STATE OF MONTANA
Department of Public Service Regulation
PUBLIC SERVICE COMMISSION

DOCKET NO. 2022.07.078

JURISDICTIONAL COST OF SERVICE

ELECTRIC ACCOUNTING AND MARGINAL CLASS COSTS OF SERVICE

NATURAL GAS ACCOUNTING CLASS COSTS OF SERVICE

PRE-FILED DIRECT TESTIMONY OF
PAUL M. NORMAND
MANAGEMENT APPLICATIONS CONSULTING, INC.

ON BEHALF OF

NORTHWESTERN ENERGY

August 8, 2022

PRE-FILED DIRECT TESTIMONY

OF PAUL M. NORMAND

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Montana Public Service Commission
Docket No. 2022.07.078
Jurisdictional Cost of Service
Accounting and Marginal Electric COS by Class
NorthWestern Energy

STATEMENT L

STATEMENT M

I. POSITION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Paul M. Normand, and my business address is Management Applications Consulting, Inc. ("MAC"), 1103 Rocky Drive, Suite 201, Reading, PA 19609-1157.

Q. Are you the same Paul M. Normand who submitted pre-filed direct testimony on behalf of NorthWestern Energy ("NorthWestern" or "Company") presenting and sponsoring the cash working capital net lag days in the revenue requirement in this docket?

A. Yes, I am. Exhibit PMN-3 of that testimony contains my qualifications.

Q. What is the purpose of your pre-filed direct testimony in this portion of the docket?

A. The purpose of my pre-filed direct testimony is to present and support NorthWestern's four studies: two electric Embedded Cost of Service ("ECOS") studies, one representing a jurisdictional cost analysis and one representing a class electric supply and delivery analysis; a marginal cost of service study ("MCOS") for electric; and a natural gas ECOS study. Statement L included in the Statements and Workpapers volumes of this filing presents these four studies for NorthWestern's electric and natural gas assets. The ECOS studies I sponsor comport with standards for conventional jurisdictional and class cost of service studies commonly relied upon in the utility industry. Additional details for the ECOS, which consists of a complete unbundled analysis showing each functional cost by customer class, a stand-alone unbundled functional study, and a description of each allocation factor with an allocation file, are also included in Statement L. Statement L also includes the MCOS for NorthWestern's electric supply and delivery service and the Company's natural gas operations.

Q. How is your direct testimony organized?

A. My Direct Testimony consists of eight sections. This first section introduces and describes the purpose and organization of my testimony. Section II describes the ECOS Jurisdictional Cost of Service Study in Statement L, which identifies the Transmission costs and revenue requirements as discussed in the Pre-filed Direct Testimony of Glenda J. Gibson. Section III describes the electric studies (embedded and marginal) included in Statement L. Section IV summarizes the electric ECOS study. Section V summarizes the electric MCOS. Section VI details the Benchmarking with respect to the Company's last electric and natural gas case results. Section VII discusses the natural gas ECOS included in Statement L. Section VIII discusses the summary results of the Natural Gas ECOS. Section IX discusses the Statement M class rate design process for both electric and natural gas. This Statement is co-sponsored by NorthWestern witness Cynthia Fang and myself.

Q. Briefly describe the exhibits you are sponsoring in your testimony.

A. Exhibit PMN-4 presents a Glossary of Terms used in my testimony. Exhibit PMN-5 represents an electric jurisdictional cost of service study (new study), which aggregates costs on a functional basis consistent with the Federal Energy Regulatory Commission ("FERC") chart of accounts. Exhibit PMN-6 presents the electric ECOS Summary Results. Exhibit PMN-7 presents the electric MCOS Summary Results. Exhibit PMN-8 presents an overview of the various tables, which summarize the cost calculations undertaken in each table. Exhibit PMN-9 lists the many terms used in the natural gas study analysis of NorthWestern's costs. Exhibit PMN-10 presents the natural gas ECOS Summary Results.

II. EMBEDDED COST OF SERVICE STUDIES

GENERAL DESCRIPTION OF STUDIES

Q. Has NorthWestern prepared four studies for use in establishing electric and natural gas utility costs and proposed pricing levels?

A. Yes. The four studies (three ECOS and one MCOS) are included in Statement L. The ECOS studies rely upon the 2021 test year adjusted as set forth in ExhibitADD-1 attached to the Prefiled Direct Testimony of Andrew D. Durkin and in Statement G included in the Statements and Workpapers volumes in this filing. The costs employed by these studies reflect NorthWestern's electric and natural gas utilities' total adjusted test period revenue requirements.

The ECOS models used in the preparation of these studies are all using the same format and should greatly facilitate reviews and possible changes by participants in this Case.

Q. Why has NorthWestern filed several ECOS studies in this rate increase application?

A. NorthWestern has prepared and filed three separate ECOS studies and one MCOS study as the underlying cost basis upon which to develop its jurisdictional (electric) and class revenue distribution levels at a uniform rate of return for both electric and natural gas operations. The ECOS studies will provide the allocated costs and related revenue requirement targets by function and rate class at NorthWestern's desired uniform Rate of

Return ("ROR"). The ECOS plant results in these studies are also used to derive the allocated property taxes by rate class. The ECOS studies also present details with respect to NorthWestern's various production assets' revenue requirements as determined by Mr. Durkin in his testimony and exhibits.

Q. Do you believe that an ECOS study is appropriate for use in allocating costs?

A. Yes, I believe that embedded cost of service studies provides a fair, transparent, and reasonable basis for allocating costs on a retail level. In fact, the use of ECOS studies for allocating costs and deriving revenue targets by cost function and class of service on a uniform equalized basis is very common in the utility industry. These results are an excellent benchmark or reference level to assist the Company in rate design as discussed in the Pre-filed Direct Testimony of Cynthia S. Fang.

Q. Generally describe the process of conducting an ECOS study.

A. An ECOS study is usually performed in three steps – functionalization, classification, and allocation. Functionalization identifies the operations level where the costs are incurred, either directly or indirectly, with respect to the physical process of providing service. For example, costs associated with distribution primary (distribution function) are segregated from costs associated with transmission (transmission function). Similarly, production investment and related costs are segregated from the costs of transmission and distribution. Classification separates costs according to the product characteristics of service as denoted by the primary cost driver – i.e., capacity, commodity, and customer-related costs. The allocation process uses this information, along with the knowledge that certain costs are incurred exclusively for the benefit of most customers (direct assignments, e.g. services and meters), to allocate or assign the specific cost components that have been functionalized and classified to specific classes. To the maximum extent practical, costs are allocated based on factors that reflect the manner in which the costs arise. As a result, several different approaches to allocation are considered: monthly production volumes, transmission costs on NorthWestern's 12 monthly peaks, and more localized maximum class demands to classes for required distribution facilities along with customer-related costs that are typically closest to the customer such as services and meters, which are typically required by all secondary customers for receiving energy from the Company.

Q. Please describe the process of cost functionalization.

A. After all of the individual cost components representing the total NorthWestern revenue requirement have been gathered for the cost of service studies, the various cost components are separated according to the function they perform. The specific line-by-line detail costs by each function have been provided in Statement L, functional cost analysis. These functions are:

- Production – costs associated with NorthWestern's various generating facilities for electric and natural gas supply;
- Transmission – costs associated with various high voltage facilities that connect various resources of electricity for delivery to distribution substation load centers and high pressure gas transmission for delivery to gas consumers;
- Distribution – costs associated with distributing the electrical energy from the high voltage transmission system to the substations and end users' points of delivery (meter) through many distribution substations and secondary voltage transformations (primary

and secondary) for electric and from gas supply to high pressure and low pressure mains, services, and meters to ultimate consumers;

- Customer – costs associated with providing electric and natural gas services to customers by connecting them to the respective grids, i.e., service lateral connecting customer locations to NorthWestern's electric or natural gas grid (secondary/primary and natural gas mains), metering, billing, etc. This approach recognizes that both electric and natural gas consumers require a lateral service and meter to receive energy from the Company; and
- Statement L – A complete and separate FERC jurisdictional cost analysis, as described by Ms. Gibson is also provided.

For the most part, the unbundled costs of a utility such as NorthWestern are already somewhat functionalized based on recorded data. In fact, the FERC Uniform System of Accounts ("USOA"), which the Montana Public Service Commission ("Commission" or "MPSC") requires NorthWestern to follow, provides for the recording of a major portion of costs by accounts defined and arranged by functional level.

Q. Please describe the process of cost classification.

A. Cost classification is the process of further categorizing the functionalized costs according to the cost-causing characteristic of the utility service provided. The three principal cost classifications are capacity-related (demand) costs, energy-related (kilowatt-hour ("kWh")) costs, and customer-related costs.

Capacity-related costs (also referred to as demand-related costs) are those fixed costs related to monthly system one-hour or monthly peaking demands upon the system (some generation and transmission) and the much greater non-coincident class peak demands for assigning more local distribution-related costs imposed by customers on the Company's extensive local delivery network. This approach highlights the fact that the majority of distribution costs are fixed in nature. Energy-related costs are those costs related to the kWh the customer utilizes over a specified period, such as fuel costs and production facilities. There does not exist any energy influence or cost driver on the vast majority of transmission and distribution costs. Customer-related costs are those costs which are incurred simply due to the number of customers on the system for delivery of energy. These are costs closest to the customer premises (meters and services), which generally are not available for use by anyone else and have no causal relationship to kWh consumption or volumes; yet all customers require these investments to be connected to the electric or natural gas grid to receive supply. Local facilities, which are the next level of delivery, require that distribution secondary transformers and some secondary circuits (conductors) be installed to connect secondary customers to the electric utility's primary voltage grid. Customer costs also include the meter reading, billing, and customer assistance provided by NorthWestern.

