Direct Testimony
Patrick P. Sullivan

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota

Docket No. G011/GR-22-504

Exhibit ___ (PPS-D)

Class Cost of Service Study

November 1, 2022

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Patrick P. Sullivan. My business address is 231 West Michigan Street, Milwaukee, Wisconsin 53203.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Minnesota Energy Resources Corporation ("MERC" or the "Company").

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am currently a Project Specialist at WEC Business Services, LLC ("WBS"). Both MERC and WBS are wholly-owned subsidiaries of WEC Energy Group, Inc. ("WEC").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of Wisconsin-Madison with a Bachelor of Science Degree majoring in economics. I subsequently graduated from the Kelley School of Business at Indiana University with a Master of Science degree majoring in finance. During my professional career, I have provided financial, credit, regulatory, and economic analysis for a variety of commercial and retail customers at Bank of America/Merrill Lynch, the Wisconsin Department of Financial Institutions, Home Savings Bank, Bankers' Bank, and John Deere Financial. I joined the Public Service Commission of Wisconsin (the "PSCW") in

January 2015 as a Public Utility Financial Analyst - Senior. I left the PSCW in May 2016 to work in the banking industry and returned to the PSCW in May 2017, retaining my role as Public Utility Financial Analyst - Senior. I was promoted to a Public Utility Auditor–Advanced in October 2018, which was a role I served in until leaving the PSCW in July 2020. I began working for WEC in March 2021 as a Project Specialist in the State Regulatory Affairs Department. In my role as a Project Specialist, I have supported the preparation of cost of service studies for general rate case proceedings for electric and natural gas utilities in Wisconsin. I have also supported the preparation of an integrated resource plan for the Upper Michigan Energy Resources Corporation before the Michigan Public Service Commission.

II. OVERVIEW OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe and present MERC's Class Cost of Service Study ("CCOSS") for the 2023 proposed test year. I also address compliance with requirements related to cost of service from prior orders of the Minnesota Public Utilities Commission's (the "Commission").

Q. ARE YOU SPONSORING ANY INFORMATIONAL REQUIREMENT DOCUMENTS WITH THIS TESTIMONY?

A. Yes. As required by Minn. R. 7825.4300(C), I am sponsoring Informational Requirement Document 12, which contains MERC's CCOSS for the 2023 proposed test year along with supporting data. Volume 3, Informational Requirement Document 12 contains the following schedules of information:

Schedule 1.0 – Class Cost of Service Results – Minimum-Size Method

1.1 – Revenue Requirements by Customer Class

1.2 – Billing Unit Cost by Customer Class

1.3 – External Allocators Results

1.4 – Discussion of Allocation Methodologies

1.5 – Transportation Administration Fee Derivation

1.6 – Discussion of Income Tax Allocation

1.7 – Summary of MERC Class Breakpoint Analysis

1.8 – Incremental Cost Study

1.9 - Summary of Revenue Deficiencies from CCOSS model

2.0 – Minimum-Size Study Results

Q. DOES YOUR TESTIMONY ADDRESS ANY OTHER FILING REQUIREMENTS?

A. Yes, my testimony addresses the following filing requirements:

First, the Commission’s June 29, 2009 Findings of Fact, Conclusions, and Order in Docket No. G007,011/GR-08-835 required that, in future CCOSS filed in general rate cases, MERC must include an explanatory filing identifying and describing each allocation method used in the study and detailing the reasons for concluding that each allocation method is appropriate and superior to other allocation methods considered. This requirement is addressed below in testimony with support from Schedule 1.4 of Volume 3, Informational Requirement Document 12.

Second, in the Commission's July 13, 2012 Findings of Fact, Conclusions, and Order in Docket No. G-007,011/GR-10-977, the Commission adopted the Administrative Law Judge's ("ALJ's") Proposed Order with changes. One item adopted by the Commission required MERC to allocate income taxes on the basis of taxable income by class that fully and only reflects the CCOSS. The Commission confirmed this allocation method for MERC in its October 28, 2014 Findings of Fact, Conclusions, and Order in Docket No. G011/GR-13-617. Included in Volume 3, Informational Requirement Document 12, Schedules 1.0 is the CCOSS for MERC that allocates income taxes on the basis of rate base, which, mathematically, is the same method as described above. Schedule 1.6 in Volume 3, Informational Requirement Document 12 demonstrates that the rate base allocation method is mathematically equivalent to allocating income taxes on the basis of taxable income by class that fully and only reflects the class cost of service. This is consistent with MERC's previous rate case filing.

Third, my testimony addresses the Commission's October 28, 2014 Findings of Fact, Conclusions, and Order in Docket No. G011/GR-13-617. The Commission's Order, at Order Point 32, required that MERC take the following actions in preparing future class cost of service studies:

- Collect data on additional variables that impact the unit cost of mains installation;

- Avoid aggregating or averaging data and use data at the finest level reasonable;
- Check ordinary-least-squares ("OLS") regression assumptions and correct for violations; and
- Make any future zero-intercept analysis more transparent to ensure that MERC's work can be easily replicated.

Additionally, Order Point 12 of the Commission's October 31, 2016 Findings of Fact, Conclusions, and Order in Docket No. G011/GR-15-736 directed MERC in future rate cases to explore the use of such project-specific data in future zero-intercept CCOSS. These requirements do not apply in this case because MERC has not elected to utilize a zero-intercept study for the classification of distribution mains.

Fourth, I address Order Point 30 from the Commission's December 26, 2018 Findings of Fact, Conclusions, and Order in MERC's last rate case in Docket No. G011/GR-17-563 ("2017 Rate Case"), which required that MERC file one cost study in future rate cases, and if the Company elects to file a zero-intercept cost study, to file a minimum-size classification in lieu of a full minimum-size cost study. As noted above, MERC has not elected to file a zero-intercept cost study in this case and is therefore submitting only one study, in accordance with the Commission's Order.

Finally, I address MERC's agreement from Docket No. G011/GR-17-563 to provide information on usage breakpoints for metering that vary across customer class usage bands, and the cost associated with those upgrades. This study is located in Schedule 1.7 in Volume 3, Informational Requirement Document 12. As described in my testimony, the results of this review support continuation of MERC's current customer classes and MERC is not proposing to adjust any of its customer classes as a result of this study.

Q. ARE THERE ANY CHANGES BETWEEN THE CCOSS PRESENTED IN THIS PROCEEDING AND THE CCOSS THE COMMISSION USED AS THE BASIS FOR SETTING RATES IN MERC'S 2017 RATE CASE?

A. In the 2017 Rate Case, the Commission considered MERC's recommended zero-intercept model, the Department's recommended zero-intercept model, and the Office of the Attorney General's blended approach in making its determination on class revenue apportionment. The only material change to MERC's proposed CCOSS model methodology in this case is the presentation of a single minimum-size study. This change in methodology better aligns with other WEC utilities, which enhances efficiency and reflects a transparent methodological approach that appropriately recognizes cost causation by classifying distribution costs as both customer-related and demand-related. The results of the minimum-size study are consistent with the minimum-size study MERC presented in Docket No. G011/GR-17-563 and yield similar results to the study relied on by the Company in that proceeding.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. First, in Section III, I provide a discussion of the purpose and process of performing a CCOSS. In Sections IV and V, I discuss the classification of production costs and transmission costs. In Section VI, I discuss the classification and allocation of distribution costs under a minimum-size method and MERC's conclusions and recommendations based on this approach to classifying and allocating distribution costs. In Section VII, I discuss the classification and allocation of customer costs. In Section VIII, I discuss the classification and allocation of administrative and general costs. In Section IX and X, I discuss the allocation of taxes. In Section XI, I provide an overview of the informational requirement I am supporting.

