and Commercial deliveries lower than 2022 weather-normalized deliveries?

A. The 2024 Test Year forecasts of Residential and Commercial deliveries are lower than 2022 weather-normalized deliveries because the average use per customer forecasts for the 2024 Test Year are lower than the 2022 weather-normalized average use per customer. The primary driver of the lower use per customer forecast is energy efficiency. The average use per customer regression models used to forecast the 2024 Test Year sales for Residential and SGS 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 2024 Test Year forecast compare to the 2022 Test Year forecast from the Final Order of Case No. U-20178?

A. The 2024 Test Year forecast of total deliveries is 1.1% lower than the 2022 Test Year forecast used to determine rates approved in Case No. U-20718. The 2024 Test Year forecast of Residential deliveries is 1.2% lower than the 2022 Test Year forecast. The 2024 Test Year forecast of Commercial deliveries is 2.5% higher than the 2022 Test Year forecast. The 2024 Test Year forecast of Industrial deliveries is 2.7% lower than the 2022 Test Year forecast.

Q. What is the impact on the 2024 Test Year revenue deficiency associated with the change in sales between the 2024 Test Year and the 2022 Historic Year from the Final Order of Case No. U-20178?

A. The reduction in total sales of 1.1% noted above results in a small increase in the revenue deficiency. However, the additional revenue from higher customer (fixed) charge revenues due to the growth in customers and MGUC's proposed slight increase in the customer charge as discussed in Company Witness Burzycki's direct testimony, primarily in the residential and small general service rate schedules, results in an immaterial decrease in the revenue deficiency, holding all else constant.

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 and for other relief.	)))))	Case No. U-21366

DIRECT TESTIMONY OF

NATHAN W. LEE

FOR

MICHIGAN GAS UTILITIES CORPORATION

March 3, 2023

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-21366

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 pre-filed direct testimony is to provide an explanation of and support for the need and customer benefits realized of the significant capital investments that have been placed in service since MGUC's last rate case, which was filed with a 2022 test year, or are forecast to be placed in service during the 2024 test year.

I will provide an update of the projects, including project costs for which MGUC received approval in Case U-20718 to implement a Main Replacement Program ("MRP") surcharge. These projects are projected to go in service for the years 2025 through 2027, which are all after the current test year.

Q. Are you sponsoring any exhibits in this proceeding?

A. No, I am not.

<u>Overview Of Significant Capital Investment Since Last Rate Case</u>

Q. What is MGUC's capital spending plan in this rate case?

A. MGUC's 2024 revenue deficiency is mainly driven by its capital spending plan. Since its last rate case, MGUC has placed or expects to place $120.1 million of capital in service. MGUC's investment in the utility 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 and spend on integrity transmission projects.

In 2023, in order to standardize processes and tools, MGUC will be implementing CGI PragmaCAD, WEC's workforce management system.

In 2023 MGUC capital spending on distribution system improvements amounts to $25.2 million, which includes system integrity, replacement of mains and services, road projects, line hits, and stations work and meters. MGUC plans to spend $4.1 million related to system growth projects and is forecasting $2.0 million to be spent on the South Grand Haven Station, with an additional $7.0 million being invested to construct an additional compressor unit at the Partello Storage Field.

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 2022 or will be placed in service during 2023 or the 2024 test year.

<u>PRAGMA CAD Mobile Workforce Management</u>

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.

[1] PCAD is the product name for an electronic dispatch suite of software.

Q. When does MGUC plan to have PCAD implemented?

A. MGUC plans to deploy PCAD in two phases in 2023 with initial roll out at the end of March 2023 and additional enhancements scheduled for August 2023. The enhancements to be implemented in August will allow for additional electronic data entry during field site visits.

Q. What is the cost of the PCAD project in this case?

A. Through 2023, the forecasted capital costs related to the PCAD project for MGUC are approximately $2.8 million.

Q. Why is PCAD being implemented in place of the current dispatch system?

A. The current dispatch software in use, G4/MobileField, is 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 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 allow 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 would also likely 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 discarded 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.