A careful review of these cost categories clearly indicates that virtually all of distribution costs are fixed in nature (customer or demand) and unaffected by any volumetric consumption. Any attempt to assign these costs on a volumetric basis is simply a misdirected effort to skew the recovery of costs thereby encouraging higher subsidy levels.

Q. Please describe the process of cost allocation.

A. Cost allocation is the assignment of functionalized and classified costs to customer classes. Allocation factors reflecting capacity requirements, customer costs, and commodity volumes rely on operating and accounting data to produce representative allocation factors in the form of percentages that add up to 100 percent. These allocation factors applied to specific plant, rate base items, and various expenses establish the total costs of providing service for each class of customer categories under review. For example, NorthWestern designs its electric distribution grid to maintain deliverability during the more local max peak demand hours, which are generally greater than a coincident peak measure and more localized for NorthWestern's extensive service area. As a result, it is reasonable to assign the costs of distribution plant on the higher class peak demands, as I have done in this case. In turn, it is possible to develop allocation factors for each detailed cost item such that costs are allocated on the metric that best embodies the manner in which costs arise. For example, actual meter costs are assigned according to the number of customers by class weighted by their relative costs of meters, as are service laterals. It is recognized that customers cannot readily use or benefit from any other customer's meter or service lateral, which are required to connect each customer to NorthWestern's delivery grid. These calculations are further constrained by the installed number of units.

ELECTRIC ACCOUNTING ECOS STUDIES

Q. Please discuss all of the cost of service studies prepared by MAC and included in Statement L.

A. Statement L contains four studies prepared for both electric (three) and natural gas distribution (one). I will discuss each as follows:

1. Electric Class Embedded Cost of Service,

2. Electric Marginal Cost of Service Study,
3. Jurisdictional Electric Transmission Study, and
4. Natural Gas Distribution Class Embedded Cost of Service.

Q. How are the results of the Jurisdictional cost of service study incorporated in the Company's proposed revenue requirement?

A. The specific discussion as to the actual recognition of the proper level of retail transmission cost recovery in this filing has been detailed in Mr. Cashell and Ms. Gibson's direct testimonies and reflected in Mr. Durkin's testimony and exhibits.

Electric Class ECOS Study

Q. Please describe the electric class ECOS study detail provided in Statement L.

A. The electric Class Cost of Service section of the ECOS consists of 238 pages divided into sections as shown below. Each section of the ECOS includes one page showing the total Montana and total class summaries followed by seven pages of customer class detail.

The electric embedded class cost of service section of the ECOS consists of 238 pages as follows:

Pages	Description of Cost of Service Study Sections
1 through 7	Summary of Results at Present Rates
8 through 14	Summary of Results at Equalized Proposed Rate of Return
15 through 28	Electric Plant in Service
29 through 35	Depreciation & Amortization Reserve
36 through 42	Additions and Deductions to Rate Base
43 through 49	Operating Revenues
50 through 64	Operation & Maintenance Expense
65 through 91	Depreciation & Amortization Expense
92 through 98	Taxes Other Than Income Taxes

99 through 112	Development of Income Tax Expense
113 through 140	Development of Salaries & Wages Allocation Factor
141 through 182	Allocation Factor Table
183 through 224	Allocation Factor Proportions Table
225 through 231	Allocated Direct Assignment Allocation Factors
232 through 238	Revenue Requirements at Present and Equalized Rates of Return

Q. Please describe how you functionalized costs in the electric ECOS model.

A. First, I defined 14 cost functions:

1. Production – Colstrip Unit 4
2. Production – Hydro Units
3. Other Generation (David Gates, Spion Kop, and Two Dot)
4. Transmission
5. Distribution Substation
6. Distribution Primary
7. Distribution Secondary
8. Distribution Line Transformers
9. Distribution – Customer Service Laterals
10. Distribution – Customer Meters
11. Street and Area Lighting
12. Customer Meter Reading
13. Customer Accounts & Records
14. Production Energy Component

A detailed Functional Labor Expense allocator (pages 113 through 140) was also developed to more accurately functionalize labor-related costs. This allocator was developed by functionalizing all labor-related Operation and Maintenance ("O&M") expenses by each account and summing these allocated amounts to create the labor expense allocation factor, which is represented by the acronym **SALWAGES**.

A list of all functional and class allocation factors (externally derived and internally derived) is also provided on pages 141 through 182. These allocation factors are converted to percentages as shown on pages 183 through 224 of the study and are used to allocation costs within in ECOS.

Q. How did you use this SALWAGES allocator?

A. I used SALWAGES to allocate certain costs relating to Rate Base deductions (pages 36-42), and with certain items of Miscellaneous Amortization Expense (pages 85-91) and Taxes Other than Income Taxes (pages 92-98).

I modified this allocator to exclude administrative and general ("A&G") expenses (SALWAGESXAG) to allocate Intangible Plant (pages 15-21), General Plant and Common Plant (pages 21-28) and A&G Expenses (pages 78-84).

Q. Please describe how costs were classified in the electric ECOS study.

A. As mentioned above, the classification of costs as capacity-, commodity-, and customer-related takes place within the development of allocators used to assign costs to customer classes. Please refer to electric ECOS pages 141-154 and pages 183-196 for external allocators (externally derived). All internally developed allocators (composite) appear on pages 155-182 and pages 197-231 of the electric ECOS study, which show the classification and allocation steps. On these pages, the costs included various Production facilities, Transmission, and Distribution Other functions that are allocated to classes using the capacity-related allocation factors, thus effectively classifying these functionalized costs as capacity-related costs. Similarly, the costs included in the Meters, Service Laterals, Meter Reading, Customer Records, and Customer Other functions are allocated to customer classes using the CMETER, CSERVICE, CMETRDG, CUSTREC, and other Customer allocation factors, thereby producing costs that are classified as customer-related costs.

Q. Please describe how you allocated costs in the electric ECOS study.

A. Once costs were functionalized and classified, I allocated these costs to customer rate classes, as shown on electric ECOS pages 15-28 of the study. These are the underlying foundation to the cost of service study results and are described in more detail below.

1. Production - Each production plant allocation factor reflects the monthly and annual operation of NorthWestern's electric production facilities based on 2021 historical data, which is provided in the Workpapers accompanying NorthWestern's filing. The production plants included in MAC's analyses consist of the following:
    a. Colstrip Unit 4;
    b. Hydro Units; and
    c. Production Other:
        1) David Gates Generating Station;
        2) Spion Kop Unit; and
        3) Two Dot Unit.

    The allocation of each production unit was prepared in a similar manner by using the monthly 2021 generation allocated to classes based on their proportion of their calendarized monthly sales adjusted for losses. This approach was deemed most representative of generation assets of NorthWestern after reviewing the monthly statistics for three years of data (2019, 2020, and 2021). The final allocator was simply the sum of all 12 months of class allocations which resulted in assigning all the costs for each production unit. This process was repeated uniquely for each unit.

2. Transmission – The transmission cost allocator was based on a simple average of each class's contribution to NorthWestern's 12 monthly one-hour system coincident peak hour. This reflects the dual nature of transmission integrating supply resources, interconnections, and dispersed substations in NorthWestern's service territory.
3. Distribution – As can be noted from the following discussions, all of the costs relating to Accounts 362 – 368 reflect fixed electric costs with the primary driver being the higher class local max demands for installing facilities as there is no support for considering any volumetric consumption in the installation and the subsequent allocation process for these costs.
   a. Substation – The distribution substation allocator was based on the customer class load contribution to class peaks based on NorthWestern's load research data after eliminating higher voltage classes not served by the distribution system.
   b. Primary – This allocator includes overhead conductors, poles, underground cable, and conduit. It was developed based on the higher class demand contribution to the class peaks after eliminating substation and higher voltage loads not served by these facilities.
      i. Primary Overhead – Accounts 364 (Poles) and 365 (Conductors),
      ii. Primary Underground – Accounts 366 (Conduit) and 367 (Conductors),

iii. Secondary Poles and Circuits – Accounts 364, 365, 366, 367, and 368 include secondary circuits, and line transformers. The secondary allocator is equal to the primary class demands less primary and higher voltage customer demands, and

iv. Secondary Transformers – Account 368 includes equipment that transforms primary voltage to a secondary level for delivery to most customer meters.

Note: Items i. and ii. relate to primary distribution. These costs were further segregated into three-phase costs (allocated to all customers) and single-phase costs (allocated only to smaller customers). Items iii and iv are secondary facilities considered as local facilities for serving customers and connecting them to the primary grid. Item iii. was also separated into three-phase and single-phase costs for allocation purposes. These secondary facilities reflect costs of serving secondary customers being transformed from primary voltages to a secondary voltage delivery service.

4. MeterCost – The meter allocator is based on typical metering cost per customer, including installation for each rate class. This is the most accurate approach to developing meter costs for each rate class as the costs can vary somewhat between service classes based on Company data. These estimated costs are then multiplied by the number of assigned meters in each class, which results in a total cost estimate by customer class that is employed as the meter cost allocator to assign actual meter costs in the electric ECOS study. The methodology for allocating meter costs to classes is the same as employed in NorthWestern's previous electric ECOS study.

5. Services – Similar to the MeterCost allocator, the services allocator is based on an estimate of service cost per customer multiplied by the number of estimated services by customer classes. Like meter costs, discussed above, this approach recognizes the varying costs by customer classes and is the most representative of cost assignment. As in the case of meters, the services allocation factor in this study is calculated in the same manner as in NorthWestern's previous electric ECOS study.
6. Lighting – These costs are identified by FERC and were a simple direct assignment based on the number of lights. A detailed analysis of each electric lighting service being provided was reviewed and re-categorized into fourteen (14) unique categories as discussed by Ms. Fang.
7. MeterRdg – The meter reading allocator was developed in a two-step process using detailed cost accounting data. Meter reading costs were separately identified for automated meter reading and manual meter reading. The count for each type of meter reading was then identified by rate class to develop the meter reading allocator. This allocation methodology remains unchanged from NorthWestern's previous filing.
8. CustRecords and Collection – Account 903 was separated into two categories - customer account and collections expense. Customer account expense is assigned to rate classes based on the number of bills. The costs of the computerized customer records system are similar for each customer and do not differ significantly by rate class, making customer count the proper allocator. This allocation methodology remains unchanged from NorthWestern's previous filing. Customer collections expense was allocated to the rate classes based on the average write-offs for the last three years, this methodology remains unchanged from NorthWestern's previous

filing. The final allocator (CUSTREC) is a composite factor which weighted these two costs categories.