III. GAS CLASS COST OF SERVICE STUDY PURPOSE AND PROCESS

A. Purpose

Q. WHAT IS THE PURPOSE OF PERFORMING A CCOSS?

A. The purpose of a CCOSS is to identify the revenues, costs, and profitability for each class of service, as required by Minn. R. 7825.4300(C). A CCOSS is necessary for transparency and serves as a starting point for determining how customers pay for the costs of serving them. The CCOSS should result in an appropriate allocation of the utility's total revenue requirement among the various customer classes based on cost causation, which can then be used as one input to help determine how costs should be recovered from customers through rate design.

Q. IS MERC'S CCOSS MODEL AN EMBEDDED COST OF SERVICE STUDY?

A. Yes, consistent with the CCOSS models filed in MERC's 2017 Rate Case, the CCOSS model is based on historical accounting data, unless otherwise noted, for the allocation of the test year revenue requirement to customer classes.

Q. HOW IS A CCOSS PREPARED?

A. In general, preparing a CCOSS involves three steps: (1) cost functionalization; (2) cost classification; and (3) cost allocation.

Q. COULD YOU PLEASE EXPLAIN COST FUNCTIONALIZATION, CLASSIFICATION, AND ALLOCATION?

A. Cost functionalization identifies and separates plant and expenses into functions within a utility. Generally, functions used in a gas CCOSS include: (1) Production; (2) Storage; (3) Transmission; (4) Distribution; (5) Customer; and (6) Administrative and General. Cost classification further assigns functionalized plant and expenses to categories based on whether they are related to (1) energy or commodity; (2) demand or capacity; or (3) customers. For example, commodity costs are those that vary with the amount of natural gas supplied; demand costs are influenced by the sizing of facilities to meet peak customer demands; and customer costs are those that vary with the number of customers connected to the distribution system. Cost allocation further assigns plant and expenses to customer groups or classes based on how each class causes costs to be incurred.

Q. HOW SHOULD THE COMMISSION REFLECT THE RESULTS OF MERC'S RECOMMENDED CCOSS IN RATE DESIGN?

A. The Direct Testimony of Company witness Ms. Joylyn Hoffman Malueg presents MERC's proposed rate design, based in part on the results of the CCOSS.

B. Process

Q. PLEASE DESCRIBE MERC'S APPROACH IN THE DEVELOPMENT OF ITS CCOSS.

A. In the development of MERC's CCOSS, MERC primarily relied upon guidance from the following industry-accepted sources: (1) American Gas Association ("AGA"), Gas Rate Fundamentals, 1987; (2) National Association of Regulatory Utility Commissioners ("NARUC"), Staff Subcommittee on Gas, Gas Distribution Rate Design Manual, 1989; and (3) NARUC, Staff Subcommittees on Electricity and Economics, Electric Utility Cost Allocation Manual, 1992. Consistent with these manuals, MERC's CCOSS attempts to associate costs with customer classes based on cost causation. That is, "to attribute costs to different categories of customers based on how those customers cause costs to be incurred."[1] There are some cases where a direct association of costs to customers exists based on causation.[2] For example, some plant costs, such as investment in meters and services, can be directly associated with customers. In

[1] NARUC, Electric Utility Cost Allocation Manual, at 12 (1992).

[2] AGA, Gas Rate Fundamentals at 135-37 (1987).

other cases, causation can be based on a direct relationship between costs and some parameter that can be related to customers. An example of this is gas supply acquisition costs, which has a direct relationship to customers' sales. Therefore, gas supply acquisition costs are allocated to customers based on sales. Other costs may have relationships to customer parameters that are not direct, but are significantly influenced by those parameters. Distribution system costs fall into this category.[3]

Q. HOW DID MERC FUNCTIONALIZE COSTS?

A. In general, the basis for functionalizing costs is the Uniform System of Accounts ("USOA") published by the Federal Energy Regulatory Commission ("FERC"). MERC assigned costs to functions following the FERC USOA. This approach is consistent with the guidelines outlined by AGA and NARUC.[4] MERC's CCOSS functional cost categories include: (1) Production; (2) Transmission; (3) Distribution; (4) Customer; and (5) Administrative and General.

Q. PLEASE DESCRIBE MERC'S PROCESS FOR CLASSIFYING COSTS.

A. All costs are classified by whether they are related to commodity, demand, or customers. MERC's CCOSS classification categories include: (1) Commodity, with sub classifications (a) Purchased Gas Cost and (b) Gas Supply Acquisition Cost; (2) Demand, with sub classifications (a) Firm Demand and (b) Interruptible

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[3] NARUC, Electric Utility Cost Allocation Manual at 90 (1992).

[4] AGA, Gas Rate Fundamentals at 135 (1987); NARUC, Electric Utility Cost Allocation Manual at 19 (1992); NARUC, Gas Distribution Rate Design Manual at 21-22 (1989).

Demand; and (3) Customer, with sub classifications (a) Customer, (b) Enhanced Other Services, and (c) Direct. Commodity-related costs are costs incurred that vary with the amount of natural gas supplied. The cost of gas, oftentimes referred to as gas purchases or purchased gas cost, is an example of a commodity-related cost. Demand-related costs are costs that are incurred to meet peak customer demands. The cost of a gas transmission main is an example of a demand-related cost. Customer-related costs are costs incurred as customers are connected to the distribution system, regardless of the amount of energy they consume or demand.

Q. PLEASE DESCRIBE MERC'S PROCESS FOR ALLOCATING COSTS.

A. MERC's cost allocation further assigns costs to customer groups or classes, on the basis of cost causation. Each classified cost element is assigned an allocation factor that reflects the cost causation principle of the cost element. For example, gas supply acquisition costs, which have a direct relationship to customers' sales, are allocated to customer classes by MERC's Sales allocator. Direct assignment of values to the appropriate customer classes was conducted whenever possible, as recommended by both AGA and NARUC.[5] An overview of MERC's allocators can be found in Schedule 1.6 of Volume 3, Informational Requirement Document 12. Additionally, the results of MERC's allocator

[5] AGA, Gas Rate Fundamentals at 140 (1987); NARUC, Gas Distribution Rate Design Manual at 31 (1989).

calculations can be found in Schedule 1.3 of Volume 3, Informational Requirement Document 12.

Q. PROVIDE A LIST OF MERC'S CUSTOMER CLASSES UTILIZED IN THE CCOSS.

A. A list of MERC's customer classes utilized in the CCOSS can be found in Schedule 1.5 of Volume 3, Informational Requirement Document 12, and are reflective of the current customer classes defined in MERC's tariffs and approved by the Commission in MERC's 2017 Rate Case.