DTE Interconnection Project

Q. What is the DTE Interconnection project?

A. The DTE Interconnection project, consisting of a new regulator station, referred to as the Scofield Carlton Station, and 1,200 ft of 12" steel gas main, is a planned interconnection between DTE Gas Company ("DTEG") and MGUC located in Ash Township. By interconnecting with DTEG, MGUC will secure an additional source of gas in that part of MGUC's service territory. This additional source would be an alternative to the currently available Panhandle Eastern Pipeline ("PEPL") supply.

Consistent with the Settlement Agreement MGUC reached with the Michigan Public Service Commission Staff and the Michigan Attorney General in Case U-20546 and approved by the Commission on May 26, 2022, the DTE Interconnection project was investigated and identified as a potential long term solution to extreme price risk during colder than normal weather conditions for a portion of MGUC's service territory. As described in detail in Case No. U-20546, the Monroe area of MGUC's territory currently depends upon natural gas supply from the PEPL to service a significant portion of demand during colder than normal weather conditions. This dependency subjected the area to extreme price risk during a period in February 2021 when colder than normal weather across the country caused extreme conditions in the southern United States, which is also served by the PEPL. This project would add an additional source of supply for the Monroe area of MGUC's service territory by construction of an interconnecting station with DTEG to supply gas to MGUC's existing 360 psi high pressure distribution pipeline.

Q. When does MGUC plan to have the DTE Interconnection implemented?

A. While project planning with DTEG is not yet complete, the expected in-service date is December 1, 2023.

Q. What is the cost of the DTE Interconnection project in this case?

A. The cost of the DTE Interconnection project is currently estimated at approximately $4.6 million, which includes both the interconnection with DTEG as well as the construction of the new Scofield-Carlton Station and extension of approximately 1,200 ft of 360 psi steel pipeline.

Q. What benefits does the DTE interconnection project provide?

A. There are two significant benefits to MGUC's customers from this project. First it provides an additional source of natural gas supply, which will reduce price risk while increasing reliability for customers. Second, this project will allow MGUC to secure not only firm delivery capacity but also natural gas commodity from additional sources, which will increase competition and, all other things equal, result in lower gas costs that would be incurred absent this project.

MGUC expects an annual winter heating season savings on capacity costs of approximately $670,000, based on a reduction in PEPL winter capacity of 15,500 DTH. We also anticipate commodity savings on replacing a portion of PEPL supply priced at PEPL TX-OK with DTE supply priced at Michcon. For Winter '22-'23, Michcon has been trading at a discount to PEPL TX-OK on average of $0.36/Dth. In addition to this, we are reducing PEPL supply that historically experienced higher price spikes. The most recent occurring in February 2021, PEPL TX-OK spiked to $224.56/Dth for four days where Michcon rose to $6.375/Dth during these days. If MGU would have had access to this DTE supply instead of PEPL in February 2021 we would have saved over $5.7 million over the course of only five days.

<u>Partello Compressor Unit Replacement</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 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 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>Partello Wells</u>

Q. Please describe the Partello Wells Planning project.

A. The Partello Wells Planning project will upgrade and make improvements to wells and the reservoir to comply with the Storage Integrity Management Program ("SIMP") and Standard API 1171. This includes the removal of sub-surface safety valves and replacement with new surface safety valves, improvements to wellhead equipment and telemetry, and establishment of logging program to evaluate integrity of the wells mandated by PHSMA. These improvements will minimize risk when performing well work and logging operations and eliminate the need for well kill and wireline equipment for maintenance, which carries a high level of risk.