9. Customer Service Expenses – The allocator for other customer service costs used a weighted factor consisting of 75% customer count and 25% sales, which is consistent with the prior study and more properly assigns these costs to all customers. As is the case with the other customer-related allocation factors, the allocation methodology remains unchanged from NorthWestern's previous filing.

Q. Please describe the where the costs to customer classes can be found in the electric ECOS study.

A. As stated above, **e**ach section of the ECOS described below includes one page of customer class summary followed by seven pages of customer class level detail. The electric ECOS study pages provide the following information:

- Pages 1 through 7 – Shows the summary results at present rates and revenues for NorthWestern by Rate Base and Operating Expense, which results in a ROR (line 34) in total and by classes (page 1) and subclasses (pages 2 to 7). Line 36 shows the Index of Return, which simply presents the level of return for each class relative to the overall system.
- Pages 8 through 14 – Shows the summary results at the proposed ROR of 7.27% (line 53) and the required revenue levels to achieve this ROR for NorthWestern in total and by class (page 8) and subclass (pages 9 through 14) as well as the increase required to achieve NorthWestern's uniform 7.27% ROR for all classes (lines 73 and 76). Note that in deriving these revenue requirements, the higher Colstrip 8.25% rate

of return was incorporated into the production category with all other ROR decreased to achieve an overall 7.27% rate of return.

Lines 79 and 80 show the class revenue required to achieve the same 7.27% return (line 55) for all classes and the associated percent increase to existing revenues shown on Table 1, line 6.

The results on pages 1 through 14 are also summarized on pages 232 through 238 of the electric ECOS study.

- Pages 15 through 42 – Present the development of rate base items and their allocation to classes.
- Pages 43 through 49 – Present all operating revenues.
- Pages 50 through 64 – Present all the allocated O&M expenses.
- Pages 65 through 91– Show the Depreciation and Amortization expenses.
- Pages 92 through 98 – Shows the Taxes Other than Income Taxes.
- Pages 99 through 112 – Show the development of Income Taxes.
- Pages 113 through 140 – Show the development of the Labor allocation factor.
- Pages 141 through 182 – Show the development of all the demand, customer, and internal allocation factors with the support for these values provided in the Statement L Workpapers.
- Pages 183 through 224 – Show the same information as pages 141 through 182 converted to a unitized basis where all columns total to 1.00. These results provide analysts with information as to the proportion that each class or subclass is assigned when using each allocation factor.
- Pages 225 through 231 – Show the allocated direct assignment allocation factor for account 904 uncollectible accounts (write-off). This allocation factors directly

assigns costs to each customer class while using the same cost component structure as sales revenues.

- Pages 232 through 238 – Shows the resulting electric ECOS study at present revenue levels and equalized (uniform ROR of 7.27%) revenues. This summary is a workpaper used to develop the unbundled cost components found in the Statement L, Section A-3. This information is also shown in more detail on pages 1 through 14 of the electric ECOS study.

Table A below summarizes the class-by-class results of the ECOS study at present and at n uniform, equalized ROR revenue level (see ECOS pages 1 through 14 and pages 232 through 238) and the increase that would be required.

Table A
Equalized (7.27%) Class Revenue Requirement Comparison

	Revenue at Present Rates	Revenue at Equalized ROR	Increase to Equalized ROR	Percent Increases from Current
Residential	243,656,855	305,908,392	62,251,537	25.55%
Secondary GS-1	236,111,829	269,787,359	33,675,530	14.26%
Primary GS-1	22,631,442	22,640,454	9,012	0.04%
Substation GS-2	14,670,941	18,658,996	3,988,055	27.18%
Transmission GS-2	6,633,988	5,895,037	(738,951)	(11.14%)
Irrigation	9,634,131	10,587,229	953,098	9.89%
Total Lighting	16,336,211	16,935,283	2,754,921	20.28%
TOTAL NORTHWESTERN	546,920,475	649,813,678	102,893,203	18.81%

Q. What is the purpose of Exhibit PMN-4?

A. Exhibit PMN-4 is a glossary of electric terms used in discussing cost of service. Because terms may take on a unique meaning when used to describe the cost of service process, a glossary is provided to avoid any possible confusion and to comply with Administrative Rules of Montana ("ARM") 38.5.176(1)(a).

<u>Jurisdictional Embedded Cost of Service</u>

Q. Please discuss the first embedded cost of service study.

A. The final embedded electric cost of service study is a jurisdictional ECOS study which represents the development of a functional total Company cost of service that identifies all costs as FERC Jurisdiction (transmission function) or MPSC Jurisdiction.

Q. What approach did you utilize as the foundation for determining these costs?

A. The primary purpose of the jurisdictional cost of service is to quantify NorthWestern's total costs relating to the Company's Transmission function using the approach generally accepted by FERC guidelines, and to then allocate those Transmission costs between NorthWestern's FERC and Montana jurisdictions. This is NorthWestern's approach for identifying costs included in its FERC annual formula rate process.

Q. Is the FERC approach reasonable in determining transmission costs in a Montana-only costs determination?

A. Yes, it is, as that is the primary approach recognized by most utilities and regulators as established on a price level using standard allocators (five) as proscribed by FERC. Using this approach, NorthWestern determines its total Transmission revenue requirement and corresponding rate applicable to all users based on appropriate billing units.

Q. Please describe the jurisdiction ECOS study detail provided in Statement L, Section C.

A. The jurisdiction ECOS consists of 34 pages divided into sections described below. The jurisdictional ECOS study provides the following information for Total Montana, FERC Jurisdiction, and the MPSC Jurisdiction:

- Page 1 – Shows the summary results at present rates and revenues for NorthWestern by Rate Base and Operating Expense, which results in a rate of return (ROR) as shown on line 34. Line 36 shows the Index of Return, which simply presents the level of return for each class relative to the overall system.
- Page 2 – Shows the summary results at the proposed ROR of 7.27% (line 53) and the required revenue levels to achieve this ROR for NorthWestern in total. The FERC Jurisdiction was set at the allowed ROR of 7.17% and the MPSC Jurisdiction was set at 7.29% to achieve the overall ROR of 7.27%

  Line 76 shows the class revenue requirements required to achieve the 7.27% return (line 55).

  The results on pages 1 and 2 are also summarized on pages 34 of the jurisdictional ECOS study.

- Pages 3 through 6 – Present the development of rate base items and their allocation to classes.
- Page 7 – Presents all operating revenues.
- Pages 8 through 12 – Presents all the allocated O&M expenses.
- Page 13 – Show the Depreciation and Amortization expenses.
- Page 14 – Shows the Taxes Other than Income Taxes.
- Pages 15 and 16 – Show the development of Income Taxes.
- Pages 17 through 20 – Show the development of the Labor allocation factor.

- Pages 21 through 26 – Show the development of all the demand, customer, and internal allocation factors.
- Pages 27 through 32 – Show the same information as pages 141 through 182 converted to a unitized basis where all columns total to 1.00. These results provide analysts with information as to the proportion that each class or subclass is assigned when using each allocation factor.
- Page 33 – Show the allocated direct assignment allocation factor for account 904 uncollectible accounts (write-off). This allocation factors directly assigns costs to each customer class while using the same cost component structure as sales revenues.
- Page 34 – Shows the resulting electric ECOS study at present revenue levels and equalized (uniform ROR of 7.27%) revenues. This information is also shown in more detail on pages 1 and 2 of the Jurisdictional ECOS study.

III. <u>MARGINAL COST OF SERVICE STUDY – ELECTRIC</u>

Q. Have you prepared an electric MCOS study for in this filing?

A. Yes, I have. The second part of Statement L presents details of the electric MCOS study, including 14 tables that show the step-by-step development of the estimated marginal costs. I attached the summary results (MCOS Table 14) as Exhibit PMN-7 to this testimony.

Q. Please summarize the objectives of a marginal cost of service study.

A. In simplest terms, a marginal cost of service study provides an estimate of the cost of providing an additional unit of service. These services include providing a source of supply (in the case of Non-Choice customers), delivering power through the transmission and distribution systems whenever requested, providing a connection to the local distribution system, preparing and processing bills, responding to customer inquiries, and other services necessary to deliver electricity to customer premises. The costs incurred by the utility to provide these services consist of both short-run and long-run marginal costs. For example, short-run costs include such services as providing a few more kWh of electricity. As the term implies, short-run costs vary instantly with changes in consumption. Long-run costs change over a longer period of time as plant investments are adjusted to meet changes in the level of services to be provided. Long-run costs include costs such as expanding the transmission or distribution system to provide capacity needed to serve additional load at the time of maximum functional demand. For rate-making purposes, the marginal cost of service study employed in this filing reflects both long-run and short-run electric costs.

Q. Please summarize the different elements of a marginal cost of service study for an electric utility.

A. In a typical electric marginal cost of service study, costs are first functionalized and then classified. In the functionalization step, the marginal production, transmission, and distribution components are developed to reflect the cost per unit of expanding the production, transmission, and distribution network to accommodate growth in customers' requirements. The functionalization step is recognized in ARM 38.5.176(2). In the classification step, the costs are further identified in terms of the unit cost to provide customers with additional demand, energy, or customer services. The marginal customer costs reflect the unitized cost, based on cost accounting data and engineering estimates, to add and maintain a customer on the system in each of the customer classes and, therefore, may include initial costs such as physical connection costs and marketing expenses, as well as on-going costs to maintain the connection, bill the customer, and service the customer's facilities. This classification step is recognized in ARM 38.5.176(3). As discussed in the testimony below, NorthWestern's marginal cost model performs these steps as well as the allocation step required in ARM 38.5.176(4).