IV. <u>CLASSIFICATION AND ALLOCATION OF PRODUCTION COSTS</u>

Q. HOW ARE MERC'S PRODUCTION COSTS CLASSIFIED?

A. Production costs are those costs that relate to producing, purchasing, or manufacturing gas. MERC classifies production costs within the appropriate categories of Purchased Gas, Gas Supply Acquisition, Firm Demand, and Interruptible Demand. Production costs that vary with the amount of gas supplied are classified as commodity-related and further broken down into categories of Purchased Gas Cost and Gas Supply Acquisition. Examples include FERC Accounts 804, Natural Gas City Gate Purchases, and 813, Other Gas Supply Expenses. These costs are incurred based on the amount of gas supplied. Production costs that do not vary with the amount of gas supplied are classified as demand-related and further broken down into categories of firm capacity-related or interruptible capacity-related. These costs are incurred while meeting peak demands on the system.

Q. HOW ARE MERC'S COMMODITY-RELATED PRODUCTION COSTS ALLOCATED TO CUSTOMER CLASSES?

A. All commodity-related production costs are allocated to customer classes by a commodity allocator, based on the quantity of gas consumed. This allocation methodology is appropriate per the NARUC Gas Distribution Rate Design Manual.[6] Gas-related Purchased Gas costs are allocated to customer classes by a Commodity Cost allocator. This allocator is based on the direct assigned purchased cost of gas for each customer class. Gas Supply Acquisition-related costs are allocated to customer classes by a Sales allocator because these costs cannot be directly assigned but vary with the amount of gas supplied.

Q. HOW ARE MERC'S DEMAND-RELATED PRODUCTION COSTS ALLOCATED TO CUSTOMER CLASSES?

A. All demand-related production costs are allocated to customer classes by a coincident peak demand allocator. This allocation methodology is appropriate because these costs are incurred to meet peak demand requirements. Therefore, customer classes should be allocated their share of costs based on each class's contribution to the system maximum peak.

[6] NARUC, Gas Distribution Rate Design Manual at 25 (1989).

V. CLASSIFICATION AND ALLOCATION OF TRANSMISSION COSTS

Q. HOW ARE MERC'S TRANSMISSION COSTS CLASSIFIED?

A. Transmission costs are incurred to transport wholesale natural gas from interstate pipelines to MERC's distribution system. All transmission-related costs are classified as demand-related, as these assets are in place for MERC to provide transmission service and are sized to meet MERC's peak system demand. Examples include plant in FERC Accounts 367, Mains, and 369, Measuring and Regulating Station Equipment. Classifying transmission costs in this manner is consistent with the practice outlined by AGA.[7]

Q. HOW ARE MERC'S TRANSMISSION COSTS ALLOCATED TO CUSTOMER CLASSES?

A. Because all of MERC's transmission costs are classified as demand-related, all of MERC's transmission costs are allocated to customer classes by a demand allocator. Firm transmission costs are allocated to customer classes by a Demand - Firm allocator and interruptible transmission costs are allocated to customer classes by a Weighted Peak Demand-Interruptible allocator. These two allocators are appropriate because these costs are incurred to meet demand requirements.

[7] AGA, Gas Rate Fundamentals at 197-201 (1987).

The only customer classes excluded from allocations of MERC's transmission costs are the Farm Tap classes and customers who pose a bypass risk.[8] It is appropriate to exclude Farm Tap classes and direct connect customers from the allocation of transmission costs because MERC's transmission assets do not serve Farm Tap or direct connect customers. Instead, these customers are directly connected to the interstate transmission pipeline.[9]

VI. CLASSIFICATION AND ALLOCATION OF DISTRIBUTION COSTS

A. Overview

Q. HOW ARE MERC'S DISTRIBUTION COSTS CLASSIFIED?

A. There are two significant cost causation relationships for distribution-related costs. As the Commission has previously recognized, a gas utility's distribution plant is designed both (1) to meet system capacity needs and (2) to connect customers regardless of their individual capacity needs.[10] Some distribution-related costs are incurred in order for customers to be connected to the distribution system. Because these distribution-related costs vary with the number of customers on the system, they are classified as customer-related. An example of customer-related distribution costs are FERC Accounts 380 and 381,

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[8] These bypass risk customers are on their own rate schedules and therefore the Company is able to properly exclude them from allocation methods. This includes Transport NNG Class 5 Interruptible - CIP Exempt, Transport NNG Electric Generation Class 2 – CIP Exempt, and Transport NNG Flexible rate customers.

[9] Additionally, these costs were not allocated to the remaining bypass risk customers, as their therm throughput could be removed from MERC's system, thus increasing costs to all customers in the event of bypass.

[10] *In the Matter of the Application of Minn. Energy Res. Corp. for Auth. to Increase Rates for Nat. Gas Serv. in Minn.*, Docket No. G011/GR-15-736, Findings of Fact, Conclusions, and Order at 33-34 (Oct. 31, 2016).

Services and Metering Equipment. Other distribution-related costs are incurred to meet peak customer demands. These distribution-related costs are classified as demand-related. An example of demand-related distribution costs is FERC Account 379, Measuring & Regulating Station Equipment. Other distribution-related costs, such as FERC Account 376, Gas Distribution Mains, are influenced by both customer and demand components, and require further analysis to derive an appropriate ratio that allocates costs to multiple classifications.

Q. WHAT FACTORS OF GAS DISTRIBUTION MAINS ARE INFLUENCED BY DEMAND ON A UTILITY'S SYSTEM?

A. Gas distribution mains are an extensive network of small (*e.g.*, two-inch) to medium (*e.g.*, twelve-inch) pipe responsible for delivering natural gas to consumers within a specific area. When gas distribution mains are installed, they are engineered to meet peak demand reliably and safely. A main will not be installed if it is incapable of serving peak demand. Therefore, a portion of costs related to gas distribution mains must be classified as demand in a CCOSS.

Q. WHAT FACTORS OF GAS DISTRIBUTION MAINS ARE INFLUENCED BY THE NUMBER OF CUSTOMERS CONNECTED TO A UTILITY'S SYSTEM?

A. Some costs of installing gas distribution mains are incurred simply to connect a customer or group of customers to the system; for example, the quantity or length of pipe installed. When installing gas distribution main, the size or diameter of that particular pipe is determined in part by the peak demands it will be responsible for meeting. However, total quantity of pipe installed is influenced by the need to expand the distribution system in order to connect to customers.

Q. WHAT METHODS EXIST FOR SEPARATING THE CUSTOMER-RELATED PORTION FROM THE DEMAND-RELATED PORTION OF A GAS DISTRIBUTION MAIN?

A. As described by AGA, some cost elements of a utility cannot be classified directly to a single classification category.[11] FERC Account 376, Gas Distribution Mains, is an example of one such cost element, and is appropriate to separate between customer-related and demand-related components. There are two commonly used studies for determining the customer- and demand-related portions of gas distribution mains: (1) the minimum-size study and (2) the zero-intercept study. Both studies are referred to as a “minimum-system study,” and as the name suggests, each study derives a “minimum system.” The minimum system consists of the minimum amount of fixed investment required to connect customers to the system regardless of their gas usage or demand (*i.e.*, the customer-related portion). Costs in excess of the minimum system are related to the demand imposed on the system by those customers (*i.e.*, the demand-related portion). The minimum-system study is used to appropriately allocate gas distribution main costs between the customer-related classification and the demand-related classifications in a CCOSS.

[11] AGA, Gas Rate Fundamentals at 137 (1987).