Q. Please discuss the cost of the Partello Wells Planning project.

A. The cost for this project was $1.2 million.

Q. Is this project currently in service?

A. Yes, this project was placed in service in 2022.

Q. Please describe how this project benefits MGUC's customers.

A. The gas storage at Partello allows MGUC to purchase gas in the summer when prices are low, place it in storage, and then withdraw gas in the winter when gas purchases off of the pipelines are more expensive. These cost savings benefit MGUC customers directly through lower gas costs and winter supply stability/reliability. The Partello Wells Planning project allows MGUC to maintain the wells and reservoir for reliability and ensures operational longevity of the storage field. The project also improves safety and reduces 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 from 2021-2022 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. Under TIMP this includes gate station rebuilds to update telemetry, regulation, heaters, odorization, filters, and station protection and to increase system capacity. This also included replacing higher risk transmission lines in High Consequence Areas.

Under DIMP this includes regulator structure replacements, replacing main with shorted casings, replacing exposed mains, eliminating Master Meter Systems and extending main and adding valves to systems to increase reliability and safety.

These projects were not placed in service during 2022 and, therefore, were not included in rate base for the 2022 test year for MGUC's last rate case (Case No. U-20718). I will describe these projects, their capital costs, actual or forecasted in-service dates, and expected customer benefits in more detail below.

Q. You listed replacement of transmission lines in High Consequence Areas (HCA) as a result of TIMP, what is the benefit of replacing these lines?

A. The 2019 "Mega" Rule (84 FR 52180) issued by the federal Pipeline and Hazardous Materials Safety Administration (PHMSA) requires that integrity assessments, material verification, and MAOP (maximum allowable operating pressure) reconfirmation be performed on pipelines in areas that meet the definitions of High Consequence Areas, Medium Consequence Areas, and Class 3 locations, as defined in 49 CFR Part 192. Each of those terms are only applicable to transmission mains and are therefore of higher risk (higher probability of failure) due to operating at a higher percentage of specified minimum yield strength (>20%). In addition, each of these terms applies to areas with a higher population density, which further increases the risk (higher consequence of failure). The required assessments include inspections for internal corrosion. Many of the existing pipelines, including the Partello line which will be described further below, do not provide the ability to inspect for internal corrosion as required. When MGUC replaces these pipeline segments, the Company installs higher grade and thicker steel which lowers the probability of failure and often relocates the pipeline segment away from densely populated areas, which lowers the consequence of a potential pipeline failure. The new transmission lines are built to accommodate the passage of internal inspection devices referred to as magnetic flux leakage pigs (MFL) that inspect for internal and external corrosion or other physical damage that could lead to rupture. Lastly, additional periodic surveys and assessments are required on certain mains located in HCAs, MCAs, or Class 3 locations. These assessments are costly and often require excavation, large equipment, traffic lane closures, and other items that are a general nuisance to the public. In addition to improving safety, projects that improve or relocate pipeline segments to avoid HCAs, MCAs, or Class 3 locations also reduce ongoing maintenance costs associated with the increased surveys and assessments that would otherwise be required.

Q. Please describe the benefit related to lower operating percent of specified minimum yield strength and how that is a benefit to MGUC's customers.

A. "SMYS" stands for Specified Minimum Yield Strength and it refers to the strength of the steel used to make the pipe. In general, greater safety risk is associated with a pipeline operating at a higher percentage of SMYS. In addition, pipelines operating above 20% of SMYS are considered “transmission pipelines” and have an increased risk of rupturing instead of leaking. Therefore operating a pipeline at a lower percentage of SMYS will be safer for MGUC customers.

Q. Please describe the Partello Transmission Pipeline (“PTP”) Replacement Project.

A. This project replaced approximately 15 miles of existing 8” steel transmission main installed in 1960 with 10” steel line. The replacement PTP begins at the Partello Compressor facility in the northeast ¼ of Section 13, Town 1 South, Range 5 West, Lee Township, Calhoun County and extending in a southwestern direction to a point of interconnection at the Marshall Station in the northeast ¼ of Section 1, Town 3 South, Range 6 West, City of Marshall, Calhoun County, Michigan. The construction of the PTP was critical to continue to provide safe, reliable, cost efficient natural gas to MGUC customers while complying with the TIMP, and was certificated in Case No. U-20853.