The NorthWestern electric marginal cost of service study summarized in Statement L identifies marginal production costs even though supply costs are not directly employed in the design of transmission and distribution rates based on the current administrative rules of the MPSC. NorthWestern provides supply services for customers who have not chosen or are required by law to take their supply from marketers. These customers, commonly referred to as Non-Choice or Electric Supply customers, purchase both electric supply and delivery services from NorthWestern. Customers who have chosen marketers to supply their energy, commonly referred to as Choice or Competitive Electric Supply Customers, take only distribution and transmission services from NorthWestern. Their transmission service is also subject to FERC jurisdiction, and their supply services are provided by an alternative supplier. Regardless of the customer type, the measurement of marginal supply costs will play no role in the measurement of transmission and distribution system delivery marginal costs.

Q. Please summarize the methodology you employed.

A. I computed the marginal costs to serve each of NorthWestern's rate classes based on costs measured as of January 1, 2024, which is the first day of the year that is two years (?) beyond the filing date of the July 2022 cost of service studies. The methodology I employed to compute marginal costs is relatively straightforward. For energy supply cost estimation, I used the forecasted price of energy delivered to NorthWestern's system to determine the hourly costs of serving a small increment of customer load. The marginal source of supply for capacity or demand is estimated based on a 50-megawatt ("MW") peaker facility at David Gates Generating Station. In the case of transmission and distribution service, I used regression techniques applied to historical and projected plant investment data to estimate the hypothetical transmission and distribution costs to serve an increment of customer load, including the unit costs of adding transmission and distribution plant facilities as well as the additional costs for O&M. I used engineering estimates and recent cost accounting data to identify the investment in secondary line transformers, services, and meters and added O&M expenses necessary to serve a new electric customer. Finally, I developed the annual revenue requirements to serve each of NorthWestern's rate classes from these factors. These costs are stated in terms of customer, energy, and demand charges.

Q. What time periods did you select for the evaluation of electric marginal costs?

A. With the exception of supply costs, I did not create time differentiated marginal costs in my study. In general, future system costs are driven by the need to serve customer summer and winter peak loads. Over the past decade, NorthWestern has experienced years in which it was a winter peaking electric utility and years in which it was a summer peaking electric utility (see Statement L, Section B, Table 2, page 1). Since the physical capability of most electric utility equipment is generally limited by temperature rise, equipment that is sized to meet summer peak loads, except for solar generation, can generally handle winter loads that can be greater. As a result, I used the summer peak load as the primary driver of forward looking marginal costs. Consequently, the summer system coincident peak hour, which places the maximum load requirements upon NorthWestern's electric system, measures all capacity costs.

Q. If the distribution peaks that drive distribution investments do not necessarily occur at the same time as NorthWestern's system experiences its system coincident peak, why did you not use non-coincident peaks to measure distribution peaks?

A. In practice, equipment loads are a function of the diversity of the loads they serve with load diversity ranging from no diversity at the customer's meter to a high level of diversity at the supply and transmission level. Ideally, the marginal cost of service study should measure equipment investment as a function of the load it serves at a diversity level matched to the equipment characteristics. So transmission line capacity is influenced by less diversity than substation capacity and substation capacity is influenced by less diversity than primary lines. However, few utilities have adequate load research data or resources to identify the historical loads throughout the transmission and distribution system. In the current study, MAC evaluated and employed annual loads dating back to 1995 in the marginal cost analysis. NorthWestern could provide coincident peak demands for each year, but could not consistently provide demands at other levels of the system other than for the current year. Consequently, the methodology I employed measures system marginal transmission and distribution costs computed per unit of coincident peak demand. Then, using current load research data to estimate the coincident peak loads for each class, I quantified the marginal costs to serve each class.

Q. How have you organized your marginal cost of service study in Statement L?

A. The electric marginal cost of service study consists of 14 different tables and supporting calculations. The organization of the marginal cost of service study can more readily be understood by referring to Exhibit PMN-8, which shows the logical progression of the calculations. The marginal study begins with plant investment data and proceeds through to the development of class revenue targets, as discussed above. The results from the marginal cost of service study are shown in Tables 12 through 14. The other 11 tables present the calculations leading to these summary results and are an integral part of the marginal cost of service study. Table 14 incorporates all the marginal cost estimates and adjusts them to constrained revenue requirements based on an equi-proportional basis, which I explain below.

Q. Referring to the flow chart in Exhibit PMN-8, please provide a brief overview of the electric marginal cost of service study.

A. The first three tables develop the plant investment necessary to serve load growth. Table 1 develops the production plant investment cost requirements based on using a peaking facility rated at 50 MW, as mentioned above. Table 2 develops the transmission investment costs. Table 3 addresses both the capacity-related distribution plant investments and the customer-related investments to the distribution system. Table 4 details the estimated marginal production O&M expenses. Table 5 computes marginal transmission capacity-related O&M expenses. Table 6 computes marginal distribution capacity-related O&M expenses as well as customer-related O&M expenses. Table 7 develops loading factors used to quantify marginal costs not individually estimated, such as A&G expenses. Table 8 presents levelized fixed charge rates used to translate one-time capital investments into annual revenue requirements. Tables 9, 10, and 11 summarize the results of all prior calculations and provide marginal capacity, energy, and customer-related costs, respectively. Table 12 summarizes the previously developed unit marginal costs, multiplies these unit costs by function and then by the units of service required by each customer class, and provides the total marginal costs for each class of customers. Table 12 also shows that the long-run marginal costs to serve NorthWestern's electric customers are significantly higher than present revenue levels. Table 13 provides billing unit costs by dividing the Table 12 total costs by the appropriate billing units for the 2021 test period presented in the revenue requirement included in this docket. The unit costs set forth in Table 13 provide marginal cost-based rates prior to reconciling to NorthWestern's allowed revenue requirement and before considering rate impacts upon customers. Recognizing that Supply and Delivery Services rates must be constrained to the revenue requirement proposed in this docket, Table 14 develops an equi-proportional adjustment to all costs (supply and delivery) and provides unit costs at NorthWestern's proposed revenue levels. The equi-proportional adjustment is an across-the-board percent reduction to calculated marginal unit costs.

Q. Earlier you mentioned the functionalization of costs. Please summarize the functional assignments that you made for this study.

A. I employed a straightforward method of functionalizing marginal costs. Referring to the marginal cost of service study flow chart, Exhibit PMN-8, the <u>Production function</u> is shown in column form along the left side of the chart and includes:

- Production Plant,
- Capacity-related Production O&M Expenses,
- Loaded Administrative and General Expenses, and

- Energy-related O&M Expenses.

The <u>Transmission function</u> is shown in the center of the chart and includes:

- Transmission Plant,
- Transmission O&M Expenses, and
- Loaded Administrative and General Expenses.

The <u>Distribution - Capacity Function</u> is shown in the third column toward the right side of the flow chart and includes:

- Distribution Plant excluding Services and Meters,
- Distribution O&M Expenses excluding Services and Meters, and
- Loaded Administrative and General Expenses.

The <u>Distribution - Customer Function</u> is shown on the right side of the flow chart and includes:

- Distribution Plant for Services and Meters,
- Distribution O&M Expenses related to Services and Meters,
- Customer-related O&M Expenses, and
- Loaded Administrative and General Expenses.

Q. How did you classify costs?

A. Referring again to the marginal cost of service study flow chart, Exhibit PMN-8, I defined three cost classifications as follows:

<u>Capacity</u>

- Production Investment – Peaker Costs
- Capacity-related Production Expenses
- Transmission Investment
- Transmission O&M Expenses
- Distribution Investment excluding Services and Meters
- Distribution O&M Expenses excluding Services and Meters
- Administrative and General Loaders related to the above
- Electric losses related to the above

Energy

- Variable Production O&M Expenses
- Administrative and General Loaders related to the above
- Losses related to the above

Customer

- Meter and Service Investment
- O&M Expenses related to Meters and Services
- Customer Accounts & Customer Service Expenses and Marketing & Sales Services Expenses
- Administrative and General Loaders related to the above

Q. In your opinion, does the electric marginal cost of service study submitted in Statement L meet the Commission's administrative rules?

A. Yes, I believe it does. NorthWestern's marginal cost of service study comport with the MPSC's generic marginal cost model requirements that are set forth in detail in ARM 38.5.176(2). NorthWestern's marginal cost of service study provides exactly the information requested. ARM 38.5.176(3) requires marginal costs to be determined using unit marginal costs as done in NorthWestern's study. ARM 38.5.176(4) specifies that the inputs used to calculate class marginal costs should include methods to compute annualized costs, which NorthWestern has done by the use of the economic fixed charge rate. This rule also requires that NorthWestern "select administrative and general marginal cost methods and compute factors..." and "select general and common plant marginal cost methods and compute factors… ." This is exactly the approach that NorthWestern has employed in its marginal cost methodology. In addition, NorthWestern's marginal cost of service study functionalizes costs as required by ARM 38.5.176(2); classify and allocate costs as required by ARM 38.5.176(3); employ loss factors, calculate operation and maintenance, employ administrative and general expense and general and common plant factors as required by ARM 38.5.176(4); employ the time frames, carrying charge calculations, and proxy cost estimates as required by ARM 38.5.176(5); and identify marginal costs by function, expressed on a per unit basis, precisely as required by ARM 38.5.176(2)(b). NorthWestern's study provides exactly the information requested and meets the MPSC's filing requirements.

Q. So far, you have addressed your marginal cost of service study in general terms. Please provide additional details of your calculations.