Q. DOES A MINIMUM-SYSTEM STUDY CHANGE THE TOTAL AMOUNT OF DISTRIBUTION MAIN INVESTMENT AND COSTS WITHIN A CCOSS?

A. No, a minimum-system study does not change or have any impact on the total amount of distribution main investment and costs being recovered in MERC's revenue requirements within the CCOSS. It is simply a method used to allocate the total investment between the customer-related classification and demand-related classification.

Q. DID MERC PERFORM A MINIMUM-SYSTEM STUDY IN THIS RATE CASE?

A. Yes. MERC performed a minimum-size study to derive the ratio of customer- and demand-related costs for FERC Account 376, Gas Distribution Mains. MERC is not electing to file a zero-intercept cost study in this case.[12]

Q. WHAT VARIABLES DID MERC WORK WITH WHEN PERFORMING ITS MINIMUM-SYSTEM STUDY?

A. MERC obtained a data set from its Plant Accounting System ("Accounting System") with the following variables: pipe material, pipe diameter, quantity installed, year of installation, total book cost, and total current cost. Table 1 in Volume 4, Sullivan Workpapers, contains the complete data that MERC utilized in its minimum-system study.

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[12] This is consistent with the Commission's December 26, 2018 Findings of Fact, Conclusions, and Order in Docket No. G011/GR-17-563, which required that MERC file one cost study in future rate cases, and required that if MERC elects to file a zero-intercept cost study, that it also file a minimum-size classification analysis in lieu of a full-blown minimum-size cost study.

Q. DID MERC UTILIZE BOOK COST WHILE CALCULATING ITS MINIMUM-SYSTEM STUDY?

A. No. MERC utilized current cost to perform its minimum-system study.

Q. WHY DID MERC UTILIZE CURRENT COST IN ITS CALCULATION OF AVERAGE UNIT COST?

A. The book cost of distribution main installations maintained in MERC's Accounting System for a given year consists of the total of material costs, labor costs, and overhead and other costs, if any, that were attributable to all of the projects completed in that given year. Comparing the book cost of distribution main installations performed in 1965, for example, would not provide an accurate comparison with distribution main installations performed in 2021, as material prices, labor prices, installation standards, and inflationary factors were generally very different in 1965 than they were in 2021. Therefore, while "normally the average book cost for each piece of equipment determines the price of all installed units,"[13] current cost is the better measure in this instance.

Q. HOW DID MERC CALCULATE AVERAGE CURRENT COST?

A. MERC utilized the Handy-Whitman Index of Public Utility Construction Costs ("H-W Index") to adjust historic book cost to current cost. Applying the H-W Index to book cost by year of installation provides a way to meaningfully compare costs in a given year to costs of a different year, for example, a 1965 book cost to a 2021

[13] NARUC, Electric Utility Cost Allocation Manual at 90-91 (1992).

book cost. This is especially important when calculating an average unit cost across MERC's entire system for use in a minimum-system study, as the average unit cost of each pipe size for MERC is the average of distribution main installations over a 60+ year period.

MERC then calculated the average current unit cost as (1) total current cost, grouped by material type and pipe diameter, divided by (2) total quantity (in feet) installed, also grouped by material type and pipe diameter.

Q. WHAT IS THE H-W INDEX?

A. The H-W Index is a widely-accepted and reliable index that will trend historic, or original, book cost records to estimate reproduction or current cost records at prevailing prices. The H-W Index provides the level of costs (stated as cost index values) for different types of utility construction for each year since 1912, and for different geographic locations throughout the 48 contiguous states. The indexes are provided consistent with the FERC USOA such that they can be applied against the historic book cost of specific utility assets, such as gas distribution mains.

B. <u>Minimum-Size Study</u>

Q. WHAT REQUIREMENTS APPLY TO MERC'S CCOSS IN THIS CASE?

A. The Commission's December 26, 2018 Findings of Fact, Conclusions, and Order in Docket No. G011/GR-17-563 required MERC to file one cost study in future rate cases, and required that if MERC elects to file a zero-intercept cost study, that it also file a minimum-size classification analysis in lieu of a full-blown minimum-size cost study.

MERC has elected to conduct a minimum-size study and performed a CCOSS utilizing the results of that minimum-size study. MERC is not electing to file a zero-intercept cost study in this case.

Q. WHAT IS A MINIMUM-SIZE STUDY?

A. A minimum-size study assumes "that a minimum-size distribution system can be built to serve the minimum loading requirements of the customer."[14] The minimum-size method is described in more detail in the NARUC Cost Allocation Manual.

Q. HOW IS A MINIMUM-SIZE STUDY CALCULATED?

A. To conduct a minimum-size study, one must determine: (1) the minimum-sized piece of equipment (in this instance, the smallest distribution pipe currently installed by the utility), and (2) the cost of that minimum-sized piece of equipment (in this instance, average unit cost). The average unit cost is then multiplied by the quantities of distribution mains currently installed by the utility to arrive at Total Minimum System Cost. Total Minimum System Cost divided by Total System Cost is considered to be the ratio of the utility's fixed investment

[14] NARUC, Electric Utility Cost Allocation Manual at 90 (1992).

classified as customer-related within the CCOSS. The remaining balance is considered to be costs in excess of the minimum system and is classified as demand-related within the CCOSS.[15]

Q. WHY HAS MERC CHOSEN TO PERFORM A MINIMUM-SIZE STUDY AND NOT A ZERO-INTERCEPT STUDY?

A. The minimum-size method is reflective of cost causation because it classifies some costs as customer, other costs as demand, and no costs as commodity. Additionally, the minimum-size method is transparent and straightforward to perform because it is based on data from the utility system. It is also widely accepted within the industry. As noted above, the minimum-size study is based on the idea that the distribution system is built to meet two criteria consistent with the physical constraints of MERC's natural gas distribution system. It must connect to all customers and it must be capable of handling the load at the time of the peak demand of the customers connected to it. The costs of connecting to the customers are classified as customer related. Equipment that is larger than the minimum size is installed to support the load demanded by the customers, so the incremental costs associated with the larger size are classified as demand related. The difference between the total distribution costs and the customer-related costs are classified as demand related.

[15] NARUC, Electric Utility Cost Allocation Manual at 91-92 (1992).

The Zero-Intercept Method is designed to arrive at the same general result as the Minimum-Size Method, but relies on regression analysis to estimate a theoretical "zero intercept" pipe. For example, given a certain-size pipe, it is assumed that as the current carrying capability of a distribution main increases, the cost increases commensurately. While the zero-intercept method is a widely accepted approach, it is significantly more complex than other methodologies and can sometimes yield results that are statistically invalid.

Q. IS MERC'S DECISION TO FILE A MINIMUM-SIZE STUDY CONSISTENT WITH OTHER RECENT MINNESOTA UTILITY NATURAL GAS RATE CASE FILINGS?

A. Yes. Two other Minnesota natural gas utilities have filed recent rate cases utilizing minimum-size studies. Northern State Power Company filed in Docket No. G002/GR-21-678 a minimum-size study to support its CCOSS on November 1, 2021. Additionally, CenterPoint Energy filed in Docket No. G008/GR-21-435 a minimum-size study to support its CCOSS on November 1, 2021.