Q. Please discuss the estimated cost of the Partello Transmission Pipeline Replacement Project.

A. The total cost of this project is approximately $19.6 million.

Q. Is this project currently in service?

A. Yes, this project was placed in service in March 2023.

Q. Please describe how this project benefits MGUC's customers.

A. The primary benefits for MGUC's customers include reduced safety concerns by replacing the highest operating stress pipe in the MGUC transmission system with a new pipe designed to operate at a lower percent SMYS. The new line operating at 28.3% SMYS versus the old line at 49.9% SMYS reduces the risk of rupture and increases reliability. The new line is built to accommodate passage of an MFL tool to verify the integrity of the pipeline as required by TIMP rules should any segment of the line become an HCA. Capacity from the storage field to the distribution system is also increased approximately 50% with the increase in pipe size.

Q. Please describe the County Line Road Station Project.

A. This project consists of installing a station to lower downstream pressure on 2.25 miles of 12" transmission main to a lower operating percent SMYS, eliminate High Consequence, Moderate Consequence, and Class 3 locations, and decrease operational risk.

Q. Please discuss the estimated cost of the County Line Road Station Project.

A. The total projected cost of this project is approximately $0.9 million.

Q. Is this project currently in service?

A. No, this project is expected to be in service in October of 2023.

Q. Please describe how this project benefits MGUC's customers.

A. As noted above, the primary benefits that will be realized by MGUC's customers include lowering the operating percent SMYS for that portion of MGUC's system, eliminating High Consequence, Moderate Consequence, and Class 3 locations, decreasing operational risk, and eliminating intrusive on-site TIMP assessments.

Q. Please describe the South Grand Haven Station Project.

A. The Grand Haven Project will relocate 1/2 mile of 8" transmission line to lower operating percent SMYS, eliminate a Moderate Consequence location and a Class 3 location, and odorize a currently unodorized line.

Q. Please discuss the estimated cost of the South Grand Haven Station Project.

A. The total projected cost of this project is approximately $2.0 million.

Q. Is this project currently in service?

A. No, this project is expected to be in service in October of 2023.

Q. Please describe how this project benefits MGUC's customers.

A. As noted above, the primary benefits that will be realized by MGUC's customers include lowering the operating percent SMYS for that portion of MGUC's system, eliminating a Moderate Consequence and a Class 3 location, and odorizing a currently unodorized section of main. In addition, this project will satisfy the requirements required under Compliance Action CA-00007005-01 issued on December 22, 2022.

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 3 projects that would be funded by the MRP rider charge that was approved in Case U-20718. These projects are included in the table below.

Project Name	Estimated Capital Costs	In Service Year(s)
Allegan Transmission Relocation	$ 6,075,000	2024
Coldwater-Marshall Pipeline	$ 40,400,000	2024 – 2026
Otsego Paper Service Line	$ 625,000	2027

Q. Can you provide a brief description of each of these projects and a brief description of the benefits for each, please?

A. Certainly. The Allegan Transmission Relocation project will involve relocating 2 miles of 8" transmission line. The impact of this project will be lowering operating percent Specified Minimum Yield Strength (“SMYS”), relocate to a less inhabited area, as well as eliminate High Consequence, Moderate Consequence, and Class 3 locations.

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), which is further explained later in my testimony.

Q. Have there been any changes to these projects since MGUC’s last rate case when the MRP rider was initially authorized?

A. Yes. There have been changes to the Allegan Transmission Relocation Project and the Coldwater-Marshall Pipeline Replacement project.

Q. Please describe the changes to the Allegan Transmission Relocation Project.

A. There are two aspects of this project that have changed. First the expected in service date has changed. During Case U-20718 MGUC had estimated the project would be in service in 2023; however, that project is now expected to be placed in-service in December of 2024. Additionally, as MGUC progresses through the planning and design process for this project, the expected capital costs have increased as well – from $2.2 million to approximately $ 6.0 million.