A. I will discuss each cost classification in sequence beginning with Capacity followed by Energy Costs and lastly, Customer Costs.

<u>CAPACITY COSTS</u>

Q. Please describe your calculation of marginal capacity costs.

A. Demand or capacity costs for electric utilities consist of all or part of the costs functionalized as production, transmission, or distribution. Production capacity costs are typically the "per unit" costs of expanding production capability to meet a long-run increase in customers' requirements for electric service.

The marginal cost method employed by NorthWestern measures capacity cost using the least capital intensive alternative to provide capacity at time of peak and measures energy costs in the short run at the margin. Thus, the least capital intensive alternative to serve growth in peak load is a 50-MW peaking unit as detailed in Table 1 of Statement L, Section B.

Q. Please describe your analysis of marginal transmission capacity costs.

A. Long-run marginal costs for historical transmission investments were calculated as shown beginning in Table 2, page 2 of Statement I, Section B. The approach used to estimate marginal transmission plant investment is relatively straightforward and similar to the method used to measure substation and primary distribution plant investment. The historical and projected plant investments were first restated to 2022 pricing levels using the *Handy-Whitman Index of Public Utility Construction Costs*. The costs were then reduced to eliminate the investments made to replace retiring plant. Investments for replacement facilities are not made to serve additional load growth and, therefore, are by definition not marginal costs. The resulting costs were tabulated in Table 2, page 1, where they were statistically evaluated against six separate measures of coincident peak demand using simple linear regression techniques. The regression results were sufficiently robust to estimate long-run marginal transmission costs.

Q. Please describe your analysis of marginal distribution capacity costs.

A. System design is driven by the need to provide adequate capacity at times of more localized distribution peaks. Distribution level (substation and primary line) coincident peak demands were employed as the causative factors driving distribution substation and line investments, respectively.

Distribution capacity costs are complicated by the need to measure capacity costs for substations, the primary delivery system, and the secondary delivery system. Many of NorthWestern's largest customers take service directly from substations and neither use nor benefit from the existence of primary lines. Similarly, larger customers are served at primary voltage and do not require secondary line transformers to receive service. Consequently, the marginal cost of service study segregated distribution capacity costs between substations, primary facilities, and secondary facilities and calculated the marginal costs separately for each.

In order to accurately estimate current marginal costs from historical distribution investments, the historical capacity-related additions were identified and restated in 2022 dollars in Table 3, pages 1-3 of Statement L, Section B, using the *Handy-Whitman Index for Public Utility Construction Costs*. Once again, costs incurred for replacement of retired plant were removed. The resulting investments were then statistically analyzed on pages 1-3 of Table 3.

Similar to the transmission analysis, various measures of coincident peak demand on the distribution system[1] were considered. Three regressions were employed to evaluate the marginal costs of substation, primary, and secondary investment. Each of these regressions was sufficient to estimate the long-run marginal costs, and the marginal cost per kW estimated by each equation produced similar and stable results.

Q. How did you compute the capacity-related component of transmission and distribution O&M expenses?

A. The calculations of the capacity-related component of transmission and distribution O&M expenses are shown on Tables 5 and 6, respectively. On page 1 of Table 5 of Statement L, Section B, the annual transmission expenses tabulated on page 2 were first restated in terms of 2022 dollars using the Gross Domestic Product Implicit Price Deflator ("GDP IPD"). Regression analyses using various measures of coincident peak demand did not reveal a significant correlation between costs and the demand measures. Similarly, a time series analysis of the unit costs proved unsuccessful. However, the incremental costs of transmission expenses over virtually all time frames analyzed were very stable and quite similar. Marginal transmission O&M expenses were estimated using annual unit costs $/kW demand for 2021.

The analysis of distribution O&M costs begins on Table 6, page 3 Statement L, Section B of the electric MCOS study. Annual expenses are segregated between substation, primary, customer, lighting, and joint and common cost components. On page 4, joint and common

[1] Distribution system coincident peak loads were estimated by excluding the customers served directly from NorthWestern's transmission lines. Primary loads were estimated by excluding the estimated loads served directly from substations.

costs were allocated to the other functions. Table 6, page 1, summarizes the analysis of substation-related costs. Lacking any statistical trends, marginal distribution O&M expenses were estimated using the 1995 through 2026 average unit costs. A similar calculation is shown in Table 6, page 2, for primary distribution and page 3 for secondary system O&M expenses. Again, each incremental cost period examined produced similar cost results; therefore, the 1995 through 2026 average costs were chosen as the best measure of marginal costs.

Q. Please describe the development of marginal capacity costs in Statement L, Table 9.

A. Table 9, page 1, develops marginal capacity costs for production, transmission, and distribution functions. Plant investments identified in Tables 1 and 2 are grossed up to include general plant. These investments are then converted to annualized revenue requirements by applying the appropriate fixed charge rates developed in Table 8. Annual operating expenses are added to this amount, including an allowance for A&G expenses. An adjustment reflecting annual revenue requirements to finance materials and supplies is added. Next, the indicated unit costs were increased to reflect line losses for each functional level and voltage. Finally, these 2021 marginal test year costs were escalated from the test year to 2024 rate year levels.

Q. How did you use the marginal unit costs by function shown in Table 9, page 1 of Statement L, Section B, to develop marginal unit costs by customer rate class?

A. Developing marginal unit costs by customer rate class is a two-step process. As shown in Table 9, page 2, I computed functional costs for each tariffed voltage level of service. This calculation adjusts the system unit costs for losses to reflect costs measured at the customer's meter. It also excludes costs for customers served at higher voltages. That is, a transmission customer's functional costs exclude substation and primary costs and are only adjusted for the losses occurring on the transmission system. At the other end of the spectrum, a small secondary customer utilizes the transmission, substation, and primary equipment and incurs losses across all three functional levels. These voltage-specific functional costs were then ascribed to customer classes as shown in Table 9, page 3, where class-specific write-off rates developed in Table 6, page 9, were applied to adjust for uncollectible accounts.

<u>ENERGY COSTS</u>

Q. Please elaborate on your calculation of marginal energy costs.

A. Marginal energy costs are developed on Tables 4 and 10 of the MCOS study. NorthWestern purchases energy on the open market through various contracts to serve only a portion of its supply load. Marginal energy costs are short-run costs measured on an hourly basis by the change in cost resulting from a small change in customer load. In order to estimate marginal costs for calendar year 2021, I employed a long-range (20-year) forecast developed for NorthWestern. This forecast provided forecasted power costs delivered to Montana on a monthly basis during heavy load hours and light load hours for the period from January 2021 through December 2038. The hourly costs for each year were then transformed to a levelized set of costs using NorthWestern's proposed cost of capital that produced the same net present value of costs as the original forecast values and restated in 2022 dollars. These hourly energy supply marginal costs were then adjusted for losses, multiplied by hourly class loads, and summarized on an annual basis. The results of these calculations are summarized in Table 4. As is evident from this table, the marginal energy costs differ very little between customer classes with the exception of lighting which is essentially served during non-peak hours.

Q. How did you employ the class estimates of energy costs from Table 4 to develop the marginal energy costs in Table 10?

A. Table 10 of Statement L, Section B begins with the energy costs from Table 4 and adjusts for miscellaneous energy-related costs such as class-specific write-off rates (uncollectibles) from Table 6. The marginal energy costs assume that no portion of the uncollectible accounts is recovered in the marginal energy cost.

CUSTOMER COSTS

Q. Please describe your calculation of marginal customer costs.

A. The long-run marginal costs of serving an additional customer were determined for each customer class of service. Three different customer costs were computed, representing the costs of connecting and serving a customer for each of NorthWestern's rate categories. These customer costs consisted of:

(1) Plant investment in services and meters,

(2) Related O&M expenses, and

(3) Billing costs such as customer accounting and customer information expenses.

Q. How did you compute customer-related plant investment?

A. I began with meters, as shown at the top of Table 3, page 5 in the MCOS study. NorthWestern provided average replacement costs for each customer class. Next, service investment was also developed from NorthWestern's cost accounting data for installed services for each appropriate customer class. These service costs were multiplied by a factor (derived by dividing the total number of services by the total number of customers) to recognize that a small number of services connect more than one customer.

Q. Please describe your computation of customer-related O&M expenses.

A. These calculations are summarized in Table 6 of Statement L, Section B, consisting of pages 6 through 11. Customer-related costs have been developed annually in Table 6, pages 4 and 5. On page 6, customer-related distribution O&M expenses were restated in 2022 dollars using the GDP IPD as a cost index. These inflation-adjusted expenses were regressed against customers, and the inflation-adjusted average costs per customer were regressed using a time series variable from 1995 to 2021. The unit cost data displayed little variation. The regression estimate is supported by the unit cost figures and was used as the marginal O&M cost estimate to serve a new customer. Table 7, page 6, sets forth the allocation of costs to customer classes, based on the services and meters investments required to serve each customer class.

Table 6, page 8, of Statement L shows the development of customer accounting and marketing services expenses, excluding Uncollectible Accounts Expense booked in Account 904. In general, the number of customers has been increasing only slightly, while these customer-related expenses have been fairly stable. The inflation-adjusted average costs per customer were regressed using a time series variable for periods from 1995 to 2021. The regression's cost per customer was chosen as the best estimate of O&M marginal cost.

The annual customer accounting, customer service, informational and marketing costs per year were not assumed to be equal for all customer classes. Table 6, page 9, identifies four different allocators and assigns costs to each customer class based upon each class's relative cost responsibility.

The customer charges shown throughout Table 6, page 4, have specifically excluded uncollectible accounts expense. A separate analysis of the uncollectible costs is shown in Table 6, page 10. On this table, uncollectible account expenses for the test year are divided by revenues to develop class-specific write-off rates. These write-off rates are used to increase unit costs to reflect the effect of uncollectible accounts in Tables 9 and 11.