Q. DID MERC UTILIZE THE DATA FROM TABLE 1 IN VOLUME 4, SULLIVAN WORKPAPERS, IN ITS MINIMUM-SIZE STUDY?

A. Yes.

Q. DID MERC MAKE A DEMAND ADJUSTMENT TO ITS MINIMUM-SIZE STUDY?

A. Yes, in order to reflect the fact that the minimum-sized pipe used to perform the minimum size study serves some level of customer load requirements, MERC incorporated a demand adjustment into its minimum-size study. MERC compared the historical minimum and maximum use per customer for residential and commercial and industrial classes 1-3 based on the data provided by Company witness Mr. Jared Peccarelli. Then, the ratio of the monthly minimum to the monthly maximum for the historical time period for each customer group—residential and commercial and industrial—was weighted by actual 2021 annual total throughput. The resulting adjustment shifted 19.76% of the customer-related costs to demand-related in order to approximate a zero diameter pipe.

Q. HOW DID MERC DETERMINE ITS MINIMUM-SIZED PIPE FOR PLASTIC AND STEEL INSTALLATIONS?

A. Two-inch main was chosen because it is the minimum-sized distribution main for both plastic and steel currently used by the Company. It is appropriate to conduct the minimum-size study based on MERC's current installation standard because a minimum-size study is going to be used within the CCOSS, which not only portrays data that is based on a forecasted test year but is also premised on creating an accurate cost causation portrayal of MERC's current customers. MERC's installation standards are based on industry standards and applicable safety requirements, as well as what is most appropriate given MERC's service territory.

For MERC, approximately 97 percent[16] and 91 percent[17] of all plastic and steel distribution main installations, respectively, are two inches and larger in diameter. As can be seen in the information provided in Schedule 2.0 of Volume 3, Informational Requirement Document 12, MERC does have distribution mains that are smaller than the current minimum size of two inches. These smaller mains were typically installed many years ago when MERC's installation standards were different. For the plastic and steel pipe diameters of less than two inches, only approximately 0.6 percent[18] and 0.5 percent[19] of those installations for plastic and steel, respectively, have occurred since the year 2000, and each involved unique construction circumstances that warranted installation of a pipe diameter less than the current minimum installation standard. Additionally, one can see from the minimum-size study shown in Schedule 2.0 of Volume 3, Informational Requirement Document 12, that the majority of installation quantities are two inches in size, comprising approximately 69 percent[20] and 41 percent[21] of total installations for plastic and steel distribution mains, respectively. This confirms that: (a) two-inch pipe is the typical minimum installation size, consistent with MERC's current minimum installation standard,

[16] Based on quantity, in feet, installed.

[17] Based on quantity, in feet, installed.

[18] Based on quantity, in feet, installed.

[19] Based on quantity, in feet, installed.

[20] Based on quantity, in feet, installed.

[21] Based on quantity, in feet, installed.

and (b) to base a minimum-sized pipe on any size less than two inches, which is rarely installed, would not be appropriate.

Q. HOW DID MERC CALCULATE THE COST OF ITS MINIMUM-SIZED PIPE FOR BOTH PLASTIC AND STEEL?

A. First, MERC utilized Microsoft Excel to analyze the data from Table 1 in Volume 4, Sullivan Workpapers. Incorrect accounting data or some other abnormality in the data can cause unreliable results, such as a negative intercept value.[22] In following the guidance of the NARUC Electric Utility Cost Allocation Manual, MERC conducted a review of the accounting data and removed "suspect data."[23] Specifically, MERC removed records that were deemed invalid due to having negative book costs. This data is considered invalid for minimum-system study purposes, as it is invalid to have a negative installation cost. Second, MERC aggregated the quantity (in feet) installed and total current cost, grouped by pipe material and pipe diameter. Once aggregated, total current cost divided by total quantity resulted in an average current cost per pipe material and pipe diameter. As stated earlier, MERC determined its minimum size pipe for both plastic and steel to be two inches. The average current cost for two-inch plastic and steel pipe is $12.37 and $11.62, respectively.

[22] NARUC, Electric Utility Cost Allocation Manual at 95 (1992).

[23] NARUC, Electric Utility Cost Allocation Manual at 95 (1992).

Q. WHAT WERE THE RESULTS OF MERC'S MINIMUM-SIZE STUDY UTILIZING A TWO-INCH PIPE DIAMETER?

A. MERC calculated Total Current System Costs of $526,581,051, of which $295,826,954 or 56.2 percent calculated as the Minimum System after accounting for the 19.76% demand adjustment. The remaining $230,754,097, or 43.8 percent, of the Current System Costs represents the demand- or capacity-related cost of the system after accounting for the 19.76% demand adjustment. The Minimum System cost was derived by multiplying average current unit cost of the minimum-sized pipe for plastic and steel, which is $12.37 and $11.62, respectively, by total quantity of plastic and steel installations, which is 19,961,899 and 7,484,502, respectively. The CCOSS results that utilize the two-inch pipe minimum-size study can be found in Schedule 2.0 of Volume 3, Informational Requirement Document 12.

C. Conclusion for Distribution-Related Cost Classification

Q. WHAT DO YOU CONCLUDE WITH RESPECT TO THE CLASSIFICATION OF FERC ACCOUNT 376, GAS DISTRIBUTION MAINS?

A. MERC concludes that its minimum-size study accurately allocates costs and should be relied upon to support setting appropriate rate levels in this rate case. Further, MERC's minimum-size study results are based on data retrieved from MERC plant accounting, which provides a transparent study for the allocation of costs.

D. <u>Allocation of Distribution Costs</u>

Q. HOW DID MERC ALLOCATE DISTRIBUTION COSTS TO CUSTOMER CLASSES?

A. Distribution-related costs are allocated to customer classes utilizing either a customer allocator, demand allocator, or internally-derived plant allocator. Farm Tap classes and customers who pose a bypass risk[24] are excluded from the allocation of costs in all distribution accounts except for FERC Accounts 301-303, Intangible Plant, 374, Land and Land Rights, and 375, Structures and Improvements. This is appropriate because all other distribution facilities do not serve MERC's Farm Tap or direct connect customers.[25]

Q. PLEASE EXPLAIN THE ALLOCATION METHODS USED TO ALLOCATE MERC'S DISTRIBUTION COSTS TO CUSTOMER CLASSES.

A. The following allocation methods were used to allocate distribution-related costs in MERC's CCOSS, found in Schedule 1.0 of Volume 3, Informational Requirement Document 12.

FERC Accounts 301-303, Intangible Plant, 374, Land and Land Rights, and 375, Structures and Improvements:

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[24] These bypass risk customers are on their own rate schedules and therefore the Company is able to properly exclude them from allocation methods. This includes Transport NNG Class 5 Interruptible - CIP Exempt, Transport NNG Electric Generation Class 2 – CIP Exempt, and Transport NNG Flexible rate customers.

[25] Additionally, these costs were not allocated to the remaining bypass risk customers, as their therm throughput could be removed from MERC's system, thus increasing costs to all customers in the event of bypass.