Q. Why have the cost estimates for the Allegan Transmission Relocation Project increased so much?

A. The costs of nearly every element of this and similar projects have increased substantially in the past 3 years. As noted in the direct testimony of Company Witness Richard Stasik, the rate of inflation is at nearly historic highs. Furthermore, many of the components for gas mains are steel and the costs of steel and products made from steel have risen at a rate that is several times higher than general inflation. Additionally, while the worst of the supply chain challenges currently appear to have passed, sourcing these materials continues to be very challenging, with vendors in many cases requiring significantly longer lead times for product orders.

The initial project estimates from U-20718 were based on estimating practices in place at the time, which relied upon projects most recently completed at that time, which for these projects was data from 2018 and prior in-service projects. In addition only preliminary routes and design criteria were known at the time of estimating. As projects work through the planning lifecycle, the estimating process is refined. Since those preliminary estimates were created, more refined routes were identified, specific pipe size and specifications have been selected, and data was gathered on current steel pipe and fitting costs as well as construction costs.

Further, the original estimates did not include any projected costs for the potential of encountering unexpected environmental conditions, spikes in steel commodity prices or other unforeseeable cost impacts. The current estimates include a contingency for these factors.

Q. Please describe the changes to the Coldwater-Marshall Pipeline Replacement Project.

A. Similar to the Allegan Transmission project, as MGUC has progressed through the planning and design process for this project, the expected capital costs have increased from $26.7 million to approximately $40.4 million.

Q. Why have the cost estimates for the Coldwater-Marshall Pipeline Replacement Project increased so much?

A. Similar to the Allegan Transmission Project, the cost of nearly every element of this and similar projects has increase substantially. As with the Allegan project the initial project estimates from U-20718 were based on estimating practices in place at the time, which relied upon projects most recently completed at that time, which for these projects was data from 2018 and prior in-service projects. As the project worked through the planning lifecycle, the estimating process was refined. Since that preliminary estimate was created, more data was gathered on easement costs, material costs and construction contractor costs.

Capital Cost Budget						
Year	**2022**	**2023**	**2024**	**2025**	**2026**	**Total**
Materials	$ -	$ -	$ 3,275,000.00	$ 2,500,000.00	$ 2,627,000.00	$ 8,402,000.00
Outside Professional Services	$ 407,000.00	$ 964,000.00	$ 7,945,000.00	$ 5,875,000.00	$ 6,391,000.00	$ 21,582,000.00
Labor and Overheads	$ 93,000.00	$ 335,000.00	$ 335,000.00	$ 335,000.00	$ 335,000.00	$ 1,433,000.00
Easements	$ -	$ 600,000.00	$ 1,500,000.00	$ 1,500,000.00	$ 150,000.00	$ 3,750,000.00
Contingency	$ 100,000.00	$ 701,000.00	$ 1,145,000.00	$ 890,000.00	$ 2,397,000.00	$ 5,233,000.00
Total	$ 600,000.00	$ 2,600,000.00	$ 14,200,000.00	$ 11,100,000.00	$ 11,900,000.00	$ 40,400,000.00

The Partello line, which was competitively bid and constructed this year, also provided current data on actual costs which support MGUC's revised estimate.

While the worst of the supply chain challenges currently appear to have passed, sourcing these materials continues to be very challenging, with vendors in many cases requiring significantly longer lead times for product orders.

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-21366

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-21366 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-21366." 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-21366." 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 and only remains available to the Receiving Party until the time expires for petitions for rehearing of a final MPSC order in this Case No. U-21366 or until the MPSC has ruled on all petitions for rehearing in this case (if any). However, 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 certify in writing to the Disclosing Party that the Protected Material has been destroyed.