Finally, Table 6, page 11, develops the marginal expenses related to lighting service. The average incremental cost for the period 1995 through 2026 was selected to estimate marginal costs.

Q. Please summarize Table 11 of the MCOS study.

A. Table 11 of Statement L, Section B consists of two pages. The first page shows the development of marginal customer-related costs by class. The calculation of customer costs is very similar to the capacity cost calculation shown in Table 9. Plant investments for customer-related costs shown in Table 3 were converted to an annual expense, using the appropriate fixed charged rate from Table 8. Annual expenses from Table 6, joint and common expense loaders from Table 8, and working capital requirements were added in a manner analogous to capacity costs, as explained previously. Finally, costs were restated in rate year (i.e., 2024) dollars, using anticipated cost escalation rate of 1.8 percent (2.3%

from Energy Outlook less 0.5% for technical progress) per year and adjusted for write-offs.

Q. Please describe the information shown in Statement L, Section B, Table 11, page 2 (subpages 2-1 and 2-2).

A. Table 11, page 2, has two pages (2-1 and 2-2), which develop the fixture costs for lighting investments in varying amounts. The Fixture Cost with Min and Max limits show the existing rate offerings in the lighting tariff. For each category, the actual investment is assumed to be the average of the minimum and maximum investments. Similar to page 1 of Table 11, investments are loaded to account for joint and common costs before a carrying charge rate is applied. Next, plant-related O&M and customer accounting expenses are added, followed by adjustments for working capital, escalation to 2024 dollars, and customer accounting write-offs.

Q. What is the purpose of loading factors in Statement L, Section B, Table 7, pages 1 and 2?

A. Table 7, pages 1 and 2, develop loading factors used in the marginal cost of service study. Loading factors are used to compute estimates of marginal costs where direct quantification is either too complex or the costs are insignificant. In the former category, A&G expenses are only indirectly related to customer load characteristics. To simplify quantification of marginal costs, A&G costs are expressed in relation to other O&M expenses or plant-related items. All loading factors were estimated using the average rates experienced from 2001 to 2021.

The top of page 2 in Table 7 shows the development of the materials and supplies and prepayments loading factor. This ratio, used in Table 9 and Table 11, is applied to estimated plant investments to compute the additional cash requirements. These indirect costs cannot be directly attributable to classes and are computed as loading factors for use in Tables 9 and 11.

Q. Please explain the development of the carrying charge rates shown in Table 8 of the MCOS.

A. Table 8 details the development of the levelized fixed charge rates for production plant, transmission plant, substation-related distribution plant, primary-related distribution plant, customer-related distribution plant, and lighting investment. These rates are used to convert one-time investments into annualized revenue requirements necessary for pricing. For rate-making purposes, utility investments in fixed plant are normally treated as rate base items. Utility rates are established periodically to allow the recovery of costs incurred in ownership, including such items as return, taxes, and depreciation. Levelized fixed charge rates compute the present worth of all revenue requirements stemming from utility ownership of an asset and then provide an equivalent annual payment stream of identical present worth.

The development of a levelized fixed charge rate applicable to production plant is shown on pages 4 and 5 of Table 8. Transmission capacity-related investment is shown on pages 6 and 7. The calculations for substation-related distribution plant (pages 8 and 9), primary and secondary-related distribution plant (pages 10 and 11), customer-related distribution plant (pages 12 and 13), and lighting investment (pages 14 and 15) are similar.

Page 1 summarizes the results for all functional fixed charge rates along with other cost and tax assumptions. Page 2 shows the input assumptions used to develop all levelized fixed charge rates. A hypothetical investment of $1,000 is used for demonstration purposes. Page 3 shows the development of weighted average service lives and salvage values used as input into the computations.

Page 4 summarizes two different fixed charge rates -- the "engineer's" and "economist's" fixed charge rates. The engineer's fixed charge rate is akin to a banker's conventional fixed rate mortgage. This value represents a percentage of the original investment that must be made in current year dollars, in order to equate to the present worth of the utility's revenue requirements. The economist's fixed charge rate differs slightly, in that it assumes that payments will escalate each year by the rate of inflation. Inherent in the engineer's fixed charge rate is the assumption that an asset is depleted more rapidly at the outset than toward the end of its service life. The economist's fixed charge rates make a different assumption--that an asset's utility at the beginning of its service life is equal to its value at the end of its service life. In the electric utility industry, old plant may be nearly as useful as new plant. As an example, meters provide the same service at the beginning of their lives as they do at their end. Consequently, the economist's fixed charge rate was used to convert one-time plant investments into annual revenue requirements.

Q. In Table 12, line 22 you show class by class summer coincident peak demands. Are those values the result of direct measurement or are they estimated?

A. They are estimated using a number of data sources. They are computed by multiplying estimated annual load factors at time of peak by the normalized sales loads shown. The load factors are developed from the direct measurement of loads of most large customers and from load research estimates for smaller customers based upon load research studies.

Q. Are NorthWestern's class coincident peak demands and class peak demands shown in both the electric marginal and electric embedded cost of service studies?

A. Yes, the same demand data are shown in both studies. In both instances the sources of the data are the same. However, system coincident peaks are not equal to and are less than the higher more localized class peak demands.

Q. Please describe the source of the coincident peak demand and non-coincident peak demand data by class that you employed in both electric studies.

A. The demand data for the Transmission, Substation, and large GS1 Primary customers were recorded on the interval data recording devices serving these customers. For the remaining customer classes other than Lighting, the monthly coincident peak ("CP") and non-coincident peak ("NCP") demands were developed from load research sample information. Because lighting loads are on during night time hours and operate at a continuous level during this period, lighting loads were estimated simply by dividing the related energy sales by the hours of night time operation.

NorthWestern performs Load Research Studies on samples of customers in its Residential and General Service ("GS") Secondary (demand metered and non-demand metered subgroups) classes on a rotating basis. The studies are designed and implemented using standard load research practices to produce accurate results with fairly small samples.

SUMMARY OF ELECTRIC MARGINAL COST RESULTS

Q. Please describe Statement L, Section B, Table 12.

A. Table 12 tabulates the long-run marginal unit costs computed in Tables 9, 10, and 11. In addition, this table calculates the revenues that would be generated if NorthWestern were to introduce full marginal cost-based pricing and if customers were to continue to consume as they have in the past. Table 12 consists of six pages. The first five pages are very similar showing the following groupings:

1. All customers taking transmission delivery services, excluding supply costs;
2. The transmission and distribution services provided to Electric Supply (Non-Choice) customers;
3. The distribution services provided to Competitive Electric Supply (Choice) customers (note that NorthWestern provides transmission services to Competitive Electric Supply customers under FERC rates);
4. The supply services provided to Electric Supply (Non-Choice) customers; and
5. The sum of the above electric services provided by NorthWestern.

On each page, the unit costs are multiplied by the appropriate units to compute the marginal costs to serve. Costs are then subtotaled for supply and delivery costs. Page 6-1 and 6-2 of Table 12 presents the marginal unit cost information for the lighting class. The unit costs computed in Table 11 are multiplied by the number of billing units to compute fixture marginal costs. At the bottom of this page, the average cost per fixture is computed for use on pages 1 through 5 of this table.

Q. What calculations are shown in Statement L, Section B, Table 13?

A. Table 13 (page 1) develops the marginal unit costs to provide transmission and distribution services. This table begins with the total marginal costs by class and function from Table 12 and divides them by the billing units employed in their respective tariffs. Using this approach, rate classes such as residential that are billed on a simple two-part rate (customer and energy) are shown with only these charges, expressed as dollars per customer per month or dollars per kWh. Rate classes whose tariffs include three-part rates are shown with customer, demand, and energy charges expressed as dollars per customer per month, dollars per kWh or dollars per kW of billing demand, respectively. The single exception to this monthly quantification of marginal customer cost per month is the Irrigation customer class whose customers are billed a seasonal customer charge on the first bill of the irrigation season due to the highly seasonal nature of their service. Irrigation customer costs are expressed as annual costs per customer. Note that irrigation customer energy and demand are billed monthly.

Table 13 (page 2) develops the production-only demand and supply costs associated with Choice customers and follows the same approach as page 1 of Table 13. If marginal cost-based rates were not constrained to utility allowed revenues and if economic efficiency was the only goal of rate design, the marginal cost figures shown in Table 13 (pages 1 and 2) could be considered marginal cost-based prices. Obviously, these prices would not be practical to implement without further adjustment.

<u>RECONCILIATION TO ELECTRIC REVENUE REQUIREMENT</u>

Q. Please explain the reconciliation process.

A. MCOS Tables 1 through 13 summarize the marginal cost of service study that I have performed. The calculations of full marginal costs in Table 12 clearly demonstrate that marginal costs exceed allowed revenue levels, at least at the present time. In order to employ marginal costs, the level of marginal costs must be reconciled to the level of revenues to be recovered by NorthWestern under conventional rate of return regulation. MPSC precedent calls for reconciliation to be performed using the equi-proportional adjustment method. This method simply adjusts all marginal costs using an identical adjustment percentage so that adjusted marginal costs exactly equal the proposed revenue levels (Table 14, page 3).

Q. Please describe your equi-proportional adjustment calculation.

A. The calculations are shown in Table 14, page 1 for Delivery, page 2 for Supply, and page 3 for total Supply and Delivery combined. I begin by tabulating existing delivery revenues on line 1, and the proposed increase is applied on a moderated basis to proposed class revenues on line 3. I then compare the resulting level of revenues on line 3 with the marginal costs to serve from Table 12, as shown on line 5. As expected, the marginal costs are substantially higher than the required revenues. In order to adjust marginal costs to the allowed revenue level the equi-proportional adjustment is made to the marginal costs for each class. The constrained marginal costs are shown on line 7, and the indicated percentage changes for each class are shown on line 6. The remainder of the page shows the unit costs from Table 13 adjusted downward by the same percentage reduction necessary to achieve allowed revenues. Page 4.1 and 4.2 of Table 14 provides similar unit cost information for each category of lighting fixture.