FERC Accounts 301-303, 374, and 375 were allocated to customer classes by MERC's internally-derived allocator, Distribution Plant. This allocator is derived from distribution plant investment in Accounts 376 through 385. It is appropriate that all customers receive an allocation of these costs because they are related to the general assets that support MERC's distribution system. Additionally, a composite allocation factor of distribution plant (excluding the items above) is appropriate in the situation where costs cannot be readily categorized to a single classification or a single customer parameter (e.g., usage).[26]

FERC Account 376, Gas Distribution Mains:

The customer-related portion of FERC Account 376 was allocated to customer classes by MERC's Customer allocator, excluding Farm Taps and bypass risk customers, as described above. As recommended by NARUC,[27] the demand-related portion was allocated to customer classes by MERC's Weighted Peak Demand – Firm, excluding Farm Taps, and MERC's Weighted Peak Demand – Interrupt, excluding Farm Taps, allocators. These allocators are appropriate, as a *portion* of costs are incurred to connect customers and a portion of costs are incurred by the size of facilities required to meet customer peak demands.

[26] NARUC, Gas Distribution Rate Design Manual at 32, 40 (1989).

[27] NARUC, Gas Distribution Rate Design Manual at 27 (1989).

FERC Account 378, Measuring & Regulating Equipment – General: FERC Account 378 was allocated to customer classes by MERC's Account 378 Demand, excluding Farm Taps and customers who pose a bypass risk[28] allocator. This allocator consists of weighted peak demand for customer classes that are class two and smaller. This allocation method is appropriate because these costs are influenced by the sizing of facilities based on the non-coincident consumption of gas on the distribution facilities. It is appropriate to allocate these costs to the small and medium size classes because these customer classes are the only classes that utilize these assets, which consist mainly of regulating stations at the distribution system level. Costs directly related to the Minnesota Farm Tap Inspection Program were identified and carved out into FERC Account 378 (Direct Farm Tap). These directly assignable costs are allocated to customer classes by MERC's Account 378 Demand – Farm Tap only allocator. Note that the costs attributable to the Minnesota Farm Tap Inspection Program are separate from, and not a part of, the Farm Tap Replacement Project approved by the Commission in Docket No. G011/M-17-409 on October 6, 2021. Per the Commission's Order in that docket, Farm Tap Replacement Project costs are to be socialized and recovered from all of MERC's customers, and not direct assigned to the Farm Tap customers.

[28] These bypass risk customers are on their own rate schedules and therefore the Company is able to properly exclude them from allocation methods. This includes Transport NNG Class 5 Interruptible - CIP Exempt, Transport NNG Electric Generation Class 2 – CIP Exempt, and Transport NNG Flexible rate customers.

FERC Account 379, Measuring & Regulating Equipment – Gate Station:

FERC Account 379 was allocated to customer classes by MERC's Weighted Peak Demand, excluding Farm Taps and customers who pose a bypass risk[29] allocator. This allocation method is appropriate because these costs are influenced by the sizing of facilities based on the non-coincident consumption of gas by all customer classes on the distribution system.

FERC Account 380, Services:

FERC Account 380 was allocated to customer classes by MERC's Services allocator excluding Farm Tap and customers who pose a bypass risk[30], direct connect, and bypass risk customers. This allocator is a weighted customer allocator based on the Cost per Foot of Services by rate class. In general, natural gas runs from the utility's distribution main to a single end-use customer, either a home or business, through a service line. Therefore, it is appropriate to use a Customer allocator while allocating Services-related costs to customer classes. The weighting by

[29] These bypass risk customers are on their own rate schedules and therefore the Company is able to properly exclude them from allocation methods. This includes Transport NNG Class 5 Interruptible - CIP Exempt, Transport NNG Electric Generation Class 2 – CIP Exempt, and Transport NNG Flexible rate customers.

[30] These bypass risk customers are on their own rate schedules and therefore the Company is able to properly exclude them from allocation methods. This includes Transport NNG Class 5 Interruptible - CIP Exempt, Transport NNG Electric Generation Class 2 – CIP Exempt, and Transport NNG Flexible rate customers.

rate class is also appropriate because this more accurately allocates costs to customer class by taking into account that larger customer classes require larger diameter service lines. Finally, exclusion of Farm Tap, direct connect, and bypass risk customers appropriately recognizes that Farm Tap and direct connect customers are not served by MERC service lines. The qualification of a Service falls under the FERC USOA definition:

> This account shall include the cost installed of service pipes and accessories leading to the customers' premises. A complete service begins with the connection on the main and extends to but does not include the connection with the customer's meter.

FERC Accounts 381, Meters, and 382, Meter Connections & Installations:

FERC Accounts 381 and 382 were allocated to customer classes by MERC's Meters allocator. This allocator is a weighted Customer allocator based on the cost per meter by rate class from actual plant investment as of December 31, 2021. It is appropriate to use this allocation method because these costs vary based on the number of customers connected to the distribution system and the complexity of the meter design and installation that is driven by the size of facilities required. For example, larger customer classes require larger and more complex meter installations than smaller customer classes. This allocation methodology is consistent with the recommendation from AGA and NARUC.[31]

[31] AGA, Gas Rate Fundamentals at 142 (1987); NARUC, Gas Distribution Rate Design Manual at 24 (1989).

Operation and maintenance ("O&M") costs associated with FERC Account 381, directly related to telemetry maintenance, were identified and allocated directly to those customer classes by MERC's Customers – Telemeter allocator. It is appropriate to use this allocation method because these costs vary based on the number of customers connected to the distribution system and are directly related to customers classes with telemetry facilities installed.

FERC Account 383, House Regulators:

FERC Account 383 was allocated to customer classes by MERC's Customer – Small/Medium, excluding Farm Taps, direct connect, and bypass risk customer allocator. It is appropriate to use this allocation method because these costs vary based on the number of customers connected to the distribution system; however, Large and Super Large customer classes do not utilize house regulator facilities. Additionally, AGA recommends House Regulators be allocated by a weighted customer allocator.[32]

FERC Account 385, Industrial Metering & Regulating Station Equipment:

FERC Account 385 was allocated to customer classes by MERC's Customers – Account 385, excluding only Farm Taps allocator. It is

[32] AGA, Gas Rate Fundamentals at 142 (1987).

appropriate to use this allocation method because these costs are incurred based on the number and size of industrial customers connected to the distribution system. Additionally, AGA recommends Industrial Metering and Regulation Equipment be allocated by a special assignment allocator.[33]

VII. CLASSIFICATION AND ALLOCATION OF CUSTOMER COSTS

Q. HOW DID MERC CLASSIFY CUSTOMER COSTS?

A. Customer-related costs were classified to the customer classification category. The majority of customer costs were assigned to the customer sub-classification of customer; however, costs incurred directly related to serving transportation customers were classified to the enhanced other services sub-classification of customer to facilitate direct assignment to transportation customer classes.

Q. HOW DID MERC ALLOCATE CUSTOMER COSTS TO CUSTOMER CLASSES?

A. In general, customer costs are allocated to customer classes by MERC's Customer allocator because these costs vary with the number of customers connected to MERC's distribution system; however, costs that could be directly assigned to specific customer classes were directly assigned to those customer

[33] AGA, Gas Rate Fundamentals at 142 (1987).

classes. This approach is consistent with the approach outlined in the NARUC Electric Utility Cost Allocation Manual.[34]

Q. WHAT CUSTOMER-RELATED COSTS WERE DIRECTLY ALLOCATED TO CUSTOMER CLASSES?

A. Costs incurred to serve transportation customers were identified and allocated directly to those customers by MERC's Transport Customer allocator. Costs directly related to residential or commercial and industrial customers in FERC Account 904, Uncollectible Expense, were identified and allocated directly to those customers by MERC's Customers – Residential and Customers – C&I allocator. The ratio of residential to commercial and industrial customers was derived from the average historical Net Write-Offs from these customer classes for the calendar year ending December 31, 2021.