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-21366, 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	)	Case No. U-21366
gas and for other relief.	)	
______________________________________	)	

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-21366, 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 Docket No. U-21366

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name) Michigan Gas Utilities Corporation
2. (Name)
3. (Name)
4. (Name)
5. (Name)
6. (Name)
7. (Name)

Name Sherri A. Wellman

Address Miller Canfield

120 N. Washington Sq., Suite 900

City Lansing State MI

Zip 48933 Phone 517-483-4954

Email wellmans@millercanfield.com

Date 03/03/2023

Signature: Sherri Wellman

Digitally signed by: Sherri Wellman
DN: CN = Sherri Wellman email = wellmans@millercanfield.com C = AD O = Miller Canfield
Date: 2023.03.03 13:54:03 -05'00'

○ I am not an attorney

◉ I am an attorney whose:

Michigan Bar # is P-38919

__________ Bar # is: __________
(state)

MICHIGAN DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS
PUBLIC SERVICE COMMISSION

ENTRY OF APPEARANCE IN AN ADMINISTRATIVE HEARING

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THIS APPEARANCE TO BE ENTERED IN ASSOCIATION WITH THE ADMINISTRATIVE HEARING:

Case / Company Name: Michigan Gas Utilities Corporation Docket No. U-21366

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name) Michigan Gas Utilities Corporation
2. (Name)
3. (Name)
4. (Name)
5. (Name)
6. (Name)
7. (Name)

Name Paul M. Collins

Address Miller Canfield

120 N. Washington Sq., Suite 900

City Lansing State MI

Zip 48933 Phone 517-483-4908

Email collinsp@millercanfield.com

Date 03/03/2023

Signature: Paul Collins

Digitally signed by: Paul Collins
DN: CN = Paul Collins email = collinsp@millercanfield.com C = AD O = Miller Canfield
Date: 2023.03.03 13:54:45 -05'00'

○ I am not an attorney

◉ I am an attorney whose:

Michigan Bar # is P-69719

__________ Bar # is: __________
(state)

MICHIGAN DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS
PUBLIC SERVICE COMMISSION

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THIS APPEARANCE TO BE ENTERED IN ASSOCIATION WITH THE ADMINISTRATIVE HEARING:

Case / Company Name: Michigan Gas Utilities Corporation Docket No. U-21366

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name) Michigan Gas Utilities Corporation
2. (Name)
3. (Name)
4. (Name)
5. (Name)
6. (Name)
7. (Name)

Name Benjamin J. Holwerda
Address Miller Canfield
120 N. Washington Sq., Suite 900
City Lansing State MI
Zip 48933 Phone 517-483-4949
Email holwerda@millercanfield.com
Date 03/03/2023

○ I am not an attorney
◉ I am an attorney whose:
Michigan Bar # is P-82110
______ Bar # is: ______
(state)

Signature: Benjamin J. Holwerda Digitally signed by: Benjamin J. Holwerda DN: CN = Benjamin J. Holwerda email = holwerda@millercanfield.com C = US O = Miller Canfield OU = Attorney at Law Date: 2023.03.03 13:55:19 -05'00'

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of	)	
MICHIGAN GAS UTILITIES CORPORATION	)	Case No. U-21366
for authority to increase retail natural gas rates	)	
and for other relief.	)	

PROOF OF SERVICE

STATE OF MICHIGAN	)
	) ss
COUNTY OF INGHAM	)

Elizabeth H. Kunc, being first duly sworn, deposes and states that on March 3, 2023, 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
Lori Mayabb	MayabbL@michigan.gov

Elizabeth H. Kunc
Digitally signed by: Elizabeth H. Kunc
DN: CN = Elizabeth H. Kunc email = kunc@millercanfield.com C = AD O = Miller Canfield OU = Legal Secretary
Date: 2023.03.03 13:55:38 -05'00'

Elizabeth H. Kunc

Subscribed and sworn to before me
on this 3rd day of March, 2023.

Kacey O'Neill
Digitally signed by: Kacey O'Neill
DN: CN = Kacey O'Neill email = oneill@millercanfield.com C = AD
Date: 2023.03.03 13:55:46 -05'00'

Kacey O'Neill, Notary Public
State of Michigan, County of Livingston
My Commission Expires: 12/26/2026
Acting in the County of Ingham

40301844.1/131120.00108