IV. SUMMARY – EMBEDDED COST OF SERVICE STUDY – ELECTRIC

Q. Please summarize your results regarding the embedded costs of service information and study submitted in Statement L of this rate filing.

A. NorthWestern engaged MAC to prepare four cost of service studies for this filing (three embedded and one marginal) to determine class revenue targets and to propose rate design for electric customers. The cost allocation methodologies employed in the ECOS study in Statement L closely follow the methodologies employed in NorthWestern's most recent electric rate filing in Docket No. 2018.02.012, including certain improvements as described herein.

I believe that the procedures employed in conducting the ECOS study comport with standard industry practices, reflect the operations and characteristics of NorthWestern and its customer classes, and provide fair and reasonable estimates of the costs of providing service to the various customer classes. In my opinion, the results of this study are a reliable and useful document for estimating class costs of service. Exhibit PMN-6 presents the summary class results at both present and uniform rate of return for each class of service.

V. SUMMARY – MARGINAL COST OF SERVICE STUDY

Q. Please summarize your recommendations regarding the marginal costs of service information and study submitted in Statement L, Section B of this rate filing.

A. NorthWestern engaged MAC to prepare an electric marginal cost of service study for this filing. The marginal cost methodology employed 14 separate tables that arrive at pricing levels presented in Table 14 by customer class. I believe that the procedures employed in preparing the marginal study reflect our best estimate of future costs and the operations and characteristics of the Company and its firm customer classes and provide a reasonable estimate of the costs of providing electric supply on a seasonal and annual basis. Exhibit PMN-7 provides a summary of these results.

VI. BENCHMARKING

MARGINAL

Q. Please provide a brief comparison of the marginal cost of service study results.

A. A comparison of the marginal cost of service study results from the prior 2017 electric study and the current 2021 study presents the following functional unit costs and revenue requirements on a $/coincident peak kW:

Table B Comparison of Marginal Costs For 2017 and 2021 Test Years			
Table #	2017 $ per kW	Test Year Function	2021 $ per kW
1	$1,738.55	Production Capacity Costs	$1,961.90
2	454.82	Transmission Plant	365.86
3	274.49	Substations	1,071.88
4	644.84	Primary	293.80
5	221.64	Secondary	
Revenue Requirements per kW of Coincident Peak			
9	203.28	Production	210.72
	73.29	Transmission	60.89
	19.09	Substation	32.15
	102.26	Primary	131.64
	26.98	Secondary	29.35

EMBEDDED ELECTRIC ECOS

Q. Are the methodologies employed in performing the ECOS studies you sponsor in this filing the same as the methodologies used to conduct the ECOS study submitted in NorthWestern's filing in Docket No. 2018.02.012 (Electric) and Docket No. D2016.9.68 (Natural Gas)?

A. The ECOS models prepared for this filing in Statement L present a more detailed recognition of costs by account and their allocators to customer classes and sub classes. As a result, complete ECOS studies have been developed for each sub class detailing all cost areas and the resulting class ROR. The electric and natural gas ECOS includes a Class Cost of Service Study, a Summary of the Functional Cost of Service, and a Summary of Unbundled Revenue and Unit Costs for each functional cost component by customer class at Present Rates of Return and a Uniform Claimed Rate of Return.

As noted above, a new and separate cost analysis addressing only jurisdictional costs has also been prepared to recognize a cost separation to reflect FERC transmission revenue requirements. The remaining ECOS methodologies are generally the same as previously used in Docket Nos. 2018.02.012 and D2016.9.68, NorthWestern's most recent electric and natural gas general rate reviews. However, as described below, I made several modifications to these studies to provide more summary information, to improve the accuracy of the allocations, to incorporate NorthWestern's production assets, and to improve the transparency of the studies and their results. These modifications include:

(a) Addition of internal allocation factors developed within the cost of service to more accurately allocate costs;

(b) Addition of more detail of line-by-line costs to be allocated to rate classes;

(c) Consolidation of the lighting class to reflect more robust cost recognition of the detail cost responsibility;

(d) Identified and separated three-phase and single-phase primary circuits for Distribution costs to better recognize the proper benefit to customers served by these facilities; and

(e) Detailed allocation of property taxes that supports the development of separate rate components designed to collect property taxes in volumetric rates from each customer class based on plant allocations.

The results presented in the Electric ECOS (Exhibit PMN-6) are similar to those results presented in NorthWestern's last filing after considering the improvements discussed above.

<u>Natural Gas Embedded Cost of Service ECOS</u>

Q. Have you made a comparison of the current gas ECOS to the results presented in NorthWestern's last gas ECOS in Docket No. D2016.9.68?

A. Any comparison of the current gas ECOS to the prior study in Docket D2016.9.68 is somewhat difficult to document as the current study uses a much improved cost model (similar to electric) where more detail has been recognized.

VII. NATURAL GAS DELIVERY ECOS STUDY

Q. Have you prepared an analysis of NorthWestern's natural gas operations with respect to developing an ECOS study?

A. Yes, I have. Statement L (Section D) for the natural gas utility contains the detailed study and supporting summary results of costs by major class of revenue.

Q. Are the methodologies employed in performing the ECOS study you sponsor in this filing the same as the methodologies used to conduct the ECOS study submitted in NorthWestern's filing in Docket No. D2016.9.68?

A. Yes. The methodologies are generally the same as previously used in Docket No. D2016.9.68, NorthWestern's most recent natural gas general rate review. However, as described below, I made several modifications to the study to provide more summary information, to improve the accuracy of the allocations, to incorporate NorthWestern's total natural gas production assets, and to improve the transparency of the study and its results.

The detailed allocation of property taxes supports the development of separate rate components designed to collect property taxes from each customer class based on plant allocations. All of the proposed volumetric transmission, distribution, storage, and production rates include two parts: a property tax component and a component without property taxes, and all monthly service charges exclude any recovery of property taxes.

Q. Do the steps you employed in conducting the gas ECOS study follow the marginal cost requirements that are set forth in ARM 38.5.176(2) through (5)?

A. Yes, they do. Even though the rules' requirements specifically relate to marginal costs, the steps I took in this ECOS study follow these requirements as well. The NorthWestern ECOS model functionalizes costs as required by ARM 38.5.176(2). The NorthWestern model classifies and allocates costs as required by ARM 38.5.176(3). The model employs loss factors, allocates O&M costs, and employs A&G expense as well as general and common plant allocation factors as required by ARM 38.5.176(4). The ECOS model employs the time frames (i.e., design day demands, annual sales volumes, and winter sales volumes), carrying charge calculations (i.e., NorthWestern's proposed rate of return and taxes), and proxy class cost estimates (i.e., meter and services investments based on the Company's data) as required by ARM 38.5.176(5). ARM 38.5.176(6) is not applicable to the ECOS, since it addresses the use of a future time frame for a marginal cost of service study.

Q. Is NorthWestern required to follow the marginal cost requirements that are set forth in ARM 38.5.176(2) through (5) in this filing?

A. No, as explained above, these requirements do not apply to delivery services costs, but I employed them in my ECOS study. The Commission granted NorthWestern a waiver of the requirement in ARM 38.5.176 to file a Marginal Cost of Service Study for natural gas in this rate review.

Q. Please describe the process of cost functionalization for your natural gas study.

A. After all of the individual cost components representing the total revenue requirement have been gathered for the cost of service study, the various cost components are separated according to the function they perform. These functions are:

- Production - costs associated with NorthWestern's Battle Creek, Bear Paw (NFR), and South Bear Paw (Devon) natural gas production plant. NorthWestern injects a limited amount (6.2%) of natural gas into storage during off-peak periods and uses storage natural gas as well as flows natural gas to meet its natural gas demands during winter peak periods;
- Storage – costs associated with storing large quantities of natural gas for use during periods of high winter demand. Normally, NorthWestern injects natural gas into storage facilities during periods of low demand and withdraws from storage during periods of high winter demand levels (October – April). As indicated below NorthWestern uses a portion (12.4%) of its storage deliverability (25,000 Dekatherms ("Dkt")) for balancing load and supplies on the transmission system;
- Transmission – costs associated with large, high pressure mains that transport large volumes of natural gas to load centers and natural gas storage facilities;
- Distribution – costs associated with distributing the natural gas from the transmission system to the end users' points of delivery; and

- Customer – costs associated with providing service to the customer, i.e., services, regulators, metering, billing, etc.

For the most part, the unbundled costs of a utility such as NorthWestern are already somewhat functionalized based on recorded data. In fact, the FERC USOA, which the Commission requires NorthWestern to follow, provides for the recording of a major portion of costs by accounts defined and arranged by functional level.

Q. Please describe the process of cost classification.

A. This process is the same as for the electric utility. Cost classification is the process of further categorizing the functionalized costs according to the cost-causing characteristic of the utility service provided. The three principal cost classifications are capacity-related (demand) costs, commodity-related (volumetric) costs, and customer-related costs.

Capacity-related costs (also referred to as demand-related costs) are those fixed costs related to the maximum Dkt demand upon the system, which is normally the design day (88 Heating Degree Days ("HDD")) Dkt capacity requirements imposed by a natural gas customer on the Company's delivery network. Commodity-related costs are those costs related to the therms[2] the customer utilizes over a specified period, such as a month or year. Customer-related costs are those costs incurred due to the number of customers on the system. These are costs closest to the customer premises (meters and services), which generally are not available for use by anyone else and have no causal relationship to consumption volumes.

[2] NorthWestern undertakes its analysis and reporting in dekatherms, but bills customers in therms. Consequently, the consumption data employed in the natural gas embedded cost of service study is expressed in dekatherms and the consumption data employed in rate design is expressed in therms.