VIII. ALLOCATION OF ADMINISTRATIVE AND GENERAL COSTS

Q. HOW DID MERC CLASSIFY ADMINISTRATIVE AND GENERAL COSTS?

A. The majority of MERC's administrative and general costs were classified to commodity, demand, and customer by MERC's internally-derived allocator, Total O&M. MERC's Total O&M allocator is derived from the summation, by classification, of Total O&M costs (excluding administrative and general, direct assigned, and cost of gas related costs). This methodology is consistent with the

[34] NARUC, Electric Utility Cost Allocation Manual at 22, 103 (1992).

approach outlined in the NARUC Electric Utility Cost Allocation Manual.[35] Costs incurred directly related to serving transportation customers were classified to the enhanced other services sub-classification of customer utilizing the proportional split of direct assigned O&M Customer Accounts Expense (Accounts 901-905) to Total O&M Expense.

Q. HOW DID MERC ALLOCATE ADMINISTRATIVE AND GENERAL COSTS TO CUSTOMER CLASSES?

A. Administrative and general costs were allocated to customer classes by either a sales allocator, demand allocator, customer allocator, or by direct assignment. Gas supply acquisition-related costs were allocated to customer classes by MERC's Sales allocator. Demand-related costs were allocated to customer classes by MERC's Demand - Firm allocator and Weighted Peak Demand-Interrupt allocator. Customer-related costs, excluding direct assignment, were allocated to customer classes by MERC's Customers allocator. Costs incurred to serve transportation customers were allocated directly to those customers by MERC's Customers – Transport allocator.

[35] NARUC, Electric Utility Cost Allocation Manual at 22, 106 (1992).

IX. ALLOCATION OF TAXES OTHER THAN INCOME TAXES

Q. HOW DID MERC ALLOCATE TAXES OTHER THAN INCOME TAXES TO CUSTOMER CLASSES?

A. Taxes other than Income Taxes ("TOTIT") associated with Real Estate & Property, Unauthorized Insurance Tax, Excise Tax, and Use Tax, and Miscellaneous Revenues in Account 493 were allocated to customer classes by MERC's internally-derived Rate Base allocator. TOTIT associated with Unemployment Compensation, IBS Payroll Tax, and Retirement Benefits were allocated to customer classes by MERC's Salaries and Wages allocator.

X. ALLOCATION OF INCOME TAXES

Q. HOW DID MERC ALLOCATE INCOME TAXES TO CUSTOMER CLASSES?

A. Income Taxes were allocated to customer classes based on MERC's internally-derived Rate Base allocator. A detailed discussion of this allocation method can be found in Schedule 1.6 of Volume 3, Informational Requirement Document 12.

XI. ROADMAP OF INFORMATIONAL REQUIREMENT DOCUMENT 12

Q. PLEASE DESCRIBE SCHEDULE 1.0 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 1.0 presents the summarized results of MERC's natural gas CCOSS, utilizing the minimum-size method for classifying distribution mains, for the Minnesota service territory. Schedule 1.0 meets the requirements of: (1) the Commission's Order in Docket No. G011/GR-17-563 requiring MERC to submit one CCOSS in future rate case filings and (2) the Commission's order in Docket

No. G007,011/GR-10-977, requiring that MERC allocate income taxes on the basis of taxable income by class that fully and only reflects the CCOSS.

Pages 1 through 5 summarize the various components of operating income, rate base, rate of return resulting from operations, and total revenue deficiency by customer class.

Pages 6 through 10 show the operating revenues by customer class based on the rates authorized in MERC's 2017 Rate Case.

Pages 11 through 15 show the allocation of O&M expenses. Page 61 contains the detailed breakdown of the classification of O&M expenses that were utilized on pages 11 through 15.

Pages 16 through 20 show the allocation of depreciation expense, with general expense apportioned. Page 60 contains the detailed breakdown of the classification of depreciation expenses that were utilized on pages 16 through 20.

Pages 21 through 25 show the allocation of TOTIT.

Pages 26 through 30 show the allocation of other income and adjustments, both before and after income taxes. In the 2023 proposed test year, there are no other income or adjustments.

Pages 31 through 35 show the allocation of plant in service, with general expense apportioned. Page 56 contains the detailed breakdown of the classification of plant in service that was utilized on pages 31 through 35.

Pages 36 through 40 show the allocation of depreciation reserve, with general expense apportioned. Page 57 contains the detailed breakdown of the classification of depreciation reserve that was utilized on pages 36 through 40.

Pages 41 through 45 show the allocation of depreciation reserve (deferred taxes), with general expense apportioned. Page 58 contains the detailed breakdown of the classification of depreciation reserve (deferred taxes) that was utilized on pages 41 through 45.

Pages 46 through 50 show the allocation of construction work in progress, with general expense apportioned. Page 59 contains the detailed breakdown of the classification of construction work in progress that was utilized on pages 46 through 50.

Pages 51 through 55 show the allocation of other rate base components.

Q. PLEASE DESCRIBE SCHEDULE 1.1 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 1.1 presents a functionalized and classified revenue requirement and rate base allocation for each customer class. Schedule 1.1 consists of 61 pages; one page of information for each customer class. The information in this schedule is derived from the CCOSS presented in Informational Requirement Document 12, Schedule 1.0, which utilizes the minimum-size method for classifying distribution mains.

Q. PLEASE DESCRIBE SCHEDULE 1.2 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 1.2 presents a summary of the CCOSS by billing unit for each customer class, based on the CCOSS presented in Schedule 1.0. Schedule 1.2 consists of 3 pages.

Page 1 of Schedule 1.2 is a summary of all the billing unit costs by customer class, broken down into the billing units of Per Meter Fixed Charge, Telemeter Maintenance Charge, Enhanced Administrative Charge, Volumetric Rate, and Gas Supply Acquisition Rate. The column titled Total per Meter Fixed Charge is the summation of Columns [B], [C] and [D] for each customer class. The column titled Total Therm Rate is the summation of Columns [F] and [G] for each customer class.

Page 2 of Schedule 1.2 shows the creation of the Volumetric Rate and Gas Supply Acquisition Rate for each of the rate schedules. Therm throughput and values were taken from Informational Requirement Document 12, Schedule 1.3 Demand Costs and Gas Supply Acquisition Costs were taken from the respective columns of Informational Requirement Document 12, Schedule 1.1, on each of the respective pages for the customer classes.

Page 3 of Schedule 1.2 shows the creation of the Fixed Charge, Telemetering Maintenance Charge, and Enhanced Administrative Charge for each of the rate schedules. Meter Counts were taken from Informational Requirement Document 12, Schedule 1.3. Customer Costs were taken from the respective column of Informational Requirement Document 12, Schedule 1.1 on each of the respective pages for the customer classes. Telemetering Maintenance costs and Enhanced Administrative Costs were taken from the Enhanced Other Services column of Informational Requirement Document 12, Schedule 1.1, on each of the respective pages for the customer classes. Telemetering Maintenance Costs were specifically taken from Column [G], line 10, and Enhanced Administrative Costs represent the remainder of the costs, excluding Telemetering Maintenance Costs, in the Enhanced Other Services column of Informational Requirement Document 12, Schedule 1.1, on each of the respective pages for the customer classes.

Q. PLEASE DESCRIBE SCHEDULE 1.3 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 1.3 presents a summary of the external allocation methodologies used within all of MERC's CCOSSs. Schedule 1.3 consists of 20 pages. A detailed discussion of each allocation method can be found in Schedule 1.4 of Volume 3, Informational Requirement Document 12.

Q. PLEASE DESCRIBE SCHEDULE 1.4 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 1.4 identifies and describes each allocation method used in MERC's CCOSS.

Q. PLEASE DESCRIBE SCHEDULE 1.5 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 1.5 provides the determination of the appropriate Enhanced Administration Monthly Fixed Charge, also known as the Transportation Administration Fee. The Transportation Administration Fee is charged only to Transportation customers to cover the added administrative costs of providing transportation service. The added administrative costs of providing transportation service are caused on a per customer basis (*i.e.*, the costs do not vary with each customer's usage). Therefore, the charge is calculated based on meter counts.

Q. PLEASE DESCRIBE SCHEDULE 1.6 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 1.6 provides verification that the Rate Base allocation method, which is used in the CCOSS to allocate Income Taxes, follows the Commission's July 13, 2012, Findings of Fact, Conclusions, and Order in Docket No. G007,011/GR-10-977, which adopts the ALJ's Proposed Order that income tax be allocated on the basis of taxable income by class that fully and only reflects the CCOSS. The Commission affirmatively confirmed this allocation method for MERC in its October 28, 2014, Findings of Fact, Conclusions, and Order in Docket No. G011/GR-13-617.

Q. PLEASE DESCRIBE SCHEDULE 1.7 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 1.7 provides a summary of the study MERC completed analyzing usage breakpoints. Included in this document is detailed information on usage breakpoints for metering MERC's customer class usage bands, and the cost associated with those upgrades. This analysis supports continuation of MERC's existing customer class bands, as recommended by Ms. Hoffman Malueg. This will be discussed in further detail later in my testimony.

Q. PLEASE DESCRIBE SCHEDULE 1.8 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 1.8 provides an incremental cost analysis providing the incremental cost of service for Class 5, Electric Generation – Class 2 and Flex rate customer classes, and is utilized by Ms. Hoffman Malueg in conducting rate design.

Q. PLEASE DESCRIBE SCHEDULE 1.9 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 1.9 provides a summary of the CCOSS models results for revenue deficiencies by customer class.

XII. USAGE BREAKPOINTS AND FIRM/INTERRUPTIBLE CUSTOMER COST PRESENTATION

Q. WHAT DO YOU ADDRESS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I address MERC's agreement from Docket No. G011/GR-17-563, to provide information on usage breakpoints for metering that vary across customer class usage bands, and the cost associated with those upgrades. This study is located in Schedule 1.7 in Volume 3, Informational Requirement Document 12. I also address the presentation of customer consumption costs for the firm/interruptible customer classes in the CCOSS.

Q. HOW HAS MERC ANALYZED USAGE BREAKPOINTS FOR METERING COSTS THAT VARY ACROSS CUSTOMER CLASS USAGE BANDS?

A. In conjunction with the completion of MERC's CCOSS model, MERC prepared an analysis comparing meter costs based on original costs and then inflating those costs using the Handy-Whitman Index to better align all installed meter costs regardless of when any one meter was installed. MERC then compared the inflated meter costs across MERC's existing customer classes midpoints between breakpoints and the 2021 historical, full-year use per customer. The relative meter cost is the basis for this analysis as meters are unique pieces of equipment directly identifiable for each customer which vary based on the throughput and physical requirements of each individual customer. The cost of each customer's meter can be accumulated to the customer class level and compared between classes for consistency across meter size which varies directly based on individual customer usage levels. The results of this analysis are presented in Schedule 1.7 in Volume 3, Informational Requirement Document 12. This analysis demonstrates that MERC's current customer class usage breakpoints reasonably align with the usage breakpoints for meters which vary in size based on customer usage (among other considerations). This further supports continuation of MERC's current customer classification definitions, as previously approved in Docket No. G011/GR-17-563.

Q. HOW DOES THE CCOSS MODEL PRESENT FIRM, INTERRUPTIBLE, AND FIRM/INTERRUPTIBLE CUSTOMER CLASS VOLUMETRIC COSTS?

A. MERC's CCOSS model allocates firm demand-related costs to firm customer classes, and interruptible demand-related costs to interruptible customer classes. MERC's firm/interruptible customer classes are allocated both firm and interruptible demand related costs based on MERC's forecast of firm and interruptible therm sales, respectively, for the firm/interruptible customer classes. When calculating the volumetric costs associated with each firm/interruptible customer class in the CCOSS, the volumetric cost is computed as a single, per therm cost that includes both firm and interruptible demand-related costs. Therefore, the volumetric cost rate being shown for the firm/interruptible customer classes in Schedule 1.2 of the COSS is a "blended" rate taking into account both the firm and interruptible consumption.

Q. DOES THE VOLUMETRIC COST PRESENTED IN SCHEDULE 1.2 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12 FOR THE FIRM/INTERRUPTIBLE CUSTOMER CLASSES PROVIDE A REASONABLE BASIS FOR CCOSS?

A. Yes. As can be seen from Schedule 1.2 of Volume 3, Informational Requirement Document 12, the "blended" volumetric consumption cost rates for the firm/interruptible customer classes consistently fall within the bands of the 100% firm consumption cost rates and the 100% interruptible consumption costs rates for the respective customer classes. This attests to the fact that firm/interruptible customers have both firm and interruptible load, and are appropriately being assigned their share of those firm and interruptible demand-related costs. The results of the CCOSS model provide a reasonable basis for revenue allocation of separate firm and interruptible costs to firm/interruptible customer classes in the 2023 test year.

Q. IS THE COMPANY PROPOSING A CHANGE IN THE EXISTING RATE STRUCTURE OF FIRM/INTERRUPTIBLE CUSTOMERS WHICH ASSIGNS A SEPARATE RATE FOR FIRM USAGE, AND A SEPARATE RATE FOR INTERRUPTIBLE USAGE?

A. No. The “blended” volumetric consumption rate presented in Schedule 1.2 of the CCOSS model is based on the computational nature of the COSS model, and its allocation of demand-related costs to this customer class, and is not to be interpreted as a proposal of changes to the existing rate structure for the firm/interruptible customer classes. Please see MERC’s proposed revenue allocation and rate design presented by MERC witness Ms. Hoffman Malueg.

XIII. <u>CONCLUSION</u>

Q. IN YOUR OPINION, DOES MERC’S MINIMUM SIZE CCOSS PROVIDE A REASONABLE BASIS FOR ESTABLISHING RATES IN THIS CASE?

A. Yes. MERC’s minimum-size CCOSS provides reasonable estimates of revenue requirements by customer class, based on sound cost causation principles, and supports the rates proposed in this case.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY ON THE CCOSS AT THIS TIME?

A. Yes.