Q. Please describe the process of cost allocation.

A. Cost allocation is the assignment of functionalized and classified costs to customer classes. Allocation factors reflecting capacity requirements, commodity volumes, and customer costs rely on operating and accounting data to produce representative allocation factors in the form of percentages that add up to 100 percent. These allocation factors applied to specific plant, rate base items, and various expenses derive the total costs of providing service for each class of customers. For example, NorthWestern designs its natural gas mains to maintain natural gas deliverability during the very coldest days. As a result, it is reasonable to assign the costs of natural gas mains on design day (88 HDD) demands by class, as I have done in this case. In turn, it is possible to develop allocation factors for each detailed cost item such that costs are allocated on the metric that best embodies the manner in which costs arise. For example, actual meter costs are allocated according to the number of customers by class weighted by their relative costs of meters.

Q. Please describe the natural gas delivery services ECOS study detail provided in Statement L.

A. The Natural Gas Delivery Services ECOS study (Statement L) consists of 16 pages. Pages 1 and 2 of the study summarize the results of the gas cost of service study. Pages 2 and 3 compare current rate revenues (pages 1 and 2) to proposed revenue levels at Equalized ROR with property taxes included in all functions (Columns B through G).

Q. How did you allocate gas production plant costs?

A. I developed a weighted allocator to recognize that a portion of production (6.2%) went to Storage and the remainder (93.8%) to Delivery. Pages 5 through 30 detail the plant accounting data, additions and deductions to rate base (pages 5 through 14). O&M expenses and taxes were detailed and allocated by account beginning on page 17 to page 30.

Q. Please describe the functionalization of storage plant that you incorporated into the current natural gas ECOS study.

A. I functionalized storage plant investment into two components to recognize that a portion of storage plant deliverability is reserved for balancing of the loads on NorthWestern's natural gas transmission lines. The ECOS study recognizes that NorthWestern reserves 25,000 Dkt per day of deliverability from the storage facilities for transmission load balancing. This amounts to 12.4% of the deliverability of total storage facilities. Consequently, I functionalized 12.4% of all storage plant investment to the transmission function.

Q. Please describe how costs were classified in the natural gas ECOS study.

A. The classification of costs as capacity-, commodity-, and customer-related takes place within the development of allocators used to assign costs to customer classes. Please refer to pages 9 through 15 of the ECOS study, which show the classification and allocation steps. On these pages, the costs included are Production, Storage, Transmission, and Distribution Other functions are allocated to classes using the capacity-related allocation factors (which are referred to in the ECOS study by the acronym, thus effectively classifying these functionalized costs as capacity-related costs.

The Commodity classification was not used in the gas ECOS as all gas costs were excluded in the analysis.

Similarly, the costs included in the Meters, Services, Meter Reading, Customer Records, and Customer Other functions are allocated to customer classes using the MeterCost, Services, MeterRdg, CustRecords, and Customer allocation factors, thereby producing costs that are classified as customer-related costs.

Q. Please describe how you allocated costs in the natural gas ECOS study.

A. Allocated costs in the natural gas ECOS study are described below:

1. The production plant allocation factor (DPROD1) reflects the operation of NorthWestern's Battle Creek, Bear Paw (NFR), and South Bear Paw (Devon) natural gas production facilities. The production plants operate at full or near-full capacity throughout the year. In the off-peak periods, the capacity delivered to the system exceeds the sales requirements, with the excess delivered to storage. It is estimated that 6.2% of the capacity is delivered to storage. To reflect the production capacity deliveries to storage, a weighted allocation factor was developed. This allocator was weighted 93.8% based on July and August average volumes and 6.2% on winter volumes. This weighted combined allocator was used for production plants.
2. StorageAlloc – Storage plant was and is used to supplement flowing gas to serve Core Customers. The amount of storage was separated into two cost categories: Transmission for balancing of 12.4% and 87.6% for withdrawals to firm customers. Deliverability is the maximum daily rate of withdrawal and is measured in Dkt per day. Capacity is the measure of total volume that can be stored for later withdrawal

and is measured in total Dkt. NorthWestern has invested in three storage plants of varying deliverability, capacity, and cost. The storage allocator reflects the operational characteristics of NorthWestern's Dry Creek, Box Elder, and Cobb storage fields for calendar 2021. Individual plant investments were allocated in two steps: first to the months in which they were withdrawals, and second to classes based on their sales in those months adjusted to reflect only sales made from storage withdrawals. These values were weighted by plant costs and summed to derive a simple composite allocator.

3. TranDD – For transmission, the Transmission Design Day allocator is based on the estimated design day demands imposed on the transmission system by each rate class. The design day demands were computed through regression analyses of monthly sales and heating degree data by establishing a base-use- and heating-use-per-degree-day factor and then extrapolating to the 88 HDD used for the design day. This allocation methodology remains unchanged from NorthWestern's ECOS study submitted in Docket No. D2016.9.68.

4. DistDD – For distribution, the Distribution Design Day allocator is based on the estimated design day demands imposed on the distribution system for each rate class. The distribution allocation factor was developed from the TranDD allocator, which zeroes out classes that are not served by the distribution system (excludes TBU, Storage, and Firm Utilities). This allocation methodology remains unchanged from NorthWestern's ECOS study submitted in Docket No. D2016.9.68.

5. MeterCost – The meter allocator is based on typical metering cost per customer including installation for each rate class. This is the most accurate approach to developing meter costs for each rate class as the costs can vary somewhat between

service classes based on Company data. These estimated costs are then multiplied by the number of customers (meters) in each class, which results in a total cost estimate by customer class that is employed as the meter cost allocator to assign actual meter costs in the ECOS study. The methodology for allocating meter costs to classes is the same as employed in NorthWestern's previous ECOS study.

6. Services – Similar to the MeterCost allocator, the services allocator is based on an estimate of service cost per customer multiplied by the number of services (customers). The actual calculation begins with the number of customers which is then slightly reduced to reflect the number of services, which is typically less for major classes. Based on Company records, certain locations have more than one customer but only one service. Like meter costs, discussed above, this approach recognizes the varying costs by customer classes and is the most representative of cost assignment. As in the case with meters, the services allocation factor in this study is calculated in the same manner as in NorthWestern's previous ECOS study.

7. MeterRdg – The meter reading allocator was developed in a two-step process using detailed cost accounting data. Meter reading costs were separately identified for automated meter reading, manual meter reading, and readings taken from the natural gas measurement system. The count for each type of meter reading was then identified by rate class to develop the meter reading allocator. This allocation methodology remains unchanged from NorthWestern's previous filing.

8. CustRecords and Collections – Customer records expense is assigned to rate classes based on the number of customers (bills). The costs of the computerized customer records system are similar for each customer and do not differ significantly by rate class, making customer count the proper allocator. The collection cost was identified

and allocated to classes based on uncollectible expense by rate class. The final allocation was a result of combining these two costs by their weighted costs.

Q. Please describe the resulting assignment of costs to customer classes in the ECOS study.

A. As stated above, **s**ummary results of the ECOS study are shown on pages 1 and 2 of the study with four separate tables on each page providing the following information:

- Table 1 – Total Actual Natural Gas Revenue for the Test Year at Current Rates shows the revenues produced by rate class and function at current rates. Note that revenues at current rates are presented for the Production, Storage, Transmission, Distribution, and Customer functions and in total for each rate class. Table 1 is identical on pages 1 and 2. I also show the customer-related revenues with and without property taxes in columns (G) and (H), respectively.
- Table 2 on page 1, – Total Natural Gas Revenue at Equalized ROR, shows the revenues that would be produced if all inter-class and inter-function subsidies were eliminated, i.e. if all rates and classes produced the proposed system rate of return on their allocated functional rate base. These revenues are the level of revenues that would be produced by a fully cost-based rate. Table 2 on page 2, Total Proposed Natural Gas Revenue from Rate Design, sets forth the revenues by function for each class that would be produced by NorthWestern's proposed rates in this filing, after customer class revenue moderation as explained by Ms. Fang.

VIII. <u>SUMMARY – EMBEDDED COST OF SERVICE STUDY – NATURAL GAS</u>

Q. Please summarize your recommendations regarding the embedded natural gas costs of service information and study submitted in Statement L of this rate filing.

A. The cost allocation methodologies employed in the ECOS study in Statement L closely follow the methodologies employed in NorthWestern's most recent rate filing in Docket No. D2016.9.68, including certain improvements as described above. I believe that the procedures employed in conducting the natural gas ECOS study comport with standard industry practices, reflect the operations and characteristics of NorthWestern and its customer classes, and provide fair and reasonable estimates of the costs of providing service to the various customer classes.

The class results of the natural gas ECOS are presented in Exhibit PMN-10 for both present and at a uniform rate of return.

IX. STATEMENT M – CLASS REVENUE ALLOCATION AND RATE DESIGN

Q. Have you prepared a Statement M for both the electric and natural gas ECOS class revenue targets and rate design?

A. Yes. Witness Cynthia Fang and I are co-sponsoring Statement M with respect to the class revenue requirements (moderated) along with the rate design process. My participation in developing Statement M for both the electric and natural gas studies begins with importing the data from the Statement L ECOS results. In Statement L, the electric ECOS (A.1) and the natural gas ECOS (D.1.) both have a flow chart as their first page with the flow charts showing shaded areas from the ECOS results that are imported into Statement M. Statement M (page 1) shows a summary of the billing statistics (revenue and sales) by customer class along with the ECOS results and the proposed moderated revenue targets for rate design purposes. The actual revenue targets and rate design constraints are detailed in Ms. Fang's direct testimony and exhibits.

Q. Does this complete your direct testimony?

A. Yes, it does.

VERIFICATION

This Pre-filed Direct Testimony of Paul M. Normand is true and accurate to the best of my knowledge, information, and belief.

/s/ Paul M. Normand
Paul M. Normand